**Question 28:**
**Please evaluate this statement: "Our post-storm data is sufficient to determine major factors that led to storm damage, and allows us to focus our hardening approach on these major factors."**

Although all options were selected by at least one responding utility, by far the most common selection was "somewhat true," which was picked 19 times (68%). Only three utilities selected "not true," while five utilities selected "true." One utility did not provide an answer. A summary of responses is as follows:

a. Not true: 3
b. Somewhat true: 19
c. True: 5
d. No answer: 1

It is interesting that five utilities answered "true" to this question while only two utilities indicated that they collected forensic data in Questions 25 and 26. Clearly, several utilities feel that they collect sufficient data during normal storm restoration activities to determine major factors that led to storm damage, and to focus hardening efforts on these major factors.

**Question 29:**
**Does your utility have damage prediction models that are used to estimate the damage that will occur during an incoming storm? If so, what data are used to develop and improve these models?**

Twenty of the responding utilities do not have damage prediction models that are used to estimate the damage that will occur during an incoming storm (71%). Of the 8 that do have damage prediction models, descriptions vary as to the detail of the model and the data used to develop and improve these models. It is difficult to summarize these different responses in short form, but most develop a correlation between weather characteristics and damage for historical storms. When a new storm approaches, weather statistics are gathered (or predicted) and used to estimate damage based on the historical correlations. Summaries of the responses include the following:

**<u>Damage Prediction Models</u>**

- We use previous storm damage versus wind speed to predict upcoming storm damage.
- We use a high level estimator.
- The data used to develop and improve the model was historic storm related sustained outages and weather data. The weather consisted of wind speeds, wind gust, wind duration, and lightning strokes. Other factors include the time of the year (winter vs. summer storms), ice accumulation, and snow accumulation.
- We use pressure gradient patterns from the last 14 years and perform correlations to customer and outage counts. We also identify peak pressure gradient periods. With this information, we forecast crews that should be pre staged for an event.
- Before the storm makes landfall, a predictive model is used to estimate damage and resource needs by region. The model is based on data from previous storms and is linked to wind tables from our weather service provider. Damage assessment teams are sent out immediately following the major storm event and collect damaged data in pre-identified areas. The tool extrapolates the damage and provides this data from a system perspective. The model has an 85% confidence level.

- We have our distribution facilities digitized in GIS (e.g., pole size and class, wire size, equipment installed, year of last ground line treating, tree location ). We use predicted weather data such as wind speed, wind gusts, wind direction, and amount and time duration of rainfall. This data is provided in GIS shape files. We lay the weather prediction shape files over the facility data in GIS and compute the predicted damage (amount and location) in accordance with algorithms that we have developed. Actual damage and actual weather data compared to the predicted values allows us to modify the algorithm and improve the damage model performance based on historical data.
- We have two separate models. The first model uses the track and wind field data provided National Hurricane Center (NHC). It determines the maximum wind speed and wind level duration over each GPS-defined substation and transmission structure. The output is the number of transmission structures and distribution poles forecasted to fail. Restoration resource needs are calculated from this data. The second model takes a broader view of the storm impact on the total system; but provides a similar output of restoration resource needs based on the NHC category of the tropical storm.

## 3.5 Hardening

**Question 30:**
**Has your company performed a system hardening review, developed a hardening roadmap, or something similar? Explain.**

Sixteen of the responding utilities have not performed a significant hardening review (57%). A few of these mention related activities such as analyses related to general system performance, maintenance & inspection programs, and aging infrastructure. But these do not constitute an explicit focus on distribution system hardening.

The remaining 12 utilities indicated that they have performed some sort of hardening review, developed a hardening roadmap, or something similar. Most offered elaboration as to what specifically has been done. Representative responses include the following:

**System Hardening Reviews**

- It is part of our Storm Hardening filing with the commission.
- We began Grade B construction in 2008.
- We did a high level study of the cost to harden and the resulting savings in storm outage times.
- We recently completed the field work on a hardening pilot on one circuit.
- We hired an outside consultant to develop a hardening roadmap after the 2006 winter storm.
- We primarily focused our efforts around increased vegetation management.
- We filed a three year hardening plan in 2007 to as per our commission order.
- We evaluated hardening alternatives after Hurricane Rita in 2005 and Hurricane Ike in 2008, and the company is in the process of analyzing the information.
- In 2007, we completed a “Hurricane Hardening Study” for transmission, substations, and distribution construction.

Of the above, four of the responses specifically state that the hardening plan or investigation was filed with the regulatory commission. This is considerable less than the ten utilities that said in Question 21 that there have been regulatory investigation related to major storms in the past 10 years.

**Question 31:**
**Has your utility committed itself to hardening its distribution system? Explain.**

Eleven of the responding utilities said that they have committed themselves to hardening their distribution system (36%). Two of the responses did not elaborate on their answer, and the nine that did gave a variety of descriptions. Representative answers from the "yes" responses include the following:

**Utility Commitments to Distribution Hardening**

- We change out wood poles to concrete at critical junctions.
- Reliability trends are analyzed and programs developed to address.
- We were just given approval by the Commission to do $3M in 2009, $15M in 2010 and $15M in 2011 for system distribution circuit hardening.
- We have adopted a policy to utilize a minimum 40 ft, Class 2 poles for primary installation, and use Grade B for all pole replacements and new pole construction.
- We have increased spending to harden the system.
- Yes, per our commission order.
- We have implemented the recommendations listed in our 2007 Hardening Study.

Seventeen of the responding utilities indicated that they have not committed themselves to distribution system hardening (61%). Of these, one is presently considering hardening, another is in the process of developing pilot projects, and a third has activities that are "limited." Another utility has "evaluated many hardening ideas" and has not found any to be justified. Nine utilities simply responded "no," and one did not provide an answer.

**Question 32:**
**Has your utility performed any significant hardening activities? Explain.**

This question is closely related to Question 31, but addresses actual distribution hardening that has taken place rather than whether a utility has committed itself to hardening. As such, answers closely parallel those of Question 31.

Seventeen of the responding utilities responded that they have not performed any significant hardening activities to date (61%). Just increased vegetation management does not count for the purposes of this survey. The remaining eleven replied that they have, with eight providing elaboration. Many of these elaborations correspond to the elaborations provided in Question 31. Representative answers from the "yes" responses include the following:

**Hardening Activities**

- Enhanced lightning protection; pole replacement/reinforcement.
- Replace old pins and cross arms before they break.
- Replacing more poles; underground conversion; improve rights-of-way.
- Storm guying for distribution lines located in open, marshy terrain near coastal areas.

- Strengthen wood pole foundations including the use of pole stabilization foam for all heavily loaded poles (e.g. corners, dead-ends, large angles, and major equipment poles) and where poor soil conditions are encountered. On a very limited basis, concrete poles are specified for highway crossings.

**Question 33:**
**Is your current budget for hardening the existing distribution system (other than vegetation spending): none, a little bit, a moderate amount, or a lot?**

Only one utility responded "a lot," while the most common response was "none." The numbers of responses for each option are the following:

| | | |
|---|---|---|
| a. | None: | 12 |
| b. | A little bit: | 8 |
| c. | A moderate amount: | 7 |
| d. | A lot: | 1 |

It is clear from this question that not all utilities have a dedicated distribution hardening budget. This said, 57% of responding utilities have at least a small budget for distribution hardening.

**Question 34:**
**Have any hardened portions of your system been subject to major storms? If so, please comment on how well they performed.**

In many ways, this is the "million dollar question" in that it has the potential to provide hard data as to the effectiveness or ineffectiveness of various hardening activities. Only six utilities were able to provide a *post hoc* assessment of hardened portions of their system, all reporting positive results. Four additional utilities report that they have had hardened areas subjected to major storms, but have not assessed performance. Summaries of the six utilities that experienced good storm performance on hardened portions of their system are now provided:

**Hardening that Worked**

- Concrete poles have stood during a few hurricanes and our aggressive right of way clearing has made a huge difference in lines down due to trees.
- We are experiencing a reduced number of pole failures that have been inspected and repaired.
- Sky Wire (static ground wire) resulted in improvements.
- Pins and crossarm work has definitely helped.
- Most damage during the last major wind and ice storms were due to downed wires. Pole damage was kept to a minimum.
- In 2008, Tropical Storm Fay hit a portion of our system. There was little damage on the storm hardening project.

**Question 35:**
**Please check all hardening activities that you are doing or have tried (for hardening purposes):**

The author tried to provide a comprehensive list of potentially effective hardening tactics, and is please to see that every option was selected at least once. Most of the utilities that indicated no hardening budgets or activities did not select any. Despite this, the average number of selections per utility (not including "other" responses) is 2.8. The number of times each selection was chosen is as follows:

| | | |
|---|---|---|
| a. | Grade B construction: | 10 |
| b. | Stronger poles: | 14 |
| c. | Shorter spans: | 9 |
| d. | Storm guys: | 7 |
| e. | Push braces: | 2 |
| f. | Extended-length pole braces: | 3 |
| g. | Relocating pole-mounted equipment: | 3 |
| h. | Relocating third-party attachments: | 3 |
| i. | Elimination of crossarms: | 2 |
| j. | Elimination of porcelain insulators: | 4 |
| k. | Small primary wire replacement: | 9 |
| l. | Elimination of bare secondary wire: | 11 |
| m. | Break-away wire ties: | 1 |
| n. | Break-away service drop connectors: | 3 |
| o. | Conversion to underground: | 4 |

In addition to the above, responses included the following hardening approaches under "other:" lightning protection, focused maintenance, overhead faulted circuit indicators, reclosers, vegetation management, pole stabilization foam, and an increased focus on foreign poles. It should be noted that this survey defines "hardening" to be activities that result in less damage during major storms. Therefore, activities that increase protection selectivity (e.g., reclosers) and aid in crew response (e.g., faulted circuit indicators), though potentially beneficial during a major storm, do not qualify as hardening. Increased lightning protection only qualifies to the extent that it results in reduced equipment damage (apart from arrestor damage).

**Question 36:**
**For poles of equal height, do you set stronger poles deeper?**

Stronger poles can only utilize their full strength if they have a sufficiently strong foundation. It is generally easier to reset a leaning pole than to replace a broken pole, but utilities typically do not design poles to intentionally lean during major storms (typically for safety reasons). This said, 20 of the responding utilities state that they do not set stronger poles deeper than weaker poles. An additional six give a qualified "no," with one setting self-supporting concrete poles deeper and four setting Class 1 poles deeper (by 1 foot). Two of the responding utilities simply said, "yes." No response said specifically that foundations for stronger poles are designed to ensure sufficient strength.

**Question 37:**
**Have you utilized cost-to-benefit analysis for spending related to hardening?**

Thirteen of the responding utilities responded that they have used cost-to-benefit analysis for spending related to hardening, although one of these was for a pilot project an another was for "limited studies." Thirteen of the responding utilities simply answer "no" and another two did not provide an answer.

**Question 38:**
**If applicable, please describe how hardening projects are prioritized.**

Nine of the responding utilities provided a description of how they prioritize hardening projects. There is no commonality to these responses. Therefore, a summary of these nine approaches is now provided:

**Prioritizing Hardening Projects**

- Hardening new projects only, we are not hardening existing system.
- Our three year storm plan calls for 2 hardening projects to critical customers.
- Reliability programs are prioritized based upon their cost efficiency for the improvement expected.
- Safety, reliability and regulatory compliance.
- By riskiness of not doing the project.
- Cost, CMI saved, past circuit outage times, priority circuits.
- Prioritized along with other system projects.
- We use a model developed by a consulting company.
- Hardening strategies are incorporated into new construction projects and into maintenance projects.

## 3.6 Best Practices

**Question 39:**
**Would an increase in the aggressiveness of distribution hardening reduce major storm damage for the hardened areas a little bit, a moderate amount, or a lot?**

Seventeen of the responding utilities answered "a little bit," eleven answered "a moderate amount," and no utilities answered "a lot." It is not clear why so many utilities feel that distribution hardening will not be able to deliver on its specific objective: to reduce major storm damage. Some may feel that hardening efforts will simply not be extensive enough to make a difference. Others may feel that most damage is due to vegetation and flying debris. Still others may feel that hardening is simply not very effective, although this is somewhat at odds with the experiences described in Question 34.

**Question 40:**
**What else besides hardening (non-vegetation related) would be effective at reducing the impact of major storms on customers?**

Seventeen of the responding utilities provided thoughts on how to reduce the impact of major storms on customers beyond hardening and vegetation management. These thoughts span a variety of approaches and are not possible to generalize. A summary of the responses is therefore provided:

**Other Suggested Ways to Reduce the Impact of Major Storms on Customers**

- Distribution automation / automatic switching / SCADA (x4).
- Additional protective devices (x2).
- More isolation points.
- Additional circuit ties.
- Smart-meter technologies to confirm customer outage status.
- Restoration process improvements.
- Heightened communication with customers.
- Better conductor connections (ensure tool torque is at appropriate levels).
- Underground conversion of overhead service drops.
- Redesign system to break into smaller taps.
- Spreading conductors out on crossarms.
- Customer education on customer-owned and maintained facilities such as service risers & weather head etc.
- Customer education on recognition of electric/CATV/telecom wires in order to contact the appropriate company for damage reporting.
- Replacement of aging infrastructure.
- Customer ownership of back-up generators.
- Do not build homes and businesses close to the beach.

As can be seen, suggestions span automation, design, operations, work practices, customer facilities, customer communications, and even building codes. Interestingly, the most common response relates to distribution automation and the use of automated feeder switches. Of course, having these additional automated switches will not reduce the amount of damage, but could let utilities more efficiently restore customers when parts of the system become repaired. These types of functionalities require communications systems to be in place. After a major storm, there will likely be extensive damage to communications systems (owned by electric utilities) in many ways similar to the damage incurred on electric systems. Therefore, utilities relying on the use of automation for major storm restoration will need to integrate communications restoration plans into their overall restoration plan.

**Question 41:**
**Please describe any hardening approaches that did not turn out to be good ideas.**

Only three of the responding utilities provided examples of hardening approaches that they felt did not turn out to be good ideas. The first observes that "complete undergrounding [is] too expensive." This is a prudent observation and has been concluded consistently by many state regulatory investigations. The next states that lightning arrestors alone were not effective during lightning storms (the same utility previously noted that they found the use of static ground wire effective). The last response states the following:

> *Prior practice was to attach storm guys about half way up the pole from the ground line. Following a recent 2008 storm, many of these poles broke in half at the guy attachment point. In contrast, poles which had storm guys attached much higher on the pole did not experience as much damage.*

This observation is appreciated, since the use of storm guys is one of the most cost-effective ways to strengthen a pole against strong winds, and the use of storm guys was the sixth most popular response in Question 35. Oftentimes, pole reinforcement is done just above the third-party attachments, with the thought that the reinforcement addresses the wind load caused by these attachments. Although most unguyed distribution poles will tend to break at the groundline, strong winds are easily capable of breaking the pole higher up. Based on this observation, storm guys should be placed as high as practicable.

**Question 42:**
**Please describe any hardening approaches that <u>did</u> turn out to be good ideas.**

Although 19 of the responding utilities did not offer their recommendations for good ideas through this question, many more responses were given than in Question 41 above, with many utilities offering multiple ideas. For the most part, answers vary widely. Two utilities find the use of Grade B construction to be a good idea, and two other find that pole inspection and replacement programs are beneficial for storm hardening. No other answers overlap. A summary of hardening approaches that turned out to be good ideas are the following:

**<u>Good Ideas for Distribution Hardening</u>**

- Construction Grade B (2 responses)
- Pole inspection and replacement program (2 responses).
- Stronger poles.
- Increased focus on foreign poles.
- Periodic pole attachment surveys (and follow-up).
- Use of trusses.
- Attaching storm guys as high as possible.
- Targeted distribution automation.
- Replacing locust pins and old crossarms.
- Elimination of bare secondary wire.
- Pole stabilization foam.
- Lighting arrester program.
- Sky Wire (static overhead ground wire).

About two-thirds of all the good ideas relate to poles, the strength of poles, the inspection of poles, and related issues. Interestingly, two of the non-pole-related responses relate to lightning protection. One utility states that a lightning arrester program has been effective (these programs typically inspect the system for failed and missing arresters, which are then replaced). Another utility had previously stated that, in its experience, lightning arrestors alone were not effective, but the use of static ground wire was effective.

The primary focus of this benchmark survey is on major storms that cause damage to distribution system through high physical loading, such as high winds and ice accretion. Therefore, the best practices analysis will not include issues related to lightning protection. Suffice to say, the basic insulation level (BIL) of typical distribution system is not sufficient to withstand a direct lightning strike without flashing over and experiencing a fault. The only way to accomplish this is to build the distribution system, from an insulation coordination perspective, to transmission standards. This said, the proper use of lightning arresters will clamp voltage across pieces of equipment and help to protect them from damage. Similarly, the use of overhead shield wire can intercept lightning strikes before they hit the primary wires, although a flashover will typically occur at nearby structures. The presence of any grounded conductor will help mitigate the impact of induced voltages from nearby lightning strikes that do not directly strike the power lines.

**Question 43:**
**What would it take for your utility to more effectively pursue distribution system hardening?**

Ten of the responding utilities did not provide an answer to this question. Of these giving answers (many with multiple elements), but far the most common response was related to regulation. These utilities felt that it was very important to have a regulatory mandate before undertaking aggressive hardening and to have a straightforward and timely cost recovery mechanism for the related expenditures. The next two most popular replies were related to (1) increased funding for hardening activities, and (2) future major storms that result in poor reliability and long customer restoration times. A summary of responses includes the following:

**Key Enablers for Hardening**
- Regulatory approval / mandate (x11)
- Increased funding / budget (x4)
- Poor storm reliability (x4)
- More customer complaints
- Partnering with communities
- Better data collection

**Question 44:**
**What would you recommend as a best practice for distribution hardening?**

Twelve of the responding utilities did not provide an answer to this question. Of these giving answers (many with multiple elements), but far the most common response was related to vegetation management. Unfortunately, vegetation management is not considered hardening for the purposes of this report. Most of the remaining responses related to construction standards and tactics to strengthen distribution structures. A summary of responses includes the following:

**Recommended Best Practices**
- Building to Grade B.
- Adherence to established construction standards.
- Follow the NESC.
- Strengthen critical junction poles.
- Storm guys.
- Shorter spans.
- Replace old wood pins and crossarms.

- Wood pole inspection programs.
- Consistent and regular maintenance.
- Frequent inspections and proactive focus on reliability concerns.
- Placement of distribution facilities in residential subdivisions underground.
- Placement of facilities in the front of the lots of new residential service.
- Underground existing overhead facilities.
- Use of statistical data analysis to surgically focus on the right programs in the right areas.
- Utilization of internal engineering resources to identify infrastructure needs.

**Question 45:**
**Any other thoughts or comments on the subject of distribution hardening?**

Twelve of the responding utilities offered concluding thoughts about distribution system hardening. A summary of these thoughts and comments is as follows:

**Final Thoughts on Hardening**

- Undergrounding is not the answer for coastal area exposed to storm surge (x2)
- Hardening will require regulatory action, bad publicity, or liability.
- It is difficult to justify the cost of hardening.
- Hardening options are specific to the circuit.
- There is no "silver bullet" for hardening.
- The utilities that are not performing pole inspections, maintaining good right of ways, etc. are making it tough of the rest of us. The regulators look at the utilities that are not doing these things and then impose various system hardening rules we have to follow when some of it is overkill.

The tone of these final thoughts is cautionary. Two utilities are clear that underground conversion is not a good idea for storm hardening, especially in coastal areas. Another observes that the benefits of hardening are difficult to justify considering the high costs involved, and another agrees by stating that significant hardening will not likely occur unless regulatory and public pressure occur. Two others caution against broad-based approaches, observing that each circuit has its own hardening needs and that any single hardening approach will not prevent major storm damage from occurring. The last observation is related, implying that prescriptive approaches mandated by regulators can be costly. These regulatory rulings are often targeted at reactive utilities, but limit the ability of proactive utilities to take a targeted hardening approach with higher benefits and lower costs.

# 4 Recommended Best Practices

Some of the utilities responding to the survey seem to be satisfied with their hardening program, and others are not planning on pursuing distribution hardening. Is it fair to use these utilities as the standard of best practice? The author's opinion is "no." Although these utilities may feel that they addressing distribution hardening in an appropriate and effective manner, they would be hard-pressed to *prove* that this is the case. With this in mind, this section presents best practices that, in the author's opinion, will ensure that distribution hardening is being managed through a process that is cost effective, consistent, transparent, and data-driven.

The best practices presented in this section should be taken in context. First, many utilities will already have many of these elements in place. Second, each utility is in a unique situation with regards to distribution hardening. Certain best practices, though appropriate for most utilities, may not be appropriate for all. In any case, all utilities are encouraged to examine the proposed best practices presented in this section. Some can be implemented at little-to-no cost, and others may allow distribution hardening to be more effectively pursued at a lower cost. Recommendations are not intended to be a "one size fits all" approach. For example, a utility with very low exposure to major storms may not need to have any formal distribution hardening program at all.

Best practices are organized into three stages. The best practices in the first stage are inexpensive and relatively simple to implement. In addition to being potential quick wins, they also set the foundation for more ambition actions. The best practices in the second stage are designed to be implemented in the medium term and generally require more utility effort, investment, and potentially change. Generally, the experience and data obtained from the first stage will be helpful when implementing the second stage. The best practices in the third stage should be considered after a utility has a very good handle on its distribution hardening vision including the costs and benefits of a more aggressive approach. Since the best practices in the third stage are potentially expensive, the utility will be in a good position to have a dialogue with regulators about benefits and rate implications.

**First Stage**

1. **Pole test-and-treat.** Wood poles are susceptible to decay, causing a reduction in strength and a corresponding increase in failure probability during a major storm. As such, utilities should establish and maintain a test-and-treat cycle for its wood distribution pole population. This program should focus on (but not necessarily be limited to) decay at the groundline since this is typically the failure point for distribution structures under wind load, and is typically the part of the pole most susceptible to decay.

   The goals of the test-and-treat program are to ensure that (1) no pole has lost more than one third of its original strength, and (2) no pole is likely to have lost more than one third of its original strength before its next scheduled inspection. This program should ensure that deficient poles are reinforced or replaced in a timely manner.

   All poles older than a designated age (e.g., fifteen years) should be inspected on a regular schedule based on expected deterioration rates (e.g., every ten years). Inspections will typically involve the following: (A) excavate around the pole and check for signs of deterioration at and below the groundline, (B) check the shell thickness, (C) measure the circumference, and (D) treat with preservatives as appropriate. Different ground conditions will result in different inspection requirements. Variations from these activities are acceptable as long as the program meets the goals stated in the previous paragraph.

2. **Feeder inspections.** Utilities should have a formal feeder inspection program that periodically examines feeders for problems that will likely lead to an outage during normal and/or storm conditions. At a minimum, all three-phase main feeder trunks should be inspected every five years, although more aggressive programs are encouraged. Inspectors should be trained on issues to look for such as broken crossarms, cracked insulators, pole-top decay, and so forth. The feeder inspection program is separate from the test-and-treat program. Information from these inspections should be kept in a common database facilitating the analyses of trends and backlog.

3. **Attachment audits.** Attachments increase the wind loading of poles. Therefore, it is important for utilities to have a good understanding of the number and size of third-party attachments on their distribution poles. Third-party attachment audits should occur, at a minimum, every five years for all three-phase main feeder trunks. The attachment audit can be combined with feeder inspections if desired. Processes should be in place to identify new attachments, whether these new attachments have overloaded the distribution poles, and to mitigate overloaded poles.

4. **Foreign-owned poles.** Not all utilities own all of the poles that on which they have equipment. Sometimes a percentage of poles is owned by another utility (often the local telephone company), and sometimes there is joint ownership of certain poles. In any case, major storms do not distinguish between pole ownership when inflicting damage. Electric utilities must try their best to ensure that foreign poles are in as good shape as their own poles in terms of remaining strength and loading. The processes addressing foreign poles can vary widely, ranging from the electric utility performing all inspections and maintenance to the electric utility ensuring that the foreign owner is doing an adequate job. Since utilities do not necessarily have control over this issue, any limitations on the inspection and maintenance of foreign-owned poles, such as lack of cooperation from the foreign company, should be documented.

5. **Setting depths.** A strong pole is of no use if its foundation is insufficient. Therefore, each utility should develop standards and processes to ensure that the foundations of distribution poles will not fail before the pole. Typically this involves setting depth, although other approaches can be used. These standards should have setting depth tables for poles of different heights and classes and for different soil conditions. Tables should also be made for very strong poles, including non-wood poles, which may be used for hardening purposes. Last, the standards should describe how a setting depth calculation should be performed when none of the tables apply.

6. **Loading calculations.** The ability of a distribution pole to withstand extreme loads (such as wind and ice) is a direct function of its loading. Therefore, a utility should have systems and processes in place to ensure that poles do not become overloaded after they are initially installed. At a minimum this should include (A) a loading assessment whenever an additional piece of equipment is placed on the pole, (B) a loading assessment whenever a new attachment is discovered on the pole, and (C) mitigation actions as appropriate. It is acceptable to use guidelines and tables when determining whether a pole is overloaded. Each utility should have the capability to perform a loading calculation for situations where guidelines and tables do not apply.

For the purposes of hardening, it is helpful for a utility to know the ability of a structure to withstand high loads. Towards this end, it is helpful if loading calculations go beyond a Boolean output of "pass/fail." For example, a utility might choose to rate pole loading based on a Grade C standard. In this case, a fully loaded pole is rated at 100% Grade C. Loadings higher than this are not acceptable. The utility may wish to designate hardened poles to be loaded no more than 67% Grade C, which is equivalent to Grade B. Utilities can also use extreme wind rating for structures in a similar manner.

## Second Stage

7. **Grade B construction.** Most utilities will already have a stronger distribution grade of construction that is used in special situation such as those used for railway and highway crossings. For most US utilities, the standard corresponds to NESC Grade B. Based on the survey, the use of Grade B for storm hardening is popular, effective, and easy to implement. This recommendation calls for utilities to have an explicit process to review new construction and rebuilds to decide whether the system should be built to Grade B (or equivalent) rather than a weaker standard.

   The intent of this recommendation is not to have utilities build new distribution construction or upgrade existing distribution structures to Grade B. Rather, its intent is to have utilities review distribution construction projects and decide whether Grade B is appropriate or not. For example, a relocation due to the widening of a coastal road may be worthwhile to consider for Grade B if the exposure to extreme winds is high enough.

8. **Non-wood poles.** There are many reasons, including hardening, why a utility may in certain cases wish to use a non-wood distribution pole. Perhaps the two most compelling are (A) they are not susceptible to decay, and (B) steel and composite poles can be very strong while remaining light enough to work without requiring the use of heavy cranes. Utilities should, at a minimum, have standards for at least one type of non-wood distribution pole and should install some on their system to gain field experience.

   The intent of this recommendation is not to have utilities build new distribution construction or upgrade existing distribution structures with non-wood poles. Rather, its intent is for utilities to have a viable alternative to wood should this be necessary in certain hardening situations.

9. **Post-storm data collection.** A lot of distribution damage occurs during major storms. When this happens, utilities are understandably focused on restoration rather than data collection. By the time a utility begins to think about how its distribution system help up, most of the system is already repaired and it is impossible to collect detailed damage data. This data is invaluable when trying to address system hardening in a manner that is most beneficial during major storms. Therefore, a utility should have a plan that has trained staff collect data on distribution damage sites immediately after the storm subsides. This data should be collected in a way that is statistically representative of the entire system.

   The intent of this recommendation is not to have a large number of data collectors that otherwise could be helping with storm restoration. Nor should other storm restoration activities be delayed during post-storm data collection. Rather, a utility should train a few data collection teams (e.g., three teams of two engineers) and have these teams spend the first two days of storm restoration collecting data. This function can also be outsourced to contractors. The cost and man-hours associated with this data collection should be very small when compared to the overall storm restoration effort.

10. **Hardening toolkit.** Utilities that intend to harden portions of their system should develop a "hardening toolkit" that consists of a set of approved approaches to hardening and an application guide for their use. The utility should ensure that all of the appropriate standards are in place for each element of the hardening toolkit, and should install pilot applications for each unfamiliar element to gain field experience. Typical elements in a distribution hardening toolkit are provided in Appendix D.

11. **Like-for-unlike replacement.** Utilities are continuously inspecting, repairing, replacing, and generally working on the distribution system. When a utility identifies a cost-effective approach to storm hardening, it should enact systems and processes that allow the system to be gradually hardened through normal work processes. For example, a utility may identify that porcelain insulators have a tendency to break during storms. Therefore, a like-for-unlike approach will ensure that any porcelain insulators needing replacement are replaced with a composite insulator instead of another porcelain insulator. Similarly, a utility may decide that it wishes to upgrade certain parts of the system to Grade B. When a pole in these areas fails, the utility should ensure that it is replaced with a larger pole that results in Grade B construction.

12. **Strengthen critical poles.** A good way for a utility to gain experience in hardening is to identify critical poles that are highly undesirable to fail during a major storm. The utility can then take targeted actions to strengthen these poles (such as upgrading them to Grade B or stronger), and monitor their performance during future major storms. Good poles to consider are poles with reclosers, poles with multiple circuits, junction poles, poles used for freeway crossings, tie switch poles, and poles with automation equipment.

    The intent of this recommendation is not to replace a large percentage of poles. Rather, the utility should address only the most important poles. For example, a utility with one million poles may choose to initially strengthen one thousand poles, or 0.1%. More aggressive hardening activities should be addressed in a hardening roadmap (see Recommendation 18).

## Third Stage

*Note on the Third Stage: These recommendations are recommended if utilities wish to significantly reduce the amount of damage that during major storms, at least on the parts of the distribution system that are hardened. Since the goal of storm restoration is to restore customers as quickly as possible, some of the recommendations in the Third Stage go beyond hardening (e.g., substation automation and smart meters) and are potentially expensive. Therefore, utilities must carefully consider whether the benefits associated with these Third Stage recommendations justify the costs and other implications.*

13. **Engage regulators.** After the appropriate elements of the first two steps have been successfully implemented, a utility will have a strong distribution integrity program and a good basis for a more aggressive hardening program. At this point, the utility must decide whether it wishes to become more aggressive in terms of funding, legal constraints, political issues, or other issues that warrant involvement with the regulator. Since the existing distribution system is in good shape, proposed costs and benefits should have high credibility with regulators.

If a utility intends to spend a significant amount of money on hardening, it is important to have an agreement with regulators on how these costs will be recovered through rates. This agreement should be in place before significant hardening investments occur.

14. **Damage prediction model.** It is helpful for utilities to understand the likely amount and type of damage that will occur due to an incoming major storm. Therefore, it is recommended that utilities develop a damage prediction model. At a minimum, this model should take key characteristics of an incoming storm and calculate the expected amount of damage by classification (e.g., number of broken poles, amount of downed wire, number of damaged service drops, etc.). It is also helpful if the model can estimate these values by operational area, and if they can estimate the number of customers that will be interrupted. These damage prediction models are initially intended to be an operational tool, allowing the utility to estimate the number of required crew-hours for repair, to estimate the required material supplies, and so forth. These damage prediction models will also serve as the basis for quantifying the impact of potential hardening activities.

15. **Cost-to-benefit models.** Best practice is to select hardening activities based on rigorous cost-to-benefit models. These models, of course, should contain the expected cost of various hardening activities. Initially, the benefit could relate to achieving a certain level of hardening on the system, such as attaining Grade B construction on a critical circuit. At a minimum, the cost-to-benefit models should allow specific hardening goals like this to be achieved for the lowest cost. More sophisticated cost-to-benefit models will be able to estimate the major storm impact for all hardening activities including the reduction in damage, reduction in restoration costs, and reduction in total restoration time. This will allow a cost-versus-benefit curve to be developed that shows the impact of various levels of hardening expenditure.

16. **Substation automation.** For the purposes of this recommendation, substation automation refers to the ability of substation feeder breakers to be remotely opened and closed. Although substation automation will not reduce the amount of damage in a storm, it greatly aids in the restoration process and can be considered one of the first steps in creating a “smart grid.” After a major storm, initial restoration efforts are typically on the main three-phase feeder trunks. Starting at the substation, crews typically make repairs while moving down the main trunk. When a sectionalizing device is reached, substation automation allows the crew to contact the dispatcher to close the breaker, eliminating the need for traveling back to the substation and/or placing a person at the substation. This advantage persists for the entire main trunk restoration.

    The intent of this recommendation is not to mandate the automation of all substations. Rather, its intent is for utilities to examine the costs and benefits of substation automation, and to automate those substations where the benefits exceed the costs. For example, very small rural substations may be relatively expensive to automate with relatively small benefits.

17. **Smart meters.** Utilities are increasingly replacing electromechanical meters with digital “smart meters” that have two-way communications. A feature of a typical smart meter is to communicate when it is energized. During storm restoration, this feature is useful. Before a crew leaves an area, it can have all of the smart meters polled to determine whether every customer is actually restored. Doing this has several advantages. First, crews will less frequently have to return to the area to addressed missed problems. Second, crews can investigate customers that remain interrupted before leaving the area, informing them about why they are still interrupted and whether they need to call an electrician to fix damage on customer-owned facilities. Last, the utility will have a more accurate count of inter-

rupted customers throughout the restoration process. This recommendation requires utilities to integrate the use of smart meter data in their restoration process.

The intent of this recommendation is not to mandate the installation of smart meters. Rather, it is to use smart meter data during storm restoration if a utility already has smart meters installed.

18. **Hardening roadmap.** Any significant in distribution hardening will be a multi-year effort. Instead of making hardening decisions each year, a utility should define its desired future state, such as a set of hardening goals achieved over the next five years. This will include goals related to the hardening of (A) parts of the system serving high priority customers; (B) important structures; (C) economic centers (i.e., areas with gas stations, grocery stores, restaurants, home improvement stores, etc.); and (D) structures that are likely to fail during a major storm. The utility can then compare the desired future state to its current state, identify gaps, and determine yearly resources and funding so that the utility can transition from its current state to the desired future state in a systematic and cost-effective manner. This plan is called a "hardening roadmap." A more detailed description of a hardening roadmap is provided in Appendix E.

What benefits can be expected from the above recommended best practices? The recommendations in the first stage will result in a well-managed distribution system from a storm hardening perspective. The second stage will allow utilities to cost-effectively pursue modest hardening efforts and prepare for more aggressive hardening efforts if desired. Most of the recommendations in the first two stages can be implemented either with little cost or with short-term costs that result in long-term savings.

Implementing the first two stages will result in a well-managed distribution system infrastructure and will establish good credibility for a utility's current and planned hardening activities. For most utilities, the best practices in the first two stages will allow for an increase in the cost-effectiveness of modest hardening activities, with corresponding modest reductions in major storm damage. Utilities wishing to be more aggressive should pursue the third stage. The recommendations in the third stage are more expensive, more difficult to implement, and of more interest to external stakeholders. This said, utilities pursuing the third-stage recommendations can expect a dramatic reduction in storm damage for the areas and structures targeted for hardening. These efforts, though costly, will reduce storm restoration costs, reduce storm restoration time, allow customers to be restored more quickly, and will restore local economy activity sooner.

Based on survey results, a few utilities already have a highly developed distribution storm hardening program, many have a nascent program with opportunities for improvement, and some have virtually no program at all. Similarly, some utilities have a regulatory mandate to pursue hardening, some are performing pilot hardening activities, and some see no need for hardening beyond their current practices. In addition to these considerations, there are many differences across utilities in terms of service territory, construction standards, storm characteristics, and other factors that necessarily impact their approach to distribution hardening. Each utility must therefore thoughtfully determine its own best approach to distribution system hardening.

# 5 Conclusions

A survey has been performed on distribution system hardening. Twenty-eight utilities responded, geographically representing the US from north to south and from east to west. The survey captured information regarding existing practices and recommended practices in the areas of inspection, motivation, post-storm data collection, hardening experience, and best practices.

Some of the utilities responding to the survey seem to be satisfied with their hardening program, and others are not planning on pursuing distribution hardening. Although these utilities may feel that they addressing distribution hardening in an appropriate and effective manner, they would be hard-pressed to *prove* that this is the case. Based on this and the overall survey results, the author has assembled a list of eighteen best practices that will help to ensure that distribution system hardening is being pursued through a process that is cost effective, consistent, transparent, and data-driven.

These best practices should be taken in context. First, many utilities will already have many of these elements, or their equivalent, in place. Second, each utility is in a unique situation with regards to distribution hardening. Certain best practices, though appropriate for most utilities, may not be appropriate for all. In any case, all utilities are encouraged to examine the proposed best practices. Some can be implemented at little-to-no cost, and others may allow distribution hardening to be more effectively pursued at a lower cost. Recommendations are not intended to be a "one size fits all" approach. For example, a utility with very low exposure to major storms may not need to have any formal distribution hardening program at all.

Best practices are organized into three stages. The best practices in the first stage are either inexpensive or good practices regardless of hardening considerations. They are also relatively simple to implement. In addition to being potential quick wins, they also set the foundation for more ambition actions. The best practices in the second stage are designed to be implemented in the medium term and generally require more utility effort, investment, and potentially change. The best practices in the third stage should be pursued after a utility has a very good handle on its hardening program including the costs and benefits of a more aggressive approach. The experience and data obtained from the first two stages will be helpful when implementing the third stage. Since the best practices in the third stage are potentially expensive, the utility will be in a good position to have a dialogue with regulators about benefits and rate implications.

**First Stage**

1. Establish a good pole test-and-treat program.
2. Perform periodic feeder inspections.
3. Perform periodic attachment audits.
4. Ensure that foreign-owned poles are in good condition.
5. Ensure appropriate setting depths for strong poles.
6. Perform loading calculations if overloading is suspected.

**Second Stage**

7. Selectively use Grade B construction.
8. Adopt a non-wood poles standard.
9. Establish a post-storm data collection process.
10. Develop a hardening toolkit.
11. Enact like-for-unlike replacement.
12. Strengthen critical poles.

**Third Stage**

13. Engage regulators.
14. Develop a damage prediction model.
15. Develop cost-to-benefit models.
16. Automate substation feeder breakers.
17. Use smart meters data during restoration.
18. Hardening roadmap.

Implementing the first two stages will result in a well-managed distribution system infrastructure and will establish good credibility for a utility's current and planned hardening activities. For most utilities, the best practices in the first two stages will allow for an increase in the cost-effectiveness of modest hardening activities, with corresponding modest reductions in major storm damage. Utilities wishing to be more aggressive should pursue the third stage. The recommendations in the third stage are more expensive, more difficult to implement, and of more interest to external stakeholders. This said, utilities pursuing the third-stage recommendations can expect a dramatic reduction in storm damage for the areas and structures targeted for hardening. These efforts, though costly, will reduce storm restoration costs, reduce storm restoration time, allow customers to be restored more quickly, and will restore local economy activity sooner.

Based on survey results, a few utilities already have a highly developed distribution storm hardening program, many have a nascent program with opportunities for improvement, and some have virtually no program at all. Similarly, some utilities have a regulatory mandate to pursue hardening, some are performing pilot hardening activities, and some see no need for hardening beyond their current practices. In addition to these considerations, there are many differences across utilities in terms of service territory, construction standards, storm characteristics, and other factors that necessarily impact their approach to distribution hardening. Each utility must therefore thoughtfully determine its own best approach to distribution system hardening.

# Appendix A – Benchmark Survey

**Directions**

- Please send to rbrown@quanta-technology.com by May 20, 2009. Sooner is appreciated!
- Answer each question to the best of your ability. Educated guesses are welcome. If you cannot make an educated guess, please respond "don't know" or leave blank.
- Commentary, context, experiences, thoughts, and other contributions are always welcome. I will compile all of this collective knowledge in the benchmark report.
- For this survey, "hardening" is defined as making the system less vulnerable to damage during a major storm.
- If your company has multiple utilities with different practices (e.g., Exelon has ComEd and PECO), feel free to fill out a separate survey for each utility.
- The focus of this survey is on distribution system hardening.
- **Check boxes:** to check, double click on the box, select "checked," and press "OK."

**General**

1. Name of responder: [answer]
2. Utility: [answer]
3. Number of electric customers: [answer]
4. Circuit miles of overhead primary distribution: [answer]
5. What types of major storms do you have?
   a. Hurricanes: ☐
   b. Linear winds: ☐
   c. Tornadoes: ☐
   d. Ice storms: ☐
   e. Wild fires: ☐
   f. Other (explain): ☐ [answer]

**Existing System**

6. Do you ever exceed minimum NESC design criteria for distribution? Explain. [answer]
7. What percentage of your distribution poles are:
   a. Wood: [answer]
   b. Concrete: [answer]
   c. Steel: [answer]
   d. Composite: [answer]
   e. Other (explain): [answer]
8. If applicable, why are you using non-wood poles? [answer]
9. How are setting depths for poles determined? [answer]
10. When adding a pole-mounted device, is a loading calculation performed? [answer]
11. When becoming aware of a new attachment, is a loading calculation performed? [answer]
12. If a pole is identified as overloaded, what mitigation actions are typically performed? [answer]

**Inspection**

13. How often, if ever, are attachment audits performed? [answer]
14. What is your target cycle for wood pole testing? [answer]
15. Are you, for the most part, meeting your target cycle for wood pole testing? [answer]
16. When a wood pole is inspected, are other aspects of the pole systematically inspected at the same time (e.g., broken crossarms, rusty equipment)? [answer]
17. When a wood pole is found to have lost more than one-third of its original strength, is it always replaced, or is a loading calculation performed? [answer]
18. About how long, on average, does it take to replace a pole that has been identified as needing replacement? [answer]
19. Do you perform dedicated distribution circuit inspections on a regular basis? If so, please describe (scope, methodology, extent, cycle). [answer]

**Motivation**

20. In the last ten years, has there been any negative publicity for your utility related to major storm damage and/or restoration? [answer]
21. In the last ten years, have there been any recent regulatory investigations for your utility related to major storm damage and/or restoration? [answer]
22. Has there been any regulatory interest in your state related to underground conversion of the electric distribution system in order to reduce storm damage? [answer]
23. Has there been any regulatory interest in your state related more general hardening of the electric system (i.e., other than undergrounding)? [answer]
24. Please indicate all of the reasons your utility is considering distribution hardening:
    a. We are not considering hardening ☐
    b. Respond to regulator concerns ☐
    c. Strengthen weak poles ☐
    d. Minimize damage on important poles ☐
    e. Minimize damage on critical circuits ☐
    f. Reduce overall storm damage ☐
    g. Reduce societal cost ☐

**Post-Storm Data**

25. After restoration is complete, what sources of data are used to determine what failed and how much failed? [answer]
26. Does your utility attempt to collect detailed damage data at a certain number of damage locations before system restoration begins? If so, please explain. [answer]
27. If the answer to the previous question is "yes," is a process followed to ensure that the collected data is statistically representative of the overall system? [answer]
28. Please evaluate this statement: "Our post-storm data is sufficient to determine major factors that led to storm damage, and allows us to focus our hardening approach on these major factors."
    a. Not true ☐
    b. Somewhat true ☐
    c. True ☐
29. Does your utility have damage prediction models that are used to estimate the damage that will occur during an incoming storm? If so, what data are used to develop and improve these models? [answer]

## Hardening

30. Has your company performed a system hardening review, developed a hardening roadmap, or something similar? Explain. [answer]
31. Has your utility committed itself to hardening its distribution system? Explain. [answer]
32. Has your utility performed any significant hardening activities? Explain. [answer]
33. Is your current budget for hardening the existing distribution system (other than vegetation spending):
    a. None ☐
    b. A little bit ☐
    c. A moderate amount ☐
    d. A lot ☐
34. Have any hardened portions of your system been subject to major storms? If so, please comment on how well they performed. [answer]
35. Please check all hardening activities that you are doing or have tried (for hardening purposes):
    a. Grade B construction ☐
    b. Stronger poles ☐
    c. Shorter spans ☐
    d. Storm guys ☐
    e. Push braces ☐
    f. Extended-length pole braces ☐
    g. Relocating pole-mounted equipment ☐
    h. Relocating third-party attachments ☐
    i. Elimination of crossarms ☐
    j. Elimination of porcelain insulators ☐
    k. Small primary wire replacement ☐
    l. Elimination of bare secondary wire ☐
    m. Break-away wire ties ☐
    n. Break-away service drop connectors ☐
    o. Conversion to underground ☐
    p. Other (please explain) ☐
36. For poles of equal height, do you set stronger poles deeper? [answer]
37. Have you utilized cost-to-benefit analysis for spending related to hardening? [answer]
38. If applicable, please describe how hardening projects are prioritized. [answer]

## Best Practices

39. Would an increase in the aggressiveness of distribution hardening reduce major storm damage for the hardened areas:
    a. A little bit ☐
    b. A moderate amount ☐
    c. A lot ☐
40. What else besides hardening (non-vegetation related) would be effective at reducing the impact of major storms on customers? [answer]
41. Please describe any hardening approaches that did not turn out to be good ideas. [answer]
42. Please describe any hardening approaches that did turn out to be good ideas. [answer]
43. What would it take for your utility to more effectively pursue distribution system hardening? [answer]
44. What would you recommend as a best practice for distribution hardening? [answer]
45. Any other thoughts or comments on the subject of distribution hardening? [answer]

# Appendix B –Survey Responses

## General

*The responses to Questions 1-5 are summarized in Table B-1.*

**Table B-1. Summary of Responding Utilities**

| Utility | Customers | Ckt Miles of OH Dist. | Types of Major Storms | | | | |
|---|---|---|---|---|---|---|---|
| | | | H | LW | T | IS | WF |
| AEP Texas Central | 811,000 | 24,868 | x | x | x | x | |
| AEP Texas North | 199,000 | 12,950 | | x | x | x | x |
| Baltimore Gas & Electric | 1,220,000 | 9,345 | x | x | | x | |
| CenterPoint | 2,080,000 | 21,050 | x | x | x | x | |
| CHELCO | 42,000 | 2,816 | x | x | x | | x |
| Cleco Power | 272,877 | 11,000 | x | | x | x | |
| CPS Energy | 692,000 | 8,000 | x | x | x | | |
| Dayton Power & Light | 514,000 | 10,500 | | x | x | x | |
| Entergy Texas | 395,000 | 10,985 | x | x | x | x | |
| Enwin (Canada) | 84,644 | 451 | | x | x | x | |
| Exelon (ComEd) | 3,781,274 | 35,861 | | x | x | x | |
| Hawaii Electric | 294,371 | 899 | x | | | | |
| Idaho Power | 480,000 | 25,000 | | x | | | |
| Kansas City Power & Light | 800,000 | 25,000 | | x | x | x | |
| Oklahoma Gas & Electric | 770,000 | 26,300 | | x | x | x | x |
| Oncor | 3,100,000 | 56,200 | x | x | x | x | x |
| PG&E | 5,200,000 | 113,500 | | x | x | x | x |
| Puget Sound Energy | 1,000,000 | 10,800 | | x | | | |
| Progress Energy Florida | 1,600,000 | 18,100 | x | x | x | | x |
| Southern California Edison | 4,851,312 | 98,500 | | x | | x | x |
| SW Public Service Co. | 400,000 | 16,000 | | x | x | x | x |
| Tampa Electric | 660,000 | 6,414 | x | x | x | | x |
| Texas New Mexico Power | 228,000 | 1,926 | x | x | x | x | |
| Toronto Hydro (Canada) | 682,560 | 2,665 | | x | | x | |
| Vectren | 147,000 | 3,100 | | x | x | x | |
| Xcel Energy (NSPM) | 1,000,000 | 14,000 | | x | x | x | |
| Xcel Energy (NSPW) | 202,000 | 9,400 | | x | x | x | |
| Xcel Energy (Psco) | 1,300,000 | 10,000 | | x | x | | x |
| **Average** | **1,222,963** | **21,070** | **39** | **86** | **71** | **64** | **32** |
| **Low** | **42,000** | **451** | | **(% of utilities)** | | | |
| **High** | **5,200,000** | **113,500** | | | | | |

## Existing System

6. Do you ever exceed minimum NESC design criteria for distribution? Explain.
   - We follow NESC design except for larger self supporting structures, like major highway and river crossings.
   - Yes our Grade of Construction is B.
   - For many years, we have used the "grade C at Crossings", safety factors for our 13kV system, and Grade B for any structure containing 34kV. However, in 2008 we began designing all new and renewed poles at Grade B standards as a method of storm hardening our system
   - Yes, on new installations at major junction poles we will install concrete poles instead of wood.

- Yes, wood poles are designed to support the maximum equipment weight in addition to the conductor weight and to meet the GRAVITY LOADING, NESC HEAVY LOADING, and EXTREME WIND LOADING criteria.
- Our company's construction standards for our distribution system are designed so that our system at the time of construction meets or exceeds the requirements of the NESC in place at that time. The situation that we exceed NESC requirements by design is: conductors near and over swimming pools. Our policy is to not install conductors over swimming pools and when in proximity to swimming pools, we default to the most stringent clearances from the NESC, NEC, or local codes.
- We have installed an increased number of lightning arresters at one of our stations, installed Sky Wire in some parts of our system.
- We design to Class B construction
- Not intentionally
- No (x4)
- Yes, Everything constructed to Grade C at crossing (x3)
- We do not exceed CSA Std. C22.3 No.1
- Yes. First, we follow General Order 95 in California, which is slightly different from NESC. We exceed G.O. 95 design in classifying some areas as an intermediate loading area, where otherwise it would be light loading. We specify additional pole setting depth.
- We follow General Order 95, California
- Our basic design meets or exceeds the minimum requirements of the NESC, except where it has been determined to provide Storm Hardening
- Yes. Our minimum pole class that is used to support distribution primary is class 4. We often chooses a larger class pole in anticipation of additional electric equipment or third-party attachments, such as cable television
- Yes. We have recently adopted a practice of installing only class 3 (or stronger) poles for three phase feeder construction in coastal areas, even though class 5 poles may be acceptable in many cases.
- Yes we have both Grade B and Grade C construction in our system. Grade B is typically used on large conductor sizes.
- Yes. NESC is the minimum criteria.
- Yes
- No, we have established construction standards which are primarily based on NESC Grade C construction criteria. However, the day to day application of our construction standards often results in a particular application exceeding the criteria defined by the NESC. A detailed design is completed for applications where NESC Grade B construction is required.
- We are applying the additional extreme wind loading to 150 mph in our coastal areas.
- No answer (x1)

7. What percentage of your distribution poles are:
   a. Wood: 75, 87, 90, 90, 92, 95, 96, 97.9, 98, 98, 98, 98.6, 99, 99, 99, 99, 99, 99, 99, 99.5, 99.5, 99.8, 99.8, 99.8, 100, 100, 100, 100
   b. Concrete: 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0.1, 0.1, 0.3, 0.4, 0.5, 0.5, 0.5, 1, 1, 1, 1, 1.5, 1.9, 8, 11, 23
   c. Steel: 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0.1, 0.2, 0.4, 0.5, 0.5, 0.5, 0.5, 1, 1, 1, 1, 1, 2, 2, 3, 5, 8.5, 10
   d. Composite: 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0.1, 0.1, 0.2, 0.3, 0.5, 0.5, 1
   e. Other (explain): 0.5 (Iron)

8. If applicable, why are you using non-wood poles?
   - We use other than wood for larger self supporting structures, like major highway and river crossings.
   - Aestheticsand self supporting applications
   - Usually where unguyed or large loads can not be supported by regular wood poles.
   - Strength, locations of hard to change-out poles, PSC requirements of system hardening
   - We no longer install non-wood poles
   - Concrete poles used on arterial roads for aestheticsand durability

- To prevent termite damage and increase pole strength
- Aesthour utilitycs
- Use steel where guying is an issue for wood poles
- Special projects
- Transmission underbuild
- Location specific requirements
- Current Standard is wood poles only
- Woodpeckers and Accessibility (i.e. rear construction)
- Specific job orientation (woodpecker, decay zones, etc.)
- Aesthetics– customer's expense
- We install concrete distribution poles due to customer preference, if the customer pays the difference in installed cost. Also, we have crossings at locations such as streets in which down guys cannot be installed. In such cases, non-wooden distribution poles are used in lieu of the down guys. In some cases, we install large class concrete distribution poles and foundations when wood applications will not meet design requirements.
- Steel distribution poles are now being installed for new interstate crossings, or for maintenance of existing interstate crossings, along hurricane interstate evacuation routes. The purpose of this practice is to eliminate the possibility of failure of weakened wood poles due to future wood rot at the ground line for these crossing poles. Our utility also installs steel or concrete poles to satisfy the aesthour utilityc requirements of certain municipalities.
- Price, available wood pole supply, and customer preference.
- The predominant reason for using non-wood poles is aesthetics. In some cases, such as Highway crossings, strength requirements are the reason.
- Non-wood poles are being used for long road or terrain crossings like freeways that have limited space for the pole and are self-supporting where there is limited space for guying.
- Concrete and steel poles are primarily used as self-supporting structures when adequate guying is unavailable. Composite poles, and less frequent concrete poles, are used when dictated by ordinance or requested and paid for by a property owner.
- Customer requests (x2)
- No response / not applicable (x4)

9. How are setting depths for poles determined?
   - 10% of pole height plus 2 feet (x12)
   - Wood poles: 10% of pole height plus 2 feet; Self supporting concrete poles depends on pole strength at ground line.
   - Poles are normally set to a depth of 10% pole height plus 2 feet; adjusted slightly deeper or shallower for extreme soil conditions.
   - For wood and fiberglass, 10% of length + 2 feet. For lamenated poles we use the manufacturer's requirements - based on load.
   - REA Standard D-804
   - Based on construction standards, per C7035. We have a Construction Standard C7035 to assist crews in determining proper setting depth. This standard is based upon ANSI (05.1-2002).
   - Construction and manufacturer standards
   - Staff created tables
   - NESC, deeper in poor soil conditions
   - Minimum depths are established in G.O. 95. Depending on the calculated overturning moment of the pole, we will specify additional depth.
   - Follow G.O.-95 setting depths
   - We determine the setting depths for poles, slack span deadends, and angle and slack span lateral structures by using Our Overhead Distribution Standards. Generally as a practice, we use 10% of the pole height plus

2 feet for most poles that are less than Class 1. Greater depths are used for larger class poles. Also, our design standards requires users to greater depths and/or improved backfill if soil loading surpasses designated strength.

- NESC pole loading
- Based on existing practices
- Pole embedment depths vary depending on the ANSI class of pole (1, 3, or 5) and the type of soil (poor, average, or good) where the pole is being installed. When the load applied increases the class of pole required the pole embedment depth also increases. As the load applied to the soil surrounding the pole increases and the quality of the soil decreases the pole embedment depth increases.
- Our distribution standards book has a table indicating setting depths for poles depending upon pole length (x2)

10. When adding a pole-mounted device, is a loading calculation performed?
    - Yes (x8)
    - No (x4)
    - If it is not a standard device and for all self supporting structures (no guy supports).
    - Yes, loading calculation are performed any time we add any material, equipment or attachments.
    - Yes; however, general guidelines and rules of thumb are use.
    - Yes, based on construction standards per C7023. We have a Construction Standard C7023 to assist crews in determining proper mounting position and pole class dependent on equipment weight. This standard is based upon guidelines set forth by the NESC
    - Only special cases (x2)
    - Generally no
    - Staff created tables sometimes referred to
    - Loading is checked against allowable loading per distribution specification
    - Yes. Our Overhead Distribution Standards have pre-calculated loading on distribution poles for most devices and attachments.
    - Yes. The design engineer will run a load calculation if it is questionable whether or not the existing pole can meet the requirements of the NESC with the increased load.
    - Loading calculations were performed to develop constructions standards that dictate the allowable weight of pole-mounted devices for each class of wood pole.
    - It is done as part of the distribution standards development for equipment attachments and poles used.
    - Loading calculations are performed and utilized to create the construction standards for pole-mounted devices. A detailed design is completed for those cases where an applicable standard does not exist.
    - Our computer-based design program contains a structural analysis module that the Engineering Tech can use if there is a loading concern (x2).

11. When becoming aware of a new attachment, is a loading calculation performed?
    - Yes (x9)
    - No (x3)
    - Only if it is a non standard device.
    - If another utility is attaching, we require that utility to perform the calculation. If we are adding an attachment, a calculation is performed unless a general guideline is applicable.
    - Depends on type of attachment.
    - Sometimes (x2)
    - Only special cases (x2)
    - Not sure of the question being asked. If it refers to attachments from other utilities, such as communication, the answer is no. We belong to a joint pole association and we do not monitor what the other owner utilities have attached to poles. Each is responsible for doing their own loading calculation each time they add an attachment.
    - When a new joint use attachment is added to a PE pole, the pole is tested for loading

- Our utility does not do an individual calculation, but designs its poles to accommodate one additional attachment. In addition, if additional attachments and clearance issues are identified, then the pole is replaced.
- Yes. The design engineer will run a load calculation if it is questionable whether or not the existing pole can meet the requirements of the NESC with the additional attachment.
- No. Efforts are made to design a pole so that it is not overloaded and allows for unplanned attachments.
- In the case of phone or cable TV making attachments, we are requiring the attaching company to provide engineering on impacts or their new attachment.
- When the new attachment is on a wood pole a new loading calculation is not performed (refer to previous question). The completion of a loading calculation is required for new attachments on concrete and steel poles since they are typically designed for a specific load case.
- Our permitting process for third party attachments requires a loading calculation, and it is the attacher's responsibility to reimburse us for any upgrade necessary to meet the loading conditions; however, some third party attachers will affix their equipment without requesting a permit (x2).

12. If a pole is identified as overloaded, what mitigation actions are typically performed?
    - Replace the pole with a larger pole.
    - Spans are shorten, equipment removed, guying added or pole is changed out to larger pole.
    - Pole is renewed
    - The pole is changed out immediately
    - Pole is generally replaced if pole loading limits are exceeded
    - The pole is upgraded as appropriate
    - Replace with higher class pole
    - Bracing (C-Truss, ET-Truss, or pole replacement)
    - Replace as scheduling allows
    - Pole is changed out, or reinforced with C-trusses
    - Replacement or guying (x3)
    - Ignored or put on list to be replaced in 1m 2 or 3 years.
    - When a pole is found to be overloaded, it is added to the list of poles to be changed because of loading issues. Asset Management will determine priority for change out.
    - Generally, a distribution pole that is identified as overloaded is replaced with a higher class pole. In certain circumstances, the spans can be reduced.
    - Look to add a pole or move equipment.
    - Generally, the pole is replaced with a higher class wood pole. In some applications, concrete or steel poles have been considered.
    - Modification of equipment attached or stronger pole installed.
    - When possible, a portion of the load may be removed from an overloaded pole thereby eliminating the need for further action. If the load can not be shifted, the old pole is replaced with a new stronger pole.
    - We look at all reasonable options, relocation of equipment currently on the pole, addition of down guys or replacement of the pole.
    - Replaced (x6)

**Inspection**

13. How often, if ever, are attachment audits performed?
    - Cable companies are every year and ATT every 5 years.
    - Whole system audits are not on a schedule, we had a stipulation in our PSC Strom Hardening filing.
    - By agreement, we are allowed to perform and audit every 5 yrs. We have performed one audit in the last 15 yrs

- Every 3 years (x2)
- A small sampling of pole data during pole inspection/testing. OH Feeder inspections are presently performed on a 4-year cycle.
- Every 10 years
- Every 5-10 years by third party attachment review
- Every 4 years
- 5 years (x8)
- 5-10 years (x2)
- 3 year visual inspection but no special focus on attachments
- Periodically, to audit third party communications attachments
- Our utility inspects distribution poles on a 5-year, continuous cycle, which means that 1,000,000 distribution poles are inspected each year over 5 years and then the process starts again.
- We have just completed an audit of communication company attachments over the last 5 years. This was done more from a lease attachment than system condition assessment. If an obvious problem was identified during the audit, it was corrected.
- We are allowed by most agreements with 3rd party attachers to perform attachment audits no more often than every 5 years. In most cases, we have maintained a 5-7 year cycle (x2).
- None / never (x2)
- No answer (x1)

14. What is your target cycle for wood pole testing?
    - 8-year cycle (x3)
    - 10 year cycle (x12)
    - 20-year cycle
    - 5-year cycle
    - 3 year inspection cycle, 1/3 of city per year
    - We are not routinely testing poles at this time
    - Starting in 2009, all poles will be tested every 12 yrs (Osmose)
    - Our utility targets distribution wood pole testing at a 15 year cycle
    - No target cycle for distribution
    - We do not have a target cycle for wood pole testing. We do inspect distribution circuits periodically.
    - For distribution it is more a spot check in high outage areas or critical feeders. We are working to implement a program that would be done on a 12-year cycle.
    - Typically, circuit projects based on reliability.
    - Coastal areas - 10 years for poles that have been in service for 10 years or longer. Other areas - 10 years for poles that have been in service for 18 years or longer.
    - 10 years for poles that have been in service for 18 years or longer.
    - No answer (x1)

15. Are you, for the most part, meeting your target cycle for wood pole testing?
    - Yes (x17)
    - No (x5)
    - Started in 2009. On schedule.
    - Less than two years behind
    - Since we currently do not have defined a cycle, we are completing the test we plan each year.
    - n/a (x2)
    - No answer (x1)

16. When a wood pole is inspected, are other aspects of the pole systematically inspected at the same time (e.g., broken crossarms, rusty equipment)?
    - Yes. We do a visual of the top of the pole, we also, repair any broken ground wires and install guy markers on any guys that are missing them.
    - Yes (x14)
    - Yes, but not for the wood pole test and treat program
    - Yes, we do circuit inspection on a 10 year cycle and a pole is inspected if it found to be a concern visually along with the other items that are inspected during a circuit inspection
    - All items are inspected and needed repairs are recorded
    - Yes, all parts of pole (x3)
    - No (x2)
    - Yes, pole testing program and line inspection programs are totally separate
    - Cross arms, guys, and attachments are visually inspected and reported
    - Yes, a visual inspection of the top of the pole is performed and deficiencies are noted.
    - During inspection of distribution wood poles, obvious damage is reported, such as broken crossarms, woodpecker damage, and missing ground wire
    - No answer (x1)

17. When a wood pole is found to have lost more than one-third of its original strength, is it always replaced, or is a loading calculation performed?
    - Yes (x2)
    - A load calculation is preformed and the pole is either replaced, reinforced with a C truss or passes the loading calculation test.
    - Both, also an alternative to is to install a C-truss.
    - We have a reinforcement program where poles are reinforced with a banded steel truss at ground level. We do run a pole loading calculation prior to renewal
    - The pole is not always replaced
    - A loading calculation is performed
    - The pole is either replaced or reinforced at the ground level if appropriate
    - Always replaced
    - Strength calcs are not done on poles, shell thickness is the gauge for replacement. Load calcs are done when the pole is replaced to ensure the correct pole size is used.
    - A load calculation is performed to see if it still meets Class B construction. Then it is either replaced or reinforced.
    - Severe deterioration –replaced, others load calc performed (x3)
    - No (x2)
    - Neither. We test until pole only has one inch of shell left before stubbing.
    - Replaced (x2)
    - Both, a loading calculation is performed, but we do replace the pole
    - Always replaced
    - Poles meeting certain criteria are either replaced or restored (braced).
    - At this time, our utility either replaces the distribution pole with a new wood pole or braces it with a steel strut. The orientation of the decay to the transverse loading is considered in the strength reduction evaluation.
    - No, it is not always replaced. Heavy loaded poles are replaced based on the inspection. Loading calculations are performed for lightly loaded poles.
    - Not always replaced; the pole may be restored to its original strength by installing a steel truss.
    - Replaced or reinforced depending upon the situation.
    - No answer (x1)

18. About how long, on average, does it take to replace a pole that has been identified as needing replacement?
    - If the pole is found to be a danger pole it is replaced immediately, otherwise, we inspect one year and perform replacement the following year.
    - Depending on how complex the structure is and location near busy street, 2 hours to 8 hours.
    - 3 to 6 months
    - 2-5 days
    - On average 18 months
    - 6-12 months
    - Under a month
    - 6 months
    - Varies from days to months
    - Depends on several factors, but on average 4 hrs
    - 1 year (x4)
    - 2 years unless a danger pole, then one year usually
    - Within a year
    - Danger Pole – within one year, Defective Pole – within three years
    - day to 3 years
    - Replacements are prioritized based on several factors including the level of deterioration and equipment supported. Priority poles are to be replaced within six weeks.
    - No formal study has been conducted; however, (1) priority poles are replaced within a few days, (2) poles that can be braced take approximately three months, and (3) poles with substantial remaining strength take approximately 12 months.
    - On average 6-12 months, but a priority pole can be replaced as soon as necessary.
    - It depends on how critical the condition of the pole is. One day if it is in imminent danger of failing. One month if not critical and can be scheduled with normal work.
    - The highest priority poles are usually replaced within one to two days.
    - Priority poles are replaced on average within 45 days. Reject poles are replaced on average within 3 years (x2).
    - Not tracked.
    - No answer (x1)

19. Do you perform dedicated distribution circuit inspections on a regular basis? If so, please describe (scope, methodology, extent, cycle).
    - No (x2)
    - Yes, we perform reliability patrols on 5% of our circuits.
    - Yes. Overhead lines are inspected, with associated maintenance performed, on a 10-year cycle. Inspections look for damaged hardware, structural defects and missing components. BGE ranks its distribution feeders annually based on reliability. The top 2% worst-performing circuits receive inspections that may result in equipment improvements and/or vegetation management work.
    - Yes, Operations inspects all circuits throughout the year and records data for future review if necessary. Plus, we perform work order inspections every month.
    - 2-yr cycle for ~ 280 34kV circuits, 4-yr cycle for ~ 5,200 4kV & 12kV circuits.
      Inspections are performed on a pole-by-pole basis and on conductors spanning between poles. Handheld computers are utilized to record items requiring repairs at each pole.
    - Our "Distribution Line Patrol" program is a 5 year cyclical inspection program that involves a full circuit visual inspection of all facilities
    - Circuit inspection performed during pole inspection, annual infrared scan performed on truck backbone
    - No, on as-needed basis
    - Worst Performing Circuits are determined every year. Then they are inspected. Priority circuits are inspected every other year. The rest of the circuits are inspected on a 10-year cycle

- All poles are given a drive-by inspections every 4 yrs and a closer look via walk-down inspection every 8 yrs
- Vegetation Management contractor inspects at time of trimming (x2)
- No. Pilot in progress -- vegetation management contractor inspects at time of trimming.
- 3 year visual inspection with defects noted and rated by severity, 1, 2, 3. 1 fixed in one year, 2 in two years, and 3 looked at again at next cycle.
- We perform an extensive inspection on 5% of our circuits annually. The circuits are selected based on reliability performance.
- Infrared inspection performed annually on three phase circuits only.
- Annually and every 5 years
- This is a combination of field employees performing such inspections in the normal course of their daily activities; and more intense inspections performed on certain poor performing feeders in compliance with PUC S.R. 25.52.
- Circuit inspections are performed on an as needed basis, generally reliability driven. The extent of the inspection is also determined by the factors that justified the inspection. The extent of the inspection ranges from the visual inspection of the facilities (including tree condition) to an infrared survey of equipment and splices
- Our utility utilizes several programs that incorporate ground-based inspection programs of overhead distribution facilities. These programs are the Infra-Red Program, the Root Cause Analysis Program for the 10% Circuits, the Hot Fuse Program and the Pole Maintenance Program. Also, personnel in the field perform inspections as they go about their daily business.

  *The Infra-Red Program.* Infra-red technology allows the Company to see the heat generated by deteriorating components on the distribution system. These "Hot Spots" will eventually result in equipment failure and a loss of service. Infra-red technology provides a unique tool to find potential equipment outages before they occur, so that proactive repairs can be made prior to an outage. This reduces the number of equipment failures and improves reliability by decreasing System Average Interruption Frequency Index (SAIFI). ¶ Infra-red scans are made of the terminal poles at the substation and major equipment on the circuit, including pole-top switches, reclosers, regulators, and capacitors. The surrounding facilities are also examined to identify other possible deterioration. The identified hot spots are reported and repairs are made. If the problem is severe enough and there is a danger of imminent failure, then procedures are taken to isolate the device. ¶ Historically, Our utility attempts to perform infra-red inspections on one-third of the distribution circuits each year. However, the program has been recently revised so that all circuits are inspected on a five-year cycle so that additional focus can be put on the 10% circuits with the highest SAIDI or SAIFI (approximately 120 circuits). In addition to the inspection of the major equipment on a circuit, Our utility has added a "full circuit option" that inspects the complete backbone of the circuit plus any lateral whose customer count is greater than 20% of the circuit. This option is performed on circuits that are 10% repeat circuits or 300% circuits. ¶ Field review of identified problems is made within one week and field corrections are completed within one week for "glowers" and within four weeks for the rest.

  *The Root Cause Analysis Program for the 10% Circuits.* The Root Cause Analysis Program involves an analysis of the 10% highest SAIDI and SAIFI circuits using an evaluation form that contains detailed information on all outages on the circuit for the past 24 months. Our utility uses outage cause, outage location, and customer-minutes of outage to develop an action plan that can include a number of possible recommendations to address the root causes of the outages. The recommendations might include a protective coordination study, an infra-red inspection, enhanced lightning protection, reconfiguration to avoid vehicle collisions, reconfiguration of line fuses, tree trimming, or installation of automated switches. The Company makes a field inspection to verify that the recommendations are appropriate and to determine if there are other items that may need to be repaired to avoid future outages. The action plan is usually implemented during the first quarter of a year to gain the most benefit. Circuit performance is watched throughout the year to determine if the analysis was correct and whether additional measures are necessary.

  *The Hot Fuse Program.* The Hot Fuse Program is a program for notifying Service Centers of line and transformer fuses that have experienced recurring outages, so there can be an investigation and corrective action. There are two hot fuse criteria: (1) recurring hot fuse – a fuse that has had a minimum of three outages within a 90-day period, and (2) ultra hot fuse – a fuse that has had a minimum of three outages within a 30-day period. Hot fuses are less likely than an ultra hot fuse to have a high impact to the Company's indices if left unaddressed after the 90-day timeframe. These fuse outages are more closely associated with wind-related events that are caused by vegetation or slack span contacts. The ultra hot fuse is more likely to have a high impact to the Company's indices if left unaddressed after the 30 day timeframe. These fuse outages are more closely associated with ongoing issues such as overloaded devices. A new criterion of 4+ outages in 12 months has recently been added. ¶ Our utility field inspects the hot fuses meeting one of these criteria and researches outage records to determine the cause of the outages causing the hot fuse. The Company then issues work orders to correct the problem. Typical remedies include tree trimming, the installation of wildlife protection devices, slack span adjustment, or the installation of additional fuses to resolve overloading.

*The Pole Maintenance Program.* Our utility has a Pole Maintenance Program, whereby a portion of the distribution system poles are inspected and treated annually by contract ground-line inspector crews. All poles are visually inspected. Poles that are seven years or older are partially excavated and inspected for decay below the ground line. They are also sounded and bored to locate internal voids. If the pole has sufficient strength to remain in service, it is treated with a ground line paste and an injection of fungicide and insecticide. If the pole is not of sufficient strength, it is either treated and braced, or if necessary, replaced. ¶ As a result of the pole maintenance program, Our utility replaces or braces approximately 2,400 rotten wooden poles per year. In addition, the Service Centers typically replace several hundred poles each year.

*"As You Go" Inspections.* As many as 700 personnel are in the field on a daily basis. This includes linemen, crew leaders, service consultants, and engineers. As they go about their daily business, they observe the condition of overhead facilities and report any unusual problems.

The main feeder trunks are visually inspected annually.

Yes. Our goal is to patrol every distribution circuit in our system every 2 years. Visual and infrared camera inspection are performed.

Yes. Currently under revision but old scope included: overhead and underground inspections annually, once every two years visit base of poles, record all defects found during the patrol.

We do circuit inspections after we have a breaker operation. There is no current plan to look at all circuits on a schedule. We have discussed this and are considering the benefits.

- Overhead distribution facilities are inspected on a 5 year cycle. The program consists of a visual inspection of poles, conductors, and pole mounted equipment (transformers, regulators, reclosers, capacitors, etc.) and related materials (insulators, brackets, terminations, cutouts, surge arrester, etc.). It includes inspection of foreign attachments (CATV, telephone, etc.) to the Company's poles for any safety related electrical or mechanical defects. Electrical and mechanical defects observed are identified and the information collected so appropriate corrective action can be taken.
- No answer (x1)

## Motivation

20. In the last ten years, has there been any negative publicity for your utility related to major storm damage and/or restoration?
    - No / Minimal (x14)
    - Yes (x5)
    - Yes, related to length of service restoration from Hurricane Floyd in 1999, and again to a lesser extent from Hurricane Isabel in 2003.
    - During the last ten years, whenever major storm damage has occurred, the restoration of service to our customers has been covered by both print and broadcast media. That coverage has tended to be factual and informational, related primarily to the cause of an outage as well as the company's plans for restoration.
    - I would label it somewhat negative. We had a massive, destructive ice storm in December 2007 that left a lot of customers complaining. But the ice storm was extraordinary with over 300,000 of our 750,000 customers out of service. Many were without service for up to a week. The Commission was bombarded with complaints and we began investigating system hardening.
    - Yes, had big fire with loss of many houses due to arcing connector during wind storm.

- There has been some negative publicity after Tropical Storm Allison in 2001, Hurricane Rita in 2005, and Hurricane Ike in 2008.
- The majority of our media coverage has been positive. Negative media coverage has been very minimal.
- Yes, more so for smaller isolated bad-weather outages rather than hurricanes. In the last 10 years, there has been, from time to time, a negative news article, TV story or letter to the editor complaining about our restoration efforts after a storm. These articles, stories and letters are in the minority of those aired or published, but they have been there nonetheless.
- Yes. In 10 years, there has been, from time to time, a negative news article, TV story or letter to the editor complaining about our restoration efforts after a storm. These articles, stories and letters are in the minority of those aired or published, but they have been there nonetheless.
- Unknown

21. In the last ten years, have there been any recent regulatory investigations for your utility related to major storm damage and/or restoration?
    - There has been several dockets requesting input about hardening and a docket requiring us to internally critique ourselves following hurricane Gustav.
    - Yes (x5)
    - We file an annual report with the Public Service Commission each year. We are also required to file a special report for each major storm (classified as greater than 100,000 customers (or 10%) out of service.
    - Yes. In October 2006, the the PUC initiated an investigation to examine the major power outages that occurred in October 2006. A PUC decision was issued in December 2008, and the investigation was closed. In December 2007, the PUC requested that we provide a detailed written report on the heavy wind and rain storm in December 2007 that resulted in downed utility poles and lines and outages. In January 2009, the PUC initiated an investigation to examine our widespread outage on December 26, 2008. The investigation is on-going.
    - December 2007
    - After every major storm the commissions receives a report of the restoration effort. It is more of a routine report than an investigation
    - Yes, had big fire with loss of many houses due to arcing connector during wind storm
    - Yes; after the major storm in 2006, we performed an independent study and shared the information/report with the commission.
    - After Hurricane Rita, the Public Utility Commission of Texas (PUCT) reviewed the practices concerning vegetation management, inspections, and system hardening of all utilities in Texas, including our utility.
    - The commission has issues request for information (RFIs) on occasion.
    - No (x14)

22. Has there been any regulatory interest in your state related to underground conversion of the electric distribution system in order to reduce storm damage?
    - Yes. There have been several dockets requesting input on the subject.
    - Yes (x7)
    - No (x13)
    - It has been discussed
    - Not since approximately 1995 – 1996
    - The commission has investigated the costs and benefits of undergrounding the electric distribution system, but has not required such conversions.
    - Yes, as part of the PUCT's overall Project 32182, "PUC Investigation of Methods to Improve Electric and Telecom Infrastructure that will Minimize Long Term Outages And Restoration Costs Associated with Gulf Coast Hurricanes," there was limited inquiry into underground conversions (x2)
    - No response (x2)

23. Has there been any regulatory interest in your state related more general hardening of the electric system (i.e., other than undergrounding)?
    - Yes. There have been several dockets requesting input on the subject.
    - Yes (x13)
    - No (x6)
    - None other than the current maintenance and inspection programs.
    - Pressure to adopt Asset Management System, maintain reliability
    - In 2007, the PUC adopted the National Electrical Safety Code, 2002 Edition, to replace PUC rules for overhead and underground construction that had been issued in the 1960's.
    - We have been asked about hardening, in general
    - Yes, increased vegetation management
    - No response / Don't Know (x3)

24. Please indicate all of the reasons your utility is considering distribution hardening:

| | | |
|---|---|---|
| a. | We are not considering hardening | xxxxx |
| b. | Respond to regulator concerns | xxxxxxxxxxxxxxxx |
| c. | Strengthen weak poles | xxxxxxx |
| d. | Minimize damage on important poles | xxxxxxxxxxxxx |
| e. | Minimize damage on critical circuits | xxxxxxxxxxxxx |
| f. | Reduce overall storm damage | xxxxxxxxxxxxxxxxxx |
| g. | Reduce societal cost | xxxxx |

**Post-Storm Data**

25. After restoration is complete, what sources of data are used to determine what failed and how much failed?
    - Material issued from the Companies stores system.
    - Forensic Data Collection is performed to determine root cause and performance of the system.
    - Review of summary of outage management system statistics, as well as system damage reports from patrol group.
    - OMS, E&O personnel, accounting records of material used
    - The interruption reporting system, which contains outage information on location, type of equipment, type of damage, and other facts about an interruption
    - Trouble call management system and inventory system
    - Trouble Synopsis (outlines when outages occur, customers affected, cause, details, etc.), Work order review.
    - Damage Assessment Reports, Repair Orders, Material Requisitions, etc.
    - Examination of SAP work orders, mostly concerned with dollars
    - Interruption Tracking Information System data, System Response Reports
    - We reports the type of facilities repaired or replaced during emergency response. These reports are input into a central database and can be retrieved using various query parameters for event analysis, facility trending, etc.
    - Investigation is performed
    - Outage data and forensic assessment
    - After restoration is complete, Our utility utilizes data from field inspectors and reports from repair crews to determine the facilities that failed during a storm.
    - We look at material issues from storerooms to determine what failed and the quantity.
    - Data from our Outage Management System (OMS) and hand written system operator records.
    - Outage reports, material charge reports.
    - Accounting records of what material and labor was used to make repairs.

- Computerized trouble system, GIS, computerized inventory system and computerized work order system that captures events, outages, work orders, field conditions, etc. In addition, records of field observed equipment damage and assessment reports are summarized.
- Damage assessment results as well as units of material charged to the restoration effort (x2).
- OMS data (x7)

26. Does your utility attempt to collect detailed damage data at a certain number of damage locations before system restoration begins? If so, please explain.
    - No (x10)
    - Yes (x2)
    - Yes, the day after the storm passes forensic data is collection.
    - Yes, we use patrollers to evaluate areas with suspected heavy system damage, so that we can then dispatch the appropriate crews to make repairs and restore service.
    - Yes, we perform a damage assessment before and during restoration
    - Generally, attempts are made to accurately record the damage/cause of outages. We use a two-prong approach. First, the majority of the feeders have SCADA so we can quickly assess the specific areas with the largest number of customers impacted. This allows for the immediate deployment of field crews. We obtain damage information from the first responders and field crews. In addition, as a part of our storm restoration process, we use Damage Assessors as whose role it is to patrol and assess targeted areas to determine the extent and type of damage. For example, number or trees down, broken poles, streets blocked, etc.
    - Not currently, however we are in the process of implementing a “storm assessment team” program whereby teams would survey damaged areas to determine the extent and location of damage
    - Outage synopsis review to determine poor performing equipment
    - No. Restoration is first priority.
    - No, very high level restoring priority circuits first
    - Yes, we send out evaluators on pre-defined routes to assess the number of broken poles, downed lines, trees in line and a few other situations. We then use an in-house model to forecast total system damage. This helps in the decision process for manpower needs and estimated restoration time.
    - Yes. We send out T-men and Make Safe teams to assess detailed damage. From a prioritization standpoint, they are also used for main line restoration. For larger storms, we use other resources such as Gas Service Representatives and Estimators to perform assessments.
    - Yes, an investigation is performed to determine what occurred
    - Yes, we have a Damage Assessment (DA) process that starts when the storm subsides and continues through the process. We start with a statistical DA to determine extent of damage and assess resources needed. We then proceed to a pole by pole DA. We have a third Forensic Assessment to satisfy the PSC requirements on cause of damage.
    - Yes. Our utility collects data from field inspectors assigned to circuits that do not have a repair crew assigned. Currently, Our utility does not perform a forensic analysis.
    - Yes, we use scouts after the storm has passed to assess the extent of the damage to determine material and labor needs. However, we do not collect data for the purpose of forensic analysis to determine the exact causes of failures.
    - No, unless it is a large event and added details are gathered to determine manpower needed and materials that are required to make repairs.
    - Yes. We employee two assessment techniques. (1) In our Rapid Assessment mode we send out personnel to multiple damage locations across our service area to provide a quick “drive by” assessment of damage. (2) For major storm events where we have one or more days of advance warning; we position damage evaluators in or near the storm area. These damage evaluators usually provide a more precise evaluation of the damage than the “rapid assessment” by substation/circuit/town.

27. If the answer to the previous question is "yes," is a process followed to ensure that the collected data is statistically representative of the overall system?
    - No answer / not applicable (x14)
    - Yes (x2)
    - No (x5)
    - Yes we use a consultant that performs a statistical sampling.
    - Usually the areas with the most significant damage are limited to parts of our service territory, rather than the whole territory, but we will patrol any area with suspected damage.
    - Outage causes are reviewed, trended, and analyzed
    - We drive out the pre-defined routes, but would not say it is statistically valid although we do enough routes that our results have been amazingly close to actual damage, e.g. # of poles replaced.
    - We attempt to look at damages associated with circuit outages, number of "wire down" calls, number of total calls, if the damage is widespread or concentrated in few areas etc.
    - Yes, the data our utility collects is extrapolated over the system to provide an estimate of damage across the Company's footprint. It is updated daily to add information as it becomes available.
    - Yes, from the perspective of the data from scouts to determine how much damage there is.

28. Please evaluate this statement: "Our post-storm data is sufficient to determine major factors that led to storm damage, and allows us to focus our hardening approach on these major factors."

| | | |
|---|---|---|
| a. | Not true | xxx |
| b. | Somewhat true | xxxxxxxxxxxxxxxxxxx |
| c. | True | xxxxx |
| d. | No answer | x |

29. Does your utility have damage prediction models that are used to estimate the damage that will occur during an incoming storm? If so, what data are used to develop and improve these models?
    - Yes. We use previous storm damage versus wind speed to predict upcoming storm damage.
    - Yes, but is a high level estimator.
    - Yes. The data used to develop and improve the model was historic storm related sustained outages and weather data. The weather consisted of wind speeds, wind gust, wind duration, and lightning strokes. Other factors include the time of the year (winter vs. summer storms), ice accumulation, and snow accumulation.
    - No. We have discussed partnering with a local university to develop a model, but not moved forward with the idea.
    - Yes, we recently tested a Storm Outage Predictive Model. We use pressure gradient patterns from the last 14 years and perform correlations to customer and outage counts. We also identify peak pressure gradient periods. With this information, we forecast crews that should be pre staged for an event. To improve the model based on the test -- we will be increasing the accuracy by accounting for non-pressure gradient variables such as snow and lighting, adjust crew restoration time assumptions, and improve our outage forecast assumptions.
    - Yes, before the storm makes landfall a predictive model is used to estimate damage and resource needs by region. The model is based on data from previous storms and is linked to wind tables from our weather service provider. Immediately after landfall, we utilizes the damage assessment (DA) tool. This is a tool that utilizes damaged data from static pod areas as a statistical representation of the entire system. DA teams are sent out immediately following the impact of a major storm event and collect the damaged data in pre-identified areas. The tool extrapolates the damage and provides this data from a system perspective (by Ops Center, Region, System). This model has an 85% confidence level.
    - Yes. Our utility has a damage prediction model that is currently being enhanced. Our utility has its distribution facilities digitized along with attributes such as pole size and class, wire size, equipment installed, year of last ground line treating, and tree location in the GIS. Our utility procures predicted weather data such as wind speed, wind gusts, wind direction, and amount and time duration of rainfall. This data is provided in GIS shape files. Our utility lays the weather prediction shape files over the facility data in the Company's

GIS and compute the predicted damage (amount and location) in accordance with algorithms that the Company has developed. Actual damage and actual weather data compared to the predicted values allows the Company to modify the algorithm and improve the damage model performance based on historical data.

- Yes, we have two separate models. One model uses the track and wind field data provided National Hurricane Center. It determines the maximum wind speed and wind level duration over each GPS-defined substation and transmission structure. The output is the number of transmission structures and distribution poles forecasted to fail. Restoration resource needs are calculated from this data. The second model takes a broader view of the storm impact on the total system; but provides a similar output of restoration resource needs based on the NHC's category of tropical system.
- We are not presently using a computer based damage prediction model prior to an incoming storm; but, base our preparations on previous storm experience and weather forecasts.
- Yes. We use failure percentages from our own experience for facilities within certain geographic areas and, as well as failure percentages from other electric utilities' experiences.
- No / No response (x18)

## Hardening

30. Has your company performed a system hardening review, developed a hardening roadmap, or something similar? Explain.
    - No (x8)
    - Yes.
    - Yes, it is part of our Storm Hardening filing.
    - Began Grade B construction in 2008
    - Not really
    - No. We do not call it system hardening. However, we do conduct a detailed analysis of system performance and direct programs to the areas of greatest concern, whether this is geographic, equipment specific, type of failure, cause of system performance, etc.
    - None other than the current maintenance and inspection programs
    - Yes, we did a high level estimate/study for the cost to harden and the resulting savings in storm outage times
    - We recently completed the field work on a hardening pilot on one circuit
    - Minor
    - Yes, we hired an outside consultant to develop a hardening roadmap after the 2006 winter storm
    - Yes, primarily focused around increased vegetation management
    - No. We are, however, in the process of looking into this.
    - Yes. We filed a three year plan in 2007 to as per our commission order.
    - Our utility evaluated hardening alternatives after Hurricane Rita in 2005 and Hurricane Ike in 2008, and the Company is in the process of analyzing the information.
    - Yes. In 2007, Our utility completed a "Hurricane Hardening Study" for Transmission, Substation, and Distribution construction.
    - Not for hardening specifically but we have performed an infrastructure analysis to determine the expenditures required to maintain or improve our system according to failure rates and asset age.
    - Limited review.
    - We have conducted some studies internally and in response to PUCT inquiries, and, as a result, it is AEP's belief that our current practices produce a reasonably reliable system without incurring costs that exceed any additional benefits. For that reason, we have not developed a "hardening roadmap".
    - We have studied the distribution system to the extent necessary to respond to the PUC questions related to hardening.
    - No answer (x1)

31. Has your utility committed itself to hardening its distribution system? Explain.
    - We are in discussion now.
    - Yes (x2)
    - Yes, we change out wood poles to concrete at critical junctions, we remove damage trees.
    - Yes, reliability trends are analyzed and programs developed to address.
    - No (x9)
    - Yes, we were just given approval by the Commission to do $3M in 2009, $15M in 2010 and $15M in 2011 for system distribution circuit hardening. Also some for vegetation management. The costs will be recovered through a regulatory rider.
    - Yes. We have adopted a policy to utilize a minimum 40ft, class 2 poles for primary installation, and use Grade B for all pole replacements and new pole construction. In addition, we have a pole replacement program to replace poles that are in bad condition.
    - We have increased spending to harden the system
    - yes, through increased vegetation management
    - Only when it comes to poles
    - Yes, per our commission order
    - Our utility utilizes good construction standards and the system has performed well in major events. During Hurricane Ike, less than 1% of the Company's distribution poles were destroyed. At the current time, Our utility has evaluated many hardening ideas and has not determined specific actions that are justified.
    - We have implemented the recommendations listed in our 2007 Hardening Study.
    - We are in the process of developing pilot projects.
    - Limited
    - Not at this point, any hardening efforts are simply a part of our normal design and construction process and not something we are specifically attempting to achieve.
    - We are committed to providing reliable service at a reasonable cost. When it makes economic sense to adopt a "hardening" practice as part of our normal design and construction processes and practices, we implement it. An example of this is the current practice of designing and constructing to exceed the NESC wind loading requirements for distribution structure within 5 miles of the coast line.
    - No answer (x1)

32. Has your utility performed any significant hardening activities? Explain.
    - Not at this time (x3)
    - Yes
    - Yes, we change out wood poles to concrete at critical junctions, we remove damage trees
    - Yes. Lightning Enhancements, Targeted Corrective Maintenance, Pole Replacement/reinforcements, Vegetation Management
    - We are starting to replace old pins and cross arms before they break.
    - Yes. We have adopted a policy to utilize a minimum 40ft, class 2 poles for primary installation, and use Grade B for all pole replacements and new pole construction. In addition, we have a pole replacement program to replace poles that are in bad condition.
    - Yes, we are replacing more poles, underground OH infrastructure, improve ROW, etc.
    - yes, through increased vegetation management
    - Yes, per our plan filed with the commission in 2007.
    - Yes. Certain design practices that can be considered "hardening activities" have been in place for many years, such as the installation of storm guying for distribution lines located in open, marshy terrain near coastal areas. These existing practices which have been shown to be beneficial will be continued. The more recent recommendations for hardening our utility distribution lines will be adopted incrementally as new facilities are installed, or during the required maintenance of existing facilities, such as the replacement of a rotten pole. The wholesale rebuilding of existing facilities is not recommended.
    - Yes, revised construction standards were developed to strengthen wood pole foundations including pole stabilization foam be installed for all heavily loaded poles (i.e. corners, dead-ends, large angles, and major

equipment poles) and where poor soil conditions are encountered. In addition, we have increased its focus on the condition of foreign poles. Finally, when practical and on a very limited basis, concrete poles are designed rather than wood poles for NESC Grade B highway crossing.

- Other than what has already been stated, the only other activity that we currently have is a pilot program to test customer/developer acceptance to the idea of front-of-lot- service. We are offering an additional allowance against the cost of extending facilities to serve the customer if the customer will agree to front-of-lot service (x2).
- No (x9)
- Not yet
- No answer (x1)

33. Is your current budget for hardening the existing distribution system (other than vegetation spending):
    a. None xxxxxxxxxxxx
    b. A little bit xxxxxxxx
    c. A moderate amount xxxxxxx
    d. A lot x

34. Have any hardened portions of your system been subject to major storms? If so, please comment on how well they performed.
    - Yes
    - No / not applicable (x13)
    - Concrete poles have stood during a few hurricanes and our aggressive right of way clearing has made a huge difference in lines down due to trees.
    - We are experiencing a reduced number of pole failures that have been inspected and repaired.
    - Sky Wire showed an increase in performance, Lightning Arresters no noticeable performance change
    - Pins and crossarm work has definitely helped.
    - Yes. They performed well. Most of the damages during the last major wind and ice storms were mainly due to downed wires. Pole damage was kept to a minimum.
    - Yes, we have not done a review of those areas yet
    - Yes. Tropical Storm Fay in 2008 hit a portion of our system. There was little damage on the storm hardening project.
    - Yes for past practices. Given the Company's recent implementation of other hardening strategies, the Company has not conducted a specific study to analyze the effectiveness of its hardening efforts.
    - Yes. However, results are masked typically from off-ROW debris/trees.
    - No. We have adopted this practice fairly recently; therefore, there have not yet been any new complete feeders that were built to the extreme wind standard exposed to a major storm (x2).
    - Don't know
    - No answer (x2)

35. Please check <u>all</u> hardening activities that you are doing or have tried (for hardening purposes):
    a. Grade B construction xxxxxxxxxx
    b. Stronger poles xxxxxxxxxxxxxx
    c. Shorter spans xxxxxxxxx
    d. Storm guys xxxxxxx
    e. Push braces xx
    f. Extended-length pole braces xxx
    g. Relocating pole-mounted equipment xxx
    h. Relocating third-party attachments xxx
    i. Elimination of crossarms xx
    j. Elimination of porcelain insulators xxxx
    k. Small primary wire replacement xxxxxxxxx
    l. Elimination of bare secondary wire xxxxxxxxxxx

m. Break-away wire ties x
n. Break-away service drop connectors xxx
o. Conversion to underground xxxx
p. Other (please explain) Lightning protection, focused maintenance, OH FCIs at strategic locations, reclosers, vegetation management, pole stabilization foam, increased focus on foreign poles

36. For poles of equal height, do you set stronger poles deeper?
- No (x18)
- Yes (x2)
- No -- only self supporting concrete poles.
- No, exception class 1 poles go 1 ft deeper (x4)
- At times.
- This is currently being evaluated.
- No answer (x1)

37. Have you utilized cost-to-benefit analysis for spending related to hardening?
- No (x11)
- Yes (x9)
- Not yet, in development
- Yes. For the pilot we did B/C for each hardening option considered.
- Our utility is still in the process of evaluating the cost-to-benefit analysis for spending.
- Nothing as sophisticated or detailed as studies reported in the Quanta Technology Report to the PUCT. However, a utility has the burden of proof to include any costs in base rates should investments in distribution be challenges during a general rate case (x2).
- Limited studies
- No answer (x2)

38. If applicable, please describe how hardening projects are prioritized.
- At this time hardening is on new projects only, we are not hardening existing system.
- Our three year storm plan calls for 2 hardening projects to critical customers at the extreme wind construction Grade B.
- Reliability programs are prioritized based upon their cost efficiency for the improvement expected.
- Safety, reliability and regulatory compliance.
- By riskiness of not doing the project
- Cost, CMI saved, past circuit outage times, priority circuits
- Have only done pilot. No plans to implement system-wide hardening
- Prioritized along with other system projects
- We use a model developed by a consulting company.
- Dedicated hardening projects are not developed. Instead, hardening strategies are incorporated into new construction projects and into maintenance projects.
- No projects were pursued (x4)
- No response/not applicable (x14)

## Best Practices

39. Would an increase in the aggressiveness of distribution hardening reduce major storm damage for the hardened areas:
a. A little bit xxxxxxxxxxxxxxxxx
b. A moderate amount xxxxxxxxxxx
c. A lot (none)

40. What else besides hardening (non-vegetation related) would be effective at reducing the impact of major storms on customers?
    - No response (x6)
    - Wind blown debris and falling trees will cause the major storm damage.
    - Distribution Automation to speed the restoration process, and smart-meter technologies to confirm customer outage status.
    - Do not build homes and businesses close to the beach
    - Restoration process improvements to reduce outage duration
    - Heightened communication with customers wouldn't eliminate the outages but could reduce the impact and anxiety that customers are subjected to.
    - Better conductor connections, tool inspection program to ensure tools torque is at appropriate levels
    - Not investigated at this time
    - Undergrounding overhead service drops
    - Additional protective devices
    - Automatic switching
    - Redesign system to break into smaller taps
    - Spreading conductors on arms
    - Educating the customer on customer owned and maintained facilities such as service riser, weather head etc., and also how to recognize electric, CATV and telecom wires in order to contact the appropriate company for damage repairs.
    - Replacing aging infrastructure
    - Undergrounding, break-away service drop connectors, reinforced service mast, storm guys
    - Additional circuit ties; more SCADA
    - We are still evaluating the plan based on storms that hit the area. We need more storms to make that evaluation.
    - Our utility believes that ownership by customers of back-up generators would effectively reduce impacts of major storms on customers. More distribution automation would help reduce restoration times.
    - It is our opinion that any utility-based strategies in addition to those that we are implementing would not be effective from a cost/benefit standpoint.
    - More isolation points and fusing.
    - In the storm surge areas - nothing. For other areas, installation requirements for the distribution facilities in either dedicated alleyways (constructed for all-weather use) or along the street right of way. This would require the cooperation of the city or county governments in their respective plat approval and permitting processes, in addition to keeping the alley or street right of way clear and trees of the proper type or properly trimmed.
    - The installation requirements for the distribution facilities in either dedicated alleyways (constructed for all-weather use) or along the street right of way. This would require the cooperation of the city or county governments in their respective plat approval and permitting processes, in addition to keeping the alley or street right of way clear and trees of the proper type or properly trimmed.

41. Please describe any hardening approaches that did not turn out to be good ideas.
    - No response / not applicable (x23)
    - Lightning arresters
    - Complete "Undergrounding", too expensive
    - We are still evaluating the plan based on storms that hit the area. We need more storms to make that evaluation
    - Prior practice was to attach storm guys about half way up the pole from the ground line. Following a recent 2008 storm, many of these poles broke in half at the guy attachment point. In contrast, poles which had storm guys attached much higher on the pole did not experience as much damage.

42. Please describe any hardening approaches that did turn out to be good ideas.
    - No response / not applicable (x17)
    - Building to Construction Grade B.
    - Target Corrective Maintenance 30422; Lighting Arrester Program, Targeted distribution automation
    - Pole replacement program and a focused inspection and repair program
    - Sky Wire (overhead ground wire)
    - Use of trusses
    - We in the process of determining
    - Replacing locust pins and old crossarms
    - Tree Trimming, Grade B construction, pole inspection and pole replacements, periodic pole attachment surveys and follow up.
    - We are still evaluating the plan based on storms that hit the area. We need more storms to make that evaluation
    - Attaching storm guys as high as possible.
    - Stronger poles, elimination of bare secondary wire, pole stabilization foam, increased focus on foreign poles

43. What would it take for your utility to more effectively pursue distribution system hardening?
    - Mandate
    - Already hardening system.
    - Money
    - Data collection, money
    - Regulatory approval which we just received
    - Commission directive, more customer complaints or more budget
    - A substantial worsening of reliability due to storms (x3)
    - PUC mandate
    - Reliability driven, directed by Regulator or Shareholder
    - The storm hardening pilot projects will be evaluated with real hurricanes that pass the service territory. The results of the evaluations will determine if more projects need to be deployed.
    - Our utility believes that prior to adopting any distribution system hardening requirements the Commission should ensure that the benefits achieved by such hardening of the system are greater than the costs for compliance with the requirements. In addition, there would need to be more effective and timely cost recovery assurances for the expenditures than currently exist.
    - Partnering with communities on hardening issues and cost sharing, and timely cost recovery from regulatory authorities, would allow the Company to more effectively implement and pursue hardening strategies.
    - A budget.
    - Assurance from regulators that costs expended for system hardening would receive adequate rate relief.
    - Cost recovery that did not put undue burden on customers and prevent us from having funds to support safety, environmental or other strategic issues.
    - We believe that we are currently utilizing all practical "hardening" practices that are reasonably cost effective; however, if the PUC decides that additional measures should be taken, the PUCT should adopt a streamlined process that would allow utilities to timely recover the additional costs without the expense and regulatory lag associated with a general rate case (x2).
    - Not applicable / No response (x7)

44. What would you recommend as a best practice for distribution hardening?
    - Building to Construction Grade B
    - follow the NECS, maintain good right of ways and strengthen critical junction poles
    - Use of statistical data analysis to surgically focus on the right programs in the right areas for the types of storms experienced

- Frequent inspections and proactive focus on reliability concerns
- Do as required to achieve reliability goals
- Not evaluated at this time
- Still learning…
- For our particular pilot, the 3 top tactics with low-medium cost and high benefits were more frequent tree trimming, installation of a mid-circuit recloser and installation of OH fault indicators
- Replace old wood pins and crossarms
- Educating the customer on customer owned and maintained facilities such as service riser, weather head etc., and also how to recognize electric, CATV and telecom wires in order to contact the appropriate company for damage repairs.
- Improve ROW and underground existing OH infrastructures
- Aggressive storm hardening on the trees, branch stiffening and reducing wind load through the trees
- Consistent and regular maintenance of the distribution system and adherence to established construction Standards. Also, for pilot project selection utilization of internal engineering resources to perform prior year patrols of the potential projects to identify the infrastructure needs and demographic data to help support the associated hardening improvements needed and the projected costs.
- Our utility believes that placement of distribution facilities in residential subdivisions underground and placement of facilities in the front of the lots of new residential service are best practices. Aggressive continued vegetation management and wood pole inspection programs are best practices. Best practices would also include removal of hazard trees outside of the easements.
- The installation of storm guys at required intervals is the most cost effective solution for structure support.
- Shorter spans.
- Tree trimming and removal.
- We believe that the best practice is to design and construct all new distribution facilities based on the proper structural analysis using NESC standards (x2)
- No response (x9)

45. Any other thoughts or comments on the subject of distribution hardening?
    - Not applicable / No response (x16)
    - We are piloting a breakaway OH service connector
    - Undergrounding is not the answer for coastal area exposed to storm surge.
    - The utilities that are not performing pole inspections, maintaining good right of ways, etc are making it tough of the rest of us. The regulators look at the utilities that are not doing these things and then impose various system hardening rules we have to follow when some of it is over-kill. Plus, it's the customer who eventually has to pay for it.
    - Difficult to justify cost
    - We'll be starting out projects quickly. Involvement from System Engineers, GIS folks and Boots (people out in the service areas) are critical to determine what needs work and what does not.
    - We concluded that hardening options are specific to the circuit and the customers it serves.
    - Won't happen until something establishes a value to outage avoidance. That will be PUC action, bad publicity, liability, or management perspective.
    - Our system held up well to the significant impact of Hurricane Ike. The Company experienced less than 1% of distribution poles were destroyed; most of the damage was due to extreme events outside of the Company's control, such as large trees falling on the lines. Harding the grid must be evaluated based on realistic results and the cost impact to electricity rate payers. There is no "silver bullet" for grid hardening.
    - Our utility does not recommend costly measures such as conversion to underground. In addition to the obvious tremendous conversion cost, underground facilities can also be damaged during storms, especially in areas subject to tidal surge and salt water intrusion leading to multiple failures, which, along with the difficulty in determining the precise location of underground line failures, leads to lengthier outages. Underground facilities will also lose power due to upstream transmission line or substation damage, even if the distribution facilities are intact. Our practices take into account experiences and knowledge from our utility's other operating companies.

- As most of our service territory is situated well inland, most of the Hardening questions and business cases appear to be more relevant to coastal regions.
- While we are applying an extreme wind loading design to new distribution construction in coastal areas, we have many circuits in coastal areas that were built to previous standards. The upgrade of those circuits to the new hardened standards could be accomplished if the PUCT adopts a streamlined cost recovery mechanism that allows a reasonable rate of return (x2).

# Appendix D – Storm Hardening Toolkit

There are many possible approaches to harden distribution systems against hurricane damage, each with advantages, disadvantages, and interrelationships with other approaches. A brief description of the major distribution hardening approaches is now provided.

**Stronger Poles –** Pole strength is one of the most important factors for extreme wind rating. This is true for new construction, where stronger poles allow for longer spacing between poles, and upgrading of existing construction, where extreme wind ratings can be increased by upgrading existing poles with stronger poles. When selecting a pole, there are several important factors that must be considered. These factors include weight, visual impact, wind performance, insulating qualities, corrosion, and climbability. The most promising alternatives to wood for strong distribution poles are steel and composite (concrete tends to be too heavy for typical digger-derrick trucks).

**Upgraded Poles –** There are several ways to increase the strength of an existing pole. This includes using an extended-length steel brace that is driven below the groundline and extends above any third-party attachments. This can typically increase the strength of the pole by two to three pole classes. Another approach is to increase the strength of the pole with a fiberglass wrap, although this is much more expensive.

**Shorter Spans –** Shorter spans directly result in a higher extreme wind rating. Using shorter spans also allows hardened systems to use standard construction practices and materials. For this reason, shorter spans should always be considered as an approach to hardening. However, sometimes it is not practical to shorten spans in certain areas, and in many places the span length required to meet extreme wind criteria would result in many close-spaced poles and a corresponding high visual impact.

**Storm Guying and Push Braces –** Adding transverse guys to existing poles (one on each side) serves to transfer some or all of the stress from wind forces from the pole to the guy wires, thus enhancing the overall ability of the installation to survive the storm event. Adding push braces to existing poles can provide similar benefits to adding storm guys. Storm guys and push braces typically move the weak point of the pole to the height of the pole attachment location. Therefore, storm guys and push braces should be connected to the pole as high as possible.

**Pole-Mounted Equipment –** Wind forces on pole-mounted equipment transmit force to the pole in addition to forces generated by conductor, attachments, and the pole itself. Therefore, wind forces on pole-mounted equipment must be considered in the hardening analysis, especially for higher gust speeds. Equipment mounted on poles can significantly impact the maximum allowed span, especially for the higher extreme wind ratings. Therefore, it is important to understand this effect and potentially leverage it when considering hardening alternatives (e.g., converting a three-phase pole-mounted transformer bank to a pad-mounted unit).

**Third-Party Attachments –** For hardening purposes, the benefits of fewer attachments are reflected in the extreme wind rating of the overall distribution design including pole height, pole strength, span length, conductors, attachments, and other pole loading considerations. All else equal, fewer and/or smaller attachments will result in a higher extreme wind rating, which will result in a reduced probability of failure during a hurricane. Removing third-party attachments can be an effective way to increase extreme wind ratings from an engineering perspective. The practicality of removing third-party attachments will vary for each specific situation.

**Pole Hardware –** Wind forces can have adverse effects on framing materials such as insulators, crossarms, conductor ties/clamps, brackets, and other associated hardware. Use of stronger design standards can reduce damage in these areas.

**Undergrounding –** The conversion of overhead distribution to underground (undergrounding) removes extreme wind as a design factor. However, undergrounding is expensive and, except in targeted situations (such as undergrounding as part of a road widening), cannot be fully justified based quantifiable benefits. Undergrounding (from a storm hardening perspective) is actually worse in coastal areas subject to storm surge damage. Therefore, justification almost always must rely on qualitative and often intangible aesthetic benefits. This conclusion is reached consistently throughout a large body of published literature.

**URD for New Construction –** It is often not too much more expensive to serve new neighborhoods with an underground system than an overhead system (consisting of pad-mounted transformers supplied by underground residential distribution (URD) cable. Many utilities are already serving most of their new communities with underground service. Utilities not doing this should consider it from a storm hardening perspective. An underground residential system allows restoration efforts to focus more on the three-phase parts of the system, and results in far less damage to service drops and customer-owned equipment.

**Elimination of Rear Lot Lines –** Distribution systems routed through rear lot lines are notorious for restoration difficulty after a major storm. Damage is typically greater than average due to the proximity of extensive vegetation, and restoration is difficult since bucket trucks and derrick-digger trucks cannot be used. Although expensive, utilities should include the elimination of rear lot lines (preferably by the conversion to a front lot underground system) in their hardening toolkit.

# Appendix E – Storm Hardening Roadmap

Hardening infrastructure for severe storms is an emerging but important topic. Ideally, a utility can compute the expected damage that will occur in future storms, compute the cost of various hardening options, and determine the expected damage reduction and societal benefits that will result from each of these options. This process allows for decisions to be made based on quantifiable costs and benefits, and goes far beyond the design of structures to a specific strength.

There are four primary motivations for targeted storm hardening:

<u>Primary motivations for targeted storm hardening</u>

1. Keep high priority customers on,
2. Keep important structures standing,
3. Keep economic centers on, and
4. Strengthen structures that are likely to fail.

**Keep high priority customers on.** After a hurricane strikes, certain customers will be assigned a high priority for restoration. Examples include hospitals, dispatch centers, fire stations, and police stations. Regardless of where these high priority customers are on the system, crews must be assigned to quickly assess damage and make repairs. This can result in an inefficient use of crews when compared to an optimized restoration plan. Therefore, strengthening the system so that high priority customers remain on allows for faster and more cost-effective overall restoration.

**Keep important structures standing.** When a hurricane strikes, there are certain structures that utilities wish to keep standing. These include structures that are expensive to repair, take a long time to repair, are difficult to access, or are critical in the restoration process. Examples are structures with automation equipment, structure critical for Smart Grid functionality, structures used for freeway crossings, junction poles, and so forth. Therefore, strengthening the system so that certain structures remain intact allows for faster and more cost-effective overall restoration.

**Keep economic centers on.** From a customer perspective, life after a hurricane is much nicer if certain facilities are available such as gas stations, restaurants, and home improvement stores. There a utility may wish to harden certain areas so that economic centers with large concentrations of these types of customers can stay on or be more quickly restored.

**Strengthen structures that are likely to fail.** It may be desirable in certain cases to strengthen structures that are particularly vulnerable to failure, just so that less damage occurs. For example, extreme wind ratings could be calculated for all structures on a distribution circuit. All structures with an extreme wind rating lower than a specified value could be strengthened if practical.

Increased performance expectations for major storms will result in many utilities choosing to exceed safety standards in an effort to reduce storm damage. This decision to harden the distribution system is potentially expensive and politically sensitive. It is therefore desirable to define a clear strategy for hardening and to translate this strategy into a hardening roadmap that identifies anticipated actions, costs, and benefits. This roadmap must address two key questions. First, how should circuits be prioritized for hardening? Second, what should be done on each circuit to be hardened?

When a severe storm hits an area and results in widespread damage, there are certain critical facilities that typically have priority for restoration. Circuits serving these facilities should be targeted first for hardening. Examples include circuits serving hospitals, nuclear plants, and dispatch centers. In addition, it is desirable to harden circuits serving large numbers of essential services such as gas stations, grocery stores, restaurants, and home improvement stores. These types of critical facilities are “no brainers” and present a good opportunity to become familiar with the rest of the hardening process.

Any significant in distribution hardening will be a multi-year effort. Instead of making hardening decisions each year, a utility should define its desired future state, such as a set of hardening goals achieved over the next five years. The utility can then compare the desired future state to its current state, identify gaps, and determine yearly resources and funding so that the utility can transition from its current state to the desired future state in a systematic and cost-effective manner. This plan is called a “hardening roadmap.”

Achieving the proper level of infrastructure performance during major storms at the lowest possible cost is a challenging task, but will increasingly be demanded of utilities by their regulators and customers.

# Hazard Trees: Benchmark Survey and Best Practices

## FINAL REPORT

**Prepared for:** **Public Utility Commission of Texas**
**Project No. 36375**

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# Executive Summary

A survey has been performed on utility hazard tree management. Thirty-two utilities responded, geographically representing the US from north to south and from east to west. The survey captured information regarding existing practices and recommended best practices in the areas of tree trimming, tree outages, hazard tree identification, and hazard tree removal.

For the purposes of this report, a *hazard tree* is a tree with a structural defect likely to cause failure of all or part of the tree, which could strike a the utility lines if it falls over. A tall but healthy tree is not a hazard tree. A healthy tree that is tall enough to fall into the power lines is called a *danger tree*.

Many of the utilities responding to the survey seem to be satisfied with their hazard tree programs. Many claim that they are keeping up with the natural rate of tree mortality, assert that additional effort in hazard tree management will not reduce storm damage, and posit that they cannot think of anything additional or different that they could do better to manage hazard trees. Although these utilities may feel that they are addressing hazard trees in an appropriate and effective manner, most would be hard-pressed to *prove* that this is the case. Based on this and the overall survey results, the author has assembled a list of eighteen best practices that will help to ensure that hazard trees are being managed through a process that is cost effective, consistent, transparent, and data-driven.

These best practices should be taken in context. First, many utilities will already have many of these elements, or their equivalent, in place. Second, each utility is in a unique situation with regards to hazard trees. Certain best practices, though appropriate for most utilities, may not be appropriate for all. In any case, all utilities are encouraged to examine the proposed best practices. Some can be implemented at little-to-no cost, and others may allow hazard trees to be more effectively managed at a lower cost.

Recommendations are not intended to be a "one size fits all" approach. For example, a utility with very little tree exposure may not need to have any formal hazard tree program at all. Similarly, utilities where tree fall-ins result in a small percentage of customer interruption minutes (e.g., less than 5%) may not need to change their approach as long as they can demonstrate cost effectiveness.

Best practices are organized into three stages. The best practices in the first stage are inexpensive and relatively simple to implement. In addition to being potential quick wins, they also set the foundation for more ambitious actions. The best practices in the second stage are designed to be implemented in the medium term and generally require more utility effort, investment, and potentially change. Generally, the experience and data obtained from the first stage will be helpful when implementing the second stage.

The best practices in the third stage should be considered after a utility has a very good handle on its hazard program including the costs and benefits of a more aggressive approach. These recommendations are recommended if utilities wish to significantly reduce the number of tree-related failures during major storms. Since most tree failures during major storms are apparently healthy trees (i.e., not hazard trees), some of the recommendations in the Third Stage go beyond hazard trees, are potentially expensive, and are sensitive to property owners. Therefore, utilities must carefully consider whether the benefits associated with these Third Stage recommendations justify the costs and other implications.

**First Stage**

1. **Culture change.** In any organization, it is important to align goals with the culture. In the case of hazard trees, it is important for all employees to be aware of the issue, its importance, the support of executive management in effectively managing hazard trees, and the expected benefits. A first step in hazard tree management is to identify an executive champion, execute an initial communications plan, and maintain continuing communications about status, wins, and future goals. Culture change is most important for utilities that need to significantly change their approach to hazard tree management.

2. **Separate hazard tree budget.** To ensure a sustained and consistent effort from year-to-year, it is important for hazard tree management to have its own budget separate from clearance activities. The way the work is managed and executed may not change, but the amount spent specifically on hazard tree management will be tracked side-by-side with tree pruning. A hazard tree budget can be part of another budget (e.g., overall vegetation management, all tree removals) as long as there is a separate estimate for hazard tree spending and separate tracking of hazard tree expenditures.

3. **Hazard tree data.** Cost-effective hazard tree management must be data driven. Therefore, it is important for utilities to have a robust data collection process for hazard trees. At a minimum, this should consist of three elements. First, all identified hazard trees should be documented in a standard form. Important information to collect includes the location, species, defect, distance from lines, date of identification, date of removal, and any information about gaining customer approval. Second, a sample of trees that fall into the distribution lines should be examined by a qualified arborist to collect similar data, especially the species, distance from the power line, and whether there were visual defects that could have been identified before the tree fell over. Third, the outage management system should be able to capture basic data for <u>all</u> tree-related interruptions on the distribution system. This requires clear cause codes that can be assigned by linemen such as: tree fall-in within ROW, tree fall-in outside of ROW, broken tree branch, tree grow-in, and other tree cause (explain). The vegetation management group should obtain regular updates of the distribution outage information and be able to easily cross-reference this data to the richer, but less extensive data collected by arborists.

4. **Post-storm data collection.** Many trees fall down during major storms. The data associated with these trees are invaluable when trying to manage hazard trees in a manner that is most beneficial during major storms. Therefore, a utility should have a plan that has damage assessors collect data on fallen trees while they are already out in the field. For example, damage assessment forms could have a check box labeled, "trees likely caused this damage," possibly with a selection of the types of trees that contributed to the damage. A process should be in place so that all damage assessment forms are retained so that the information can later be entered into a spreadsheet or database for analysis.

5. **Inspection procedures.** In order to improve the effectiveness of hazard tree identification, inspection procedures should be documented and the inspections should be performed according to these procedures. Typical inspection procedures should include who should perform inspections, when inspections should occur, and specific actions that should take place during inspections. These procedures may be different for different situations (e.g., dedicated hazard tree inspections, pre-inspections done by arborist prior to cycle trim, inspections done by linemen during circuit patrols, etc.). These procedures should specify, at a minimum, how far back from the lines to inspect, when the inspector should

walk around the tree, and specific defects to look for in different tree species. It may be appropriate to have different procedures for different geographic areas.

6. **Maximize customer approvals.** Even if a utility can forcibly remove a hazard tree from customer property, it is always desirable to obtain customer pre-approval. Utilities should collect data on initial customer approval rates and ultimate customer approval rates. The benchmark data suggests that a 95% approval rate is reasonably possible to achieve. If approval rates are lower, the utility should employ more extensive negotiation tactics that may include negotiation training, customer education, debris removal, tree replacement, tree vouchers, and possibly the threat of financial liability. If not being done already, the utility should strongly consider paying for the removal of customer-owned trees that pose a hazard to utility equipment.

**<u>Second Stage</u>**

7. **Manage backlog.** There should be clearly documented goals and processes for the removal of identified hazard trees. Documentation should also exist to show that these goals are being met. Processes should be in place to ensure that imminent threats are addressed immediately. Hazard trees identified on pre-patrols should, of course, be removed when the tree crews arrive at the location. Hazard trees identified through other processes should generally be removed within one month. Showing that the hazard tree backlog is being well-managed establishes credibility, in addition to being a best practice.

8. **Maintain pruning cycle.** Since the pruning cycle is often the primary mechanism for hazard tree identification, being behind on the pruning cycle will result in being behind on hazard tree removals. In addition, utilities that are behind on their pruning cycle often, in an effort to catch up, shift focus and budgets from hazard trees to clearance work.

   Tree growth rates can vary from year to year based on precipitation and other factors. Therefore, a strict and inflexible pruning cycle is not the intent of this recommendation. Once a utility establishes its pruning cycle, it is appropriate in certain cases to defer pruning on certain scheduled parts of the system if there is evidence that pruning is not necessary.

9. **Hazard tree database.** Once a utility begins to manage their hazard tree program dynamically based on extensive field data, it becomes important to have a hazard tree database where all of the data can be gathered, maintained, and analyzed in an efficient and secure manner. At a minimum, this database should be a repository for the data collected according to Recommendation 3. The database should be able to track factors such as the number of hazard trees identified each month, the number of removals each month, the number of refusals, average removal time, and so forth.

10. **Assess the utility forest.** An assessment of the utility forest is recommended for utilities that have a significant percentage of customer interruption minutes attributable to fall-in trees (e.g., 10% or more). The utility forest consists of all trees capable of falling into the utility lines. An assessment of the utility forest will require a statistical sampling at various locations in the system. The result is an estimate of the total number of trees, by species, in the utility forest. Mortality rates for different tree species can be obtained from state forester data. The utility forest statistics, combined with tree mortality rates, results in the expected number of new hazard trees in the utility forest each year. This can be compared to the number of hazard tree removals to see if hazard tree removals are keeping up with the natural rate of tree mortality.

11. **Prioritize by species.** A combination of the utility forest data and the hazard tree data allows inspections and removals to be tailored by tree species. For example, a certain species of tree may only constitute 10% of the utility forest but is involved in 30% of fall-in events. This species should be given special attention for inspection and removal. Inspections can also be tailored by species by documenting the typical types of defects that are common for that species. For example, certain species may be subject to decay as evidenced by a certain type of fungal growth, another species may be subject to cracks, another may be prone to large branch failures, and yet another may be subject to simply blowing over when it is the tallest tree in the area.

12. **Plan for epidemics.** Any hazard tree program will be extremely stressed should a tree epidemic occur such as a beetle infestation. If an epidemic occurs, the tree mortality rate will increase significantly and the existing level of hazard tree activity will be insufficient to identify and remove the infested trees. Therefore, utilities that have the possibility of a tree epidemic should have a written plan on how it will deal with this epidemic. This plan should address issues related to funding, resources, reliability, public relations, other stakeholder relations, and other factors.

## Third Stage

*Note on the Third Stage: These recommendations are recommended if utilities wish to significantly reduce the number of tree failures during major storms. Since most tree failures during major storms are apparently healthy trees (i.e., not hazard trees), some of the recommendations in the Third Stage go beyond hazard trees, are potentially expensive, and are sensitive to property owners. Therefore, utilities must carefully consider whether the benefits associated with these Third Stage recommendations justify the costs and other implications.*

13. **Engage regulators.** After the appropriate elements of the first two steps have been successfully implemented, a utility will have a strong hazard tree program that is data driven, efficient, and cost efficient. At this point, the utility must decide whether it wishes to become, with respect to tree damage during major storms, more aggressive in terms of funding, legal constraints, political issues, or other issues that warrant involvement with the regulator. Since the existing program is very good, proposed costs and benefits should have high credibility with regulators.

14. **Address legal, regulatory, and political issues.** After the first two stages, the utility will have a good understanding of any legal, regulatory, or political issues that are hampering effective hazard tree management. Using data, the utility will be able to demonstrate the impact, and quantify the benefits of potential changes. Choosing its battles wisely, the utility can now attempt to change one or more of these situations in a collaborative fashion. It is not advisable to address these issues before good data and analyses are available.

15. **Targeted annual inspections.** For utilities interested in being more aggressive with regards to hazard trees, dedicated annual inspections can be performed for critical parts of the system. For example, a utility might identify twenty percent of its feeders that it deems critical to minimize damage during a major storm. The three-phase portions of these feeders could then be inspected on an annual basis for hazard trees (these inspections could be coupled with an overall inspection of the circuit). This inspection is completely separate from trim cycle work. Aggressive utilities may choose to perform an-

nual inspections on all three-phase portions of the system. Targeted annual inspections should be based on a credible cost-to-benefit analysis.

16. **Targeted danger tree removal.** During major storms, many of the trees that fall over could not have been identified ahead of time. Therefore, the only certain way to dramatically reduce the number of fall-in events during a major storm is to reduce the utility forest. Broad-based widening of all rights-of-way is almost certainly cost prohibitive (in addition to being unacceptable to many stakeholders). However, targeted danger tree removal can be considered on critical parts of the system that are especially important to have a minimum of damage during a major storm.

    Many property owners will probably be less-than-enthusiastic about targeted danger tree removal, perhaps to the extent that makes this recommendation impossible or undesirable to implement. However, targeted danger tree removal is the only sure way to dramatically reduce the number of tree fall-ins during major storms. Any utility that pursues targeted danger tree removal should keep detailed data so that, over time, the impact of the widening can be determined.

17. **Targeted ground-to-sky pruning.** Branches over conductors pose a hazard to the conductors. Furthermore, overhanging conductors greatly increase the probability that a tree will strike the conductors if it should fall over. Therefore, ground-to-sky pruning will be effective for improving both daily reliability and storm reliability.

    Transitioning from under pruning to ground-to-sky can be initially expensive, although these costs can typically be capitalized as a right-of-way permanent asset improvement. Transitioning to ground-to-sky will also typically involve an extensive amount of customer outreach and coordination with many other stakeholders.

    Despite these challenges, utilities should consider using ground-to-sky pruning on critical parts of the system that are especially important to have a minimum of damage during a major storm. Some utilities might also consider not allowing branch overhangs on all three-phase portions of their distribution system. At a minimum, this should involve pruning as high as the lift will reach, with an attempt to prune above the "hinge point," where a branch that splits at the trunk will swing to the trunk without hitting the conductors. Any utility that pursues a transition to ground-to-sky pruning should keep detailed data so that, over time, the costs and impacts can be better understood.

18. **Customer outreach.** If and when a utility decides to change its approach to UVM in a way that affects customers, the utility should develop and implement a customer outreach program. The goal of this program is to educate customers on what will be done, why it will be done, when it will be done, the associated benefits, and the process for communicating concerns or comments to the utility. This plan should be developed from the customer's perspective and the benefits that the customers will receive. It should also allow for customer input so that those who wish can feel that they are part of the process and have the ability for their voice to be heard and considered.

    Customer interaction with respect to trees presents both an opportunity and a risk. Trees are a sensitive issue for many customers. A thoughtful customer outreach program presents the opportunity for utilities to strengthen their relationship with customers. An insufficient or misguided customer outreach program, in contrast, could irritate customers and result in backlash.

The recommendations in the first two stages will result in a well-managed and data-driven hazard tree program. A utility may already be doing a good job with respect to hazard trees, but the recommendations in the first two stages will allow the effectiveness of the hazard tree program to be demonstrated based on budgets, processes, and data. For most utilities, the recommendations in the first two stages will allow for an increase in the cost-effectiveness of hazard tree management, and modest reductions in daily and storm tree in-falls. Most of these recommendations can be implemented either with little cost or with short-term costs that result in long-term savings (e.g., maintaining an optimal trim cycle).

In the survey, many utilities claim that only ten percent or less of in-fall trees could have been identified as hazard trees prior to failure. If this is the case, more aggressive hazard tree removal will only provide incremental storm benefits. Consider a major wind storm where eighty percent of damage is due to in-fall trees, with eight percent of damage due to identifiable hazard trees. Assume that a utility implements an aggressive hazard tree program that is able to identify and remove seventy five percent of all identifiable hazard trees *on the entire system*. This implies a six percent reduction in overall storm damage, reducing a fourteen day storm to a thirteen day storm. This may not seem like much, but each day of storm restoration is very expensive and the cost of such a hazard tree program may be justifiable based on reduced storm costs. The economics will vary for each utility, but are worthwhile to examine.

The economics of hazard trees should include societal benefits. Each dead and diseased tree in a populated area will eventually fail and have to be removed. Even if the tree does not do any damage, the cost difference between reactive removal after failure and proactive removal is minimal, since the cost is dominated by the amount of biomass involved. Therefore, the additional societal cost for utilities proactively identifying and removing hazard trees, not considering damage, is equal to the cost of identification and program management. Assuming that the cost of hazard tree identification and program management is fifteen percent of overall costs, society is better off if the reliability benefits and reduced storm damage benefits exceed about fifteen percent of the overall program costs (not including the benefits of reduced customer property damage). This analysis does not necessarily extend to forested areas where fallen trees are not removed. Regulators must ultimately decide how much utility hazard tree management effort is appropriate for inclusion in rates, but there is already strong precedent for utilities to pay for the removal of trees on customer property and to recover these costs through rates.

Significant reductions in storm damage can be achieved by reducing the utility forest and by reducing the amount of branches that overhang conductors. The societal economics for hazard trees do not apply in these cases, requiring the benefits to exceed the full costs for justification. However, storm benefits could be substantial. Consider again a major wind storm where eighty percent of damage is due to in-fall trees. If a utility reduces the utility forest on a critical circuit by fifty percent, storm damage on this circuit will be reduced by forty percent.

Based on survey results, some utilities have a highly developed hazard tree management program, many have a good program with opportunities for improvement, and some have programs that are not effectively managing hazard trees. In addition, there are many differences across utilities in terms of service territory, vegetation density, vegetation type, storm characteristics, and other factors that necessarily impact their approach to hazard tree management. Each utility must therefore thoughtfully determine its own best approach to hazard tree management.

# 1 Introduction

On December 12, 2008, the Public Utility Commission of Texas (PUCT or Commission) issued a Request for Proposal (RFP No. 473-09-00155) to provide a cost-benefit analysis of the recommendations in the Final Staff Report (Project No. 32182, Item No. 93), *PUC Investigation of Methods to Improve Electric and Telecommunications Infrastructure to Minimize Long Term Outages and Restoration Costs Associated with Gulf Coast Hurricanes*. The scope of this project is to: (1) determine the costs associated with vegetation management and pole inspection programs throughout the State of Texas; and (2) determine the costs and benefits associated with storm hardening efforts such as requiring new transmission and distribution lines built within 50 miles of the Texas coast to meet the most current National Electrical Safety Code (NESC) standards. The analysis is to consider the societal costs associated with lost productivity during extended power outages and the benefits associated with shorter restoration times.

The PUCT selected Quanta Technology to perform the work described in the RFP, which resulted in the report titled *Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs*, March 3rd, 2009. This report identified several cost-effective recommendations for hardening Texas utility systems against future hurricanes. The PUCT expressed interest in identifying industry best practices for two of these recommendations: hazard tree removal and targeted distribution system hardening. As such, the PUCT issued a scope extension to the original contract to perform an industry benchmark survey for each of these subjects. This report summarizes the findings of the benchmark survey done for hazard trees. A similar report, titled *Distribution Hardening: Benchmark Survey and Best Practices*, summarizes the findings of the benchmark survey done for targeted distribution hardening.

This report is organized as follows. Section 2 provides an overview of hazard trees and the utility management of hazard trees. Section 2 provides an overview of utility vegetation management in general, including the role of tree mortality and hazard tree formation. Chapter 4 presents the results of the survey, presenting each question followed by a summary of the survey responses. Chapter 5 presents eighteen recommended best practices organized into three stages. Chapter 5 ends the report with conclusions.

# 2 Hazard Trees

For a utility, a tree is not a concern unless it is tall enough to have the potential to fall into and damage facilities such as overhead lines. In this report, a tree that is tall enough to fall into utility lines is called a *danger tree*. A danger tree that has fallen into a power line is shown in Figure 2-1.

All danger trees have the possibility of falling over due to forces such as strong winds, lightning strikes, vehicular accidents, or defects that are not easily detectable from an inspection. Conceptually, a utility could remove all danger trees and eliminate the possibility of danger tree damage. In reality, this approach is not practical or desirable for a variety of reasons. It would be prohibitively expensive. Property owners would resist mightily. Aesthetics would degrade. Wildlife habitat would be damaged. And so forth. For these and other reasons, utilities must be targeted in their approach and focus their efforts on danger trees with high probabilities of structural failure, and/or severe consequences should they fall into power lines.

The United States Department of Agriculture defines a *hazard tree* as, "a tree with structural defects likely to cause failure of all or part of the tree, which could strike a target."[1] For a utility, the target of interest is overhead lines. Therefore, a hazard tree from a utility's perspective is a danger tree with a noticeable defect that makes the tree likely to fail. Typical defects include dead wood, cracks, weak branch unions, decay, cankers, root problems, poor tree architecture, and excessive lean. Pictures of typical tree defects are shown in Figure 2-2.

Most distribution facilities have a trim zone where the utility is allowed to remove vegetation, including trees and tree branches, that is too close to conductors. For the purposes of this report, the ground underneath this allowable trim zone is loosely referred to as the utility's *right-of-way* (ROW). The rights of the utility to perform actions within this right-of-way are governed by a legal document called an *easement*.

**Figure 2-1.** A *danger tree* is a tree that is tall enough to fall into nearby power lines.

[1] *How to Recognize Hazardous Defects in Trees*, United States Department of Agriculture, NA-FR-01-96.

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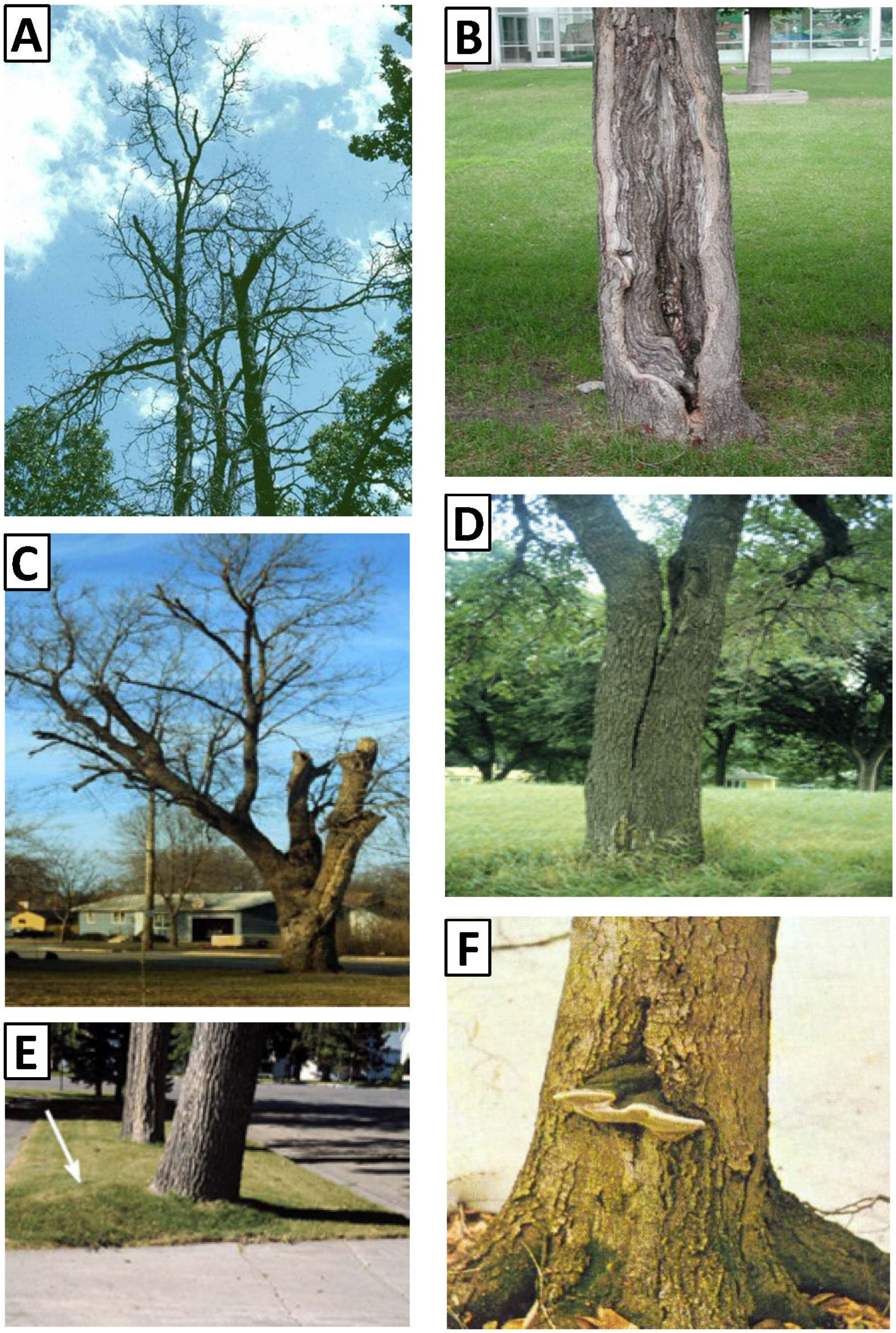


**Figure 2-2.** Typical hazard tree defects: (A) dead trees; (B) severe canker; (C) poor tree architecture; (D) severe crack; (E) excessive lean (causing the ground to bulge); (F) fungus indicating decay.

For safety and reliability reasons, utilities attempt to keep trees and tree branches from encroaching on bare conductors. The most common activity to achieve this is commonly called *tree trimming*, more properly called *tree pruning*, where tree branches are periodically pruned back away from the conductors. A tree pruning program may also involve the removal or replacement of fast growing trees, the application of herbicides, mowing, and other activities.

Tree pruning is an important and expensive activity, but will not generally impact the amount of tree-related damage that a utility experiences during a major storm. This is because most tree-related storm damage is caused by entire trees falling over into the power lines. To make matters worse, many of these trees are outside of the utility's right-of-way, often on private property. A major storm will cause many hazard trees to fall over, but will also cause many apparently healthy trees to fall over as well.

Since it is not desirable to have hazard trees falling into power lines, most utilities have processes and procedures in place to identify and remove hazard trees. A common approach is to combine the hazard tree program with the tree pruning program. Before a circuit is trimmed, an inspector is sent out to identify and mark hazard trees, in addition to other activities (often called a *pre-inspection*). Typically, property owners will be contacted at this time and asked for permission to have the hazard tree on their property removed. When the tree crews arrive, they remove the identified hazard trees in addition to performing the tree pruning work. This is just an example, and there are many other ways that utilities identify and remove hazard trees and/or danger trees.

Hazard trees are an important and sometimes overlooked issue. Since hazard trees can have an important impact on both daily reliability and storm reliability, it is beneficial to understand the range of typical utility practices and attempt to identify best practices. When doing this, it is beneficial to have a proper conceptual framework about trees surrounding utility power lines and the natural mortality of these trees. This framework is presented in the next section by Siegfried Guggenmoos, who uses the term "utility forest" to describe all of the trees that can impact the utility system. According to Mr. Guggenmoos, a utility forest can and should be managed just like any other forest, keeping in mind the specific needs and goals of the utility.

# 3 Overview of Utility Vegetation Management[2]

Throughout their one hundred year history, utilities have been challenged by tree-conductor conflicts. For many utilities, trees are the number one cause of unplanned distribution outages. Across the utility industry, tree-related outages commonly comprise twenty percent to fifty percent of all unplanned distribution outages. While these percentages indicate trees are a major threat to reliability, the convention of excluding outage statistics arising from severe storm events means the extent of the problem is, in fact, understated.

North American utilities spend an estimated $7 billion to $10 billion annually on utility vegetation management (UVM) to prevent service interruptions and safety hazards associated with trees contacting conductors. Considering the long history of attention and resources focused on reducing or eliminating tree-conductor conflicts, the incidence of tree-caused outages originating on transmission systems and the general extent of the ongoing level of tree-related outages on distribution systems, suggests something is missing.

Tree-related outage statistics provide information about the extent of tree exposure and efficacy of the vegetation management program. However, these statistics are after the fact. What is required is a conceptual framework for sustainable tree-related outage reductions – a means of truly managing tree-related outages.

The first part of this section provides the conceptual framework. The second part explores tree-related outages and establishes reasonable expectations for their mitigation.

## 3.1 UVM Concepts and Principles

Trees that interrupt electric service can be categorized as *in-growth trees* and *in-fall trees*. The inventory of all trees that have the potential to either grow into a power line or, on failure (breakage), fall into and strike a conductor will be referred to as the *utility forest*. While we commonly think of forests in terms of more or less rectangular blocks, the utility forest amounts to ribbons or transects of the service area. Generally, the centerline of these transects is the power line. The utility forest has the same characteristics as any forest. In most cases, the tree species composition is what is native to the area. The same patterns of biomass addition (tree growth) and tree mortality apply. Both of these patterns are significant factors in power line security and both can be mathematically represented by geometric progressions, as illustrated in Figure 3-1 and Figure 3-2. Biomass additions result in trees that encroach on conductors, thereby necessitating tree pruning and either mechanical or chemical (herbicide) brush clearing. Failure to mitigate this encroachment leads to deteriorating safety and reliability. Figure 3-1 shows an asymptotic curve that is typical of biological populations. Tree mortality produces decadent trees that are subject to breakage or tipping over (Figure 3-2). Tree mortality is not an event that occurs at a specific point in time. Rather, tree mortality occurs over a period of months and years.

[2] *This section was written by: Siegfried Guggenmoos, President, Ecological Solutions Inc., (780) 467-6389, sig@ecosync.com.*

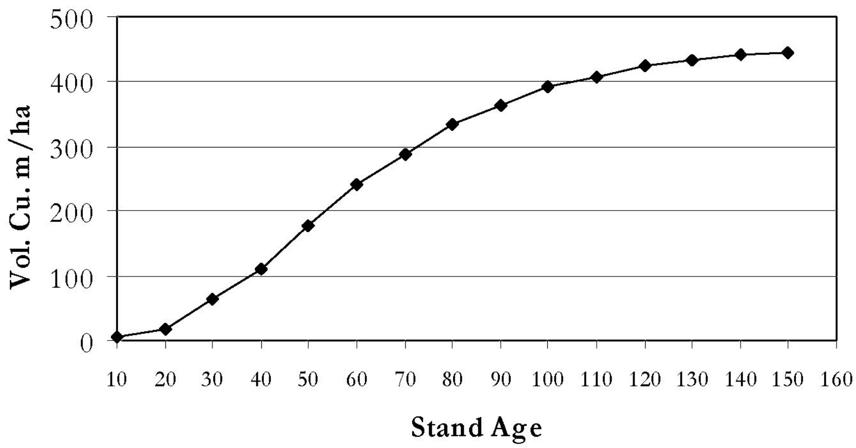


**Figure 3-1.** Vegetation Management Concepts and Principles Forest Biomass Addition Timber Production Spruce on Good Site [Source: B. Freedman and T. Keith, *Planting Trees for Carbon Credits*, Tree Canada Foundation, 1995.]

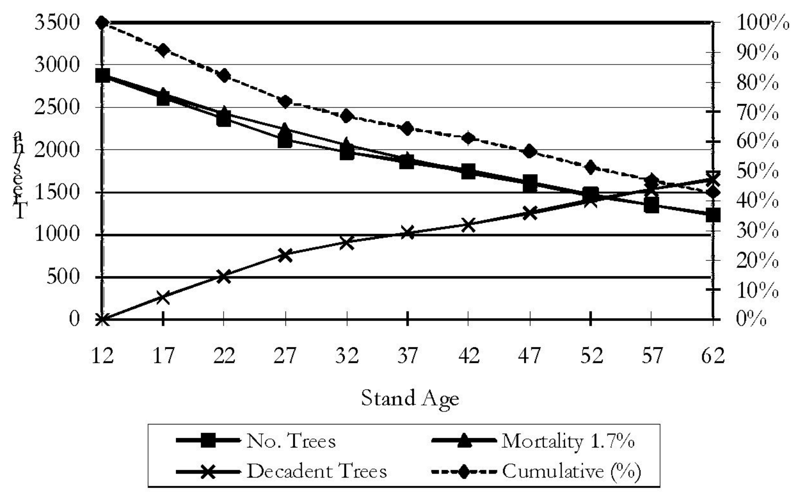


**Figure 3-2.** Vegetation Management Concepts and Principles Stand Density South Carolina State Forest. The graph shows the remaining live, viable trees. Of interest to utilities is the 60% of trees in the stand that die over 50 years because they hold the potential to disrupt electrical service. [Source: N. L. Crookston, *Suppose: An Interface to the Forest Vegetation Simulator*, 1997]

Natural tree mortality is a process of losing vigor either due to the stress of competition for light, water and nutrients or an inability to sustain the attained mass. In the early stages of senescence or decline, there may be no visible defect. However, as the tree becomes increasingly decadent and subject to failure under increasingly less stress loading, symptoms of the decline become apparent. Such senescent trees must be identified as faulty and prone to failure under weather stress and must be removed prior to the occurrence of stress. Figure 3-2 shows both the forest stand density over time and the population of trees of concern to utility facilities, the Decadent Trees. While the South Carolina forest data is restricted to sixty-two years, the line for Decadent Trees is seen to be approaching an asymptote. Further, because the capacity of the land-base to produce biomass is limited, the line for the evolution of decadent trees must be asymptotic. The nature of the expansion of the two sources of tree-caused interruptions, biomass addition (in-growth) and tree mortality (in-fall) is additive or constructive. This in conjunction with the process of tree mortality leads to insight into the consequences of failure to manage trees in proximity to power lines.

From a utility perspective, trees represent a liability in both the legal and financial sense. The fact that the utility forest changes by a geometric progression is significant. It means that the tree liability, if not managed, will grow exponentially.

Trees cause service interruptions by growing into energized conductors and establishing either a phase-to-phase or phase-to-ground fault. Trees also disrupt service when they or their branches fail, striking the line and causing phase-to-phase faults or phase-to-ground faults or breaking the continuity of the circuit. Because the two factors that are responsible for service interruptions, tree growth (biomass addition Figure 3-1) and tree mortality (Figure 3-2), change by geometric progressions, the progression of tree-related outages is, necessarily, also exponential (Figure 3-3) up to the approach of the asymptote. Failure to manage the tree liability leads to both exponentially expanding future costs and tree-related outages. Conversely, it is possible to simultaneously minimize vegetation management costs and tree-related outages (Figure 3-4).

It is not possible to totally eliminate the tree liability because the ecological process of succession is a constant force for the re-establishment of trees from whence they were removed. The tree liability then is like a debt that can never be completely repaid. Under such circumstances, the best economy is found in maintaining the debt at the minimum level, thereby minimizing the annual accrued interest. However, irrespective of cost, minimizing the size of the tree liability or utility forest is rarely an option for utilities because there are multiple stakeholders with an interest in the trees. What can be achieved, however, is equilibrium. The tree liability can be held at a constant point by annually addressing the workload increment. To continue the debt analogy, a debt is stabilized when the annual payments equal the interest that accrues throughout the year. The interest equivalent in the utility forest is comprised of annual tree growth and mortality. Actions that parallel the reduction in the debt principal are actions that actually decrease the number of trees in the utility forest. Such actions include removal of trees and brush by cutting or through herbicide use.

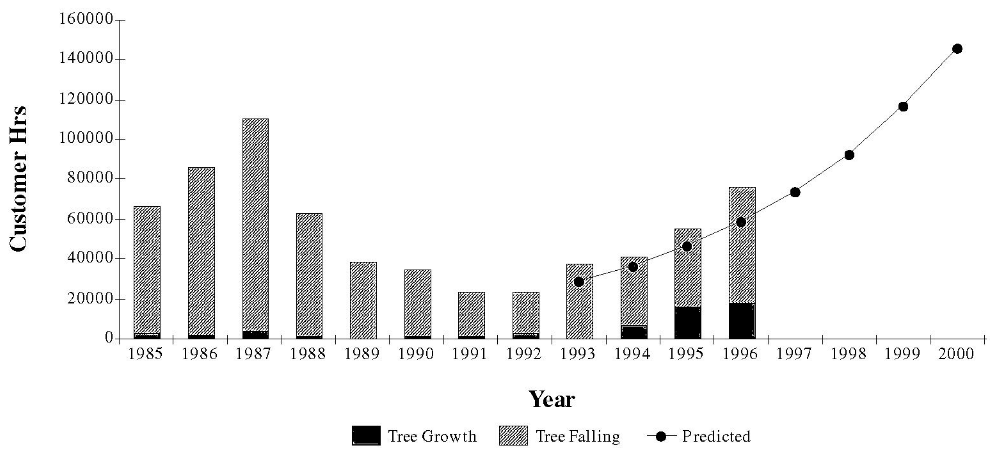


**Figure 3-3.** Vegetation Management Concepts and Principles Tree-caused Distribution Outage Statistics. This work and prediction for future tree-caused outages was performed in early 1997 to show the expected trend to 2000 based on funding below that required to remove the annual workload volume increment. [Source: Western Canadian utility]

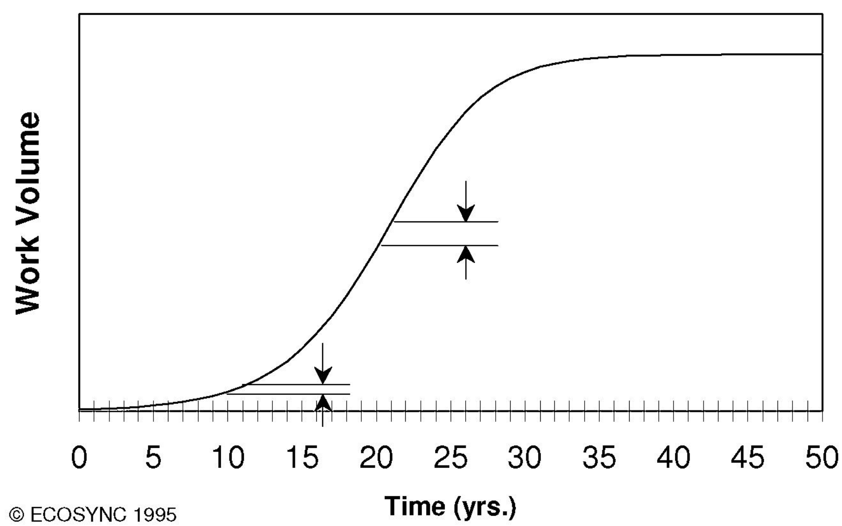


**Figure 3-4.** Vegetation Management Concepts and Principles Stabilizing Tree Workload (Illustrative Model). The graph shows the work volume that must be completed in a year to hold tree work inventory, costs and reliability steady. Performing less than the annual workload-volume increment shifts the total tree work inventory to the right, thus necessitating greater annual vegetation management expenditures to arrest the expansion of tree-related service interruptions.

When the pruning cycle removes the annual growth increment and the hazard tree program removes trees as they become decadent (Figure 3-4), tree-related outages are stabilized. The residual level of tree-related outages reflects the interaction of several characteristics, including the size of the utility forest, chosen maintenance standards (such as clear width), tree-conductor clearance, and tree-species characteristics (such as mode of failure and decay). An expression of a managed tree liability, one in which the annual workload volume increment is removed, is stable tree-related outages. Reducing tree-related outages below an achieved equilibrium necessitates actions that decrease the size of the utility forest. Actions are not limited to vegetation management. For example, increasing conductor height reduces the size of the utility forest as it reduces the number of trees that are capable of striking the line.

### 3.1.1 Funding

There are three possible outcomes determined by the level of investment made in vegetation management: (1) the annual workload volume increment is removed, thus keeping the size of the tree liability and next year's workload increment constant; (2) more than the annual workload volume increment is removed, thus decreasing the size of the tree liability and the subsequent year's workload increment; and (3) less than the annual workload volume increment is removed, thus increasing the size of the tree liability. That is because the work not done expands exponentially, thus increasing the workload increment for the following year.

Tree-related outages are an expression of the tree liability. Hence, changes in the tree liability result in proportional changes in tree-related outages (Figure 1-3, Figure 1-5). Actual outage experience may deviate from the trend based on variance from mean weather conditions.

When less than the annual workload volume increment is removed, the fact that tree liability increases by a geometric progression has two major implications for future costs and reliability. First, the impact of doing less vegetation management work than the annual workload volume increment, as expressed through tree-related outages, may be relatively imperceptible for a few years. Second, the point at which the impact of under-funding is readily observed in deteriorating reliability is where the effect of annual compounding in the workload, and thereby costs, is large (Figure 1-5). The lack of a significant negative reliability response to reduced vegetation management investment (Figure 1-3, 1992 to 1995) may provoke further funding reductions, thereby exacerbating the size of the future re-investment required to contain tree-related outages.

Recognition that the tree workload expands by a geometric progression serves to explain some common utility experience. For many utilities, graphing customer hours lost on tree-caused interruptions over the last ten to twenty years reveals cyclical up and down trends (Figure 1-3). There are periods when trees are perceived as a problem and funding is increased. Increased funding permits a buying down of the tree liability, reducing tree risks and tree-related outages. Faced with these positive results, spending on vegetation management is reduced. While this tendency is perfectly logical, without the conceptual framework outlined, it is inevitable that funding will be reduced to the point where there is an observable response in tree-related outages. Unfortunately, by the time that tree-related outages are definitively observed to be on an increasing trend, for some years, vegetation management investment has been less than what is required to remove the annual workload volume increment.

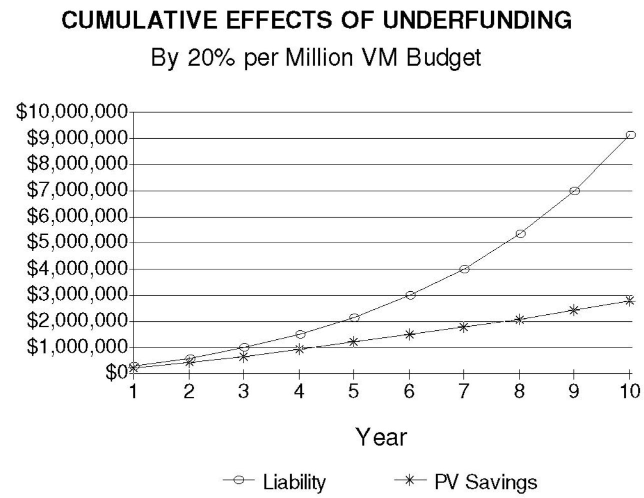


**Figure 3-5.** Vegetation Management Concepts and Principles Impact of Under-Funding Vegetation Management Revealed Over Time Rate of change in liability based on western Canadian utility with a 4-month growing season. Discount rate = 6%. © ECOSYNC 1997.

At this point, the power of compounding is well underway and only a very aggressive increase in funding will arrest the trend. The rate of change in the workload liability in Figure 3-5 is approximately equal to a compounding rate of 27% per year. Warmer climates with a longer growing season support higher rates of change. In other words, for distribution systems, the rate of change in the tree workload is substantially higher than the discount rate (currently 3-11%) one would conceivably use to derive the present value benefit of deferred maintenance spending. Taking a short-term financial perspective, any deferred or diverted vegetation management funding that inhibits removal of the annual workload volume increment is poorly allocated unless it provides a better rate of return. The example provided in Figure 3-5 shows that returning the work volume and reliability to the original levels after 10 years of under-funding by 20%, increases costs by 80% over maintenance, which annually removes the workload volume increment.

It has been shown, through Figure 3-3 and Figure 3-5, that under-funding UVM has a substantial impact on future reliability and costs to return to the level of reliability enjoyed before under-funding. The increase in workload due to deferred maintenance is not linear. Hence, the impacts of a dollar deferred this year cannot be erased with an investment of a dollar next year. Further, this section has provided the conceptual context that utilities have lacked, which lack has allowed the inefficient, repetitive cycles of under-funding followed by reactive catch-up periods.

Figure 3-5 shows that failing to make the necessary investment in vegetation management will, in most circumstances, result in higher life cycle costs. While utilities are expected to justify their intended vegetation management expenditures, regulators play a role in the effectiveness of the program. Failure to understand the nature of vegetation management workload expansion or skepticism that leads to decisions limiting the ability to remove the annual workload volume increment will impose the inefficiencies illustrated in Figure 3-5. If a regulatory process focuses on short-term cost containment, it risks supporting such inefficiency. This poses a challenge for utilities that are behind on their optimal vegetation management cycle. A short-term increase in spending will result in long-term cost reductions and reliability improvement. However, utilities often find it difficult to proactively act until noticeable reliability problems become evident. This is because regulators are often reluctant to approve spending increases until performance deterioration can be demonstrated. The result is often a reactive approach to maintenance by the utility with the attendant cyclical inefficiencies.

### 3.1.2 Managing the Tree Liability for Positive Returns

Trees should be recognized as a liability in a utility context. While this puts utilities in conflict with community perceptions of trees as assets, the conflict does not change the fact that trees hold only the capacity to impair the safe, reliable operation of the electric system, not to augment it in any way. The recognition and quantification of the utility forest as a liability provides a measure of the potential for, or risk of, tree-conductor conflicts. Furthermore, it connects and clarifies the influence of design and operating decisions on maintenance costs and reliability risks.

Managing the tree liability necessitates an understanding of how and where tree risks arise, a quantification of the extent of tree exposure, the rate of change in the tree liability, and a commitment to funding that permits, at a minimum, the removal of the annual workload volume increment.

Appropriate investment in vegetation management is one of the best investments a utility can make. It serves to minimize tree-caused interruptions for the chosen clearance standard, thereby avoiding customer complaints, the need for regulator intervention, and in some cases performance penalties. It avoids the inefficiencies that are inherent in the cycle of allowing trees to become a major problem, getting trees under control by buying down the tree liability, and then losing the investment by failing to contain the tree liability. Investment based on the removal of the annual tree workload increment provides the conceptual approach that is needed to deliver a sustainable, least-cost vegetation management program. Simultaneously, such a program provides the lowest incidence of tree-caused service interruptions (Figure 3-4) for community-accepted clearance standards, thereby benefiting ratepayers and shareholders alike.

## 3.2 Tree-caused Outages

Section 3.2 discusses tree-caused electric service interruptions, establishing a baseline understanding by citing specific work and findings. It guides the reader towards realistic expectations regarding the mitigation of tree-caused interruptions. By articulating the implications and conclusions that can be drawn from the current state of knowledge, the hope is to bring rigor to the thinking and questioning that often occurs in the aftermath of major storms.

For example, should the mitigation strategies applied by a utility be expected to limit tree-related service interruptions during normal operating conditions, during major storms, or both? Are there outage mitigation strategies, which effectively limit major storm damage and are they different from routine maintenance practices? By categorizing tree-related outages by type, tree location, failure type, tree condition, etc., we can begin to answer these questions. Not only do different outage mitigation strategies begin to emerge but also their applicability or potential to address specific conditions.

In communicating this section some distinctions are necessary. Accordingly, the following definitions are provided. A hazard tree is a tree that has a target, in this case electrical equipment, and a visually discernable defect. A danger tree is any tree, which on failure could interfere with the electric service. These definitions are consistent with those used by the International Society of Arboriculture and the American National Standards Institute.

### 3.2.3 Categorizing Tree-Caused Outages

Tree-caused outages have two possible causes: in-growth or in-fall. Trees causing electrical faults can be located either within or outside the right-of-way. In-growth outages occur about equally from trees within and outside the right-of-way. In-fall outages arise almost exclusively from trees located outside the right-of-way.

Tree trimming (or properly, *tree pruning*) establishes the air space between tree branches and conductors so as to avoid in-growth interruptions. While a small portion of in-fall outages may be prevented by tree pruning, generally, avoiding in-fall outages involves the removal of hazard trees. These actions are typical and routine for utility vegetation management programs. There is variation between utilities regarding the frequency of inspections and the term of maintenance cycle.

It is important to understand the type of electrical faults that occur from the in-growth and in-fall of trees. In-growth can result in phase-to-ground faults, but more commonly result in phase-to-phase faults. In-fall can result in mechanical damage to the conductor, phase-to-phase faults and phase-to-ground faults. In-growth outages have a greater impact on interruption frequency indices. In-fall outages, which tend to result in equipment damage, more heavily influence interruption duration indices.[3]

There has been considerable advancement since 1994 in understanding how trees cause phase-to-phase faults that arise from tree in-growth.[4] The current understanding of in-growth outages is that trees contacting a single distribution phase do not typically cause outages (Figure 3-6), particularly when the phase-to-phase voltage is 13 kV or less. Sustained outages occur when a branch forms a substantial bridge between phases.[5] Most tree-related outages are due to tree failures and these trees are outside the right-of-way.[6]

When a pruning program begins to fall behind, tree branches grow into conductors. Initially, as branches begin to make contact with energized distribution conductors the shoots tend to be "burned off" through momentary contact (see Figure 3-6). Rarely, at this early stage of tree-conductor contact would we expect a fault to occur. Rees, of Baltimore Gas & Electric, attributed only 2% of all tree-related outages to trees growing up into a line.[7] Guggenmoos showed tree growth to account for 2% to 10% of tree-related outages on TransAlta Utilities' distribution system.[8]

3 Simpson, Peter. 1997. EUA's Dual Approach Reduces Tree-Caused Outages. Transmission & Distribution World, Aug 1, 1997.
4 Rees, Jr. William T., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E. 1994. Priority Trimming to Improve Reliability. ISA Conference presentation, Halifax, Nova Scotia, 1994.
5 Goodfellow, J.W. 2005. Investigating Tree-caused Faults. Transmission & Distribution World, November 2005.
6 Guggenmoos, S. Effects of Tree Mortality on Power Line Security. Journal of Arboriculture, 29(4), July 2003.
7 Rees, Jr. William T., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E. 1994. Priority Trimming to Improve Reliability. ISA Conference presentation, Halifax, Nova Scotia, 1994.
8 Guggenmoos, S. 1996. Outage Statistics - As a Basis for Determining Line Clearance Program Status. UAA Quarterly, 5(1), Fall 1996.

**Figure 3-6.** Tree-caused Outages Branch Burn Off. New growth has been "burnt off" from occasional line contact.

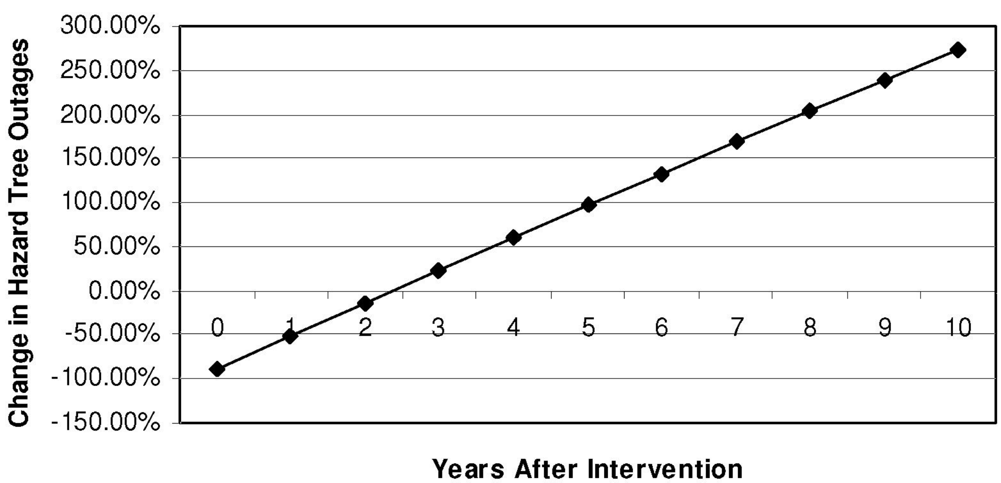


**Figure 3-7.** Tree-caused Outages Hazard Tree Removal Benefit Duration

Finch, reporting on Niagara Mohawk's tree-caused outages, indicates tree growth accounts for 14% of outages,[9] while Rogers explains part of the reasoning behind Puget Sound Energy's Tree Watch program is that only 13.5% of tree-related outages are attributable to tree growth.[10] Since 1997 Puget Sound Energy's experience has shifted to less than 5% of tree-related outages being attributable to in-growth.[11]

From these geographically, ecologically diverse utility systems a common thread emerges: tree growth into power lines accounts for less than 15% of all tree-related outages. A marked increase in outages due to growth is not likely to occur until the pruning program is so far behind cycle that tree branches are of a more substantial diameter and in simultaneous contact with two phases.[12] [13] [14] Over 30 years of experience in utility vegetation management leads the author to the opinion that when in-growth outages exceed 15% it is a strong indicator of either a faulty, misdirected vegetation management program, underfunding or both.

What is the role of in-growth outages during storm events? It is minimal. There may be some incidence of collision between swaying branches and conductors resulting in phase-to-phase contact and repeated intermittent bridging of phases resulting in faults. Baltimore Gas & Electric,[15] Eastern Utilities Associates[16] and TransAlta Utilities[17] have reported only 2% of tree-related outages due to in-growth when the pruning program is on cycle. Even if wind gusts increased these outages by hundreds of percent, they will still comprise a very small component of all storm related tree outages.

If in-growth causes only 2 to 15% of tree-caused interruptions, then 85% to 98% must be attributable to tree in-fall. Storm loading, whether wind or ice, results in tree failures - either branch or trunk breakage or uprooting. Simply by the fact that the number of trees outside the right-of-way, which can affect continuity of service, vastly outnumbers such trees within the right-of-way, most of the 85% or more of in-fall outages arise from trees located outside the right-of-way. On distribution systems, the maintained right-of-way typically represents 10-20% of the utility forest land base.[18] For transmissions lines (69 kV and above), where the tolerance for trees within the right-of-way is considerably lower, the maintained right-of-way generally represents 30-70% of the utility forest.[19]

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9 Finch, K.E., C. Allen 2001. Understanding Tree Caused Outages. EEI Natural Resource Conference, Palm Springs, CA, Apr. 2001.
10 Rogers, Beth, I. 2001. Puget Sound Energy Tree Watch Program. EEI Natural Resource Conference, Palm Springs, CA, Apr. 2001.
11 Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.
12 Rees, Jr. William T., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E. 1994. Priority Trimming to Improve Reliability. ISA Conference presentation, Halifax, Nova Scotia, 1994.
13 Goodfellow, John W. 2000. Understanding the Way Trees Cause Outages. ECI and Allegheny Power. Slide presentation (34 slides).
14 Finch, K.E., C. Allen 2001. Understanding Tree Caused Outages. EEI Natural Resource Conference, Palm Springs, CA, Apr. 2001.
15 Rees, Jr. William T., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E. 1994. Priority Trimming to Improve Reliability. ISA Conference presentation, Halifax, Nova Scotia, 1994.
16 Simpson, Peter. 1997. EUA's Dual Approach Reduces Tree-Caused Outages. Transmission & Distribution World, Aug 1, 1997.
17 Guggenmoos, S. 1996. Outage Statistics - As a Basis for Determining Line Clearance Program Status. UAA Quarterly, 5(1), Fall 1996.
18 Guggenmoos, S. Effects of Tree Mortality on Power Line Security. Journal of Arboriculture, 29(4), July 2003.
19 Guggenmoos, S. Effects of Tree Mortality on Power Line Security. Journal of Arboriculture, 29(4), July 2003.

Tree failures can be segregated by branch or whole tree failures. Branch failure is a major source of interruptions. Eastern Utilities Associates found 63% of tree-caused outages were due to branch failure.[20] For Puget Sound Energy, branch failures account for 35% of tree-related outages.[21] This range should be considered typical in the absence of a policy to remove all overhangs and where forest cover is greater than 60%. Branch failures tend to be a major cause of outages during wind storms and they are the predominant cause in ice storms.

Utilities seek to prevent outages due to tree failure through hazard tree removal programs. However, due to tree stocking and natural tree mortality, the hazard tree removal program provides a reliability benefit of limited duration. Assuming average distribution line construction and line clearance standards, a 1% annual tree mortality rate, and what would be considered an aggressive hazard tree program that removes an average of ten trees per mile of line the reliability benefit endures for only 2 years (Figure 3-7). Additionally, the identification of hazard trees is challenging. Death of a tree commonly occurs over a period of years. Invasive and destructive methods of tree evaluation are not an option for municipal or privately held trees. Utility personnel must rely on exterior symptoms of decadence, which may take years to appear. Further, assessing tree health by examining a 70-100 foot tall tree in a forest setting from the ground is difficult and consequently less than perfect. None the less, as determined by examining trees that have failed, utilities typically do reasonably well in identifying hazard trees, as less than one half of the failed trees are hazard trees. Indeed, the majority of trees that fail have no visible fault indicator. Both Eastern Utilities Associates[22] and Puget Sound Energy[23] found 56% of failed trees had no visible indication of fault. Another 12% of trees, which caused outages on Puget Sound Energy's system, were in fair health and therefore difficult to justify as removals.

That more than 55% and up to 70% of the trees causing outages have no discernable defect has important implications for understanding and mitigating tree-related outages. It suggests that successful mitigation will necessitate a reduction in the electrical system tree exposure. Work on the National Grid[24] and Puget Sound Energy[25] transmission systems found line height, tree height and clear width are not significantly correlated to tree-caused outage frequency. However, trees per mile edge, a measure of tree exposure, is significantly correlated to tree-caused outage frequency, with r values (coefficient of correlation) of 0.85 and 0.92, respectively. The strong correlation informs us that the sure way of reducing tree-caused outages is to reduce the electric system's extent of tree exposure. Consequently, it is unreasonable to expect conventional utility vegetation management programs to drastically reduce tree-related service interruptions. Such programs do not target the apparently healthy trees, which account for 55% to 70% of tree-caused interruptions. The efficacy of mitigating outages arising from the 30% to 45% of defective or hazard trees is dependent upon maintenance cycle, environmental factors such as availability of moisture, staff arboricultural competency, clearance standards, management and regulator support, etc.

[20] Simpson, Peter. 1997. EUA's Dual Approach Reduces Tree-Caused Outages. Transmission & Distribution World, Aug 1, 1997.
[21] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.
[22] P. Simpson, R. Van Bossuyt. "Tree-Caused Electric Outages," *Journal of Arboriculture* 22(3): p.117, May 1996.
[23] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.
[24] Guggenmoos, S., T.E. Sullivan. 2007. *Outside Right-of-Way Tree Risk Along Electrical Transmission Lines*. Utility Arborist Association Mar. 2007. http://www.utilityarborist.org/images/Articles/SideTreeRisk.pdf
[25] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.

### 3.2.4 Storm-caused Tree-related Outages

A vegetation management program that does not remove the annual workload volume increment leads to an increasing population of decadent trees, which are subject to failure under decreasing levels of stress loading. Such a program will experience a high number of interruptions during relatively minor storms as the decadent trees fail. Should it experience a major storm, the damage may appear to occur in two waves as the decadent trees fail early in the storm event as loading is increasing, and again at much higher stress load levels as the tolerance of healthy trees to bear the load is overcome. If the average percent of healthy trees contributing to outages is 56%, then one would expect during major storm events that the percentage of healthy tree failures is even greater, dependent upon both the degree of stress loading and duration, the decadent trees being removed early in the storm event.

Using ten years of outage and wind data to determine tree failure rates, it is found that tree failures occur exponentially to wind speed (Figure 3-8).[26] Tree failures increase rapidly at wind speeds over 60 mph. If we assume all hazard trees fail at or below 60 mph winds, then a storm of 75 mph winds would have tree failures comprised of only 4% hazard trees and over 96% healthy trees (Figure 3-9). That is, 96% of the outages can be considered to be unpreventable. This leads to the conclusion that there is only one means of avoiding tree-related outages during major storms – reducing electric system tree exposure.

### 3.2.5 Mitigation Options and Strategies

***Tree Failure***

Avoiding outages caused by tree failures involves the reduction of tree exposure. The options for reducing system tree exposure include increasing the clear width, reducing tree height, increasing line height or undergrounding the line. Reductions in tree exposure avoid outages caused by hazard trees, danger trees and branch failures, during major storms and during normal operating conditions.

However, this is not the approach of conventional utility vegetation management programs. Conventional vegetation management programs do not seek to eliminate exposure to trees, which cannot be categorized as hazard trees. Consequently, these programs offer little protection during major storms when tree-related outages are predominantly due to the failure of apparently healthy trees.

***Branch Failure***

Branch failures are a particular type of tree failure warranting a separate discussion. First, as has been shown, branch failures represent a major portion of tree caused outages under normal operating conditions but even more so during ice storms. In addition to reductions in tree exposure, there is a pruning standard that can reduce service interruptions due to branch failures. The pruning standard is the elimination of branches overhanging conductors.

[26] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Produced from data of Puget Sound Energy, March, 2009.

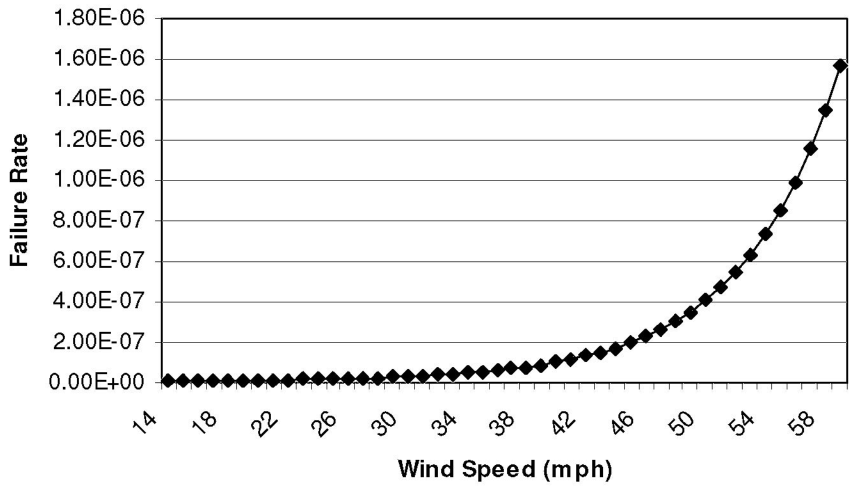


**Figure 3-8.** Tree-caused Outages Tree Failure Rate.
[Source: Puget Sound Energy, *Storm Hardening the Electric Transmission System*]

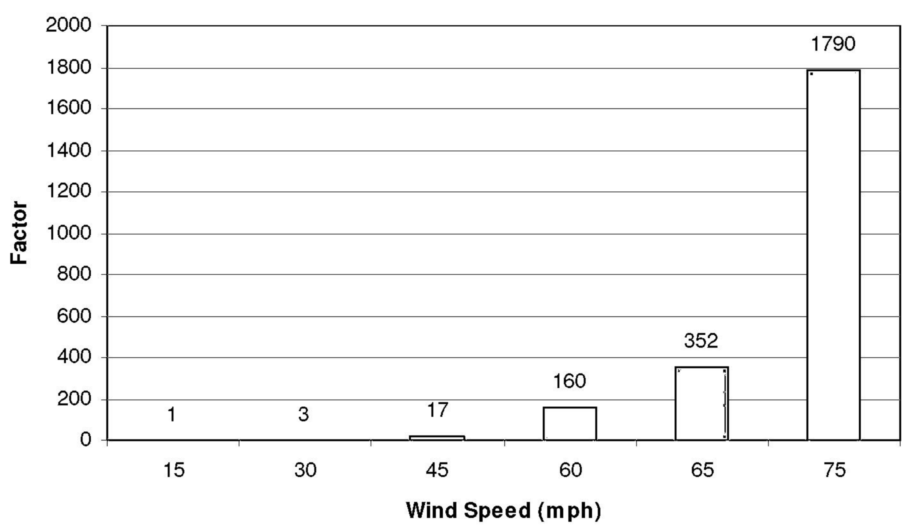


**Figure 3-9.** Tree-caused Outages Tree Failure Ratio

Overhanging branches (Figure 3-10) threaten electric service in two ways: there is the risk that stress loading will cause the branch to fail and fall across conductors; the probability of line contact on a whole tree failure is greater when there are overhanging branches.[27]

One of the methods to reduce outages due to branch failures is "ground-to-sky" pruning. What this entails is the removal of all branches on the line side (Figure 3-11). This approach is particularly effective during ice storms. Some utilities selectively apply "ground-to-sky" pruning to critical line segments such as between the substation and the first protective device.[28] While "ground-to-sky" pruning addresses only overhanging branches from trees situated beside electrical lines, this is the condition that gives rise to most overhanging branches.

***Residual Hazard Trees***

It has been previously stated that mortality of trees is a process, which occurs over a period of time. As it would be unlikely for all but the very smallest utilities to remove all hazard trees within days or a few weeks, there is an ongoing residual population of hazard trees. Indeed, most utility hazard tree programs cover their service territory once over a period of three to eight years.

The local, natural tree mortality rate applies to the utility forest. Because a percentage of the utility forest dies annually, all electrical systems with any tree exposure need an ongoing, cyclical hazard tree program. At the most elementary level, the effectiveness of the hazard tree program is dependent on the match between the number of trees removed annually by the hazard tree program and the number of trees added annually to the hazard tree population through natural tree mortality. Achieving this balance, in what is a resource-constrained environment, does not occur haphazardly or accidentally.

The residual hazard tree population is often greater than the amount of annual additions through mortality. Hazard tree programs have many challenges that can impact their efficacy.

- Very few utilities know the average number of hazard trees that are annually added to their system. You cannot manage what you don't measure.
- The duration of benefit of the hazard tree program is generally believed to be greater than it actually is.
- Most hazard trees are located on private property; perceived not as a liability but an asset by the landowner.
- There is no cost effective, practical means of patrolling for hazard trees that are 30 feet or more inside the forest edge.
- There being no means of instantaneously assessing or monitoring tree health on a system wide basis, utilities are left to make judgments about appropriate inspection and maintenance cycles, balancing costs and line security.
- Environmental conditions such as drought or pest infestations can dramatically impact the tree mortality rate.

[27] Guggenmoos, S. 2007. Increased Risk of Electric Service Interruption Associated with Tree Branches Overhanging Conductors. UAA Quarterly, 15(4), Fall 2007.
[28] Rees, W.T. 2005. BGE Transforms Vegetation Program. Transmission & Distribution World, Nov. 1, 2005.

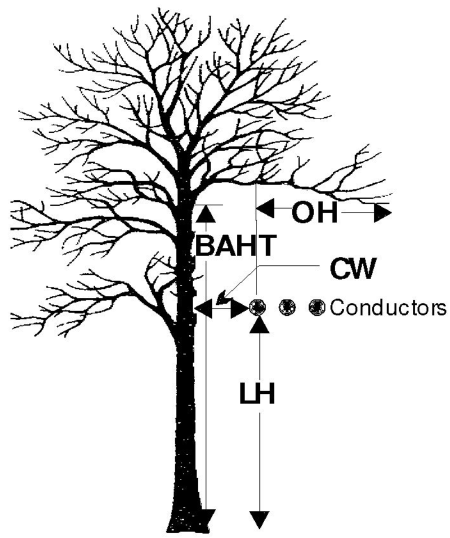


**Figure 3-10.** Tree-caused Outages: Variables for Branches Overhanging Conductor (BAHT = branch attachment height; CW = clear width; LH = line height; OH = overhang).

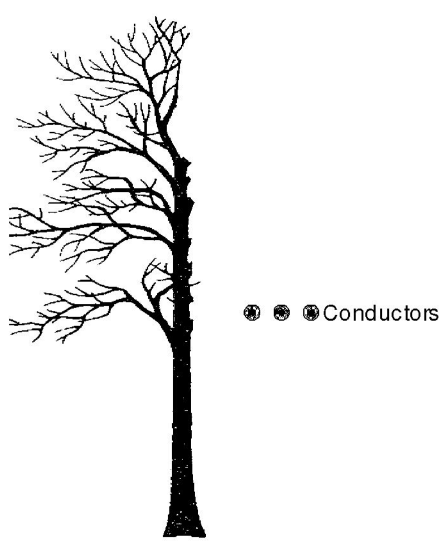


**Figure 3-11.** Tree-caused Outages: Ground-to-Sky Utility Pruning

Utility vegetation management programs focus first on the most visible and direct responsibility, tree-related outages from trees within the right-of-way. For hazard tree identification and removal, most of which are located outside the right-of-way and outside of any prescriptive rights, the degree of responsibility is not as clear. Consequently, should vegetation management funding become constrained, it is typically in the hazard tree program where the shortfall finds expression. Utilities can avoid this pitfall by determining their total tree exposure and natural tree mortality rate, which permit the calculation of the number of annual hazard tree additions and the funding requirements to address them, therein providing unarguable justification for funding the hazard tree program.

### 3.2.6 Managing Tree-caused Outages

Research has shown that tree-related outages are correlated to only one field measurable variable, the extent of tree exposure. Consequently, managing tree-related outages requires quantification of total system tree exposure. On the one hand, this sets the stage for progressive reliability improvements. On the other hand, knowing the number of trees that would need to be removed to effect a 50% reduction in tree-related outages highlights the fact that it could not be accomplished without an extraordinary amount of political will.

What follows is a summary of the strategies (Figure 3-12) utilities use to manage tree-caused service interruptions and comments on the utility or success of the strategy.

The first element of managing tree-caused outages, the pruning program, is directed to the avoidance of in-growth outages (2-15%). A quick measure of the effectiveness of the pruning program can be derived from the percent of in-growth outages. In-growth outages of 10-15% of all tree-related outages, is generally indicative of a good utility vegetation management program. Most utilities are relatively successful in managing their in-growth outages. In fact, some utilities have been able to limit in-growth outages to 2-8% of total tree-caused outages.[29] [30] [31] [32]

The further components of managing tree-caused outages are directed to decreasing in-fall outages (85-98%). The chief of these is the identification and removal of hazard trees. The hazard tree program may identify branches with a high risk of failure and remove the risk through pruning or tree removal. However, the risk of outages due to branch failures can be further mitigated by the removal of overhangs either on selective line segments or system wide. The removal of overhangs is extremely effective for the control of branch failure outages.

The effectiveness of hazard tree programs is highly variable. Further, because there is, even under the most informed, best managed vegetation management program, a steady, residual population of hazard trees, hazard tree programs are never totally effective. The typical extent of the residual hazard tree population is indicated by the data provided that about 30-45% of the tree-caused outages were found to be

[29] Rees, Jr. William T., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E. 1994. Priority Trimming to Improve Reliability. ISA Conference presentation, Halifax, Nova Scotia, 1994.

[30] Guggenmoos, S. 1996. Outage Statistics - As a Basis for Determining Line Clearance Program Status. UAA Quarterly, 5(1), Fall 1996.

[31] Simpson, Peter. 1997. EUA's Dual Approach Reduces Tree-Caused Outages. Transmission & Distribution World, Aug 1, 1997.

[32] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.

attributable to hazard trees.[33] [34] When the concept of a residual hazard tree population is accepted as an attribute of tree exposure, then it follows that outages caused by hazard trees can reduced but can never be completely eliminated.

The vegetation management program components for managing tree-related outages summarized to this point do not address the source of 55-70% of all tree-related outages (red box in Figure 3-12). These are the outages due to the failure of apparently healthy trees that are not targeted by the vegetation management program. For the most part, the utility industry has no strategy to deal with these 55-70% of tree-caused outages. As previously stated, trees are a liability to electric utilities. This is not a view shared by the public, nor consequently politicians and regulators. Generally, regulators and the public are not supportive of actions that would decrease the extent of this liability or tree exposure. These trees would only be addressed by utilities seeking to limit storm damage and cognizant of the correlation between outages and tree exposure. To date, only a few utilities have quantified this connection and are positioned to use it either to justify mitigation or gain acceptance for current system performance.

Based on the current state of knowledge, tree-caused outages, including major storm outages, become predictable. By actions that decrease tree exposure or decrease the risk of branch failures, outages could be substantially reduced. However, doing so requires trade-offs. Consequently, utilities can implement strategies to limit storm damage only if landowners, regulators and other stakeholders value the reliability gain more than the loss of trees.

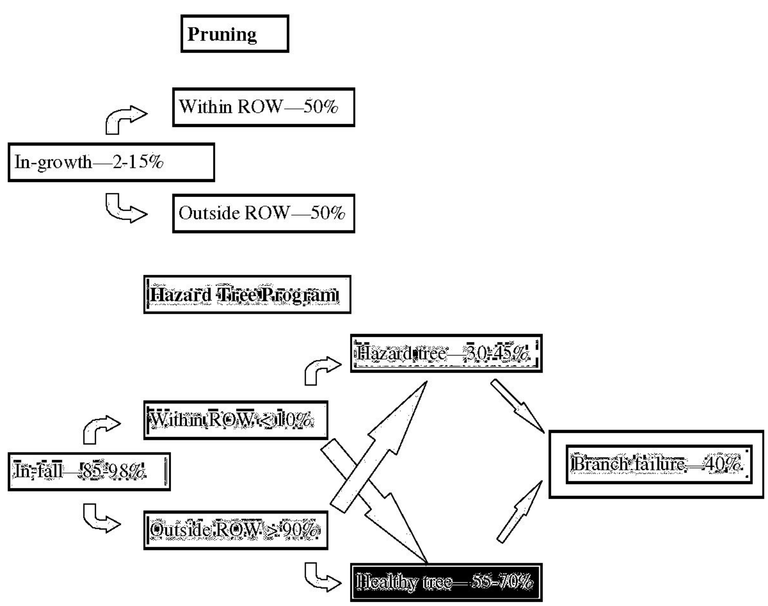


**Figure 3-12.** Tree-caused Outages Tree Outage Summary & Mitigation.
Percentages refer to percent of total tree-caused outages

[33] Guggenmoos, S. 2009. Storm Hardening the Electric Transmission System. Report produced for Puget Sound Energy, March, 2009.
[34] P. Simpson, R. Van Bossuyt. "Tree-Caused Electric Outages," *Journal of Arboriculture* 22(3): p.117, May 1996.

# 4 Survey Results

This section presents the results of the hazard tree survey. A copy of the survey is provided in Appendix A, and a compilation of all responses is provided in Appendix B. The purpose of this section is not to interpret or analyze the survey responses. Rather, it summarizes the survey so that the reader can ascertain the content of the responses in a compact form.

The survey was sent out to a total of 83 utilities, all in the US and Canada. A total of 32 utilities responded, a response rate of 38%. Three of the responding utilities are Canadian and the remainder are domestic. The survey was sent to Texas utilities through the PUCT, which may have led to more careful responses when compared to non-Texas utilities.

A summary of the 32 responding utilities is shown in Table 4-1. The number of electrical customers ranged from a low of 42 thousand to more than 5 million, with an average of 1.4 million. There was a similar wide range of overhead distribution circuit miles with a low of 451, a high of 113,500, and an average of about 24,000.

The approximate geographic distribution of responding utilities is shown in Figure 4-1. The dots show the location of the utility headquarters, but the utility service territories may include areas far away from this location. The responses span the US from east to west and from north to south. Since the PUCT required Texas investor-owned utilities to respond to the survey, Texas is heavily represented. The three responding Canadian utilities are all in close proximity to the US.

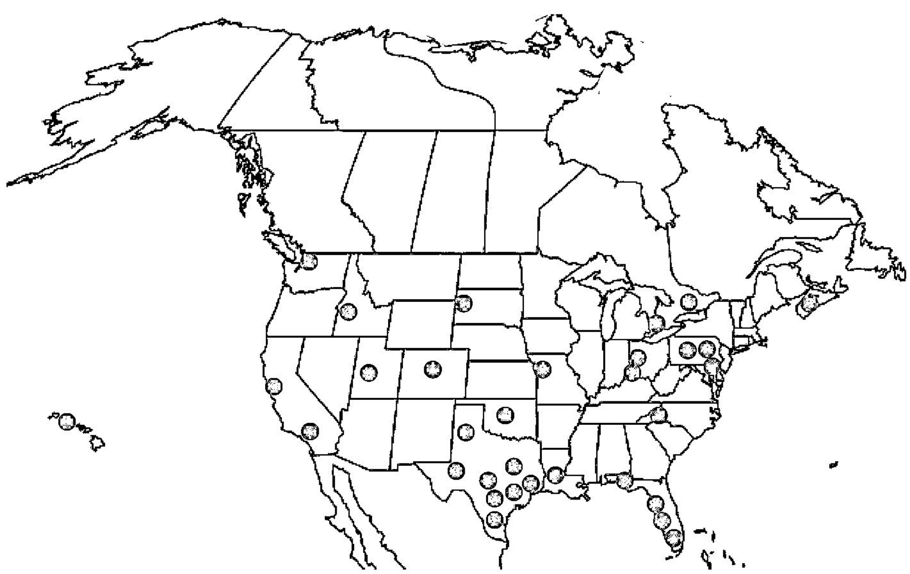

**Figure 4-1.** Approximate locations of responding utilities.

**Table 4-1.** Summary of Responses to Questions 1-6

| Utility | Customers | Ckt Miles of OH Dist. | Cust. per Trim Mile | % System Tree Density | | | Types of Major Storms | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | H | M | L | H | LW | T | IS | WF |
| AEP Texas Central | 810,890 | 24,868 | 68 | 22 | 26 | 52 | x | x | x | | x |
| AEP Texas North | 199,000 | 12,950 | 36 | 15 | 28 | 57 | | x | x | x | |
| Baltimore Gas & Electric | 1,220,000 | 9,345 | --- | --- | --- | --- | x | | | x | |
| Black Hills Power | 202,100 | 5,100 | 47 | 25 | 60 | 15 | | x | x | x | x |
| CenterPoint | 2,080,000 | 21,050 | 121 | 25 | 57 | 18 | x | x | x | x | |
| CHELCO | 42,000 | 2,816 | 15 | 50 | 50 | 0 | x | x | x | | x |
| Cleco Power | 272,877 | 11,000 | 28 | 50 | 40 | 10 | x | | x | x | |
| CPS Energy | 692,000 | 8,000 | 108 | 50 | 30 | 20 | x | x | x | | |
| Dayton Power & Light | 514,000 | 10,500 | 65 | 25 | 50 | 25 | | x | x | x | |
| Duke Carolinas | 2,500,000 | 54,000 | 58 | 30 | 50 | 20 | x | x | x | x | |
| Duke Midwest | 1,600,000 | 16,000 | 154 | 7 | 58 | 35 | x | x | x | x | |
| Entergy Texas | 395,000 | 10,985 | 42 | 50 | 35 | 15 | x | x | x | x | |
| Enwin (Canada) | 84,644 | 451 | 313 | 20 | 40 | 40 | | x | x | x | |
| Florida Power & Light | 4,500,000 | 35,000 | 161 | 50 | 30 | 20 | x | | | x | |
| Hawaii Electric | 294,371 | 899 | 437 | 25 | 50 | 25 | x | | | | |
| Idaho Power | 480,000 | 19,387 | --- | --- | --- | --- | | x | | x | |
| Kansas City Power & Light | 800,000 | 25,000 | 36 | 28 | 60 | 12 | | x | x | x | |
| Nova Scotia Power (Canada) | 467,317 | 15,982 | 42 | 40 | 30 | 20 | x | | x | | |
| Oklahoma Gas & Electric | 770,000 | 26,300 | 42 | 45 | 25 | 30 | | x | x | x | x |
| Oncor | 3,100,000 | 56,200 | 59 | 74 | 19 | 7 | x | x | x | x | x |
| PacifiCorp | 1,700,000 | 45,000 | 58 | 35 | 30 | 25 | | x | x | x | x |
| PECO Energy | 1,600,000 | 12,000 | 157 | 65 | 20 | 15 | x | x | x | x | |
| PG&E | 5,200,000 | 113,500 | 54 | 60 | 25 | 15 | | x | x | x | x |
| PPL | 1,380,887 | 27,965 | 90 | 25 | 30 | 45 | x | x | x | x | |
| Puget Sound Energy | 1,000,000 | 10,800 | 97 | 60 | 35 | 5 | | x | | | |
| Progress Energy Florida | 1,600,000 | 18,100 | 110 | 30 | 50 | 20 | x | x | x | | x |
| Southern California Edison | 4,851,312 | 98,500 | 164 | 10 | 20 | 70 | | x | | x | x |
| SW Public Service Co. | 400,000 | 16,000 | 38 | 33 | 33 | 34 | | x | x | x | x |
| Tampa Electric | 670,000 | 6,400 | 140 | 25 | 50 | 25 | x | x | x | | x |
| Texas New Mexico Power | 228,000 | 1,926 | 132 | 40 | 50 | 10 | x | x | x | x | |
| Toronto Hydro (Canada) | 682,560 | 2,665 | 285 | 60 | 30 | 10 | | x | | x | |
| Xcel Energy | 3,326,436 | 51,700 | 79 | 39 | 42 | 19 | | x | x | x | x |
| **Average** | **1,364,481** | **24,075** | **108** | **37** | **38** | **24** | **56** | **84** | **78** | **75** | **38** |
| **Low** | **42,000** | **451** | **15** | **7** | **19** | **0** | **(% of utilities)** | | | | |
| **High** | **5,200,000** | **113,500** | **437** | **74** | **60** | **70** | | | | | |

1. H=High; M = Medium; L = Low
2. H = Hurricanes; LW = Linear Winds; T = Tornadoes; IS = Ice Storms; WF = Wild Fires
3. Additional responses included: Floods (x2), Thunderstorms (x2), Micro Climates, Supercells, and Heat Waves
4. This is equal to the number of customers divided by the number of overhead distribution circuit miles categorized as either high or medium tree density.

For each responding utility, Table 4-1 computes a value labeled "customers per trim mile." This is equal to the number of customers divided by the number of overhead distribution circuit miles categorized as either high or medium tree density. This value is an attempt to determine the number of customers available to fund each mile of significant distribution vegetation management work. High values indicate that vegetation management costs can be spread among a relatively high number of customers while low values mean that relatively few customers are footing the bill. The values for customers per trim mile vary from 15 to 437, with an average of 108. Urban utilities tend to have higher values due to higher customer density and a higher percentage of underground primary distribution. Utilities serving a high percentage of rural areas tend to have lower values due to lower customer density and a higher percentage of overhead primary distribution.

With just one exception, all responding utilities characterize more than 50% of their system as either moderately or heavily treed, with an average of only 23% of a typical system being lightly treed. Utilities, on average, reported about the same amount of heavy and moderate tree density on their system at 37% and 39%, respectively. Clearly, most electric utilities have to deal with tree-related issues on a majority of their overhead system. Vegetation management is an important and core issue.[35]

All of the reporting utilities reported being affected by at least one type of major storm, with most reporting at least three. More than three-fourths of responding utilities reported themselves being subject to linear winds, tornadoes, and ice storms. Almost sixty percent of responding utilities reported themselves being subject to hurricanes. The least-reported was wild fires, at 36%.

At this point, the reader should have a basic understanding for the utilities that responded to the survey in terms of size, geographic location, tree density, and exposure to major storms of different types. The remainder of this section discusses survey results, and should be read with the context of the responding utilities in mind.

## 4.1 Tree Trimming

**Question 7:**
**Briefly describe your distribution tree trimming cycle (e.g., 4-year cycle).**

Of the respondents, 18 indicated a homogeneous cycle across their system, 10 indicated a combination of cycles depending upon various factors, and 4 indicated programs that are not based on cycle time.

Of the respondents indicating a homogeneous cycle across their system, cycle time ranged dramatically from one year to eleven years. Three utilities indicated an annual trim cycle. Most indicated a four or five year cycle. Only one utility indicated more than a five year cycle. This was a large utility that indicated more than three quarters of its system being moderately or heavily treed.

Many utilities use a combination of cycle times typically ranging between three and five years. Two utilities indicate shorter cycle times for main feeder trunks and longer cycle times for lateral branches. More commonly, utilities indicate shorter cycle times for urban feeders and longer cycle times for rural feeders. Presumably, this is because greater clearances can be achieved in rural areas, resulting in a longer time for branches to grow close to conductors. One utility indicates that cycle times are set based on growing conditions and the growth rate of trees.

Four utilities indicated that they do not use cycle times for tree trimming. Each of these utilities targets feeders with poor reliability that will benefit from tree trimming.

[35] No criteria were given for utilities for classifying parts of their system as heavily treed, moderately treed, or lightly treed. There are several ways to measure tree density, such as trees per mile and trees per acre. Since many utilities will not have this data, the survey intentionally allowed for qualitative judgments in this area.

**Question 8:**
**About what percentage of your distribution trimming is outsourced?**

A large majority of responding utilities (27 of 32) indicate that 100% of distribution trimming is outsourced. Two utilities indicate that 95% is outsourced, and two others indicate that 85% is outsourced. Only one utility performs most of its trimming with in-house resources.

**Question 9:**
**Are you, for the most part, keeping up with your tree trimming cycle goals?**

Fourteen of the responding utilities responded with an unqualified "yes" to this question. Another eight responded with a qualified yes of some sort. Eight of the responding utilities indicated that they are behind on their cycle goals, while two did not directly answer the question.

From these responses, it seems that a majority of utilities are, for the most part, keeping up with their tree trimming cycle goals, but falling behind on cycle goals is not uncommon.

**Question 10:**
**Is there a separate budget for hazard tree removal?**

Responses to this question were almost split down the middle. Fourteen utilities said that there is a separate budget for hazard tree removals. Two have recently implemented this policy, while one has a separate budget that has been set to zero for 2009. Seventeen utilities do not have a separate budget for hazard tree removals. One has a fund for all removals (including hazard trees), while another is considering a separate budget for epidemic diseased trees such as those affected by the Mountain Pine Beetle. One utility has a separate budget for some operating companies and no separate budget at others.

**Question 11:**
**Are you, for the most part, keeping up with your goals for hazard tree removal?**

Only four utilities stated that they were not keeping up with their goals for hazard tree removals, although another four stated that they had no set goals. The yes responses, however, should be taken in context. Question 26 indicates that sixteen utilities feel that they would benefit from more aggressive tree trimming a "moderate amount" or "a lot." Therefore, this question should be interpreted as a utility meeting its stated goals, but benefits may result from more aggressive goals.

One utility responds that it is able to keep up with its goals for hazard tree removal under normal circumstances, but not necessarily when epidemic tree diseases arise.

**Question 12:**
**Is it more difficult for you to address hazard trees when you are behind on your trimming cycle? Explain.**

Responses to this question are mixed. Eleven utilities state that it is not more difficult to address hazard trees when behind on the trimming cycle. For the responses offering commentary, the reasons relate to having a separate focus on hazard trees that is apart from the normal trimming cycle. This is evidenced by phrases such as "separate crews," "separate program," and "we treat hazard trees as a priority."

Fifteen utilities state that it is more difficult to address hazard trees when behind on the trimming cycle. Reasons are varied, including lower priority for hazard trees, co-dependence of trimming and hazard tree programs, the lack of an independent hazard tree program, less opportunity for hazard tree identification, and budgetary constraints.

Six utilities gave ambiguous answers, such as "we do not get behind on our trimming cycle," "there is no hazard tree removal program," and "we do not make an effort to identify hazard trees."

**Question 13:**
**On about what percentage of your distribution system do you trim "ground-to-sky," not allowing branches to exist directly above conductors? Thoughts and experiences on ground-to-sky trimming are welcome.**

"Ground-to-sky" trimming practices vary widely. Ten utilities responded that they practice this method of trimming on 5% or less of their distribution system, including four that state "none." None of these utilities stated strongly that they feel that this low amount is appropriate. One utility states that this practice will begin as part of a system hardening initiative, and another recommends the practice.

Eight utilities responded that they practice ground-to-sky trimming on 90% or more of their distribution system. These responses are mostly descriptive and do not advocate the practice. Four more utilities perform ground-to-sky trimming on a majority of the three-phase portion of the distribution system. One of these responses states, "Moving from a ground-to-sky approach to this targeted approach has led to lower costs on our first and second cycles. It also improved reliability as we were able to get more of our system on-cycle." Another response reflects a different perception of cost by stating, "Ground-to sky trimming is a more costly method of trimming."

The remaining eight utilities give a variety of responses that typically range from 10% to 25% ground-to-sky trimming. Several utilities indicate that this is done in targeted areas with reliability problems. Other insights from these responses include, "If a tree is 'sky-trimmed' extensively there is a risk of later mortality," and "Ground to sky … allows for more light penetration to the floor, which allows more growth from the ground … targeted removal of overhang is a more conducive practice for us."

## 4.2 Tree Outages

**Question 14:**
**Excluding major storms, approximately what percentage of outage events are due to: (a) Entire trees, outside of the right-of-way, falling into conductors, and (b) Other tree-related causes.**

There was some confusion when answering this question. Some responded as to the percentage of all outages, while others responded as to the percentage of only tree-related outages. Therefore, the results should be interpreted carefully. With this said, the average response of entire trees was about equal to the average response of other tree related causes. For many utilities, entire trees falling into conductors is not just a major storm problem.

**Question 15:**
**During major storms, approximately what percentage of outage events are due to: (a) Entire trees, outside of the right-of-way, falling into conductors, and (b) Other tree-related causes.**

Like Question 14, there was some confusion when answering this question. Some responded as to the percentage of all outages, while others responded as to the percentage of only tree-related outages. Therefore, the results should be interpreted carefully. Similar to the non-major storm case, the average response of entire trees was almost identical to the average response of other tree related causes. However, the total percentage is about 50% more during major storms, showing that trees account for more damage during major storms.

This result is somewhat surprising since many feel that entire trees falling over become a greater issue during major storms. The survey results of Question 14 and Question 15 does not support this view. Although there are more vegetation-related failures during major storms, the split between entire trees falling and other tree-related events, in the opinion of the survey responders, does not change much.

**Question 16:**
**Approximately what percentage of trees that fall into conductors has visible warning signs that could have been detected prior to the tree falling over?**

Nineteen utilities bravely answered this question while thirteen others understandably responded with an “unknown” or similar answer. The responses ranged from “less than 1%” to 50%, which is a surprisingly large spread. The most common response was about 10%, implying that 90% of tree fall-in events are not preventable, on average, in the opinion of the responders.

## 4.3 Identification

**Question 17:**
**Is the identification of hazard trees outside of the trim zone explicitly addressed in your vegetation management procedures?**

Only eight utilities responded “no” to this question, with an additional utility responding “somewhat.” Twenty-four utilities responded that they explicitly address the identification of hazard trees outside of the trim zone in their vegetation management procedures.

**Question 18:**
**Do your private property easements allow for the removal of hazard trees within the right-of-way?**

Twenty one utilities responded yes to this question. One stated that a portion of its private property easements do, and eight responded no to this question. However, it appears that private property owners typically allow hazard tree removal even if there is not a provision in the easement (see Question 28).[36]

**Question 19:**
**Do your private property easements allow for the removal the removal of hazard trees adjacent to the right-of-way?**

Only five utilities responded that, in most cases, their easements allow for the removal of hazard trees adjacent to the right-of-way. Another states that "a portion" of their private property easements address this issue. One of the responses cites its traditional easement language as follows:

> *… remove or modify from time to time trees, limbs, and/or vegetation outside the said right-of-way which the Grantee considers a hazard to any of its electric power or communications facilities or is a hazard to the rendering of adequate and dependable service to the Grantor or any of the Grantee's customers, by use of a variety of methods used in the vegetation management industry.*

Twenty-four utilities do not have easements that address hazard tree removal outside of the right-of-way. This effectively means that it is at the customer's discretion as to whether a hazard tree is allowed to be removed (although some utilities address this issue in their customer service agreement). Again, Question 28 shows that most customers allow hazard tree removal even if there is not a provision in the easement.

**Question 20:**
**Do your public property easements allow for the removal of hazard trees within the right-of-way?**

Fourteen utilities responded that, in most cases, their public property easements allow for the removal the removal of hazard trees adjacent to the right-of-way. This is slightly less than the number that responded yes to the same question regarding private property easements (Question 18). An additional four utilities responded with a qualified "yes" based on prior approval, small tree diameter, or varied treatment in different areas. Ten utilities responded "no," and one responded "unknown."

**Question 21:**
**At your utility, would you characterize the focus of identifying off-right-of-way hazard tree as: (a) focus is weak; (b) focus is moderate; and (c) focus is strong.**

There was a balance of responses to this question, with ten utilities stating that the focus is weak, eight stating that the focus is moderate, and fourteen stating that the focus is strong.

[36] In this question, "easement" is intended to represent the documented right to place facilities on private property, while the right-of-way represents the land on which utilities facilities exist. Most of the responses seemed to understand this intention.

**Question 22:**
**About what percentage of identified hazard trees are discovered through the following: (a) Normal trimming cycle; (b) Dedicated circuit inspections; (c) Noticed by crews doing other things; (d) Customers; (e) Other (please explain).**

The average responses to this question are as follows:

- The normal trimming cycle: 56%
- Dedicated circuit inspections: 21%
- Crews doing other things: 10%
- Customers: 9%
- Other: 4%

Clearly, most hazard trees are identified during the normal trimming cycle. However, for the companies that have dedicated circuit inspections that focus on hazard trees, half or more of hazard trees are identified through the inspection. Serendipitous identification through crews doing other things or by customers remains relatively small, but together still comprise almost 20% of identifications. There were only two "other" responses, both related to outage follow-ups.

**Question 23:**
**Do you have a database of hazard tree information (i.e., location of removed trees, known hazards, customer refusals, etc.)?**

Eight utilities state that they have a database of hazard tree information. Many of the remaining responses describe how information is kept in lieu of a database. For example, responses refer to spreadsheets, hard copies of information, and paper records. One utility notes that it is starting to use GPS equipment, and another notes that it is planning to deploy a GIS-based system in the near future.

## 4.4 Removal

**Question 24:**
**Do you remove hazard trees located on customer property at your own cost?**

Only three utilities stated that they do not remove hazard trees at their own cost. Most responses simply state "yes." One response qualifies that a tree will only be removed at the utility cost if it endangers utility facilities, which is likely the case for most utilities. Similarly, another utility responds that is will only remove an "immediate hazard," and that the customer is responsible for any additional work.

**Question 25:**
**Are there any complications with hazard tree removal related to third-party-owned or jointly-owned facilities?**

This question was intended to address third-party-owned or jointly-owned facilities, such as those involving telephone companies and municipalities. Five of the responders either did not answer or answered in a way that interpreted "third-party" to mean the land owner or customer. Of the remaining responses, nineteen utilities stated that this is typically not a problem while eight state that this is a problem. One states that, "complications are usually related to recovering shared costs." Another observes that, "communications companies do very little tree work to protect their facilities."

**Question 26:**
**Do you have the ability to remove hazard trees located on customer property without the prior consent of the customer, such as condemning dead hazard trees? Please explain.**

Twenty utilities state that they cannot remove hazard trees located on customer property without the prior consent of the customer. This means that a customer can refuse to have a known hazard tree removed. It also means that a hazard tree cannot be removed if the customer cannot be contacted. Ten utilities do have the right to remove hazard trees located on customer property without the prior consent of the customer. Many of the responses emphasize that there must be compelling situation, using terms such as emergency, eminent danger, severe hazard, and safety hazard. Several other responses indicate that, although they have the right to remove a hazard tree, customer consent is always sought.

**Question 27:**
**Please describe how hazard tree removal requests are performed.**

There are a variety of responses to this question, not all addressing specifically how customers are contacted with respect to removing a hazard tree on their property. All of the complete responses are available in Appendix B.

There seems to be two general approaches seen in the responses. The first is the use of a "door hanger" to notify customers of upcoming tree work on their property and possibly asking for a signature. The other is direct contact with the customer by a utility employee or representative. There are a variety of position titles mentioned that have responsibility for communicating with the customer and obtaining permission. These titles include: coordinator, contractor notification person, inspector, field inspector, certified arborist, qualified arborist, company arborist, facilitator, supervisor, forester, and general foreman.

**Question 28:**
**About what percentage of hazard tree-removal requests are granted by customers?**

Twenty three utilities responded that 90% or more of hazard tree removal requests are granted by customers. Of these, six stated that essentially 100% are granted (probably because it is required, see Question 26). Although this might seem high, recall that Question 26 revealed that eighteen utilities have the right to remove hazard trees located on customer property without the prior consent of the customer, essentially making customer consent desirable but unnecessary. Two responses indicated an 85% customer permission rate, another indicated an 80% customer permission rate, and another two indicated a 75% customer permission rate.

**Question 29:**
**If a customer does not respond to a hazard tree removal request, can you remove the tree? Explain.**

This question is similar to Question 26, which addressed the right to remove a hazard tree without prior consent. Fifteen utilities responded "yes" to this question, which is higher than the ten utilities that responded "yes" to Question 26. Two additional utilities stated that they can remove the tree in certain situations. This question, unlike Question 26, prompted many comments about legal issues, legal actions, legal departments, and the involvement of law enforcement officers.

**Question 30:**
**If a customer initially refuses to have a hazard tree removed, are any follow-on persuasion activities performed? How effective have these been?**

Every responding utility stated that they perform follow-on persuasion activities after an initial refusal. The only exceptions were three utilities that did not provide an answer. Responses can be grouped into two categories: coercive and persuasive. Only five utilities indicated the use coercive techniques, while 24 indicated persuasive techniques. Some representative examples of coercive and persuasive tactics are as follows:

<u>Examples of coercive tactics</u>

- Notify the customer in writing that they will be responsible for damages.
- The City will remove the tree and apply the charge to the customer's municipal property taxes.
- We advise the customer that they will be held liable for any damages.

<u>Examples of persuasive tactics</u>

- Take down additional trees at customer request.
- Replace the tree with a short-growing species and/or grind stumps.
- Haul the brush or debris or negotiate some other work activity.
- Discuss the potential of the hazard tree creating an outage for the customer and the benefits of having the tree removed. By communicating and educating the customer to the real hazards of these situations, we are generally successful in persuading the customer to allow us to remove the tree.
- Offer replacement trees or shrubs.
- Currently trying to set up a voucher system with local nurseries to allow us to just hand local nursery gift card voucher to the property owner as incentive.

**Question 31:**
**If a customer refuses to have a hazard tree removed, and the tree later damages the utility system, do you ever hold the customer financially liable for the resulting damage? Explain.**

Seven of the thirty-two responding utilities indicated yes to this question. Three of these indicate that this is part of the negotiation process when attempting to get permission to remove a hazard tree. One response states, "We do advise customers in our final danger tree letter that we will hold them financially responsible." Another states, "This threat is used as part of the 'negotiation', but most situations do not get assessed back to the property owner." None of the utilities responding "no" to this question say that the reason is due to customer-relationship issues.

**Question 32:**
**About how much time, on average, elapses from the identification of a hazard tree until it is removed?**
There were a wide variety of answers to this question, ranging from 1-3 days to 1-6 months. The most common responses ranged from 1-2 weeks (11 responses). Several of the responses separated eminent threats from less immediate hazards. One states, "One week, unless immediate action is necessary." Another states, "Imminent threats on done within days, others typically take a few weeks." Yet another states, "If the hazard tree is prioritized as a high it is addressed within 24 hours. If it is a low or medium, the tree will addressed within 14 days." None of the responses define their criteria for a hazard tree being an immediate threat.

**Question 33:**
**After cutting down a hazard tree on a customer's property, do you remove the resulting wood?**

Nine of the responding utilities reported that they will remove the resulting wood after a hazard tree is cut down on a customer's property. However, many of these responses qualify that this is only done at the request of the customer, or as part of the negotiation. Nine utilities simply responded "no," while fourteen responded with a "qualified no." Some of the qualified responses included the following statements:

**<u>Some conditions where utilities may consider removing wood</u>**
- Not typically but we have done so as part of a special reliability project.
- In an urban setting we may consider chipping the limbs, but we do not remove the log wood.
- Company policy is to leave the wood however realistically actually handled on case by case basis.
- Not normally; however, in a few cases, this has been done to avoid litigation.

**Question 34:**
**When removing a hazard tree on a customer's property, do you ever replace the tree? Explain.**

Responses to this question were mixed. Sixteen utilities responded that they do not replace the tree. Another six imply that this is only rarely done. Ten utilities state that they sometimes do provide a replacement tree after removing a hazard tree. Two of these responses indicate the use of tree vouchers rather than direct replacement. Some representative comments from the "yes" responses are:

**<u>Some representative approaches to tree replacement</u>**
- We may offer small replacement trees to facilitate removal in isolated incidents.
- We provide a pre-paid VISA card for the customer to use as they like. Educational materials are provided with the card to assist the customer in selecting a proper tree to plant near the power lines."
- Customers are offered tree vouchers through our Tree Replacement Program.
- We offer replacement trees or shrubs to compensate for the loss of the tree.

**Question 35:**
**Do you have a program to identify and replace undesirable tree species? How aggressive is this program?**

Twenty utilities state that they do not have a proactive tree replacement program. Eleven utilities state that they have a program, with most offering short descriptions (one utility did not provide an answer). Some of these descriptions include the following:

**Descriptions of some tree replacement programs**
- The program is extensive with letters to customers, a communication campaign involving multiple forms of media, public presentations, as well as participation in Arbor Day and Earth Day events and the like.
- "Right tree/right place" program. Usually only on palm trees.
- Based upon growth potential, cost, and system reliability.
- The whole program is centered on nurturing the growth of compatible vegetation. We do plant in some instances, however, lean heavily on Mother Nature to provide compatible shrubs naturally.
- We aggressively pursue removal of several troublesome species (i.e., cycle-busters).
- We aggressively target fast growing species. We try to work with city governments on tree ordinances, and we have even developed educational material that is made available publicly in an effort to inform customers and city code enforcement officials.

## 4.5 Best Practices

**Question 36:**
**A certain percentage of trees die naturally every year. Do you feel that your utility, on an annual basis, removes enough dead and diseased trees to keep up with this natural process?**

Ten utilities state that they are probably not removing enough dead and diseased trees on an annual basis to keep up with the natural tree mortality rate. Four utilities respond that they are not sure. The remaining eighteen utilities feel that they are generally keeping up with the natural process. Several of these responses state that hazard tree removal is sufficient in normal years, but not necessarily when unusual events occur. These responses stated the following:

Situations that may result in difficulty removing newly-developed hazard trees
- Under normal conditions exclusive of hurricanes and tornadoes, we generally keep up with this natural process.
- Exception is bark beetle infestation.
- We stay current, barring an infestation of some type.
- [We are] seeing a larger number of stressed trees uprooting and shedding major scaffold limbs due to drought/disease issues.

**Question 37:**
**Would an increase in the aggressiveness of hazard tree removal reduce major storm damage (a) a little bit, (b) a moderate amount, or (c) a lot.**

Sixteen utilities responded "a little bit," seven responded "a moderate amount," and eight responded "a lot." One utility did not provide an answer. No specific criteria was provided for these categories. No utility provided justification for its response, such as citing the mortality rate of tree species and the estimated number of trees in the "utility forest."

**Question 38:**
**What else besides hazard tree removal (vegetation related) would be effective at reducing major storm damage?**

There are a wide variety of responses to this question that can broadly be categorized into trim specifications, trim cycle, and miscellaneous. Because the responses are difficult to generalize, summaries of some of the responses in each category are now provided.

**Trim specifications**
- Widening right-of-way.
- Set minimum clearance and maintenance requirements for owners of trees.
- A dramatic increase in the maintained ROW along primary conductors.
- Removing additional overhang on laterals (single phase lines).
- A better trim specification. Currently the floor is not cleared and overhangs are allowed.
- Overhang removal (blue-sky or hinge point) targeting weak-wooded and other problematic species.
- Eliminate all tall-growing trees from beneath the power lines.
- Increased clearances at the time of pruning.
- Clear the right-of-way based on species & growth rate.
- Hard wood overhang removal.
- Palm tree skinning program.

**Trim cycle**
- Staying on trim cycle.
- Routine cycle trim maintenance.
- Reducing the cycle time while keeping the current ground to sky specification.
- Reduced cycle period.
- Increased tree removal/replacement.
- Mid-cycle inspections.
- More lateral (neighborhood) line clearing.
- Ability to complete a total annual work plan.

**Miscellaneous**
- Franchise rights that provide for tree abatement without the owner's permission.
- Cooperation of governmental entities, state, city and county, in addressing vegetation issues.

- Being notified by adjacent landowners of land use change. Many landowners have decided to clear cut their land … there remains a strip of trees adjacent to the power line that inevitably fall the next time the wind blows.
- Educating the public and builders about planting the right trees in the right place.

**Question 39:**
**Please describe any attempts to more effectively address hazard trees that <u>did not</u> work very well.**

Twenty-seven of the responding utilities did not provide an answer to this question. The five responses are summarized as follows:

**<u>Ideal that did not work very well</u>**
- Lump sum bidding. Contractors' desire to make a profit put extra pressure on our supervisors to catch skipped hazard trees.
- Removing dead trees only.
- A stand-along hazard tree program (separate from the routine trimming cycle) was more effective.
- Lack of property owner notice and "buy-in" prior to initiating work has proven to be a deal-breaker for many political subdivisions.
- Having multiple screeners checking backlogged hazard trees did not work very well.

**Question 40:**
**Please describe any attempts to more effectively address hazard trees that <u>did</u> work very well.**

Seventeen of the responding utilities did not respond to this question. The fifteen responses varied widely, but can generally be categorized as workforce, increased effort, customers, and miscellaneous. Summaries of some of the responses in each category are now provided (some utilities provided multiple answers).

**<u>Workforce</u>**
- Use of retirees to assist in coordination and inspections.
- Having a two-man crew dedicated to removing hazard trees.
- Trouble & linemen calling in hazards.
- Holding the contractor responsible for tree outages caused by missed or skipped hazard trees over the entire trimming cycle.
- Continuous training and education of our contractor pre-inspection arborists.
- Controlling contractor employee turnover.

**<u>Increased effort</u>**
- More patrols by servicemen/linemen & full removal when the trees are identified.
- Increasing mid-cycle patrols to include single-phase laterals.
- Reclaiming of ROW line clearing practices in some limited areas.
- In a designated "natural" area, we obtained permission to clear cut everything below the lines and any dead trees within a fall arc of the lines. We chipped the wood and created a walking trail beside the lines. The City seemed to like this idea and we had no complaints from residents and users of the "natural" area. Tree contacts have significantly been reduced and reliability increased in an area that was performing poorly during storms.

**Customers**

- Proactive notice and negotiated agreements prior to work starting.
- Personal face to face contact with property owner.
- One on one education of the customer about hazard trees and the potential they have.

**Miscellaneous**

- Investigating and analyzing tree caused outages, then summarizing the findings and educating field forces on identification.
- Developing a hazard tree rating system.
- Implementing a system-wide vegetation management reliability program.
- Implementing a hazard tree quality control program that examines abatement decision making.
- Tracking and analyzing outages has led to identification of areas that require more extensive hazard tree identification and removal.

**Question 41:**
**What would it take for your company to more effectively manage hazard trees?**

Only three of the responding utilities did not respond to this question. The responses varied widely, but can generally be categorized as increased resources, data/analysis, approach, and legal/regulatory. Summaries of some of the responses in each category are now provided (some utilities provided multiple answers).

**Increased Resources**

- Increase in funding and/or resources for hazard tree removal (9 responses).
- Increase funding for tree replacement (4 responses).
- Dedicated budget for hazard tree removal (3 responses).
- A mechanism to allow for the concurrent recovery of vegetation related expenses (2 responses).
- A separate crew that can climb a tree and fell it into the woods. No need for a bucket truck or disposal when the forest is the adjacent land type.
- Specialized inspector to identify hazard trees.

**Data/Analysis**

- Better tree failure data that shows failure trends by species that include: how the tree fails (wholly, partially, or both), its rate of failure as a function of population, and the time of year the species is likely to fail.
- An analysis of weather's influences over failure patterns.
- Good data collection tools and analytical support.
- A good business case to show we get more value than the cost (mainly in reducing major storm costs).
- Better data to support an increase in funding.

**Approach**

- Mid-cycle inspections.
- Cycle trimming.
- Find a way to get beyond the “business as usual” pruning and create a hazard tree program.

- Only right-of-way expansion would address the "look-OK-but-fail-anyway" trees.
- Better education for the public and better facilitation of requests to have trees removed with the public.

**Legal/Regulatory**

- Stronger stance of regulatory agencies to back-up clearance and hazard reduction initiatives.
- Better support for tree removal from public agencies.
- Include tree removal as part of new easement agreements.
- Take firm legal action against property owners.
- Establishing statutory utility liability for damages caused by hazard trees that is based upon a negligence standard rather than a strict liability standard.

**Question 42:**
**What would you recommend as a best practice for managing hazard trees?**

Seven of the responding utilities did not respond to this question. The responses varied widely, but can generally be categorized as approach, data/analysis, overall UVM program, and miscellaneous. Summaries of some of the responses in each category are now provided (some utilities provided multiple answers).

**Approach**

- Use a stratified approach based on the importance of the facilities, e.g. use a complete tree walk-around process 40' on either side of the pole line for subtransmission lines and distribution feeder main; otherwise detect hazard trees on remaining facilities as viewed when walking along the pole line.
- We recommend a three-pronged approach. This includes hazard tree identification and removal by contractors as part of an ongoing proactive circuit trim maintenance program; vigilant reporting and removal of hazard trees identified by utility personnel during the course of operations; and prompt inspections with the appropriate actions taken following notification from customers of potential hazards.
- Mid-cycle patrols and outage investigations.
- Train pole inspectors to identify hazard trees during regular inspections.
- Use tree trimmers to identify during area trimming.
- Have an annual danger tree crew to find and address hazardous trees.
- Every six months, inspect main feeder lines for hazard trees in areas that would have a high customer impact if an outage occurred.
- Establish a quality control mechanism that objectively analyzes tree abatement decision making and require open dialogue about the QC findings.

**Data/Analysis**

- Know species risk, target specific areas known to be at risk.
- Gather species-specific tree failure data & utilize that data to drive tree-abatement decision making.
- Establish a reasoned method to analyze the risk (impacts) associated with tree failure and utilize that analysis in tree abatement decision making.
- Recognition of targeted problem species that need to be given special attention.

**Overall UVM Program**

- Remaining on cycle and doing mid-cycle inspections.
- Several years of consistent funding.
- Aggressive removal policy as part of routine circuit maintenance.
- Include this as part of the routine patrols made.
- Establish a patrol standard that includes hazard trees.

**Miscellaneous**

- Require ANSI standards in tree abatement practices.
- Put a high emphasis on customer satisfaction.
- Widespread education of the customers regarding removal/replacement and governmental ordinances that do not hinder the removal of hazard trees by utilities.
- Holding the contractor responsible for tree outages caused by missed or skipped hazard trees over the entire trimming cycle.

**Question 43:**
**Any other thoughts or comments on the subject of hazard trees?**

Only a few utilities took the opportunity to respond to this question, with most of these repeating content provided in previous answers. The most popular theme is that hazard tree removal is not absolutely necessary, and must therefore be justified by either a business case (i.e., more money is saved than is spent) or by reliability improvement. Another response reiterates that a large number of trees that fall into the system are apparently healthy. The only way to deal with these types of trees is to more aggressively remove or replace all trees that could fall into the utility lines, which is a difficult proposition from both a financial and a customer relations perspective.

# 5 Recommended Best Practices

Many of the utilities responding to the survey seem to be satisfied with their hazard tree program. Many claim that they are keeping up with the natural rate of tree mortality, assert that additional effort in hazard tree management will not reduce storm damage, and posit that they cannot think of anything additional or different that they could do to better manage hazard trees. Is it fair to use these utilities as the standard of best practice? The author's opinion is "no." Although these utilities may feel that they are addressing hazard trees in an appropriate and effective manner, they would be hard-pressed to *prove* that this is the case. With this in mind, this section presents best practices that, in the author's opinion, will ensure that hazard trees are being managed through a process that is cost effective, consistent, transparent, and data-driven.

The best practices presented in this section should be taken in context. First, many utilities will already have many of these elements in place. Second, each utility is in a unique situation with regards to hazard trees. Certain best practices, though appropriate for most utilities, may not be appropriate for all. In any case, all utilities are encouraged to examine the proposed best practices presented in this section. Some can be implemented at little-to-no cost, and others may allow hazard trees to be more effectively managed at a lower cost.

Recommendations are not intended to be a "one size fits all" approach. For example, a utility with very little tree exposure may not need to have any formal hazard tree program at all. Similarly, utilities where tree fall-ins result in a small percentage of customer interruption minutes (e.g., less than 5%) may not need to change their approach as long as they can demonstrate cost effectiveness.

Best practices are organized into three stages. The best practices in the first stage are inexpensive and relatively simple to implement. In addition to being potential quick wins, they also set the foundation for more ambitious actions. The best practices in the second stage are designed to be implemented in the medium term and generally require more utility effort, investment, and potentially change. Generally, the experience and data obtained from the first stage will be helpful when implementing the second stage. The best practices in the third stage should be considered after a utility has a very good handle on its hazard program including the costs and benefits of a more aggressive approach. Since the best practices in the third stage are potentially expensive, the utility will be in a good position to have a dialogue with regulators about benefits and rate implications.

## First Stage

1. **Culture change.** In any organization, it is important to align goals with the culture. This allows the small decisions that are made by everyone everyday to work toward a common vision. In the case of hazard trees, it is important for all employees to be aware of the issue, its importance, the support of executive management in effectively managing hazard trees, and the expected benefits. A first step in hazard tree management is to identify an executive champion, execute an initial communications plan, and maintain continuing communications about status, wins, and future goals. Culture change is most important for utilities that need to significantly change their approach to hazard tree management.

2. **Separate hazard tree budget.** Most utilities are budget-driven. To ensure a sustained and consistent effort from year-to-year, it is important for hazard tree management to have its own budget separate from clearance activities. The way the work is managed and executed may not change, but the amount spent specifically on hazard tree management will be tracked side-by-side with tree pruning. This accomplishes several things. First, it allows the volume of work performed on hazard trees to be more easily tracked. Second, it provides additional transparency into hazard tree activities. Third, it makes it more difficult to reduce hazard tree spending disproportionately to tree trimming, as often happens when there is a single integrated UVM budget that experiences a reduction. A hazard tree budget can be part of another budget (e.g., UVM, all tree removals) as long as there is a separate estimate for hazard tree spend and separate tracking of hazard tree expenditures.

3. **Hazard tree data.** Cost-effective hazard tree management must be data driven. Therefore, it is important for utilities to have a robust data collection process for hazard trees. At a minimum, this should consist of three elements. First, all identified hazard trees should be documented in a standard form. Important information to collect includes the location, species, defect, distance from lines, date of identification, date of removal, and any information about gaining customer approval. It is helpful to include a GPS location of the tree so that information can be easily visualized in mapping software, but this is not essential. Second, a sample of trees that fall into the distribution lines should be examined by a qualified arborist to collect similar data, especially the species, distance from the power line, and whether there were visual defects that could have been identified before the tree fell over. Third, the outage management system should be able to capture basic data for all tree-related interruptions on the distribution system. This requires clear cause codes that can be assigned by linemen such as: tree fall-in within ROW, tree fall-in outside of ROW, broken tree branch, tree grow-in, and other tree cause (explain). The UVM group should obtain regular updates of the distribution outage information and be able to easily cross-reference this data to the richer, but less extensive data collected by arborists.

4. **Post-storm data collection.** Many trees fall down during major storms. When this happens, utilities are understandably focused on restoration rather than data collection. By the time a utility begins to think about the role of trees in storm damage, chain saws and chippers have typically removed most of the evidence. This data is invaluable when trying to manage hazard trees in a manner that is most beneficial during major storms. Therefore, a utility should have a plan that has damage assessors collect data on fallen trees while they are already out in the field. For example, damage assessment forms could have a check box labeled, "trees likely caused this damage," possibly with a selection of the types of trees that contributed to the damage. A process should be in place so that all damage assessment forms are retained so that the information can later be entered into a spreadsheet or database for analysis.

5. **Inspection procedures.** Hazard trees cannot be removed unless they can be identified. In order to improve the effectiveness of hazard tree identification, inspection procedures should be documented and the inspections should be performed according to these procedures. Typical inspection procedures should include who should perform inspections, when inspections should occur, and specific actions that should take place during inspections. These procedures may be different for different situations (e.g., dedicated hazard tree inspections, pre-inspections done by arborist prior to cycle trim, inspections done by linemen during circuit patrols, etc.). These procedures should specify, at a minimum, how far back from the lines to inspect, when the inspector should walk around the tree, and specific defects to look for in different tree species. It may be appropriate to have different procedures for different geographic areas.

6. **Maximize customer approvals.** Even if a utility can forcibly remove a hazard tree from customer property, it is always desirable to obtain customer pre-approval. Utilities should collect data on initial customer approval rates and ultimate customer approval rates. The benchmark data suggests that a 95% approval rate is reasonably possible to achieve. If approval rates are lower, the utility should employ more extensive negotiation tactics that may include negotiation training, customer education, debris removal, tree replacement, tree vouchers, and possibly the threat of financial liability. If not being done already, the utility should strongly consider paying for the removal of customer-owned trees that pose a hazard to utility equipment.

**Second Stage**

7. **Manage backlog.** There should be clearly documented goals and processes for the removal of identified hazard trees. Documentation should also exist to show that these goals are being met. Processes should be in place to ensure that imminent threats are addressed immediately. Hazard trees identified on pre-patrols should, of course, be removed when the tree crews arrive at the location. Hazard trees identified through other processes should generally be removed within one month. Showing that the hazard tree backlog is being well-managed establishes credibility, in addition to being a best practice.

8. **Maintain pruning cycle.** Unless the hazard tree program for a utility is, for the most part, separate from cycle clearance, it is important to maintain the pruning cycle. Since the pruning cycle is often the primary mechanism for hazard tree identification, being behind on the pruning cycle will result in being behind on hazard tree removals. In addition, utilities that are behind on their pruning cycle often, in an effort to catch up, shift focus and budgets from hazard trees to clearance work.

   Although not directly related to hazard trees, it should be emphasized that maintaining an optimal pruning cycle is less expensive from a life-cycle perspective than falling behind and then catching up. As discussed in Section 3, this is because the biomass addition to trees occurs exponentially, in addition to pruning difficulties that occur when branches begin to encroach upon conductors (see Section 3). In most cases, a regular cycle (implemented in a thoughtful manner) is the least-cost approach for parts of the system with a significant utility forest.

   Tree growth rates can vary from year to year based on precipitation and other factors. Therefore, a strict and inflexible pruning cycle is not the intent of this recommendation. Once a utility establishes its pruning cycle, it is appropriate in certain cases to defer pruning on certain scheduled parts of the system if there is evidence that pruning is not necessary.

9. **Hazard tree database.** Once a utility begins to manage their hazard tree program dynamically based on extensive field data, it becomes important to have a hazard tree database where all of the data can be gathered, maintained, and analyzed in an efficient and secure manner. At a minimum, this database should be a repository for the data collected according to Recommendation 3. The database should be able to track factors such as the number of hazard trees identified each month, the number of removals each month, the number of refusals, average removal time, and so forth. More advanced systems, if desired, can be based on a geographic information system (GIS) so that information can be displayed and analysis be done on a geographical basis. GIS has the additional advantage of being able to display a variety of additional data with the hazard tree data such as streets, circuits, plots, devel-

opment zones, municipal boundaries, satellite imagery, weather data, and a host of other easily obtainable data sources.

10. **Assess the utility forest.** An assessment of the utility forest is recommended for utilities that have a significant percentage of customer interruption minutes attributable to fall-in trees (e.g., 10% or more). The utility forest, as discussed in Section 3, consists of all trees capable of falling into the utility lines. An assessment of the utility forest will require a statistical sampling at various locations in the system. The result is an estimate of the total number of trees, by species, in the utility forest. Mortality rates for different tree species can be obtained from state forester data. The utility forest statistics, combined with tree mortality rates, results in the expected number of new hazard trees in the utility forest each year. This can be compared to the number of hazard tree removals to see if hazard tree removals are keeping up with the natural rate of tree mortality.

11. **Prioritize by species.** A combination of the utility forest data and the hazard tree data allows inspections and removals to be tailored by tree species. For example, a certain species of tree may only constitute 10% of the utility forest but is involved in 30% of fall-in events. This species should be given special attention for inspection and removal. In contrast, another tree species might consist of 40% of the utility forest but only 5% of fall-in events. This species can be addressed in a less strict manner. Inspections can also be tailored by species by documenting the typical types of defects that are common for that species. For example, certain species may be subject to decay as evidenced by a certain type of fungal growth, another species may be subject to cracks, another may be prone to large branch failures, and yet another may be subject to simply blowing over when it is the tallest tree in the area.

12. **Plan for epidemics.** Any hazard tree program will be extremely stressed should a tree epidemic occur such as a beetle infestation. If an epidemic occurs, the tree mortality rate will increase significantly and the existing level of hazard tree activity will be insufficient to identify and remove the infested trees. Therefore, utilities that have the possibility of a tree epidemic should have a written plan on how it will deal with this epidemic. This plan should address issues related to funding, resources, reliability, public relations, other stakeholder relations, and other factors.

## Third Stage

*Note on the Third Stage: These recommendations are recommended if utilities wish to significantly reduce the number of tree-related failures during major storms. Since most tree failures during major storms are apparently healthy trees (i.e., not hazard trees), some of the recommendations in the Third Stage go beyond hazard trees, are potentially expensive, and are sensitive to property owners. Therefore, utilities must carefully consider whether the benefits associated with these Third Stage recommendations justify the costs and other implications.*

13. **Engage regulators.** After the appropriate elements of the first two steps have been successfully implemented, a utility will have a strong hazard tree program that is data driven, efficient, and cost efficient. At this point, the utility must decide whether it wishes to become, with respect to tree damage during major storms, more aggressive in terms of funding, legal constraints, political issues, or other issues that warrant involvement with the regulator. Since the existing program is very good, proposed costs and benefits should have high credibility with regulators.

14. **Address legal, regulatory, and political issues.** After the first two stages, the utility will have a good understanding of any legal, regulatory, or political issues that are hampering effective hazard tree management. Using data, the utility will be able to demonstrate the impact, and quantify the benefits of potential changes. Choosing its battles wisely, the utility can now attempt to change one or more of these situations in a collaborative fashion. It is not advisable to address these issues before good data and analyses are available.

15. **Targeted annual inspections.** For utilities interested in being more aggressive with regards to hazard trees, dedicated annual inspections can be performed for critical parts of the system. For example, a utility might identify twenty percent of its feeders that it deems critical to minimize damage during a major storm. The three-phase portions of these feeders could then be inspected on an annual basis for hazard trees (these inspections could be coupled with an overall inspection of the circuit). This inspection is completely separate from trim cycle work. Aggressive utilities may choose to perform annual inspections on all three-phase portions of the system. Targeted annual inspections should be based on a credible cost-to-benefit analysis.

16. **Targeted danger tree removal.** During major storms, many of the trees that fall over could not have been identified ahead of time. Therefore, the only certain way to dramatically reduce the number of fall-in events during a major storm is to reduce the utility forest. Broad-based widening of all rights-of-way is almost certainly cost prohibitive (in addition to being unacceptable to many stakeholders). However, targeted danger tree removal can be considered on critical parts of the system that are especially important to have a minimum of damage during a major storm.

    Danger tree removal does not involve the removal of all trees within a certain distance to the conductors. Rather, only trees that have the potential to fall into the conductors are considered for removal or replacement. For example, a utility might currently remove all trees within twelve feet of the conductors. Targeted danger tree removal might include the removal of all trees between twelve and twenty feet of the conductor that have the potential of falling into the conductors. The utility should be aware that this type of removal strategy might result in increased growth of other trees due to the availability of more sunlight and less competition for soil nutrients.

    Many property owners will probably be less-than-enthusiastic about targeted danger tree removal, perhaps to the extent that makes this recommendation impossible or undesirable to implement. However, targeted danger tree removal is the only sure way to dramatically reduce the number of tree fall-ins during major storms. There is emerging research on the effects of canopy thinning to reduce tree damage from strong winds, but this research has focused on small-diameter trunks and is not applicable to utility danger trees, which tend to have large trunks.

    Any utility that pursues targeted danger tree removal should keep detailed data so that, over time, the impact of the widening can be determined.

17. **Targeted ground-to-sky pruning.** Branches over conductors pose a hazard to the conductors. Furthermore, overhanging conductors greatly increase the probability that a tree will strike the conductors if it should fall over. Therefore, ground-to-sky pruning will be effective for improving both daily reliability and storm reliability.

    Once ground-to-sky pruning is established, it is often slightly less expensive to maintain as long as taller lifts and/or climbing is not required. As discussed in Section 3, this is because of the exponential biomass growth characteristics of trees. Less biomass on the trees results in less biomass to remove on an ongoing basis. In addition, pruning over live conductors is often less efficient than pruning away from the conductors.

Transitioning from under pruning to ground-to-sky can be initially expensive, although these costs can typically be capitalized as a right-of-way permanent asset improvement. Transitioning to ground-to-sky will also typically involve an extensive amount of customer outreach and coordination with many other stakeholders.

Despite these challenges, utilities should consider using ground-to-sky pruning on critical parts of the system that are especially important to have a minimum of damage during a major storm. Some utilities might also consider not allowing branch overhangs on all three-phase portions of their distribution system. At a minimum, this should involve pruning as high as the lift will reach, with an attempt to prune above the "hinge point," where a branch that splits at the trunk will swing to the trunk without hitting the conductors. Any utility that pursues a transition to ground-to-sky pruning should keep detailed data so that, over time, the costs and impacts can be better understood.

18. **Customer outreach.** If and when a utility decides to change its approach to UVM in a way that affects customers, the utility should develop and implement a customer outreach program. The goal of this program is to educate customers on what will be done, why it will be done, when it will be done, the associated benefits, and the process for communicating concerns or comments to the utility. This plan should be developed from the customer's perspective and the benefits that the customers will receive. It should also allow for customer input so that those who wish can feel that they are part of the process and have the ability for their voice to be heard and considered.

    Customer interaction with respect to trees presents both an opportunity and a risk. Trees are a sensitive issue for many customers. A thoughtful customer outreach program presents the opportunity for utilities to strengthen their relationship with customers. An insufficient or misguided customer outreach program, in contrast, could irritate customers and result in backlash.

What benefits can be expected from the above recommended best practices? The recommendations in the first two stages will result in a well-managed and data-driven hazard tree program. A utility may already be doing a good job with respect to hazard trees, but the recommendations in the first two stages will allow the effectiveness of the hazard tree program to be demonstrated based on budgets, processes, and data. For most utilities, the best practices in the first two stages will allow for an increase in the cost-effectiveness of hazard tree management, and modest reductions in daily and storm tree in-falls. Most of these recommendations can be implemented either with little cost or with short-term costs that result in long-term savings (e.g., maintaining an optimal pruning cycle).

In the survey, many utilities claim that only ten percent or less of in-fall trees could have been identified as hazard trees prior to failure. If this is the case, more aggressive hazard tree removal would only provide incremental storm benefits. Consider a major wind storm where eighty percent of damage is due to in-fall trees, with eight percent of damage due to identifiable hazard trees. Assume that a utility implements an aggressive hazard tree program that is able to identify and remove seventy five percent of all identifiable hazard trees *on the entire system*. This implies a six percent reduction in overall storm damage, reducing a fourteen day storm to a thirteen day storm. This may not seem like much, but each day of storm restoration is very expensive and the cost of such a hazard tree program may be justifiable based on reduced storm costs. The economics will vary for each utility, but are worthwhile to examine.

The economics of hazard trees should include societal benefits. Each dead and diseased tree in a populated area will eventually fail and have to be removed. Even if the tree does not do any damage, the cost difference between reactive removal after failure and proactive removal is minimal, since the cost is dominated by the amount of biomass involved. Therefore, the additional societal cost for utilities proactively identifying and removing hazard trees, not considering damage, is equal to the cost of identification and program management. Assuming that the cost of hazard tree identification and program management is fifteen percent of overall costs, society is better off if the reliability benefits and reduced storm damage benefits exceed about fifteen percent of the overall program costs (not including the benefits of reduced customer property damage). This analysis does not necessarily extend to forested areas where fallen trees are not removed. Regulators must ultimately decide how much utility hazard tree management effort is appropriate for inclusion in rates, but there is already strong precedent for utilities to pay for the removal of trees on customer property and to recover these costs through rates.

Significant reductions in storm damage can be achieved by reducing the utility forest and by reducing the amount of branches that overhang conductors. The societal economics for hazard trees do not apply in these cases, requiring the benefits to exceed the full costs for justification. However, storm benefits could be substantial. Consider again a major wind storm where eighty percent of damage is due to in-fall trees. If a utility reduces the utility forest on a critical circuit by fifty percent, storm damage on this circuit will be reduced by forty percent.

Based on survey results, some utilities have a highly developed hazard tree management program, many have a good program with opportunities for improvement, and some have programs that are not effectively managing hazard trees. In addition, there are many differences across utilities in terms of service territory, vegetation density, vegetation type, storm characteristics, and other factors that necessarily impact their approach to hazard tree management. These recommendations are not intended to be a "one size fits all" approach, and each utility must therefore thoughtfully determine its own best approach to hazard tree management.