PUC DOCKET NO. 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	§ § § § § § §	2006 MAY 31 AM 9:01 **PUBLIC UTILITY COMMISSION OF TEXAS**

AEP RESPONSE TO STAFFS "DRAFT EXECUTIVE SUMMARY AND RECOMMENDATIONS."

NOW COME Southwestern Electric Power Company (SWEPCO), AEP Texas North Company (TNC) and AEP Texas Central Company (TCC) (hereinafter referred to as "AEP" or "Companies") and file the following comments to address the recommendations made by the Public Utility Commission Staff ("Staff") in Project No. 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*).

On May 10, 2006, Staff filed a "Draft Executive Summary and Recommendations" outlining measures to be taken by Transmission and Distribution Utilities (TDUs) and Telecommunication Utilities (TUs) to minimize future outages and associated restoration costs related to hurricanes. Subsequently, Staff held a workshop on May 15, 2006 to provide clarification of those recommendations and to receive oral comments. AEP appreciates the time and effort Staff has dedicated to this project and the opportunity to provide input, including the following comments on Staff's recommendations on hardening the infrastructure in addition to AEP's thoughts on cost recovery.

AEP understands the extreme difficulty in maintaining the proper balance between the cost of hardening the infrastructure against significant weather events to ensure reasonable reliability of the electric grid and the actual value that customers may derive as benefits. For example, is it prudent to invest large amounts in an infrastructure that will withstand a storm that will leave no buildings standing (as we all saw last year)? AEP believes that the costs of implementing Staff's proposed recommendations, as currently stated, will be excessive and will exceed the potential benefit to be gained. As currently stated, most recommendations are not cost effective and many are difficult to implement (some impossible within the stated time line). However, the main thoughts behind Staff's recommendations are on point, and with appropriate modifications, the electric systems will be improved, and customers will receive additional benefits without being faced with unreasonable costs for those benefits.

One threshold issue that must be dealt with prior to implementing any of the proposals outlined by Staff is the question of cost recovery – who is going to pay for the additional investment and operation and maintenance (O&M) dollars, and how will those dollars be collected? As discussed in more detail below, the current regulatory scheme does not support timely cost recovery of the magnitude of cost embedded in Staff's recommendations. AEP has outlined in broad terms, some mechanisms for the Commission's consideration and looks forward to working with the parties to implement a cost recovery mechanism. AEP would urge the Commission to explore and implement a cost recovery mechanism prior to adopting any costly "infrastructure hardening" standards. In the time available for comment, AEP has attempted to quantify and qualify the Companies' concerns with implementing Staff's recommendations, and where possible, provided a modified recommendation as an alternative that the Companies believe will result in a more cost effective means of realistically hardening the Texas electric grid while providing reasonable benefits.

I. Cost Recovery

As indicated in previous comments, all of the TDUs in Texas currently design and build their transmission and distribution facilities to meet and/or exceed the current NESC standards established for their particular geographic area. These standards contain provisions for areas susceptible to hurricane-force winds, icing conditions, and other extreme weather events and climates. Should the PUC decide to establish more stringent design parameters for Texas, all of the state's TDUs will incur significant costs. Cost recovery through the traditional ratemaking process using test-year costs and considering the regulatory approval time lag do not provide adequate timely recovery. Prior to implementing any of the proposed recommendations, the Commission should investigate and adopt a new cost recovery mechanisms that would allow timely recovery of the extensive capital investments and O&M expenses that would be incurred by the the TDU's.

AEP believes that the Transmission Cost of Service (TCOS) rules allow for the recovery of capital investments for "hardening" the transmission grid; although, a review of the rule should be conducted to ensure that costs for both capital *and* O&M expenses incurred due to compliance with Staff's recommendation are indeed recoverable through that mechanism. Importantly, while ERCOT transmission utilities may avail themselves to TCOS rules, no such mechanism has been developed for those utilities outside of ERCOT. Although HB 989 was enacted during last year's legislative session, the Commission has not begun a rulemaking to implement the provisions of that law.

Furthermore, AEP supports the development of an alternative regulatory mechanism that would allow for more timely recovery of incremental distribution costs. The companies suggest that the capital investment and the O&M costs associated with implementing any recommendations adopted by the Commission be recovered through this alternative mechanism. As discussed in previous comments, AEP offers the following suggestions as means to accomplish a timely recovery of the massive investments in distribution facilities that will be necessary to comply with Staff's requirements:

1. Commission adoption of a mechanism similar to the TCOS and/or TCRF process to apply to distribution investments;
2. Acceptance by the Commission of a separate rider to a distribution utility's tariffs to allow recovery of incremental distribution investment costs that are associated with hardening the distribution infrastructure;
3. Commission adoption of a mechanism similar to the Gas Reliability Infrastructure Program which is a mechanism currently in use at the Railroad Commission of Texas for gas distribution utilities to seek recovery of incremental investment costs; or
4. Commission adoption of a band-width mechanism that would consist of periodic (most likely annual) filings with PUC, without a full rate case,

that allow rate adjustments if a distribution utility's return on equity is determined to be outside the pre-set bandwidth.

While all of these suggestions have the potential to provide a more timely recovery of distribution investments, the Companies believe that either of the first two options can be more readily adopted by the Commission in a relatively short period of time to address the TDU's needs so that hardening the electric system can begin this year. However, as stated timely recovery of O&M costs is essential.

II. AEP Response to Staff's Recommendations

Recommendation 1: *Require the development and implementation of an inspection cycle for vegetation management for all overhead electrical and telecommunication lines. This cycle should consider the growth rates of common vegetation in the service area. Utilities should provide the Commission with the details of its vegetation inspection program within six months.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION # 1

AEP suggests that recommendation #1 be reworded as follows:

<u>All utilities should develop and implement a vegetation inspection plan that cost effectively manages vegetation in easements to reduce tree related outages. If concerns develop regarding excessive vegetation related outages, the Commission can request the respective utility to provide its inspection data and other supporting information to show that it has an adequate plan for vegetation management.</u>

AEP Comments regarding Recommendation #1: AEP currently conducts regular ground based inspections of all its distribution line facilities in Texas and has initiated a circuit inventory to determine vegetation density and wire impact. This inventory will allow AEP to better forecast and negotiate future vegetation management costs.

As currently proposed, the requirement to conduct a complete vegetation inspection of all AEP transmission and distribution circuits in Texas would cost in excess of $20 million. A better use of these funds would be the actual clearing and maintaining of easements.

Should the Commission decide that specific vegetation inspection cycles are required, some flexibility should be allowed, to exclude from a specific inspection cycle circuits with little vegetation, or little probability of being affected by hurricane type conditions. The Commission should also provide for the timely recovery of the associated costs.

<u>Recommendation 2:</u> *Require the development and implementation of a regular, ground-based inspection cycle for all overhead electrical and telecommunication facilities, including a condition-based assessment of wood pole suitability for continued service. Utilities should provide the Commission with the details of this inspection program within six months.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #2

AEP suggests that recommendation #2 be modified as follows:

Require the development and implementation of a regular, ground-based inspection cycle for all overhead electrical and telecommunication facilities, including a condition–based assessment of wood pole suitability for continued service. ~~Utilities should provide the Commission with the details of this inspection program within six months.~~ <u>Utilities that do not currently have such programs will have six months to develop them and subsequently file a summary of the program with the PUC.</u>

AEP Comments on Recommendation #2: As indicated in previous comments, AEP currently conducts regular ground-based inspections of its transmission and distribution line facilities in Texas. Transmission inspections include walking inspection and wood pole ground-line inspection, as appropriate. Distribution inspections include a ground-based assessment of wood pole suitability for continued service.

<u>Recommendation 3:</u> *Require utilities to establish processes, and incorporate these requirements into their existing contracts or tariffs, to ensure the structural integrity of poles and attachments in situations where utilities augment or add cable facilities to existing poles.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #3

AEP suggests that Recommendation #3 be deleted since there are other codes and standards that govern attachments to electric facilities.

AEP Comments on Recommendation #3: This is a normal utility practice and should not be required by the Commission. In addition, this recommendation is not required because, Section 224 of the Communications Act of 1934, as amended by Section 703 – Pole Attachments of the Telecommunications Act of 1996, establishes the rules of general applicability, access, rates, federal, state and local requirements, terms, conditions and industry standards.

At issue is not the process by which the attachments are reviewed and allowed but rather connecting utilities (telecommunication, cable, etc.) that ignore or refuse to follow the permitting process.

Recommendation 4: *Require each utility to provide the Commission with a report within one year that evaluates the level of inventory for transmission facilities considering the requirements of staff's recommendations.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION # 4

Recommendation #4 is not necessary and it should be deleted.

AEP Comments on Recommendation #4: AEP recommends that no special inventory report be required by the Commission. AEP has extensive experience with many hurricanes and other storm situations and has continued to modify and further develop its storm procedures and has continued to enhance its mutual assistance programs such that these needs are being met voluntarily. Sufficient procedures are already in place to meet AEP's transmission line restoration needs. An inventory report would serve no purpose. It is not until after the amount of damage can be assessed that it can be determined the type and the amount of materials that will be required. AEP continuously monitors its overall needs for structures, conductor, insulators and other materials required to restore transmission lines to service from outages by storms or other causes. Inventory is kept at appropriate levels for local storerooms for more routine or smaller storms. Additional materials are also kept at larger regional warehouses. AEP's expansive operations in eleven states also allows for materials to be repositioned internally in times of emergency or larger disasters. When weather predictions indicate the possibility of hurricanes or other large storms, AEP storm planners often begin to strategically transfer emergency materials to selected locations in advance preparation for post-storm restoration activities.

Recommendation 5: *Require removal within one year of all trees that could potentially damage electrical or telecommunication structures or facilities and that are located within the right of way (ROW) easement.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #5

AEP recommends that recommendation #5 be reworded as follows:

The Commission will work with the utilities, state government officials and local government officials to establish guidelines for the scope of clearing to be achieved, as well as a reasonable timeline for implementation of the guidelines, that considers the various climate zones within the state. All utilities should implement, within 12 months after those guidelines have been established, a vegetation management program based on those guidelines.

AEP Comments on Recommendation #5: As currently worded, every utility will likely be in violation of this recommendation. It is both practically and politically impossible to implement this recommendation, especially within the given time frame, because:

- There are not sufficient tree clearing resources available to accomplish this requirement in one year. AEP believes that the Texas labor pool could not support such an endeavor, nor would anyone be interested in investing in the equipment resources for a one-year project. AEP Texas alone would require at least 6,000 additional workers.
- Total removal of all potential encroaching trees in one year is impractical due to cost and specific easement use/accessibility issues,
- The local governments will not accept this requirement, and
- The private sector will not accept this requirement.

As presented, the phrase "potentially damage" must be clarified in order to determine appropriate easement widths which will then need to be negotiated for with property owners, city, county and state governments. Further, the recommendation, as proposed, would find each utility in violation within one year because it is both practically and politically impossible to implement this recommendation. Total removal of all potential encroaching trees in one year is impractical due to cost, easement issues, and lack public and private acceptance. The emphasis should be to incorporate selected tree removal with other management activities over a set number of years. Further, public policy must be strengthened to facilitate success of any vegetation management program.

The removal of all trees within the AEP Texas ROWs, that have the potential to cause damage to facilities, would cost an estimated $200 million for distribution and $95 million for transmission (man-power and equipment). However, completing this task in one year is not feasible since it is doubtful the Texas labor pool could support such an endeavor. AEP Texas alone would require at least 6,000 additional workers requiring out of state crews resulting in additional costs. AEP has not even attempted to quantify the additional cost requirement for the supporting equipment (bucket trucks, saws, chippers, etc.) that would also be needed to perform this task.

One additional issue that requires consideration is the disposal of wood debris. Currently, AEP removes approximately 42% of all trees encountered in and near the easement and has found disposal of the debris to be problematic.

Assurance of timely cost recovery is mandatory before additional expenditures of any magnitude can be initiated.

Recommendation 6: *Require each utility to perform a study within one year that evaluates the reasonableness and costs of retrofitting overhead distribution facilities so that, under conditions of high wind and/or ice loading, the conductors and or support hardware will fail before the structures fail and provide the Commission with its evaluation and any recommendations.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #6

AEP recommends that recommendation #6 be reworded as follows:

Electric distribution facilities including those less than 60' above ground or water shall be designed and constructed in accordance with the wind loading standards of the latest edition of the NESC for the specific geographic region.

AEP Comments on Recommendation #6: AEP strongly suggests that the Commission reconsider this recommendation that could result in:

1. The dropping of energized conductors into other utilities and facilities mounted on the poles, and
2. The dropping of energized conductors onto, or close enough to, the ground where members of the public could easily come in contact with the energized conductors.

AEP believes that requiring a study of new and unproven technology would require a significant investment of time and resources, even if performed as a joint study by the electric utilities of Texas. Because this "break away" concept is relatively new, AEP is concerned that it may actually have the affect of lengthening restoration time and causing potential safety hazards.

A piece of support hardware designed to fail is not the answer. Under high wind conditions it is unlikely that failure of the support hardware would result in the conductors and other equipment falling clear of, or, to the base of the pole. It is more likely that the conductors will hang on the pole, other pole mounted equipment or become entangled with distribution conductors lower on the pole. This would create additional stress on the structure. High winds will also result in structure failure of homes, buildings and other facilities in the area of the distribution lines, and the resultant flying debris will cause some amount of pole failure. The netlike effect of conductors balled up somewhere between the top of the pole and the ground will trap flying debris and result in pole failure.

Under normal operating conditions, having energized conductors fall prematurely may expose the public to additional hazards and the utilities to additional liabilities. Simple outages such as a car hitting a pole may become more complex because shock loading could cause failure of multiple conductor support devices for several spans on either side of the accident site creating additional safety hazards for the public. This creates the potential to expand the damage and increase the outage, especially if the failed devices drop conductors across a major thoroughfare where vehicular traffic hangs on the dropped conductors, before service can be restored.

Recommendation 7: *Require utilities to perform a study within one year that evaluates the current practice of automatically sectionalizing a distribution line to improve reliability and examines a practice of increasing the number of automatic sectionalizers to gain additional enhancements to reliability. The utilities should provide the Commission with this study and any recommendations.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #7

AEP proposes that recommendation #7 be deleted or modified to read:

The Commission should initiate a project to re-evaluate Substantive Rule 25.52 to provide utilities with incentives for improved reliability as measured by SAIFI, SAIDI and Distribution feeder performance.

AEP Comments on Recommendation #7: Staff's requirement addresses overall service quality and reliability. It does not directly address hardening of the electric infrastructure to minimize hurricane damage as this project and Staff's recommendations were entitled. Should the Commission decide that this requirement is desirable, it would best be accomplished by amending Substantive Rule 25.52 to include incentives for utilities to exceed the SAIDI and SAIFI performance standards mandated pursuant to that Rule. The incentives should not be limited to automatic sectionalizing equipment, and should be adequate to reimburse the utility for the expenses associated with accomplishing the greater service reliability levels.

A requirement to perform a study is unnecessary because this measure will not prevent damage due to wind and ice loads and would not specifically minimize the duration of outages resulting from Gulf Coast hurricanes. Further, evaluating the need for automatic sectionalizing devices is routinely done as a part of the study to improve the overall reliability and performance of a specific distribution circuit. It involves an overall coordinated system protection scheme for day to day operations. A Commission mandated study to evaluate the current practice is unnecessary because the Commission already has a mechanism through Substantive Rule 25.52 for monitoring a utility's service quality through its SAIDI and SAIFI for feeder performance requirements.

The addition of automatic sectionalizers is related to the ongoing daily operation and reliability of the distribution electrical system. The main purpose of these devices is to minimize the number of customers affected by an outage and outage duration. The use of such devices on a circuit is weighed against the use of a fused cutout as a means of automatically sectionalizing a distribution line. Although the use of fused cutouts provide for a more cost effective means of limiting the number of customers out of power due to an event it may have adverse effects on the reliability performance of a circuit as the fuse may blow during a temporary fault condition.

Recommendation 8: *Require utilities to conduct inspections of all distribution circuits to determine whether the amount of non-electric equipment on structures is causing an overload on those structures. If overloads are identified utilities should be required to correct the problem. Furthermore, utilities should be required to institute practices that will prevent such overloads in the future. The results of this initial inspection should be reported to the Commission within a year.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #8

AEP proposes that recommendation #8 be deleted.

AEP Comments on Recommendation #8: AEP believes that there is a better venue for addressing the issue. What is needed is a change to Section 224 of the Communications Act of 1934, as amended by Section 703 – Pole Attachments of the Telecommunications Act of 1996. This law provides for the establishment of a penalty system for utilities that "attach" without following the rules of general applicability, federal, state and local requirements, terms, conditions and industry standards. However, the "teeth" for enforcement are not strong enough. Currently the TDU can only back bill to the last inventory, and even then it must often undergo costly litigation in an the attempt to collect the amount due. There are no additional penalties; therefore, there is no incentive for an attaching utility to follow the process.

Inclusion of this recommendation does not solve the underlying problem but rather places a continued and costly policing activity burden on the TDUs. The enactment of this recommendation would require TDUs to conduct ongoing inventory inspections of their entire electrical distribution systems as a policing activity to identify violation. The estimated annual cost to TCC and TNC would be $1,300,000 and $825,000 respectively just for the policing activity, and does not include the added cost of making corrections to the facilities to comply with the requirement.

Recommendation 9: *Require telecommunications utilities to install onsite generators with a minimum of seventy-two hours of fuel in all central offices in hurricane prone areas. Utilities should also be required to have processes in place to ensure refueling of these generators for extended periods of time.*

AEP Response: No response/Not applicable

Recommendation 10: *Require annual upgrades to current National Electric Safety Code (NESC) wind loading standards of at least 10% of the 230 kV or greater aboveground transmission infrastructure and 5% of the 138 kV or less starting with the highest voltage lines. In addition, all transmission infrastructure upgrades within ten (10) miles of the Texas coastline should be required to meet current NESC standards assuming 140 mile-per-hour wind speed. Annual reports on the utilities' upgrading programs should be reported to the Commission.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #10

AEP proposes that recommendation #7 be deleted or modified to read:

Require utilities to design to the latest, effective NESC edition wind loading standards for new transmission facilities and significant upgrades, including replacements of one or more structures, to existing transmission facilities. Utilities may build new lines in lieu of replacing structures in existing lines, if it can be demonstrated that new lines are a more cost effective means to provide long-tern system reliability under severe weather conditions.

In addition, all significant upgrades, including replacements of one or more structures, to existing transmission facilities within ten (10) miles of the Texas coast inland shall be required to meet the maximum wind occurring anywhere along the

Texas Gulf Coast as defined in the current, effective NESC extreme wind loading criteria.

AEP Comments on Recommendation #10: AEP believes that requiring annual upgrades to 10% of all 230 kV and greater and 5% of all 138 kV and below is very costly, unrealistic and overly burdensome. A better approach to addressing existing transmission facilities is to utilize the current effective NESC when significant upgrades of these lines have been identified. All utilities are currently required to build new facilities under current NESC codes[1] and NESC rules permit major, significant upgrades to existing facilities to be brought into compliance with current NESC rules regardless of the facility's original requirements.

AEP has approximately 1,400 miles of 345kV Transmission Lines in Texas and over 10,000 miles of 69kV and 138kV. The chart below provides the total number of miles of transmission lines built by decade since the 1920's:

Decade	138kV and below	>138kV
1920's	1797	
1930's	311	
1940's	788	
1950's	1851	
1960's	1892	35
1970's	1019	730
1980's	710	435
1990's	468	100
2000's	211	125
unknown	1089	

Assuming that all lines constructed prior to the 1970's, and that a percentage of the lines built after that time must be rebuilt to meet current NESC (2007), AEP estimates the following miles of line affected and the approximate cost impact:

[1] The National Electrical Safety Code (NESC) is updated and published every 5 years with the next version being effective in January 2007 (2007 NESC). Wind loading and ice loadings have been included in the NESC since its conception and the foundation of the current NESC Loading districts can be traced back to the Third Edition NESC, October 1920. The 1977 NESC was revised to include an extreme wind loading condition that structures and their supporting equipment must withstand if any portion of the structure (or its supporting facilities are 60' or more above ground or water level).

Decade	miles	approx cost to upgrade
1960's and earlier	6674	$3-$4 billion
1970's	~1200	$600 million
1980's	~550	$275 million
1990's	~50	$25 million
unknown	~600	$500 million

AEP has been using NESC Medium ice loading criteria and 140 mph wind speed loading criteria on its transmission line designs within 50 miles the coast (as defined by the barrier island Gulf coast line) since 1971 (Hurricane Celia). Currently, AEP has approximately 10-15 miles of transmission line within 10 miles of the coast. Of this, 3-4 miles were built prior to AEP's current coastal wind loading criteria. Many of these lines would only have a portion that falls within the 10-mile boundary.

An additional hurdle to Staffs recommendation is that many of the current transmission easements contain limitations that may not permit the line to be rebuilt to higher standards. Specifically, many easements contain language restricting the number and/or type of structures. Some may also contain limitations as to tree clearing and vegetation maintenance.

This recommendation by Staff does not completely define "significant upgrade"; however, it implies that the replacement of one or more structures is a significant upgrade. A significant upgrade might be better defined as when one or more structures are replaced in a transmission line during non-emergency, routine work. Staff's recommendation, without further clarification, could in fact delay service restoration. If a transmission line is required to be upgraded when it is necessary to replace one or more structures, service restoration after a storm would need to be delayed until the transmission line could be rebuilt in its entirety to the new standards.

AEP does not oppose the establishment of a 10-mile coastal zone (a coastal zone defined as those counties fronting on the Gulf of Mexico might be easier to administer) and requiring the utilization of 140 mph wind speeds (50 PSF) in the design of all significant transmission upgrades or new construction. However, the enforcement of extreme wind load standards should only be required of structures 60 feet in height or higher, as recognized by the NESC.

An alternative approach, rather than fixing a 140 mph wind design standard, would be to refer to the highest wind speed isobar/contour identified in the NESC Wind Contour map at the Texas coast and utilize it up to 10 miles inland for all construction along the Texas coast. Again, the extreme wind loading criteria should apply only to structures 60-feet tall or more. This would allow for flexibility should the NESC augment the code to higher wind speeds along the coast in the future. Currently, the maximum contour line of 140 mph only exists for the southern most Texas coastline.

Recommendation 11: *Require all new and replacement transmission structures to be pre-stressed concrete or steel.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #11

AEP proposes that recommendation #7 be deleted or modified to read:

Electric transmission lines shall be designed and constructed in accordance with the wind loading standards of the latest edition of the NESC. The use of steel or pre-stressed concrete is encouraged, but in all cases, the determining factor is the selection of materials shall be to provide the cost effective construction materials and methods to meet the applicable NESC design criteria.

AEP Comments on Recommendation #11: Although AEP utilizes concrete and steel for many of its transmission line structures, regardless whether they are of coastal or inland, AEP recommends that structure strength be the determining factor, not structure materials.

The choice of material should be left to the utility and based on local needs, as well as the costs of various alternatives at the time of facility construction. In many cases, it is possible to select and install a wood pole of strength equal to that of concrete or steel poles. The installation of concrete or steel structures typically requires the use of more specialized heavy equipment that may be in short supply during larger disasters. Also, such heavy equipment may not be easily maneuvered under the wet conditions after a tropical storm.

Regardless of the original line construction, it might be more expedient to use wood transmission poles for replacement of damaged structures after a storm if rapid line restoration is required to keep the electric grid reasonably intact.

<u>Recommendation 12:</u> *Require utilities, through negotiation with landowners, to remove all trees that have limbs extending into, or those that may potentially extend into, the transmission and distribution ROW easements under high wind conditions.*

<u>AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #12</u>

AEP suggests that recommendation #12 be reworded as follows:

<u>The Commission will work with utilities, and state and local government officials should establish guidelines that include the scope of clearing to be achieved, as well as a timeline for implementation that considers the various climate zones within the state. All utilities will have a reasonable amount of time to implement those guidelines once they have been established.</u>

AEP Comments on Recommendation #12: The comments provided by AEP to Staff's Recommendation #5 are applicable here also. AEP believes that intense public education efforts are necessary to fully achieve and maintain effective vegetation clearances. The success of this type of an endeavor to reduce vegetation related outages is dependent upon the Commission, and all other government entities (specifically, city, county, and TxDOT) taking an active role in supporting aggressive line clearance operations. This support must go beyond written requirements and includes active participation. Commission and other governmental entity support of tree trimming efforts is also needed during litigation concerning a utility's right to trim and remove trees.

<u>Recommendation 13:</u> *Require utilities to identify any damage of transmission and distribution facilities that occurs as the result of a weather event other than lightning, and provide an annual report to the Commission that includes; the cause of the damage, the type of facility involved and the voltage, and age of the structure or facility.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION # 13

AEP suggests the deletion of recommendation #13.

AEP Comments on Recommendation #13: This recommendation appears to be in conflict to the goal of this project, which is to minimize the utilities' downtime occurring as a result of a significant weather event. During restoration efforts for weather events, utilities are focused totally on getting the customer back in service as quickly as possible. All resources are committed to service restoration, and there are no processes in place to gather the data required by this recommendation. At most, the reporting made under this requirement would be very subjective and inaccurate. In many cases the cause of damage is not easily identified during a major storm event; it could be that extreme wind alone caused the failure, or wind blown debris, or some other unidentifiable cause.

The gathering of this information after service has been restored would be incomplete at best. Diverting resources to perform the investigation and reporting required to comply with this reporting requirement will likely lengthen the restoration times resulting in a degradation of reliability as measured by SAIDI across the board. The ages of structures and attachments are not easily obtained, available, and are not currently captured in outage records. This would require substantial effort in time and costs to gather all this information for little or no benefit to Texas customers.

As stated above, the forensic investigation necessary to comply with this recommendation during restoration efforts will add a significant amount of time to the recovery effort (days in the event of a hurricane). A utility's service restoration activities after a hurricane are very likely to be supplemented through the use of mutual assistance resources. The recovery effort will involve a number of resources from outside its service territory and perhaps the state. It would not be practical or cost effective to require them to assist in reporting.

Should the Commission decide that this recommendation be adopted, the phrase "weather event other than lightning" should be clarified. As an example, in portions of AEP's service territory, a drought is a weather event that results in salt contamination related outages.

Recommendation 14: *Require utilities to design and construct all substations* ***so that no*** *water enters the control house or damage any electrical equipment in the substation during a 500-year rain event rendering electrical equipment inoperable due to accumulated water.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #14

AEP suggests the following change to Recommendation #14:

Require utilities to design and construct all future substations so that, water ingress to the extent of the 100-year floodplain as indicated on the current FEMA DFIRM (Digital Flood Insurance Rate Map) for that area be considered and steps taken to limit the damage to the control house and any electrical equipment in the substation so as to resist damage from accumulated water and facilitate restoration.

AEP Comments to Recommendation #14: As discussed at the recent workshop, it is unclear what constitutes a 500-year rain event and AEP has been unable to find a standard definition. Regardless, designing for a 500-year rain event is excessive and does not necessarily provide any benefit for the potential cost. AEP suggests that DFIRM maps be used since they are statistically derived indications of flood inundation for a particular area for a specific return period and they are considered the reasonable benchmark for insurance and floodplain management issues. Since actual flooding experience is unpredictable, using an existing benchmark line the DFIRM maps is reasonable. Should flooding occur beyond the confines of the designated flood zones or if the potential for flooding change within the entire designated flood zones, FEMA can update the maps with written notice. Therefore, the current maps would reflect the reasonable risk of flooding to be considered at the time engineering is designing a new substation.

Recommendation 15: *Electric utilities have embarked on projects to modernize the electric grid by deploying intelligent devices on the network. These deployments will enable real time monitoring of outages, selective switching of electric supply routes, and preventative maintenance of protective devices to increase the reliability of the power grid. The Commission should establish incentives to encourage such deployments by electric utilities.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #15

AEP does not have a specific change to recommend at this time.

AEP Comments on Recommendation #15: AEP applauds Staff for submitting a recommendation that incorporates incentives to accomplish the intended goals. Properly designed incentives will simultaneously accomplish the desires of the Commission, and should address the utilities' cost recovery concerns. This approach is the best tool to encourage updating the infrastructure by the deployment of intelligent devices. This approach would work to achieve the goals sought by the Commission, yet allows the utilities the freedom to determine how, when, and the most cost effective means to deploy intelligent devices on the network.

Recommendation 16: *If new underground distribution facilities must be installed in the rear of residential lots, require developers and homeowners to provide at least a 10-foot ROW restriction upon the inclusion of trees or other structures so that suitable access is available for any future repair work.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #16

AEP proposes the deletion of recommendation #16, or at a minimum that it be reworded as follows:

The Commission will work with TDU's, state and local governments to develop standard easements guidelines regarding the placement of underground communications and electrical distribution facilities necessary to serve new residential developments.

AEP Comments on Recommendation #16: Other than the prohibition regarding trees, much of the platted easements today in AEP's service territory meet the criteria stated in this recommendation; however, there is no local enforcement of the restrictions placed on the easements. In most of AEP's service territory, the size and location of easements used for placement of underground electrical distribution facilities is controlled by the city's subdivision ordinance. The easements are included as a part of the platting process and are dedicated as utility easements. They are not specifically granted to a specific type of utility. To change these specific requirements will require all cities to amend their current subdivision ordinances.

There will be significant opposition to this recommendation because residential lot sizes are kept to the smallest dimensions practical. Developers are very sensitive to the slightest decrease in usable lot size due to easements for the location of utility facilities. There is a constant push by developers to shrink easements without appreciably enlarging the lots in an effort to allow them to offer lots with larger usable area for larger homes. Any increase in easement size will certainly create a political backlash from developers contacting their city, county and state officials about the increase.

Recommendation 17: *Require burial of all new distribution lines serving new residential developments.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #17

AEP suggests the deletion of recommendation #17 from this project.

AEP Comments on Recommendation #17: This recommendation is unnecessary becasue the Companies have line extension policies that address placement of underground facilities (UG) in residential developments. Recently, many of the major cities in AEP's service territory have established ordinances encouraging the installation of UG electrical distribution in new subdivisions in accordance with standard line extension policies. In the majority of the cases, the infrastructure within the interior of the development is installed underground. The perimeter facilities are typically overhead to allow for efficiently increasing the capacity and the flexibility in serving future development adjacent to the subdivision. Should the developer wish to have those facilities installed underground, the Companies will work with them to develop an overall plan to serve the current and future developments in the area; however, a design that provides for expansion and good service reliability requires significant redundancy and the costs are considerable.

While AEP is supportive of installing UG facilities within the interior of new residential subdivisions, recent meetings with developers and legislators to explain TCC line extension policy indicate that it is unlikely developers, at least in the TCC territory, would be accepting of rules or policy changes that would increase their costs. TCC continues to work with developers that desire a total underground concept, but has found that most choose not to do so due to the cost, as well as the need to have a fully developed master plan for the area because underground electrical facilities once in place are not easily modified. If TCC is required to install UG facilities at all new subdivisions as a standard offering, TCC estimates the costs to be as high as $30 million annually.

Recommendation 18: *Encourage developers of new residential developments to locate underground facilities in front of homes or in accessible alleyways.*

AEP PROPOSED ALTERNATIVE FOR RECOMMENDATION #18

Recommendation #18 should to be reworded as follows:

The Commission will work with state and local governments to develop mandatory guidelines for the placement of underground communications and electrical distribution facilities serving new residential developments in front of homes or in accessible alleyways.

AEP Comments on Recommendation #18: The language proposed by Staff does not go far enough to really effectuate change. Access to facilities and meters in rear back-to-back easements is becoming more of an issue every day. AEP has tried to gain acceptance of front of property facilities; however, this has met with strong resistance from developers and city officials alike. Many developers feel that front lot installations devalue the subdivision, or they are unwilling to give up land that could be sold as lots in order to dedicate alleyways. In some of AEP's service territory, the city subdivision ordinances are very specific as to where the easements and facilities are to be placed, so front lot construction or placement in alleyways is not an option even if a developer were to agree to it.

AEP has had sufficient experience in this area to believe that a requirement to "encourage" this to happen will result in no change. It will require a unified effort by the Commission, city governments, state governments and representatives for the developers to accomplish a reasonable change similar to the basis for Staff's recommendation.

III. Conclusion

AEP appreciates the opportunity to provide these comments and looks forward to its participation in future workshops and meetings regarding infrastructure improvement.

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