Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs

FINAL REPORT

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

Prepared by: **Quanta Technology**

Contact: **Richard Brown, PhD, PE**
rbrown@quanta-technology.com
4020 Westchase Blvd., Suite 300
Raleigh, NC 27607
919-334-3021 (Office)
919-961-1019 (Mobile)

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Quanta Technology's Background on Similar Projects

<u>Similar Projects</u>

The following storm hardening projects have been performed by Quanta Technology:

<u>Florida Undergrounding Study, Florida Electric Utilities</u>
This project performed a three-phase project for a consortium representing all electric utilities in Florida (managed through the Public Utility Research Consortium of the University of Florida). Phase 1 performed a comprehensive literature review and assessment.[1] Phase 2 performed four case studies of completed underground conversion projects.[2] Phase 3 developed a hurricane simulation model capable of predicting the costs and benefits to all stakeholders for potential underground conversion projects, as well as comparing these costs and benefits to a hardened overhead system.[3]

<u>Reliability Improvement Roadmap, Puget Sound Energy</u>
Puget Sound Energy (PSE) was exploring the possibility of significantly improving the reliability of its system, including performance during major storms. This three-phase project assisted them in this effort. The first phase consisted of the development of a 10-year reliability roadmap including an assessment of the current state, an identification of the desired future state, and the development of a high-level set of transition steps to harden the system. The second phase consisted of a detailed cost-versus-reliability assessment for a pilot area to gain a full understanding of cost quantification, benefit quantification, and estimates of budget, time, and resources required to achieve reliability improvement goals on a system-wide scale. The third phase extrapolated results into a system wide plan capable of reducing SAIDI by 50% over the ten year roadmap period and significantly reducing expected infrastructure damage should a major storm occur.

<u>Hurricane Hardening Roadmap, Florida Power & Light</u>
This project developed a hurricane hardening roadmap for Florida Power & Light (FPL). This included the development of a "hardening toolkit," standards, specifications, criteria, application guidelines, and supporting tools. It also included a pilot study that demonstrated and refined these concepts, and provided a basis for a ten-year roadmap in terms of projected cost and effort. Last, this project developed a ten-year reliability roadmap that achieved all FPL's distribution hardening objectives for the least possible cost.

<u>Extreme Wind Hardening Benchmark Survey, BC Hydro</u>
This project performed a survey of hardening initiatives of utilities in the Pacific Northwest following the severe wind storms of Dec. 2006. This project also surveyed hardening initiatives in other parts of the country and around the world.

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[1] Quanta Technology, *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion.* Submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI, Feb. 2007.
[2] Quanta Technology, *Undergrounding Assessment Phase 2 Final Report: Undergrounding Case Studies.* Prepared by Quanta Technology the Florida Electric Utilities and submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI, Aug. 2007.
[3] Quanta Technology, *Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling.* Prepared for the Florida Electric Utilities and submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI, May 2008.

Wood Pole Failure Assessment, Midwest Energy
This project performed a forensic analysis after a wind storm blew down a series of transmission poles and distribution poles spanning 2 miles. This included a review of maintenance records, a pole loading analysis, and a comparison to nearby distribution pole performance.

Project Team

The primary contributors to the content of this report are the following:

- Richard Brown, PhD, MBA (project manager, data analysis, societal cost)
- ML Chan, PhD (technology impact)
- Luther Dow, MBA (cost of inspection programs)
- Bill Snyder, MBA (cost-to-benefit analysis)
- Le Xu, PhD (hurricane modeling and simulation)

Brief bios of team members are now provided.

Richard Brown. Dr. Brown is Vice President of Operations for Quanta Technology and also serves as an Executive Advisor. He is an internationally recognized top expert on all aspects of power system reliability. This includes reliability assessment, reliability benchmarking, undergrounding, infrastructure hardening, post-storm damage assessment, predictive modeling for infrastructure performance during storms, and cost-to-benefit analysis. He has published more than 80 technical papers related to these topics and has provided consulting services to most major utilities in the United States and many around the world. He is author of the book *Electric Power Distribution Reliability*, which is the currently the only published book with content on utility storm hardening. Selected recent activities by Dr. Brown related to electric infrastructure performance during storms includes the following:

1. Invited Speaker, "Hurricane Hardening Efforts in Florida", *IEEE PES 2008 General Meeting*, Pittsburg, PA, July 2008.
2. Invited Speaker, "Pole Hardening Following Hurricane Wilma," Southeastern Utility Pole Conference, Tunica, MS, Feb. 2007.
3. Invited Speaker, "Distribution Storm Hardening," ESMO, Albequerque, NM, Oct. 2006.
4. Instructor, "Infrastructure Hardening," Post-Conference Workshop, *Electric Distribution Reliability Conference*, EUCI, Long Beach, CA, Sept. 2006.
5. Invited Speaker, "Hurricane Impact on Reliability in Florida," *IEEE PES General Meeting*, Montreal, CA, June 2006
6. Keynote Speaker, "Distribution Storm Hardening," EEI Transmission, Distribution, & Metering Conference, Houston, Texas, April 2006.
7. Invited Speaker, "Hurricane Hardening," Florida Public Service Commission Staff Workshop on Electric Utility Infrastructure, Tallahassee, FL, Jan. 2006.

Over the last five years, Dr. Brown has worked with the following utilities on issues related to storm hardening and related cost-to-benefit analyses: BC Hydro, Florida Electric Cooperatives Association, Florida Municipal Electric Association, Florida Power & Light, Gulf Power, Lee County Electric Cooperative, Midwest Energy, Progress Energy, Puget Sound Energy, and Tampa Electric.

Over the last eighteen years, Dr. Brown has developed several storm reliability and cost-to-benefit models for electric utility systems. This includes models for the Florida Public Utility Commission (hurricanes), Snohomish County PUD #1 (high winds), Baltimore Gas & Electric (high winds and rain), Dominion, Oklahoma Gas & Electric (high winds and rain), Xcel Energy (high winds and ice buildup), and Florida Power & Light (hurricanes). He has also performed system reliability studies for the following utilities: AEP, Baltimore Gas & Electric, Electricity de Portugal, Exelon, Florida Power & Light, Midwest Energy, National Grid USA, North Delhi Power Limited, Oklahoma Gas & Electric, Pacific Gas & Electric, PacifiCorp, Progress Energy, San Diego Gas & Electric, Scottish Power, Snohomish County, Southern Company, and TXU.

Dr. Brown is an IEEE Fellow. He has a BSEE, MSEE, and PhD from the University of Washington, Seattle, and an MBA from the University of North Carolina, Chapel Hill. He is a registered professional engineer. Dr. Brown has worked (chronologically) at Jacobs Engineering, the University of Washington, ABB, KEMA, and Quanta Technology.

ML Chan. Dr. Chan's areas of expertise are Smart Grid and the utilization of computer and communications system technologies to deliver power system reliability, performance improvement, and optimal asset management for utilities. He combines his power system planning and operations expertise to integrate demand responses and load management, AMI/AMR systems, Home Automation Network (HAN), feeder automation, substation automation, EMS/SCADA, DMS/SCADA, PMU/WAPS, asset condition monitoring, condition-based maintenance (CBM) into a Smart Grid vision. For more than 35 years, Dr. Chan has provided consulting services to over 70 utilities in the United States and around the world. He has published over 60 technical papers and has given many presentations and speeches in seminars and tutorials. He is the Chair of IEEE Power System Planning and Implementation Committee, and a member of Executive Advisory Committee for DistrbuTECH Conferences. He is also on the Editorial Board of *IEEE Transactions on Power Systems*. Dr. Chan has SB, SM and Electrical Engineer's degrees from MIT, and PhD from Cornell University. Prior to joining Quanta Technology, he has worked with Energy Resources Company, Tetra Tech, Systems Control, Energy Management Associates, ECC, ML Consulting Group, SchlumbergerSema, and KEMA.

Luther Dow. Mr. Dow has more than thirty five years of utility engineering and operating experience. His areas of expertise are planning, asset management, emergency restoration, system condition assessment, and aging infrastructure management. During his career, Mr. Dow has managed emergency restoration effort for both high voltage substations and high voltage transmission towers. He also developed and implemented a multi-year reliability plans for the city of San Francisco, which improved reliability by 50% as measured by System Average Interruption Duration Index (SAIDI). Managerially, Mr. Dow has led both large and small organizations through major organizational and cultural change, and helped bring new technologies and techniques into the workplace. Mr. Dow has a BSEE and an MBA from California State University, Sacramento and is a registered professional engineer. He has worked (chronologically) at Pacific Gas & Electric, Doble Engineering, EPRI, and Quanta Technology.

Bill Snyder. Mr. Snyder, Vice President of Maintenance and Standards, has a unique background in utility operations, management and change initiatives resulting from over 28 years experience in the electric utility industry. He has successfully led consulting engagements to review and evaluate operational processes and standards, storm restoration efforts, conducted evaluations of asset condition and value, and led major process change identification and implementation programs in the engineering and operations functions. He has provided storm hardening support to a number of utilities including Florida Power & Light, Ameren, and Puget Sound Energy. His experience in power engineering and his understanding of management needs and challenges to continuously improve operational performance provide him a unique insight into utility company operations, culture and improvement opportunities. As both a utility manager and as a consultant, he has experience working with senior officers to develop and implement operational strategy to achieve new levels of operational efficiency, service reliability and cost savings. Bill earned a BS degree in Engineering from North Carolina State University and MBA degree from Wake Forest University and is a member of IEEE.

Le Xu, PhD. Dr. Xu is an expert in extreme weather modeling and its application to utility failure and reliability analysis. He has published more than 10 technical papers in this area. Dr. Xu has applied statistical approaches and computational intelligence methods to outage data from several large utilities including Duke, Progress Energy, Pacific Gas & Electric, Baltimore Gas & Electric, and Southern California Edison. He is a member of IEEE and chairs the IEEE Eastern North Carolina Section (ENCS) Computational Intelligence Society (CIS) chapters. He received his B.Eng. from Tsinghua University, Beijing, and his MSEE and PhD from North Carolina State University, Raleigh. He has worked at North Carolina State University (research assistant), KEMA (intern), and Quanta Technology.

Executive Summary

Hurricanes can cause significant damage to utility infrastructure, resulting in large restoration costs for utilities (ultimately borne by customers) and further societal costs due to reduced economic activity. Despite these costs, hardening utility infrastructure so that it is less susceptible to hurricane damage is very expensive.

This report examines the costs, utility benefits, and societal benefits for a variety of storm hardening programs (see Table A). Based on data provided by utilities and other assumptions, the following programs are found to be cost-effective:

<u>**Cost-effective Storm Hardening Programs**</u>

1. **Improved post-storm data collection.** Most damage data available to utilities is from accounting and work management systems. A much better understanding of infrastructure performance can result from carefully designed post-storm data collection programs that capture key features at failure sites and are statistically significant. Improved storm data allows for more cost-effective spending on hardening programs.
2. **Hazard tree removal.** Hazard trees are dead and diseased trees outside of a utility's right-of-way that have the potential to fall into utility lines or structures. Removing dead and diseased trees is desirable from a societal perspective in any case and can significantly reduce hurricane damage. Further benefits can result from the removal of healthy "danger trees" that are at risk of falling into utility facilities. Many utilities already attempt to address these issues but often encounter resistance from property owners.
3. **Targeted electric distribution hardening.** This approach targets spending to high-priority circuits, important structures, and structures that are likely to fail. Since all spending must be justified based on a cost-to-benefit analysis, targeted distribution system hardening is cost-effective by definition. The targeted hardening of about 1% of distribution structures is likely to be cost-effective for Texas utilities.

In general, the targeted hardening of transmission structures is not cost-effective. However, the transmission structures of Entergy Texas experienced extremely high failure rates during both Hurricanes Rita and Ike. Based on these high failure rates, an analysis shows that the targeted hardening of Entergy Texas transmission structures is potentially cost-effective and should be investigated further.

Findings and conclusions are based on (1) hurricane damage and cost data provided by the utilities and (2) a hurricane simulation model. Utility data is never perfect, and many assumptions are used within the hurricane simulation model and the cost-to-benefit analysis. Therefore, the findings and conclusions are necessarily broad and may or may not be applicable to specific situations. Brief descriptions of major findings and conclusions are now provided.

Electric Utility Restoration Costs. Since 1998, electric utilities in Texas have incurred about $1.8 billion in restoration costs due to hurricanes and tropical storms, for an average of about $180 million per year. About 80% of these costs are attributed to distribution and 20% to transmission. Nearly all of the restorations costs are attributed to wind damage, tree damage, and flying debris. Storm surge damage is occasionally a major concern in specific areas, but generally represents a low percentage of restoration costs.

Telecom Utility Restoration Costs. Since 1998, telecom utilities in Texas have incurred about $181 million in restoration costs due to hurricanes and tropical storms, for an average of about $18 million per year. This is about 10% of the electric utility restoration costs over the same time period. Telecom utilities attribute a higher percentage of hurricane damage to storm surge and flooding when compared to electric utilities, but a majority of damage is still due to wind damage, tree damage, and flying debris.

Hurricane Simulation. A hurricane simulation model has been developed that simulates hurricane years. For each year, the model determines the number of hurricanes that make Texas landfall. It then simulates each hurricane including size, strength, landfall location, path, infrastructure damage, restoration time, and other key factors. The average results of 10,000 simulation years are used for cost and benefit calculations.

Table A. Summary of Findings.

#	Hurricane Mitigation Program (a)	Incremental Utility Cost ($1000s)	Utility Hurricane Benefit ($1000s/yr)	GDP Hurricane Benefit ($1000s/yr)	Cost Effective (b)
Vegetation Management					
1.	Annual patrols for transmission	$136 /yr	$0	$0	No
2.	Annual patrols for distribution	$2,760 /yr	$0	$0	No
3.	Hazard tree removal program	Not examined	$13,800	$9,200	Yes
Ground-Based Patrols					
4.	Annual patrols for transmission	$15,400/yr	$0	$0	No
5.	Annual patrols distribution	$32,700/yr	$7,500	$4,900	No
Substations & Central Offices					
6.	New substations outside of 100-yr floodplain	Site specific	$16 per site	$0	Depends
7.	New COs outside of 100-yr floodplain	Site specific	$4 per site	$0	Depends
8.	Backup generators for substations within 50 miles of coast	$21,800	$0	$1,384	No
9.	Backup generators for COs within 50 miles of coast	$4,152	$0	$442	Yes (c)
Infrastructure Hardening					
10.	Improved post-storm data collection	Not examined	Not examined	Not examined	Yes
11.	Non-wood structures for new transmission	Varies	$0	$0	No
12.	Harden new transmission	$0 (d)	$0	$0	No
13.	UG conversion of existing transmission	$32,885,000	$27,000	$18,300	No
14.	UG conversion of existing distribution	$28,263,000	$126,000	$85,400	No
15.	Targeted hardening existing transmission	$2,400,000	$9,000	$6,100	No (e)
16.	Targeted hardening existing distribution	$320,000	$14,400	$9,800	Yes
Smart Grid Technologies					
17.	Technologies for transmission	Not examined	Not examined	$1.8	No
18.	Technologies for distribution	Not examined	Not examined	$47.4	No

(a) Unless otherwise stated, these mitigation programs are evaluated on a broad basis with the assumption of widespread deployment. Even if widespread deployment is not cost-effective, there may be certain specific situations where the approach is cost-effective.

(b) The cost-effective rating is based on hurricane benefits only. There may be other benefits that make these mitigation programs cost-effective.

(c) Most COs (central offices) already have backup generator capability in addition to battery backup.

(d) Targeted hardening of the Entergy Texas transmission system is potentially cost-effective and should be investigated in more detail.

(e) New transmission is already required to meet NESC extreme wind criteria.

Societal Cost. Societal costs are based on GDP for metropolitan statistical areas along the Texas coastline (Beaumont-Port Arthur, Brownsville-Harlingen, Corpus Christi, Houston-Baytown-Sugar Land, and Victoria). Annually, GDP for these areas is $384 billion. Based on the hurricane simulation model, lost GDP due to hurricanes is an average of $122 million per year.

Vegetation Management. Annual vegetation patrols apart from normal vegetation management activities will not result in significant hurricane benefits. During hurricanes, most vegetation damage is from falling trees located outside of the utility right-of-way. Typical vegetation patrols focus on clearance violations, which is not a major hurricane issue. As stated previously, a cost-effective hurricane vegetation program must focus on the removal of hazard trees and potentially danger trees.

Ground-Based Patrols. Ground-based patrols are used by utilities to visually inspect structures from the ground and identify maintenance needs, including problems that may result in poor hurricane performance (inspections for groundline deterioration is typically performed separately). Comprehensive ground-based patrol programs for transmission are common, but not generally cost-effective to perform annually. Comprehensive ground-based patrol programs for distribution are less common, with inspections typically occurring as part of daily operations.

Substations & Central Offices (COs). Substations and central offices have relatively low failure and damage rates during storms and have low contributions to total restoration costs. Locating a particular new substation and/or CO outside of the 100-year floodplain will have both benefits and costs, and the cost-effectiveness will vary with each situation. Loss of substation auxiliary power has not been a major factor for utilities after hurricanes, and the installation of backup generators in substations for auxiliary power is generally not cost-effective. In contrast, backup generators at COs are cost-effective. In practice, large COs already have permanent backup generators and smaller COs have the ability to utilize portable generators. The incremental costs of placing permanent backup generators at small COs typically do not justify the incremental benefits.

Infrastructure Hardening. Infrastructure hardening is expensive, and most general approaches are not cost-effective. However, targeted distribution hardening is cost-effective by definition, since a specific hardening activity is only performed if analyses show that it is cost-effective. A targeted program will typically identify and address high priority circuits, critical structures in these circuits, and structures with a very high probability of failing during a hurricane. The cost-effectiveness of distribution hardening can be significantly increased through the use of data collected through a well-designed post-storm data collection process.

Smart Grid Technologies. There are many potential storm restoration benefits that can be derived from a variety of Smart Grid technologies. These benefits are magnified if a comprehensive suite of technologies are integrated and work together seamlessly. This said, technology components located on poles are of little use if the pole blows over, and technology components requiring communications are of little use if the communications system is destroyed. Therefore, the restoration benefits of Smart Grid technologies require a Smart Grid plan that specifically addresses issues related to major storms. Even if this is done, the hurricane benefits of Smart Grid are small compared to the costs. However, these benefits should be included in the overall Smart Grid cost-to-benefit analysis that will include many other benefits.

Summary. Recent Texas hurricanes have caused a significant amount of utility infrastructure damage and other societal costs. However, damage is unpredictable and small as a percentage of total installed infrastructure. Broad prescriptive approaches to hurricane hardening are generally not cost-effective since many structures must be hardened for every failure that is eventually prevented. However, certain targeted vegetation and hardening approaches can be cost-effective, especially if they are based on detailed post-storm data collection and analyses.

1 Introduction

Hurricane Ike made landfall at Galveston, Texas, on September 13, 2008. At landfall, it was a large Category 2 hurricane with hurricane force winds extending 275 miles from the center. Hurricane Ike was the third costliest U.S. hurricane of all time, behind Hurricane Andrew of 1992 and Hurricane Katrina of 2005. Ike caused more than thirteen million businesses and homes to lose power, many for more than a week. In addition to the direct repair costs of utility systems, Texas incurred large economic losses due to a virtual halt in normal business activities.

In the past few years, there have been a number of highly visible extreme weather events that have caused extensive damage to utility systems across the country, particularly to electric systems and associated communications attachments. Some of these recent weather events are shown in Table 1-1.

Table 1-1. Recent Major Weather Events

2002 Events	January Central Plains Ice Storm
2003 Events	Hurricane Isabel
	Hurricane Claudette
	Hurricane Erica
2004 Events	Hurricane Charlie
	Hurricane Frances
	Hurricane Ivan
	Hurricane Jeanne
	Hurricane Dennis
2005 Events	Hurricane Emily
	Hurricane Katrina
	Hurricane Rita
	Hurricane Wilma
	December Southern States Ice Storm
2006 Events	December Pacific Northwest Wind Storm
2007 Events	January North American Ice Storm
	Hurricane Humberto
2008 Events	Hurricane Gustav
	Hurricane Dolly
	Hurricane Ike

Many parts of utility systems are not designed to survive major weather events like hurricanes. This includes direct damage from wind, direct damage from storm surges, and indirect damage from falling trees and flying debris. Many in the industry are beginning to inquire as to whether it may be beneficial for utilities to "harden" their systems so that they will incur less damage from extreme weather events and be better able to quickly restore utility services. Of particular interest are the costs of various hardening approaches and the corresponding benefits of these approaches, including the economic benefits of faster restoration.

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. This report is the response of Quanta Technology's research and analysis.

2 Hurricane Data Review

This section reviews and evaluates data collected by the PUCT from electric and telecommunications utilities related to hurricanes and tropical storms impacting the Texas coast within the last ten years with the goals of (1) assessing infrastructure damage caused by wind, trees, flying debris, inland flooding, and storm surge and (2) assessing the associated restoration costs.

The Texas utility damage data assessed in this section is derived from a PUCT request for information. Responses to this request are filed under Docket No. 36209. Quanta Technology created a supplementary set of questions related to electric utility infrastructure and operational data. These questions are shown in Appendix D and the responses are filed under Docket No. 36375.

This section begins by providing a summary of hurricanes and tropical storms (collectively called *named storms*) that have made landfall in Texas over the last ten years. It then has a section analyzing damage and cost data for electric utilities, followed by a separate section analyzing damage and cost data for telecom utilities.

2.1 Overview of Hurricanes

A tropical cyclone is a low-pressure system that develops over tropical waters. A hurricane is the name for a tropical cyclone that occurs in the Atlantic Ocean. Tropical cyclones with maximum sustained surface winds of less than 39 mph are called *tropical depressions*. Once the tropical cyclone reaches winds of at least 39 mph, it is called a *tropical storm* and assigned a name. If sustained winds reach 74 mph, the tropical cyclone is called a *hurricane*. Together, tropical depressions and hurricanes are called *named storms*.

A hurricane forms when a mass of warm moist air over the ocean begins to rise. When the moist air reaches higher and cooler altitudes, water vapor condenses, releasing heat and causing the air to rise further. The rising air creates low surface pressure that causes surrounding air to flow into the area of low pressure. This inflowing air then rises and the cycle repeats. The Coriolis effect of the Earth's rotation causes the incoming surface winds to rotate counter clockwise in the Northern Hemisphere. If high altitude wind speeds are not similar at all altitudes, the resulting "wind shear" causes the tropical cyclone to lose organization and weaken.

A hurricane is typically assigned a "category" of one through five based on its maximum 1-minute sustained wind speeds according to the Saffir-Simpson Hurricane Scale. The minimum and maximum sustained wind speeds corresponding to each hurricane category are shown in Table 2-1. Since the extreme wind ratings of utility structures are based on a three second gust, it is useful to also think of hurricane categories in terms of gust speeds. A typical hurricane will have 3-second gusts that are about 25% faster than 1-minute sustained wind speeds (this can vary). Using this 25% gust factor, the minimum and maximum expected 3-second gust speeds corresponding to each hurricane category are also shown in Table 2-1.

Table 2-1. Saffir-Simpson Hurricane Scale

Category	1-min sustained (mph)		3-sec gust (mph)	
	Min	Max	Min	Max
1	74	95	93	119
2	96	110	120	138
3	111	130	139	163
4	131	155	164	194
5	156	180	195	225

Hurricanes cause damage to utility systems in a variety of ways. Many utilities report that a majority of damage is due to entire trees blowing over into power lines, which results in broken conductors, broken crossarms, broken insulators, broken poles, and leaning poles. Other hurricanes caused damage primarily by blowing over structures. Damage can also result from flying tree branches, sheet metal, and a variety of other debris. After a hurricane, utilities also typically report wind-related damage to riser shields and streetlights. Figure 2-1 shows images of distribution system damage caused by hurricanes. This emphasizes the range of damage that hurricanes can do, including overhead system damage, underground system damage, and flooding.

When a hurricane approaches land, it blows a wall of water onto shore called a *storm surge*. A storm surge tends to pick up a large amount of sand and debris. The sand can bury and contaminate pad-mounted equipment, and the debris can damage and dislodge pad-mounted equipment. When the storm surge recedes, it can carry away sand and dirt, leaving formerly underground cables, vaults, and manholes exposed.

When a storm surge floods coastal areas, salt water immerses all of the pad-mounted and sub-surface electrical equipment in the storm surge area. When the storm surge recedes, a salt residue can be left on insulators, bushings, and other components. This contamination can result in an immediate failure when the equipment is energized, or can result in a future failure when the contamination is exposed to moisture.

With a hurricane comes an extensive amount of rain and the potential for flooding. This causes water-immersion problems similar to a storm surge but somewhat less severe since the flooding is with fresh water instead of salt water. Typically live-front equipment performs worst when flooded, dead-front equipment is preferable to live-front equipment, and only submersible equipment can be considered immune from hurricane damage. [4]

Even if utility equipment survives a hurricane, it may be damaged during the cleanup effort. Typically, a hurricane will result in piles of debris that can easily cover pad-mounted equipment. When bulldozers come through the area, non-visible electrical equipment will incur severe damage if struck.

[4] "Live-front" equipment has energized equipment, such as busbars, exposed and easily accessible while "dead-front" equipment does not have energized parts exposed on the operating side. Submersible equipment contained in waterproof enclosures.

Overhead lines damaged in a coastal area.

Substation flooding.

Storm surge damage.

A concrete pole broken by high winds.

Figure 2-1. Images of Hurricane damage.

Figure 2-2. Debris is a major hurricane concern.

Figure 2-2 illustrates several issues related to hurricane debris. The left image shows a corrugated steel roof that detached and flew into power lines, acted as a sail, and caused strong concrete poles to blow down. The right image shows a pile of debris that may be covering undamaged pad-mounted equipment. When bulldozers clear this pile, the pad-mounted equipment is vulnerable to damage (some utilities scout debris piles and mark buried utility equipment with flags).

2.2 Recent Texas Tropical Storms and Hurricanes

A list of tropical storms and hurricanes making landfall on or near the Texas coast in the last ten years is shown in Table 2-2. This table shows the date of landfall, the assigned storm name, and the strength of the storm at landfall. Of course, every hurricane is unique in terms of wind, size, wind patterns, landfall location, track, speed, and a variety of other factors. To illustrate these differences, tracks of recent hurricanes making landfall in Texas are shown in Figure 2-3. After this, brief descriptions are provided for each of the tropical cyclones listed in Table 2-2.

Table 2-2. Recent Named Storms Making Landfall within 50 miles of Texas

Date of Texas Landfall	Name	Strength at Landfall
August 22, 1998	Charley	Tropical Storm
September 11, 1998	Frances	Tropical Storm
August 23, 1999	Bret	Category 3
June 5, 2001	Allison	Tropical Storm
September 7, 2002	Fay	Tropical Storm
June 30, 2003	Bill	Tropical Storm
July 15, 2003	Claudette	Category 1
August 16, 2003	Erika	Category 1
August 31, 2003	Grace	Tropical Storm
September 24, 2005	Rita	Category 3
August 16, 2007	Erin	Tropical Storm
September 13, 2007	Humberto	Category 1
July 23, 2008	Dolly	Category 2
August 5, 2008	Edouard	Tropical Storm
September 13, 2008	Ike	Category 2

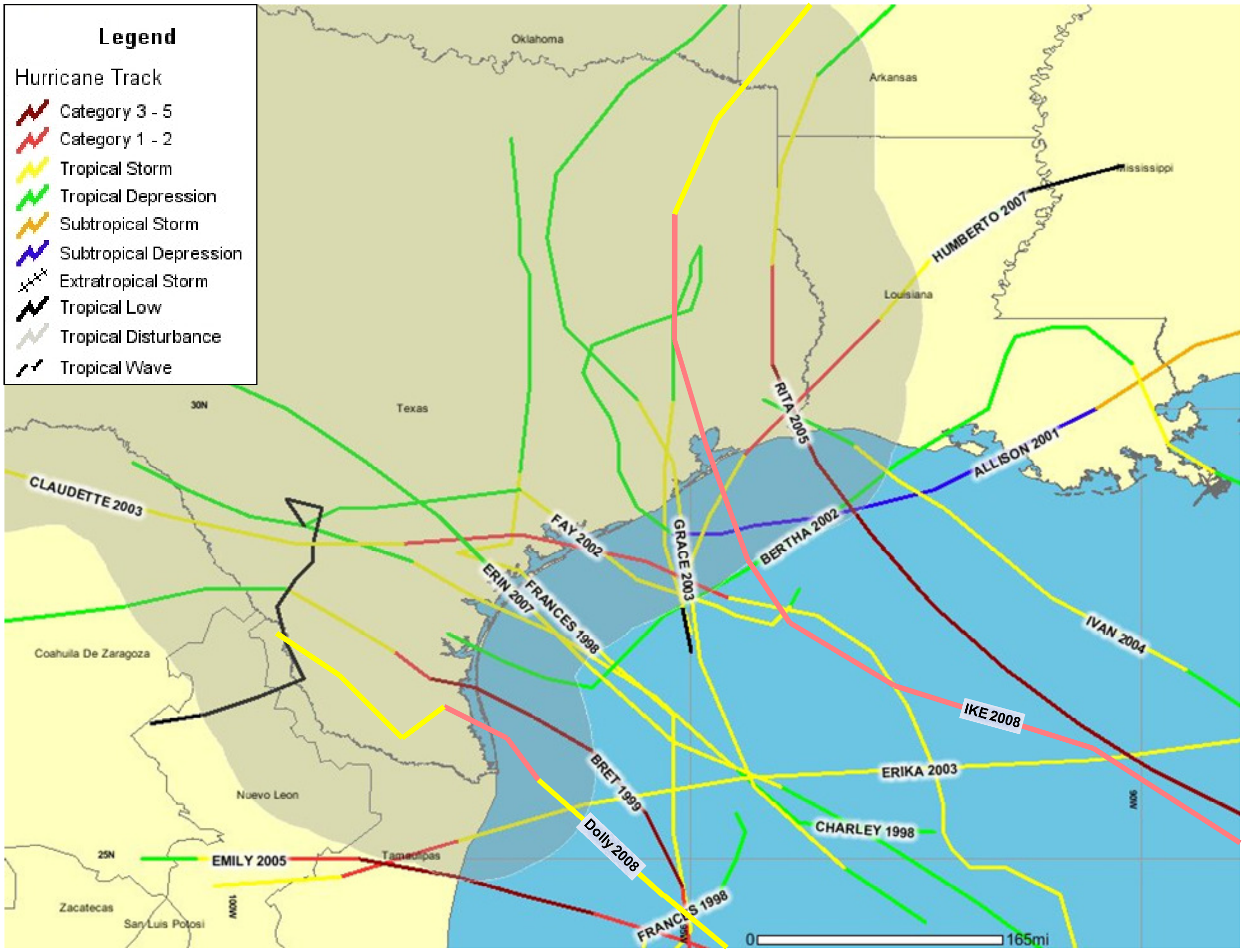

Figure 2-3. Tracks of hurricanes making Texas landfall in the last ten years.

Figure 2-3 demonstrates that no part of the Texas coastline is safe when it comes to hurricanes. In the last ten years, the distribution of hurricane landfall locations is, for the most part, uniformly distributed from Brownsville in the southernmost point to Port Arthur in the northernmost point. In addition, there is no discernable relationship between landfall location and hurricane strength. For the most part, hurricanes make landfall in uniformly random locations and are of random strength independent of landfall location. These observations are statistically examined in the probabilistic hurricane simulation model, discussed in Appendix A.

August 22, 1998 – Tropical Storm Charley made landfall near Port Aransas. The storm's major impact was its very heavy rain. Charley produced 17 inches of rain in Del Rio in a 24-hour period, a new record daily rainfall for the city. Refugio, Texas received 7.2 inches of rain, and Woodsboro, Texas recorded 5 inches. The storm surge on areas of the Texas coast was small. Sustained tropical storm force winds reached 41 miles per hour. Damage from the storm, while generally light, was severe locally. At one point, two-thirds of Del Rio was underwater after a natural dam broke in the San Felipe Creek, flooding the city with a sudden surge of water. Eight counties in Texas were declared disaster areas.

September 11, 1998 – Tropical Storm Frances made landfall north of Corpus Christi as a moderately strong tropical storm. Winds gusted as high as 66 mph at Sea Rim State Park. Three tornadoes touched down at Caney Creek, La Porte, and Galveston. A major disaster declaration was issued for Brazoria, Galveston, and Harris counties. Frances caused significant amounts of flooding across southeastern Texas, with a peak of 21 inches in the Houston metropolitan area. Sections of the Middle Texas coast, closer to the point of landfall, and the Golden Triangle of southeast Texas reported over 10 inches of rainfall as well, resulting in significant flood damage. A storm surge of 5.4 feet was measured at Sabine Pass, Texas and 8 feet was measured at the Matagorda Locks.

August 23, 1999 – Hurricane Bret made landfall as a Category 3 hurricane at Padre Island, becoming the first major hurricane to hit Texas since Alicia in 1983. Bret made landfall on August 23rd on Padre Island with 115 mph winds. Bret's strong winds were confined to a small area and only affected a sparsely populated region.

June 5, 2001 – Tropical Storm Allison made landfall near Freeport. It stalled over eastern Texas for several days, dropping extreme amounts of rain which led to catastrophic flooding. The worst of the flooding occurred in Houston where over 35 inches of rain fell. Allison killed 41 people, of which 27 drowned, making Allison the deadliest tropical storm on record in the United States. Allison had sustained winds of up to 43 mph.

September 7, 2002 – Tropical Storm Fay made landfall near Port O'Connor, where it caused heavy rainfall. The effects in Texas were moderate to severe in some locations with flooding being the main source of damage. Storm surge along the Texas coast was 4.5 feet above the normal high tide. Rainfall totals up to 24 inches caused severe flash flooding.

June 30, 2003 – Tropical Storm Bill dropped light rain across southeastern Texas, peaking at 1.1 inches in Jamaica Beach. Sustained winds from the storm remained weak with peak gusts of 20 mph in eastern Galveston County. Upon making landfall, Bill caused a storm surge of 3.8 feet at Pleasure Pier. Effects in Texas were minimal, limited to minor beach erosion on the Bolivar Peninsula.

July 15, 2003 – Hurricane Claudette made landfall at Matagorda Island near Port O'Connor as a strong Category 1 storm with maximum sustained winds of 90 mph. Upon making landfall, Claudette's storm surge reached a maximum height of 5.3 feet in Galveston. Claudette produced moderate rainfall across southern Texas, peaking at 6.5 inches in Tilden. Severe beach erosion occurred from High Island to Freeport. The outer bands of the hurricane spawned two tornadoes. Strong winds downed numerous power lines, leaving around 74,000 residents without power in the immediate aftermath.

August 16, 2003 – Hurricane Erika made landfall in the Mexican state of Tamaulipas as a Category 1 hurricane, causing minor coastal damage and beach erosion in parts of southern Texas. Erika produced light rainfall across southern Texas, peaking at 3.8 inches in Sabinal, though most locations reported less than two inches. Sustained winds from Erika in south Texas peaked at 39 mph in Brownsville. The storm caused minor flooding and beach erosion along South Padre Island.

August 31, 2003 – Tropical Storm Grace made landfall near San Luis Pass with maximum sustained winds of 40 mph, causing heavy rainfall along the Texas coast. Upon landfall, Tropical Storm Grace produced a light storm surge of 3.5 feet in Matagorda and North Jetty. Rainfall was moderate to heavy across eastern Texas, peaking at 10.4 inches in Spindletop Bayou. Overall, damage was minor.

September 24, 2005 – Hurricane Rita made landfall as a Category 3 hurricane at the Texas/Louisiana border. Major flooding was reported in Port Arthur and Beaumont. Offshore oil platforms throughout Rita's path also suffered significant damage. For the most part, Houston escaped major damage, apart from extensive loss of power. North of Houston, the 2.5-mile-wide Lake Livingston dam sustained substantial damage from powerful waves driven by 117 mph winds. Communities in Beaumont, Port Arthur, and Orange sustained enormous wind damage. Texas Governor Rick Perry declared nine counties as disaster areas. In Beaumont and Groves an estimated 25% of the trees in the heavily wooded neighborhoods were uprooted. Rita's storm surge was contained by Port Arthur's extensive levee system. Bolivar Peninsula between Galveston and Sabine Pass experienced only a small storm surge, in contrast to areas east of Rita's center where a 20-foot surge struck Louisiana's unprotected towns.

August 16, 2007 – Tropical Storm Erin made landfall near Lamar with rainfall reaching 11 inches and sustained winds reaching 39 mph. The passage of the storm caused several bayous in the Houston area to reach or exceed flood levels. Upon moving ashore, the storm produced a minor storm surge peaking at 3.2 feet (at Pleasure Pier), which caused minor beach erosion. Erin left about 20,000 electrical customers without power, though most outages were quickly restored.

September 13, 2007 – Hurricane Humberto made landfall just east of High Island with sustained winds of up to 92 mph, dropping up to 14 inches of rain. Upon moving ashore, Humberto produced a minor storm surge of 2.9 feet at Rollover Pass; the combination of surge and waves resulted in light beach erosion. The combination of saturated grounds and strong winds uprooted many trees and downed power lines across the path of the hurricane. Over 114,000 customers in Southeast Texas lost power. Oil production was slowed as a result of Humberto at least four refineries due to the loss of power.

July 23, 2008 – Hurricane Dolly made landfall at South Padre Island with sustained winds of 100 mph. Dolly is considered to be the most destructive hurricane to hit the Rio Grande Valley in 41 years. President Bush declaring 15 counties of Texas as federal disaster areas, and Governor Rick Perry declaring 14 counties disaster areas. The storm caused 212,000 customers to lose power in Texas as well as 125,000 in Tamaulipas, and dropped estimated amounts of over 16 inches of rain in isolated areas. Virtually all 91,000 acres of the Lower Rio Grande Valley cotton crop was destroyed by Dolly.

August 5, 2008 – Tropical Storm Edouard made landfall near Port Arthur, with winds near 65 mph and storm surges of 3.9 feet. Heavy rainfall fell along and inland of the upper Texas coast. In Jefferson County, about 30,000 customers lost power at the peak of the storm. Overall damage was fairly light.

September 13, 2008 – Hurricane Ike made landfall at Galveston as a large Category 2 hurricane. Ike was the most destructive hurricane to ever hit Texas and one of the deadliest. In Galveston, the rising storm surge overtopping the 17-ft seawall resulted in widespread flooding (see Figure 2-4). On Bolivar Peninsula, a twelve foot storm surge destroyed more than 80% of exposed homes (see Figure 2-5). The storm surge also damaged almost every home in Bridge City. In Houston, Ike resulted in broken windows in downtown buildings. Damage to power systems was extensive with more than four million customers losing power. Full restoration took several weeks.

Figure 2-4. Flooding in Galveston as a result of Hurricane Ike.

Figure 2-5. Damage in Gilchrist as a result of Hurricane Ike.

2.3 Electric Utility Analysis

Electricity infrastructure in Texas is owned by three types of entities. Investor-owned utilities (IOUs) are owned by private investors and are for-profit businesses. Municipal utilities (munis) are owned by city governments and are not-for-profit. Cooperative utilities are member-owned, are not-for profit, and tend to be very small when compared to IOUs and munis. The service territories of IOUs and munis operating in Texas are shown in Figure 2-6. The utilities with Gulf coastline exposure, and therefore increased hurricane exposure, are AEP Central, CenterPoint, Entergy Texas, parts of Southwestern Electric Power Company (SWEPCO), and TNMP. Although slightly inland, large parts of the Oncor system are also exposed to typical hurricane paths.

The regulatory authority of the PUCT is primarily over IOUs. Therefore, the focus of this section is on IOUs. To gather IOU data, Quanta Technology prepared a set of questions that were sent out by the PUCT as a data request. The questions are listed in Appendix C and the responses are summarized in Table 2-3.

CenterPoint and Oncor are, by far, the largest Texas utilities in terms of customers served. The Oncor system is not on the coast, but has a much less dense service territory requiring more miles of transmission and distribution per customer. Of the IOUs with coastline exposure, all have between 34% and 44% of overhead (OH) distribution miles within 50 miles of the coastline. Overhead transmission exposure varies more widely, with Texas-New Mexico Power (TNNP) having the lowest at 22% and CenterPoint having the highest at 68%.

All Texas IOUs construct their overhead transmission primarily to NESC Grade B and construct their overhead distribution primarily to NESC Grade C, which is standard utility practice in the U.S. Assuming an overload factor of 1.33, Grade B construction corresponds to an extreme wind rating of 104 mph and Grade C construction corresponds to an extreme wind rating of 85 mph (assumes full wind loading and 3-second gusts).[5] In terms of hurricanes, Grade B construction can withstand a weak Category 1 hurricane and Grade C construction can withstand a moderate tropical storm. This assumes direct wind damage. Tree and debris damage can occur even if the structures themselves can withstand the high winds.

Some insightful ratios are shown in Table 2-4. The first is the number of customers served per circuit mile of distribution. Most of the IOUs serve about 30 customers per mile. The outliers are AEP North, which only serves 14 customers per mile, and CenterPoint, which serves 52 customers per mile.

The high density of CenterPoint makes it vulnerable to a direct hit by hurricanes since high winds can easily affect a large percentage of the system and a correspondingly large number of customers. In contrast, the low density of AEP North makes it more vulnerable to large storms that inflict damage across a wide geographic area. The remaining IOUs have moderate customer density and will incur damage levels based on both hurricane size and path.

[5] These calculations are based on equivalent extreme wind ratings for structures built to normal NESC Grade B and Grade C strength requirements assuming an overload factor of 1.33.

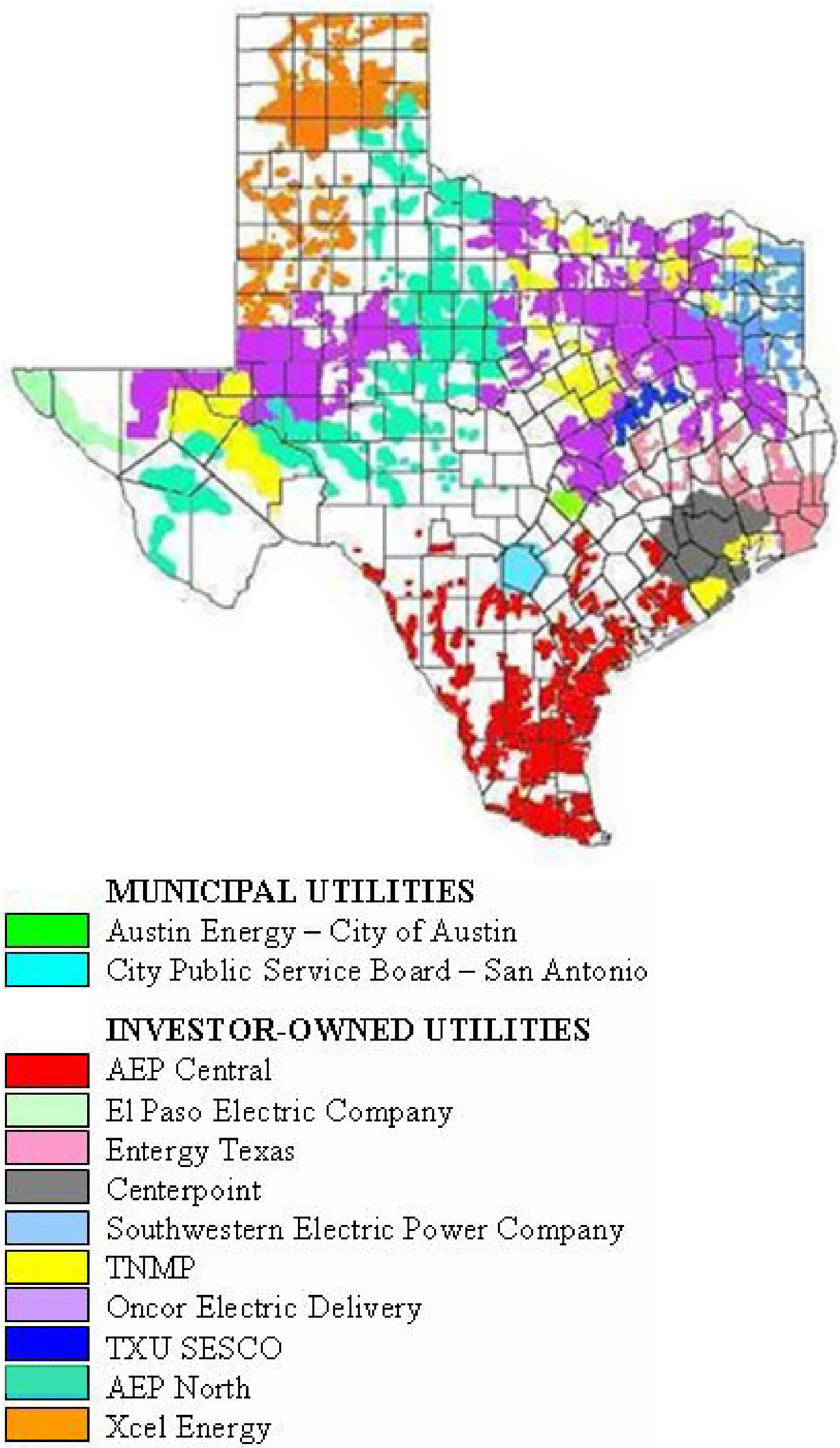

Figure 2-6. Electric IOU and municipal utility service territories in Texas.

Table 2-3. Data for electric IOUs in Texas.

		TNMP	Entergy Texas	Oncor	Center Point	AEP TX Central	AEP TX North	SWEPCO
1	Retail customers	216,000	391,000	3,123,192	2,064,854	810,980	199,254	177,789
2a	Trans. construction (a)	Grade B	Grade B	Grade B	Grade B	Grade B	Grade B	Grade B
2b	Dist. Construction (a)	Grade C	Grade C	Grade C	Grade C	Grade C	Grade C	Grade C
3a	OH Dist. miles	5,666	11,000	77,905	26,802	24,868	12,950	5,967
3b	UG Dist. miles	2,006	1,700	24,774	12,532	4,417	837	403
3c	OH Trans. Miles	954	2,500	14,862	3,727	4,582	4,322	2,113
3d	UG Trans. Miles	0	0	43	26	12	0	0
4a	Dist. Poles	36,862	336,000	2,229,520	1,029,611	840,268	365,235	288,615
4b	Trans. Structures	12,600	27,000	153,293	24,548	34,225	55,073	20,867
4c	Substations	122	378	974	267	327	294	150
5a -	OH Dist. within 50 miles of coast	34%	35%	0%	44%	43%	0%	0%
5b -	UG Dist. within 50 miles of coast	66%	20%	0%	68%	38%	0%	0%
5c -	OH Trans. within 50 miles of coast	22%	58%	0%	68%	52%	0%	0%
5d -	UG Trans. within 50 miles of coast	0%	0%	0%	0%	100%	0%	0%
6a -	OH Dist. vulnerable to storm surge	17%	20%	0%	7%	1%	0%	0%
6b -	UG Dist. vulnerable to storm surge	33%	10%	0%	2%	4%	0%	0%
6c -	OH Trans. vulnerable to storm surge	11%	3%	0%	5.8%	4%	0%	0%
6d -	UG Trans. vulnerable to storm surge	0%	0%	0%	0%	100%	0%	0%
7a -	Miles of dist. veg. management	497	2,400	2,500	4,263	1,169	212	394
7b -	Miles of trans. veg. management	153	740	1,500	583	5,222	444	213
8a -	Cost of dist. veg. patrol (1000s) -	$137	Included in 9a	$0	$0	$358	$26	$366
8b -	Cost of trans. veg. patrol (1000s)	$123	$170 (b)	$0	$106	$73	$70	$50
9a -	Cost of dist. veg. mgmt (1000s)	$3,048	$10,300	$22,900	$17,578	$5,956	$663	$4,825
9b -	Cost of trans. veg. mgmt (1000s)	$58	$1,900	$6,200	$3,444	$1,750	$1,800	$2,000
10a -	Miles of dist. visual inspection	5,666	265	0	0	10,009	1,600	403
10b -	Miles of trans visual inspection	954	50	5,000	703	6,710	5,786	2,058
11a -	Cost of dist. visual insp. (1000s)	$2,229	$61	$0	$0	$200	$50	$366
11b -	Cost of trans. visual insp. (1000s)	$193	$67	$0	$377	$474	$262	$120
12 -	Substations in floodplain	14	Unknown	0	42	50	84	43
13 -	Substations with backup generators	0	4	0	2	0	0	0

(a) - Grade B and Grade C refer to construction requirements as specified by the National Electrical Safety Code (NESC). In terms of wind loading, Grade B is about 50% stronger than Grade C.

(b) - Cost is for helicopter aerial inspections (both vegetation and infrastructure).

Table 2-4. Key ratios for electric IOUs.

Utility	Cust. per mile of dist.	Dist. poles per mile	Trans. structures per mile	Dist. vegetation cycle	Trans. vegetation cycle	Dist. vegetation $/mi	Trans. vegetation $/mi
TNNP	28	6.5	13	11	6	6,133	379
Entergy Texas	31	30.5	11	5	3	4,292	2,568
Oncor	30	28.6	10	31	10	9,160	4,133
Centerpoint	52	38.4	7	6	5	4,123	5,907
AEP Texas Central	28	33.8	7	21	1	5,095	335
AEP Texas North	14	28.2	13	61	10	3,128	4,054
SWEPCO	28	48.4	10	15	10	12,245	9,390

Table 2-5. Primary hurricane exposure for electric IOUs.

		TNMP	Entergy Texas	Oncor	Center Point	AEP TX Central	AEP TX North	SWEPCO	Total
Within 50 miles of coast	OH Dist. Miles	1,926	3,850	0	11,793	10,693	0	0	**28,263**
	UG Dist. Miles	1,324	340	0	8,522	1,678	0	0	**11,864**
	OH Trans. Miles	210	1,450	0	2,534	2,383	0	0	**6,577**
	UG Trans. Miles	0	0	0	0	12.0	0	0	**12.0**
	Dist. Poles	12,533	117,600	0	453,029	361,315	0	0	**944,477**
	Trans. Structures	2,772	15,660	0	16,693	17,797	0	0	**52,922**
Vulnerable to storm surge	OH Dist. Miles	963	2,200	0	1,876	249	0	0	**5,288**
	UG Dist. Miles	662	170	0	251	177	0	0	**1,259**
	OH Trans. Miles	105	85	0	216	183	0	0	**589**
	UG Trans. Miles	0	0	0	0	12	0	0	**12**
	Substations in 100-yr floodplain	14	0*	0	42	50	84	43	**233**

*Data not available

Vegetation management is discussed in detail in Section 3. However, it is of interest to note that the vegetation management cycle for distribution ranges from 5 years to 61 years, based on miles trimmed in 2008 divided by total miles. These numbers do not account for the fact that many parts of a utility's overhead distribution system may not require vegetation management at all. For example, the computed distribution vegetation cycle for AEP Texas North is 61 years. It is likely that this includes significant overhead distribution exposure that does not require trimming (e.g., desert). Vegetation management cycles for transmission range from 1 year to a maximum of 10 years. The cost of vegetation management also varies widely. Distribution vegetation management ranges from about $3,000 to $12,000 per mile. Transmission vegetation management ranges from about $300 to $9,000 per mile. Vegetation management costs are expected to vary widely based on vegetation density and growth rate.

Indicators of total hurricane exposure for Texas IOUs are shown in Table 2-5. This shows the number of circuit miles and structure within 50 miles of the coastline, and the number of circuit miles that are vulnerable to storm surge damage. It also reproduces the number of substations in the 100-year floodplain from Table 2-3. These tables are helpful for estimating hurricane damage and potential benefits of hardening activities. This information is used in Section 5 precisely for this purpose. However, it must be emphasized that not all hurricane damage occurs within 50 miles of the coast. For example, Oncor does not have any facilities within 50 miles of the coastline, but experienced over $22 million in damage from both Hurricane Rita and Hurricane Ike.

Table 2-6. Hurricane damage statistics for Texas IOUs.

Utility	Year	Storm	Cat	Number of Failures					Cost ($)	
				Trans. (a)	Dist. (b)	UG (c)	Subst. Damaged (d)	Subst. Flooded (e)	Trans.	Dist. (includes s/s)
SWEPCO	2005	Rita	3	2	102	0	0	0	88,081	2,352,401
SWEPCO	2008	Ike	2	6	308	0	0	0	334,736	7,428,333
Entergy Texas	2005	Rita	3	664	10649	9,291(f)	50	0	60,600,000	373,200,000
Entergy Texas	2007	Humberto	1	67	315	6,050 (f)	0	0	5,800,000	26,100,000
Entergy Texas	2008	Eduoard	0	0	104	0	0	0	1,300,000	7,100,000
Entergy Texas	2008	Ike	2	560	5693	90,681 (f)	50	12	(i)	(i)
TNMP	2002	Fay	0	0	20	0	0	0	0	382,198
TNMP	2003	Claudette	1	0	10	0	0	0	0	744,888
TNMP	2005	Rita	3	0	80	0	0	0	0	1,758,618
TNMP	2008	Ike	2	6	758	1	0	0	0	16,662,906 (g)
AEP Central	1999	Bret	3	3	192	0	0	0	277,000	3,523,000
AEP Central	2003	Claudette	1	11	440	0	0	0	0	7,000,000
AEP Central	2008	Dolly	2	58	1048	0	0	0	3,200,000	34,000,000
AEP Central	2008	Ike	2	0	29	0	0	0	141,000	1,800,000
CenterPoint	2001	Allison	0	0	32	340	5	2	0	5,168,902
CenterPoint	2002	Fay	0	0	0	9	0	0	0	1,233,173
CenterPoint	2003	Claudette	1	0	32	2	1	0	0	1,146,097
CenterPoint	2005	Rita	3	1	799	64	1	0	223,473	37,252,224
CenterPoint	2008	Eduoard	0	0	2	4	0	0	72,319	1,779,756
CenterPoint	2008	Ike	2	60	7949	171	22	3	(h)	(h)
Oncor	2005	Rita	3	10	358	0	0	0	495,209	22,579,269
Oncor	2008	Ike	2	6	658	2	0	0	962,484	21,738,300

a. Number of transmission structures replaced
b. Number of distribution poles replaced.
c. Number of underground facilities damaged
d. Number of substations damaged
e. Number of substations flooded
f. Entergy Texas reported this number as feet of cable replaced
g. TNMP does not have this value. This is an estimate extrapolated from Rita costs.
h. CenterPoint does not have these values. It estimates a total cost between $650 and $750 million.
i. Entergy Texas does not have these values. It estimates a total cost between $435 and $510 million.

Damage data from recent hurricanes, broken down by utility, is shown in Table 2-6. There are several important observations to make. First, by far the largest number of transmission structure failures occurred on the Entergy Texas system, first with Rita in 2005 and next with Ike in 2008. Second, these two storms caused extensive damage to the Entergy Texas distribution system. The distribution system of CenterPoint also suffered massive damage during Ike, but fared relatively well during Rita (Rita was a glancing blow to CenterPoint while Ike was a direct hit). Last, damage costs to the distribution system are always much higher for a utility than damage costs to the transmission system.

Several key ratios based on hurricane damage data are shown in Table 2-7. This includes the cost per customer for total storm costs, and the percentage of distribution and transmission structures that were replaced (based on the total population, not just the structures exposed to tropical storm or hurricane force winds).

Table 2-7. Key hurricane damage ratios for electric IOUs.

Utility	Year	Storm	Cat	Total Cost	Cost per Customer	Dist. Poles Replaced	Trans. Structures Replaced
SWEPCO	2005	Rita	3	2,440,482	14	0.035%	0.010%
SWEPCO	2008	Ike	2	7,763,069	44	0.107%	0.029%
Entergy Texas	2005	Rita	3	433,800,000	1,109	3.169%	2.459%
Entergy Texas	2007	Humberto	1	31,900,000	82	0.094%	0.248%
Entergy Texas	2008	Eduoard	0	8,400,000	21	0.031%	0.000%
Entergy Texas	2008	Ike	2	435M to 510M	1,228	1.694%	2.074%
TNMP	2001	Fay	0	382,198	1.8	0.054%	0.000%
TNMP	2003	Claudette	1	744,888	3.4	0.027%	0.000%
TNMP	2005	Rita	3	1,758,618	8.1	0.217%	0.000%
TNMP	2008	Ike	2	16,662,906	77	2.056%	0.048%
AEP Central	1999	Bret	3	3,800,000	4.7	0.023%	0.009%
AEP Central	2003	Claudette	1	7,000,000	9	0.052%	0.032%
AEP Central	2008	Dolly	2	37,200,000	46	0.125%	0.169%
AEP Central	2008	Ike	2	1,941,000	2.4	0.003%	0.000%
CenterPoint	2001	Allison	0	5,168,902	2.5	0.003%	0.000%
CenterPoint	2002	Fay	0	1,233,173	0.6	0.000%	0.000%
CenterPoint	2003	Claudette	1	1,146,097	0.6	0.003%	0.000%
CenterPoint	2005	Rita	3	37,475,697	18	0.078%	0.004%
CenterPoint	2008	Eduoard	0	1,852,075	0.9	0.000%	0.000%
CenterPoint	2008	Ike	2	700,000,000	339	0.772%	0.244%
Oncor	2005	Rita	3	23,074,478	7.4	0.016%	0.007%
Oncor	2008	Ike	2	22,700,784	7.3	0.030%	0.004%

Table 2-7 shows that the damage caused by Hurricanes Rita and Ike to the Entergy Texas system was by far the highest in terms of cost per customer served. Both storms caused more than $1,000 in damage per customer served by Entergy Texas. Ike was also costly to CenterPoint, causing $339 in damage per CenterPoint customer. Ike caused $77 in damage for each TNMP customer, and all other recent storms caused less than $50 per customer.

Over the last ten years, hurricanes have caused about $1.8 billion in damage to the electric IOUs listed in Table 2-7. This amounts to an undiscounted cost of $27 per customer per year. Entergy Texas customers are much higher than this average at an undiscounted cost of $244 per customer per year.

Transmission structures seem to hold up relatively well during hurricanes. Over the last ten years, the utilities listed in Table 2-7 only had to replace an unweighted average of 0.24% of the transmission structure population when affected by a tropical storm or hurricane. However, this percentage is skewed by very high transmission failure rates for Entergy Texas (during Rita and Ike). Without these outliers, the unweighted average reduces to 0.04%, or one transmission structure out of every 2,500.

Distribution structures, typically wood poles, fail more frequently during hurricanes when compared to transmission structures. This is to be expected since (1) distribution structures are built to a lower grade of construction, and (2) distribution rights-of-way are typically narrower and more subject to tree-related damage. Over the last ten years, the utilities listed in Table 2-7 had to replace an unweighted average of 0.39% of distribution structures when affected by a tropical storm or hurricane. Excluding the outliers of Entergy Texas during Rita and Ike, the unweighted average reduces to 0.19%, almost five times as high as the 0.04% for transmission structures.

Table 2-8. Hurricane costs for Texas IOUs.

Utility	Year	Storm	Cat	Total Cost ($)	$ per Cust.	Structures Replaced		Damage Amount by Cause			
						Dist.	Trans.	Wind	Surge	Flood	Trees/ Debris
AEP Central	1999	Bret	3	3,800,000	5.6	0.02%	0.01%	20%	0%	0%	80%
Entergy Texas	2007	Humberto	1	31,900,000	81	0.09%	0.25%	58%	42%	0%	0%
AEP Central	2008	Dolly	2	37,200,000	55	0.12%	0.17%	30%	0%	0%	70%
CenterPoint	2002	Fay	0	1,233,173	0.6	0.00%	0.00%	(a)	(a)	(a)	(a)
TNMP	2002	Fay	0	382,198	1.7	0.05%	0.00%	50%	0%	0%	50%
Total				1,615,371							
TNMP	2003	Claudette	1	744,888	3.3	0.03%	0.00%	50%	0%	0%	50%
AEP Central	2003	Claudette	1	7,000,000	10	0.05%	0.03%	30%	0%	0%	70%
CenterPoint	2003	Claudette	1	1,146,097	0.6	0.00%	0.00%	(a)	(a)	(a)	(a)
Total				8,890,985							
SWEPCO	2005	Rita	3	2,440,482	11	0.04%	0.01%	60%	0%	0%	40%
TNMP	2005	Rita	3	1,758,618	7.8	0.22%	0.00%	50%	0%	0%	50%
Entergy Texas	2005	Rita	3	433,800,000	1,098	3.17%	2.46%	97%	3%	0%	0%
CenterPoint	2005	Rita	3	37,475,697	19	0.08%	0.00%	100%	0%	0%	0%
Oncor	2005	Rita	3	23,074,478	7.7	0.02%	0.01%	30%	0%	0%	70%
Total				498,549,275							
Entergy Texas	2008	Eduoard	0	8,400,000	21	0.03%	0.00%	100%	0%	0%	0%
CenterPoint	2008	Eduoard	0	1,852,075	0.9	0.00%	0.00%	(a)	(a)	(a)	(a)
Total				10,252,075							
SWEPCO	2008	Ike	2	7,763,069	34	0.11%	0.03%	60%	0%	0%	40%
Entergy Texas	2008	Ike	2	480,000,000 (b)	1,215	1.69%	2.07%	43%	57%	0%	0%
TNMP	2008	Ike	2	16,662,906	74	2.06%	0.05%	50%	1%	0%	49%
AEP Central	2008	Ike	2	1,941,000	2.9	0.00%	0.00%	20%	0%	0%	80%
CenterPoint	2008	Ike	2	700,000,000	350	0.77%	0.24%	96%	1%	0%	3%
Oncor	2008	Ike	2	22,700,784	7.6	0.03%	0.00%	30%	0%	0%	70%
Total				1,229,067,759							

a. Information not provided

b. This is an assumption made by Quanta Technology. Entergy estimates total cost between $435M and $510M.

Electric utility damage and associated costs, grouped by storm, are shown in Table 2-8. By far, the most costly hurricane for Texas was Ike, with over $1.2 billion in electric IOU storm recovery costs. The next most costly was Rita, with almost $500 million in storm recovery costs. A comparison of Ike and Rita shows the difficulty of predicting storm costs. Ike was a weaker storm than Rita (Category 2 versus Category 3). Despite having slower winds, it inflicted more than twice the damage due to its large size and path. Utilities allocated damage causes in a similar manner for both Rita and Ike, with damage split primarily between damage due to high winds and damage due to trees and debris. Based on Table 2-8, the exception is Entergy Texas during Ike, which experienced a significant amount of damage due to storm surge. CenterPoint also experienced considerable storm surge damage during Ike (at Galveston and Baytown), but only reported having 1% of damage due to storm surge.

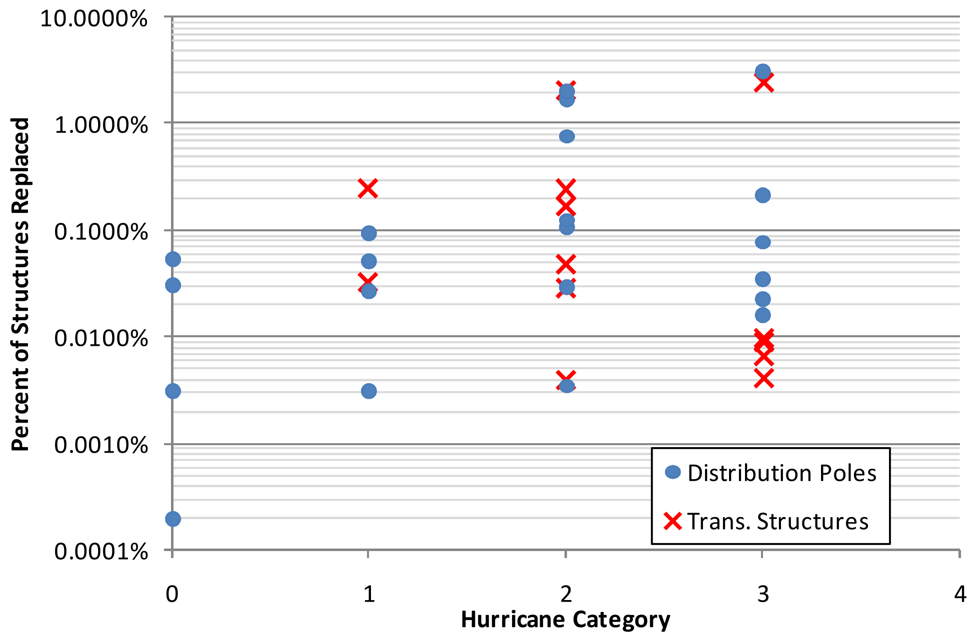

Figure 2-7. Structure replacement versus Hurricane Strength

A scatter plot of structure failures (requiring replacement) versus hurricane strength is shown in Figure 2-7. These results are difficult to generalize since structure failures range widely for each hurricane category (Category 0 refers to a tropical storm). Transmission structures seem to perform well during tropical storms with no utilities reporting the replacement of structures over the last ten years. The data seems to imply that Category 1 and Category 2 storms produce more transmission structure failures than Category 3 storms, which could not be due to wind speed and must be a result of other factors. The data for distribution failures is better behaved, and generally increases with storm category, as expected. However, the range of damage for each category is large, spanning two orders of magnitude in most cases.

In summary, it is difficult to generalize hurricane damage, and cost relationships for electric IOUs based on the last ten years of data. Certain interesting observations can be made for certain utilities during certain hurricanes, but a statistical cost-to-benefit approach to broad programs would not be meaningful. The most meaningful statistical observation is that IOUs in Texas that are affected by hurricanes, on average, incurred $27 per year per customer in hurricane costs over the last ten years.

Since a statistical approach is not practicable, a cost-to-benefit analysis must use probabilistic modeling. Florida has recently taken this approach with some success. The data presented in this section is used, with other data, to develop the probabilistic model forming the basis for the cost-to-benefit analyses described in Section 5. Details of the probabilistic model are provided in Appendix A.

2.4 Telecom Utility Analysis

There are a large number of telecom service providers in Texas. Thirty-two of these provided information with regards to hurricane and tropical storm damage experienced in the last ten years. Of these, eleven reported at least some named storm damage and twenty-one reported no damage. The responding utilities, grouped by whether they have experienced recent named storm damage, are shown in Table 2-9. Although more telecom utilities reported no damage, many of these are relatively small local carriers and coops. The largest telecom utilities all reported damage (e.g., AT&T, Embarq, Verizon, Windstream), along with some smaller companies.

Damage statistics by company for each hurricane in the last ten years are shown in Table 2-10. Nine central offices (COs) have been damaged and an additional seven have experienced flooding. Of these sixteen incidents, Dolly was responsible for seven and Ike was responsible for six. The only other incident was damage to a La Ward CO during Claudette, Windstream during Rita, and AT&T during Rita.

By far, the two most expensive hurricane events were experienced by AT&T Texas, with an estimated \$79.9 million after Ike in 2008 and \$71.7 million after Rita in 2005. The next most costly experience was only \$7.8 million to Verizon after Ike. The average restoration cost for a telecom utility experiencing hurricane damage was \$7.5 million, but this is highly influenced by AT&T events. The restoration cost for all telecom utilities other than AT&T was only \$1.1 million.

Table 2-9. Telecom utilities experiencing hurricane and/or tropical storm damage since 1998.

Damage from Named Storms	No Damage from Named Storms
1. AT&T Texas	1. Industry Telephone
2. Cameron Communications	2. Etex Telephone Coop
3. Consolidated Communications	3. Big Bend Telephone
4. Embarq	4. Guadalupe Valley Telephone Coop
5. Gandado Telephone	5. Electra Telephone
6. La Ward Telephone Exchange	6. Tatum Telephone
7. Lake Livingston Telephone	7. Riviera Telelphone
8. Livingston Telephone	8. Santa Rosa Telephone Coop
9. Valley Telephone Coop	9. Blossom Telephone
10. Verizon Southwest	10. Poka Lambro Telecommunications
11. Windstream Communications Southwest	11. Alenco Communications
	12. Taylor Telephone Coop
	13. Cap Rock Telephone Coop
	14. Community Telephone
	15. Colorado Valley Telephone Coop
	16. Dell Telephone Coop
	17. Hill Country Telephone Coop
	18. Eastex Telephone Coop
	19. Brazos Telecommunications
	20. Peoples Telephone Coop
	21. Wes-Tex Telephone Coop

Table 2-10. Hurricane damage statistics for Texas telephone utilities.

Telephone Company	Year	Storm	Cat	Damaged						Replaced		Total Cost ($)
				CO	CO flood	UG	RT	Poles	Equip.	Poles	Equip.	
Livingston	2005	Rita	3	0	0	0	0	0	0	15	0	255,156
Livingston	2008	Ike	2	0	0	0	0	0	0	10	0	335,000
Cameron	2008	Ike	2	1	0	583	0	0	0	0	0	580,000
Verizon	1999	Bret	3	0	0	0	0	0	0	124	0	398,780
Verizon	2003	Claudette	1	0	0	0	0	0	0	228	0	395,686
Verizon	2005	Rita	3	0	0	0	0	0	0	281	3	3,256,536
Verizon	2008	Dolly	2	0	0	0	0	0	0	127	0	206,800
Verizon	2008	Eduoard	0	0	0	0	0	0	0	4	1	52,799
Verizon	2008	Ike	2	0	0	0	0	0	0	547	2	7,756,854
Valley Coop	1999	Bret	3	0	0	0	2	0	0	0	0	12,500
Valley Coop	2008	Dolly	2	4	0	0	4	0	0	0	0	75,100
La Ward	2003	Claudette	1	1	0	0	0	0	0	0	0	15,100
Lake Livingston	2008	Ike	2	0	0	0	2	0	0	6	0	15,000
Ganado	2003	Claudette	1	0	0	0	0	0	0	0	0	4,000
Ganado	2007	Erin	0	0	0	0	0	0	0	0	0	3,000
Windstream	2005	Rita	3	1	0	0	2	117	0	110	79	1,502,749
Windstream	2008	Ike	2	0	1	0	5	66	0	162	202	3,068,209
AT&T Texas	2005	Rita	3	1	1	5600[1]	6	2500	0	2500	20	71,700,000
AT&T Texas	2008	Dolly	2	2	1	0	1	28	0	9	36	7,100,000
AT&T Texas	2008	Ike	2	4	4	0	15	1746	0	1200	88	79,900,000[4]
Consolidated	2005	Rita	3	0	0	0	0	0	0	12	0	2,000,000[2]
Consolidated	2008	Ike	2	0	0	0	11	0	0	15	0	3,000,000[2]
Embarq	2005	Rita	3	0	0	0	2[3]	0	0	5[3]	0	1,137,631
Embarq	2008	Ike	2	0	0	0	4[3]	0	0	2[3]	0	2,850,573

1. - 2.8 million feet of cable replaced. This number assumes 500 feet per section.
2. - These are estimated numbers based on damaged equipment.
3. - These are estimated numbers based on damage costs by category.
4. - AT&T does not currently have this amount. Corporate wide hurricane related expenses were approximately $145M in 2008 Q3, including wireless and wireline. It is assumed that wireline is responsible for 80% of these costs and that AT&T Texas is responsible for 75% of all wireline costs, for a total of $87M. In its data request, AT&T reports a hurricane cost of $7.1M for Dolly. Other costs such as Midwest flooding are assumed to be negligible, leaving the cost of Ike at an estimated $79.9M. This is a very rough estimate.

Table 2-11. Hurricane costs for telecom utilities.

Telephone Company	Year	Storm	Cat	Total Cost ($)	% Wind	% Surge	% Flood	Trees/ Debris
Verizon	1999	Bret	3	398,780	55%	0%	0%	45%
Valley Coop	1999	Bret	3	12,500	50%	10%	10%	30%
				411,280				
Verizon	2003	Claudette	1	395,686	20%	0%	0%	80%
La Ward	2003	Claudette	1	15,100	100%	0%	0%	0%
Ganado	2003	Claudette	1	4,000	50%	0%	0%	50%
				414,786				
Livingston	2005	Rita	3	255,156	0%	0%	0%	100%
Verizon	2005	Rita	3	3,256,536	15%	0%	5%	80%
Windstream	2005	Rita	3	1,502,749	68%	10%	0%	22%
AT&T Texas	2005	Rita	3	71,700,000	*	*	*	*
Consolidated	2005	Rita	3	200,000	*	*	*	*
Embarq	2005	Rita	3	1,137,631	70%	0%	10%	20%
				78,052,072				
Ganado	2007	Erin	0	3,000	50%	0%	0%	50%
Verizon	2008	Dolly	2	206,800	20%	0%	0%	80%
Valley Coop	2008	Dolly	2	75,100	30%	20%	40%	10%
AT&T Texas	2008	Dolly	2	7,100,000	*	*	*	*
				7,381,900				
Verizon	2008	Eduoard	0	52,799	23%	0%	0%	77%
Livingston	2008	Ike	2	335,000	0%	0%	0%	100%
Cameron	2008	Ike	2	580,000	*	*	*	*
Verizon	2008	Ike	2	7,756,854	23%	0%	0%	77%
Lake Livingston	2008	Ike	2	15,000	27%	0%	0%	73%
Windstream	2008	Ike	2	3,068,209	47%	33%	0%	20%
AT&T Texas	2008	Ike	2	79,900,000	*	*	*	*
Consolidated	2008	Ike	2	300,000	*	*	*	*
Embarq	2008	Ike	2	2,850,573	50%	0%	40%	10%
				94,805,636				

* Information not provided

Hurricanes seem to most consistently cause damage to utility poles, which is similar to the case for electric utilities. Other damage is more difficult to predict. Consider Ike, which caused pole damage to Livingston and Verizon, CO and underground damage to Cameron, remote terminal (RT) damage to Lake Livingston and Consolidated, and broad damage to AT&T. Hurricane strength is also an imperfect predictor of damage. Ike was a weaker storm than Rita (Category 2 versus Category 3), but caused almost four times as much damage to AT&T. Bret was a much stronger hurricane than Claudette (Category 3 versus Category 1), but damage to Verizon was similar in both cases.

Telecom utility damage and associated costs, grouped by storm, are shown in Table 2-11. The most costly hurricanes for Texas were Ike with almost $95 million in damage and eight affected telecom utilities, and Rita with $78 million in damage and six affected utilities.

Telecom utilities attributed more damage to storm surge and flooding than electric utilities. Of note is Ike, which caused major storm surge damage to Windstream and major flooding damage to Embarq. Still, a majority of damage was due to high winds and flying debris.

Over the last ten years, hurricanes have caused about $181 million in direct restoration costs to Texas telecom facilities, 88% of which was due to AT&T. This $181 million was only 10% of amount of the $1.8 billion in electric facilities restoration costs that occurred over the same time period. An examination of the data shows that a statistical approach to cost benefit analysis is not feasible for telecom utilities. Rare but powerful hurricanes dominate costs, but statistics do not tell us whether or when another Ike will occur. Therefore, a cost-to-benefit analysis must use probabilistic modeling. The data presented in this section is used, among other data, to develop the probabilistic model forming the basis for the cost-to-benefit analyses in the next section. Details of the probabilistic model are provided in Appendix A.

2.5 Post-Storm Data Collection

In the aftermath of a major storm that has inflicted widespread damage to infrastructure, the primary objective of all parties is to repair the infrastructure and restore services to customers. Only after that primary task is achieved is much attention given to investigation and analysis of the extent and pattern (if any) of the damage. When attention does turn to that task, the most important information or evidence to support the analysis, the damaged infrastructure itself, has been removed, and post-storm damage analysis is limited to data from accounting and work management systems.

A forensic data collection process that is implemented immediately upon the passing of a storm can provide much more detailed and statistically significant information needed to support failure investigation and analysis that should be performed after restoration has been completed.

The process of post-storm forensic data collection, when properly implemented, will provide the information required to perform a statistically significant analysis of the storm damage. The analysis will facilitate comparison of the actual damage to expected damage based on the engineering and construction standards to which the facilities are built. Field inspection of damage with appropriate data collection techniques will provide the necessary inputs to determine the root causes of failures as well as significant contributing factors of the failures. The overall analysis will ultimately produce data on the performance of the infrastructure in the storm and a determination as to whether or not the actual damage is within the range of reasonable expectation based on storm intensity and comparison to prior storms. Perhaps more importantly, the data can be used to better estimate the benefits of potential hardening options so that hardening programs can be more cost-effective.

2.5.1 Data Collection Process

A typical forensic data collection process involves the dispatch of teams of knowledgeable personnel to the field immediately following a storm for the purpose of collecting damage information according to a documented process. The preparation for this field investigation is the key to the value of the process. The preparation includes such elements as:

Key Elements in the Data Collection Process

- Pole inventory acquisition
- Database development (e.g., pole inventory, line equipment inventory, territory maps)
- Damage information requirements
- Data entry forms and processes
- Field data collection process documentation

In addition to the above elements, program preparation includes development of the data analysis process. The purpose is to create a methodology that will not vary by incident or with the personnel involved in the program.

Following the defined data collection process, investigators will collect all available information that can be reasonably attained through safe evaluation of infrastructure damage while the damaged facilities are still in place. As an example, a field investigator will record a broken pole by including any evidence of tree contact with the line spans or pole, the equipment on the pole (including foreign attachments), the condition of the pole, ground conditions at the pole, right-of-way condition, etc. The investigator will also verify that the pole itself (size, class, age, material) matches what is shown in the pole inventory. All the needed data will be entered into a pre-loaded form on a computer that is linked to the pole inventory database.

Prior to dispatching field investigators, program managers will develop a statistical sampling process based on the initial storm damage information. The sample will be a function of the geographic extent of the damage and the facilities known to be within that geographic area. Intensity of the damage will also inform the sampling process such that sample size will be a function of the total area affected and the quantity of facilities within that area.

Once the data to satisfy the required sampling is collected, field data collection is complete and the necessary information for a detailed damage analysis is available for later use.

2.5.2 Forensic Analysis

Forensic damage analysis is a function that will take some time and research to properly complete. The process will include correlation of weather data to infrastructure failures at specific locations. The purpose of the analysis will be to identify and study any damage patterns that may indicate field conditions that should be addressed in a normal engineering and/or maintenance plan. Examples are such things as overloads of poles due to equipment additions not shown on pole inventories; deteriorated pole conditions not identified in a pole inspection process; and conditions around a pole that contribute to damage exposure. The data analysis will result in tables such as Figures 2-8 and 2-9 that summarize findings, contributing factors of damage, and failure rates of specific materials and applications.

Type	Wind Only	Possible Design Overload	Tree	Presence of Deterioration	Other	Total
Creosote Feeder	64	10	22	64	2	162
	40%	6%	14%	40%	0%	100%
Creosote Lateral	7	1	27	49	5	89
	8%	1%	30%	55%	6%	100%
CCA Feeder	446	33	83	3	20	585
	76%	6%	14%	1%	3%	100%
CCA Lateral	4	0	9	2	2	17
	24%	0%	53%	12%	11%	100%
Concrete Feeder	48	2	35	0	11	96
	50%	2%	36%	0%	12%	100%
Concrete Lateral	2	0	0	0	1	3
	67%	0%	0%	0%	33%	0%

Figure 2-8. Example damage analysis of wood poles. Percentage values are equal to the number of failures for a specific cause divided by the total number of failures

Type	Wind Only	Possible Design Overload	Tree	Presence of Deterioration	Others	Total
Creosote Feeder	1.26%	0.20%	0.43%	1.26%	0.04%	3.19%
Creosote Lateral	0.10%	0.01%	0.38%	0.69%	0.07%	1.25%
CCA Feeder	2.26%	0.17%	0.42%	0.02%	0.10%	2.96%
CCA Lateral	0.05%	0.00%	0.11%	0.02%	0.02%	0.20%
Wood pole total	0.78%	0.07%	0.30%	0.31%	0.06%	1.51%
Concrete Poles	0.55%	0.02%	0.36%	0.00%	0.14%	1.08%
Total	0.75%	0.06%	0.31%	0.27%	0.07%	1.46%

Figure 2-9. Wood pole failure rates by type (example).

Over time, the failure analysis provides a record of storm performance of field facilities and creates a database that can be used when considering engineering and design standards. This information is valuable in determining how to best use limited funds for future system upgrades potentially to validate effectiveness of pole test and treat programs.

2.5.3 Program Benefits

As part of a major storm restoration effort, a forensic data collection process is relatively minor both in time and costs. It typically involves four to six teams of two persons collecting data in the field for a few days immediately following a storm. The time required and number of data points to be gathered are a function of storm severity and area of damage. But because a statistical sampling methodology is used, the overall data gathering is relatively short-lived. A program of this type does require some initialization costs, including the development of pole and equipment databases from existing company inventories.

A concern of some is the use of any personnel during the period following a storm for any purpose other system restoration. This is a valid concern but one that can be addressed through use of contractors or knowledgeable company personnel whose storm duties may not be part of the initial staging and response. The forensic data collection is often completed before the field restoration process is fully mobilized.

A forensic data collection process can provide valuable insight into the performance and integrity of system infrastructure during adverse conditions. The process provides detailed field information that can be used for various analyses long after the storm restoration has been completed. Perhaps most important, forensic data allows for rigorous cost-to-benefit calculations for hardening alternatives, improving the cost-effectiveness of hardening programs.

3 Vegetation Management Programs

This section evaluates the cost for electric IOUs in Texas to implement vegetation management programs that require annual inspections of all overhead facilities. This type of program goes beyond the regularly scheduled vegetation management required under current standards set by the North American Electric Reliability Corporation (NERC) and the Electric Reliability Council of Texas (ERCOT). The requirements for this program may be different for transmission and distribution.

A summary of current vegetation inspection programs for Texas IOUs is shown in Table 3-1. Most utilities perform comprehensive transmission vegetation patrols at least once per year. A few utilities perform vegetation patrols on distribution, but most lump this activity as part of daily operations and do not take a systematic approach.

Cost per mile of transmission vegetation patrol varies widely, between $17 per mile and $65 per mile. The lower costs are typically associated with aerial patrols and the higher costs are typically associated with foot patrols. Cost per mile of distribution vegetation patrol also varies widely, from less than $1 per mile to almost $25 per mile. The variation in distribution vegetation patrol costs is probably due to different interpretations of the data request.

Table 3-1. Vegetation Patrol Data.

Company	Transmission Vegetation Patrol				Distribution Vegetation Patrol			
	OH Miles	Current Practice	2008 Spending	$/mile	OH Miles	Current Practice	2008 Spending	$/mile
AEP (SWEPCO, TNC, TCC)	11,017	Annual aerial	$192,500	$17	43,785	Undefined	$476,449*	$10.88
Cap Rock	309	Annual patrol (assumed)	$17,000	$55	9,793	Undefined	$6,200	$0.63
Centerpoint	3,727	Annual aerial	$106,000	$28	26,802	Part of day to day ops	$0	n.a.
El Paso	1,799	Every 3 years	not provided	n.a.	7,266	Every 3 years for feeder trunk	not provided	n.a.
Entergy Texas	2,500	Semi-annual aerial	$170,000	$31	11,000	5-yr average	tracked separately	n.a.
Oncor	14,862	Semi-annual; special foot patrols in critical areas	not provided	n.a.	77,905	No separate patrols; part of day to day operations	not provided	n.a.
Sharyland	15	Annual inspections	not provided	n.a.	N.A	Annual	not provided	n.a.
SW Public Service	5600*	Part of day to day ops	not provided	n.a.	5,000*	Part of day to day ops	$0	n.a.
TNMP	954	Semi-annual; 1 aerial, 1 foot	$123,450	$65	5,666	Annual patrol	$136,650	$24.12

*Estimate

The North American Electric Reliability Corporation (NERC) requires transmission line owners to develop and maintain a vegetation management plan.[6] The Electric Reliability Council of Texas (ERCOT) also requires that each transmission owner have a vegetation management plan to prevent transmission line contact with vegetation. This plan must include inspections at regular intervals.

Most of the electric utilities regulated by the PUCT reported performing a minimum of one annual patrol of their entire transmission system to inspect for potential vegetation problems. Generally, this is an aerial patrol supplemented with ground or foot patrols as deemed necessary by the utilities. El Paso Electric patrols one-third of its system annually while Southwestern Public Service does not have a separate, distinct vegetation management patrol or inspection process. Rather, Southwestern Public Service depends upon non-vegetation employees identifying and reporting potential problems as part of their day to day operations.

Assuming $20 per mile for an aerial vegetation inspection, El Paso would have to spend an additional $24,000 per year to ramp up to an annual patrol cycle. Also assuming $20 per mile, Southwestern Public Service would have to spend $112,000 per year to ramp up to an annual patrol cycle.

Unlike for the transmission system, most of Texas IOUs do not identify a separate vegetation management inspection or patrolling program for their distribution systems. Entergy Texas inspects on its regular trimming cycle which averaged five years. Sharyland Utilities and TNMP reported annual or semi-annual vegetation management patrols. El Paso Electric reported patrolling one-third of this system annually. The remaining utilities did not identify a separate program or reported that they did not perform these patrols. The AEP companies did not identify a separate vegetation management patrol, but reported expenditures that indicate that they perform this activity.

Since most Texas utilities do not perform separate distribution vegetation management patrols, representative costs for Texas are not available. The reported costs for the few utilities that perform distribution vegetation management patrols range from $11 to $24 per mile. On the other hand, utilities outside of Texas have experienced costs approaching $100 per mile, but this number typically includes associated repair costs for identified defects. Assuming that only AEP and TNMP currently perform distribution vegetation patrols and that the cost per mile is $20, the cost for the remaining Texas IOUs (138,000 circuit miles of overhead distribution) is $2.76 million per year.

3.1 Hazard and Danger Trees

As shown in Table 2-8, trees are a major concern during hurricanes. However, the tree issues addressed by traditional utility vegetation management do not typically result in substantial hurricane benefits. Typical vegetation management is focused on maintaining a specified clearance between vegetation (e.g., tree branches) and energized conductors. During normal weather, this clearance reduces the number of branches that come into contact with conductors and cause a fault. During hurricanes, tree-related damage is typically due to entire trees falling over into lines and structures (see Figure 3-1).

[6] NERC Standard FAC-003-1. There is an updated draft of this standard, FAC-003-2. If approved, FAC-003-002 would require annual transmission vegetation inspections.

Figure 3-1. Tree falling into transmission lines.

In order to reduce the amount of tree-related damage that occurs during hurricanes, vegetation patrol programs must not just look for clearance violations. Instead, the patrols must look for trees both inside and outside of the right-of-way that are likely to fall into structures or lines when subjected to high winds. Certainly, dead and diseased trees, typically called *hazard trees*, should be identified and removed (although it is often not clear whether the utility or the land owner should pay for removal). In addition, utilities can attempt to identify ways of working with property owners to remove or replace other trees that are potentially hazardous to the utility system during hurricanes, typically called *danger trees*.

This section does not imply that Texas IOUs are not currently focusing on hazard and danger trees. Oftentimes transmission easement rights explicitly allow for the removal of hazard and danger trees. Many vegetation management processes also inspect for these trees and attempt to remove as many as possible. However, many utilities do not have mature processes in this area.

This project did not collect enough data to determine the current state for Texas utilities. However, several other utilities around the country have found that an increased focus on hazard and danger tree removal resulted in reduced damage during wind storms. For example, vegetation management for Pacific Power in Oregon now has a strong focus on tree removal. This focus only became possible after establishing maturity in its 4-year vegetation management cycle. Initially, much of the vegetation management work was branch trimming for establishing clearances. After time, maintaining clearances required less effort, allowing for a more aggressive focus on removal. Tree removal resulted in significantly less storm damage during the windstorms of December 2006 compared to previous storms.

The situation is similar at Puget Sound Energy, where a significant amount of damage during wind storms is due to trees outside of the right-of-way. During normal O&M activities, hazard trees on private property are identified and communicated to the vegetation management team. This team then contacts the property owner and discusses the hazard associated with the tree. Often times the owner refuses to allow the tree to by trimmed or removed.

Seattle City Light (SCL) is a third example. Most of the damage that occurs during wind storms is due to large trees outside of the right-of-way falling over into the power lines. After the 2006 wind storm, SCL surveyed its system, identified trees that have become dangerous (e.g., excessive leaning), and prioritized these danger trees for pruning or removal. SCL has found that few customers, when asked, will allow trees on their property to be removed or extensively trimmed so that the utility will experience less damage during future storms.

The cost-effectiveness of hazard and danger tree removal depends on the ability of utilities to remove or extensively trim the trees in question. It also depends upon whether the program is integrated into existing vegetation activities or performed separately. Although rigorous cost-to-benefit analysis has not been performed for Texas, experience at other utilities shows that hazard and danger tree removal is a cost-effective way to mitigate wind storm damage. Effectiveness is greatly increased if utilities have the ability, at a minimum, to condemn dead and diseased trees that can fall into the utility lines. From a societal perspective, dead and diseased trees should be removed in any case.

Table 2-8 shows that trees and flying debris cause 38% of all hurricane damage (unweighted average). It is assuming that an aggressive hazard and danger tree removal program is able to reduce 20% of this damage. Over the last ten years, hurricane restoration costs have averaged $180 million per year. Therefore, the estimated utility benefits of an aggressive hazard and danger tree removal program are $180 million x 38% x 20% = $13.8 million per year.

The societal cost of hurricanes is estimated to be $122 million per year. Therefore, the estimated societal benefits of an aggressive hazard and danger tree removal program are $122 million x 38% x 20% = $9.3 million per year.

3.2 Trimming Cycles

This section summarizes the tree trimming cycles for the electric and telecom utilities that supplied the data. Typically a trimming cycle is based on required clearances and growth rates. Periodically, tree branches are trimmed away from utility equipment. Ideally, the trimming is such that the tree branches will not grow such that clearances are violated until the next scheduled cycle of trimming. Other activities may be combined with trimming activities such as mowing, herbicide treatment, and tree removal. Telecom utilities that are primarily underground or are primarily located on electric utility poles are not addressed, since their trimming needs are minimal.

Telecom Utilities

AT&T Texas presently inspects and trims trees on an as-needed basis when technicians are on location to place or splice cable, or when performing other services. Trees are trimmed in cases where limbs are touching or are within direct reach of the telecommunications infrastructure.

Brazos Telephone Cooperative has servicemen perform random inspections of aerial facilities while performing their normal daily assignments. Areas found in need of vegetative trimming are trimmed at that time or reported as "facilities maintenance needed" and a crew is dispatched as soon as possible to the site.

Cap Rock Telephone Cooperative performs tree trimming on an as-needed basis.

Comanche County Telephone Company performs tree trimming on an as-needed basis.

Consolidated Communications does not have regular trimming cycles. It performs bi-annual inspections. Based on the inspection reports, it prunes accordingly.

Embarq does not use a specific tree trimming cycle. Due to wide geographic dispersion, Embarq has local field personnel schedule tree trimming on an as-needed basis. Additionally, Embarq conducts structural integrity of its poles on a regular schedule (will be doing the 7,000 poles within 100 miles of the Coast this year) and, if needed, schedule tree trimming after those reviews.

Five Area Telephone Cooperative does not have regular trimming cycles. Employees make routine inspections, as time allows, of all overhead facilities to make sure that vegetation is kept trimmed and away from all overhead cable, poles, and pole attachments.

Ganado Telephone Company annually hires and local high school students during the summer months with the primary goal of cable route maintenance and vegetation control. Further, on an as needed basis, it contracts professional tree trimmers to clear away major tree growth.

Livingston Telephone Company (LTC) inspects and trims each route on a three-year cycle. LTC removes remove trees that are directly under, or so close to the lines that they may pose a hazard. Most trimming is done by the power companies who own the poles.

Mid-Plains Rural Telephone Cooperative does not have a formal program for trimming. When vegetation problems are encountered in areas of public access, they trim trees as necessary.

North Texas Telephone Company performs tree trimming on an as-needed basis.

Verizon Southwest does not have a regularly scheduled tree trimming cycle. Whenever work is performed on outside plant, a visual inspection of the surrounding vegetation is performed. If a dangerous or threatening condition is found to exist, it is promptly addressed and rectified. This practice has proven successful while striking a balance between cost and facility integrity.

West Plains Telecommunications does not have regular trimming cycles. Employees make routine inspections, as time allows, of all overhead facilities to make sure that vegetation is kept trimmed and away from all overhead cable, poles, and pole attachments.

Windstream Communications performs tree trimming on an as-needed basis.

Electric Utilities

AEP (AEP Texas North, AEP Texas Central, and SWEPCO) does not have a regular tree trimming cycle. With regards to distribution facilities, a long-term plan spanning multiple years is used to coordinate tree trimming efforts. With regards to transmission facilities, AEP uses a systematic integrated vegetation management program.

Bowie-Cass Electric Cooperative maintains distribution and transmission on a 5-year cycle. For 2 consecutive years approximately 50% of the transmission system is trimmed and mowed. The following 2 years approximately 50% of the transmission system is treated with herbicide. Each year approximately 20% of the distribution system is trimmed and mowed, and 20% of the distribution system is treated with herbicide.

Cap Rock Energy has a 5 to 7 year cycle on vegetation management based upon factors such as vegetation growth rate and rainfall quantity.

CenterPoint is on a 5 year trimming cycle for transmission (69 kV, 138 kV, and 345 kV). For distribution, 35-kV lines are cleared when 3 or more years have passed since the last trimming, and 12-kV lines are cleared when 4 or more years have passed since the last trimming. Each July, CenterPoint reviews the probable 10% least reliable circuits (as measured by the average customer interruption duration) and schedules trimming on these circuits for the fourth quarter of each year.

Cherokee County Electric Cooperative specifies annual inspections, mowing every five years on average, and tree trimming to provide adequate clearances for a minimum of 5 years.

Deep East Texas Electric Cooperative specifies mowing/spraying every 5 years on average, and tree trimming to provide adequate clearances for a minimum of 5 years.

East Texas Electric Cooperative specifies that an aerial or ground based inspection annually, mowing every two years on average, and tree trimming to provide adequate clearances for a minimum of ten years.

El Paso Electric generally attempt to perform trimming on a two-year cycle. Areas with special consideration may impact the tree-trimming cycle. For example, there are areas where the magnitude of tree trimming necessary to maintain a two-year cycle creates aesthetic concerns from customers. In these areas, extensive trimming may be postponed until the non-growing season.

Entergy Texas performs routine helicopter aerial inspections of its transmission system. There are 2 aerial patrols of the entire transmission system, plus 1 aerial patrol on 230-kV, 345-kV and 500-kV lines. During these aerial patrols, the personnel inspect the transmission infrastructure as well as vegetation to identify any reliability issues. Routine vegetation maintenance consists of a 2-year cycle for the "floor" and side trimming. There is a 3-year cycle for urban areas and conditioned-based trimming for rural areas. Entergy Texas averages a 5-year trimming cycle for distribution. In addition, there are reactive patrols conducted as part of a reliability program and/or in response to the public identifying a vegetation issue.

Houston County Electric Cooperative clears rights-of-way from floor to ceiling every five years. Additionally, hot-spot clearing is done as required. Herbicide is applied on a two-year cycle.

Jasper Newton Electric Cooperative follows the guidelines of RUS Bulletin 1730-1. Mowing occurs on an average two-year cycle and trimming provide adequate clearances for a minimum of five years.

Lower Colorado River Authority (LCRA) conducts comprehensive assessments every ten years, which are used to identify tree encroachments and vegetation issues. Based on these assessments, the following 2.5-year cycles are alternates. Cycle 1 involves re-shredding and/or herbicide treatment as needed. Cycle

2 involves a total right-of-way re-shred and/or herbicide treatment and tree issues. This process results in essentially a 5-year trimming cycle.

Oncor does not rely on fixed trimming cycles for transmission or distribution. For transmission, Oncor relies on a variety of patrols to determine when and where trimming is needed as to comply with NERC Standard FAC-003-1. For distribution, Oncor considers numerous factors to determine when and where vegetation clearing or trimming is required such as safety concerns, inspections, outages, storm damage, circuit performance and reliability. Field operation employees clear or trim vegetation in a specific or local area as appropriate in the performance of their normal maintenance and/or construction duties.

Panola-Harrison Electric Cooperative specifies that an aerial or ground based inspection of all ROW shall be performed annually, that mowing shall be performed every four years on average, and tree trimming shall provide adequate clearances for a minimum of five years.

Rusk County Electric Cooperative specifies mowing every three years on average, and tree trimming to provide adequate clearances for a minimum of five years.

Sam Houston Electric Cooperative trims distribution lines on a four- or five-year cycle. Approximately sixty percent of the system is on a four year trim cycle and the remainder is on a five year cycle. Transmission is trimmed on an eight to ten year cycle. Mowing and underbrush removal along transmission lines is completed every two years. Both distribution and transmission ROW is inspected twice a year for dead trees or potential problems.

Sharyland Utilities perform trimming passed in visual inspections. Its policy for visually inspecting for vegetation contact on distribution facilities is based on a yearly cycle. However, due to its small service territory and the construction activity, it is able to visually inspect overhead distribution lines at least once a quarter. Sharyland has approximately fourteen miles of overhead transmission lines that are inspected on a six-month cycle at this time.

South Texas Electric Cooperative does not have a formal trimming cycles. Its program specifies that an aerial or ground-based inspection shall be performed annually, that right-of-way mowing shall be performed every five years on average, and that tree trimming shall provide adequate clearances for a minimum of three years.

Southwestern Public Service (SPS) has a distribution tree trimming cycle goal of five years. For transmission, the goal is three to four years in Texas. At the end of 2009, SPS estimates that 94% of its distribution system will be on a five year cycle and that 100% of its transmission system will be on a three to four year cycle. Most of the SPS transmission in Texas is on a four year cycle, but some are on a three year cycle due to construction type and tree density.

TNMP has developed a vegetation management program that is both time and condition-based. The time-based component incorporates herbicide treatment, hazard tree removal and tree trimming. TNMP's goal is to schedule these tasks at three to five year intervals. Specific schedules are recommended according to growth rate and types of trees located in the geographic area and the types and configuration of electric transmission and distribution facilities in proximity of vegetation. The condition-based component provides for TNMP to address hazard tree removal and tree trimming based on-site inspections and outage incidents. To prevent the recurrence of outages and eliminate repeating worst performing circuits, TNMP continually monitors system reliability while staff foresters help prioritize tree trimming on select circuits.

The flexibility of using this two-phased approach allows the Company to most effectively manage the costs associated with these activities.

Trinity Valley Electric Cooperative specifies trimming for distribution lines on a five- or six year cycle Approximately 50% of the system is on a five-year trim cycle and the remainder is on a six year cycle. Mowing is completed during the trimming cycle. Both distribution and transmission are inspected twice per year for deed trees or other potential problems.

Wood County Electric Cooperative performs distribution trimming on a six- to eight-year cycle. Transmission is mowed on an annual basis. During mowing, transmission trimming needs are identified and addressed.

4 Ground-Based Inspection Programs

This section evaluates the cost to implement an annual ground-based inspection program for overhead facilities, including poles and other support structures, as compared to the regularly scheduled inspections of utility poles and overhead equipment currently used.

Most utilities reported a ground-based inspection (GBI) program for both their transmission and distribution systems, although the programs for the transmission and distribution systems within a company were usually different. Inspection cycles vary from annually to ten years for the transmission system and from annually to 15 years for the distribution system. Cap Rock Energy did not report a specific GBI cycle but rather this activity was performed as part of its day to day operations.

Data for ground-based inspection activities for Texas IOUs are shown in Table 4-1. Cost per mile varies widely for transmission. Part of this is due to the types of structures involved, the number of structures per mile, and whether a climbing is performed. The high amount for Entergy Texas is because it includes the cost of sounding and boring to check for wood deterioration. Cost per mile also varies widely for distribution, most likely for similar reasons.

Table 4-1. Ground-Based Inspection Data.

Company	Transmission Ground-Based Inspection					Distribution Ground-Based Inspection				
	OH Miles	Current Practice	2008 mi. of GBI	2008 Spending	$/mile	OH Miles	Current Practice	2008 mi. of GBI	2008 Spending	$/mile
AEP (SWEPCO, TNC, TCC)	11,017	Wood: 4-5 yr Non-wood: 5-10 yr cycle	11,017	$855,582	$78	43,785	5 year cycle	12012	$889,795*	$74.08
Cap Rock	309	Part of day to day ops	309	$18,500	$60	9,793	Part of day to day ops	9793	$97,930	$10.00
Center Point	3,727	5 year cycle	703	$377,000	$536	26,802	15 year cycle	1787	$706,068*	$395.11
El Paso	1,799	345 KV semi-annual; 69 and 115 KV annual	not provided	not provided	n.a.	7,266	3 year cycle for main trunk	n.a.	n.a.	n.a.
Entergy Texas	2,500	10 year cycle	50	$67,000	$1,340	11,000	10 year cycle	265	$61,000	$230.19
Oncor	14,862	Non-wood - 5 years; wood > 15 yrs old annual	5,000	not provided	n.a.	77,905	No separate patrols; part of day to day operations	not provided	n.a.	n.a.
Sharyland	15	Annual	not provided	not provided	n.a.	n.a.	Annual	not provided	n.a.	n.a.
SW Public Service	5600	Annual	not provided	not provided	n.a.	5,000	12 yr cycle	not provided	n.a.	n.a.
TNMP	954	Undefined	954	$192,750	$202	5,666	Annual	5666	$228,540	$40.34

*Estimated

In this discussion, ground-based inspections are structural inspections that include a visual examination of structure condition, insulators, mounted equipment, conductors, and so forth. This *does not* include an examination of the degradation of strength at the groundline (for wood structures). This separate activity, typically called test-and-treat, is commonly performed on a 10-year cycle and does not need to be performed annually. Some of the spending numbers shown in Table 4-1 include the test-and-treat costs along with the inspection costs (e.g., Entergy Texas).

El Paso, Sharyland, Southwestern Public Service, and TNMP all perform ground-based transmission inspections at least annually. The remaining utilities have a combined 34,214 miles of transmission lines. Assuming that an average of 10% of this exposure is currently inspected, and that transmission inspections are $500 per mile, the annual cost to achieve annual ground-based transmission inspections is $15.4 million per year.

Typical utility practice is to perform ground-based transmission inspections every five to ten years, with lines of special concern perhaps being inspected every three years. Annual ground based transmission inspections are not expected to have significant hurricane benefits and are therefore concluded to not be cost-effective.

Sharyland and TNMP both perform ground-based distribution inspections at least annually. The remaining utilities have a combined 181,551 miles of distribution lines. Assuming that an average of 10% of this exposure is currently inspected, and that distribution inspections are $200 per mile (including repairs), the cost to achieve annual ground-based distribution inspections is $32.7 million per year.

Based on Table 2-8, falling trees and flying debris cause most hurricane damage. Ground-based distribution inspections only have a limited ability to mitigate this type of damage. However, assuming that annual ground-based inspection programs are able to reduce 5% of hurricane damage. Over the last ten years, hurricane distribution restoration costs have averaged about $150 million per year. Therefore, the estimated utility benefits of annual ground-based inspection programs are $150 million x 5% = $7.5 million per year.

The societal cost of hurricanes is estimated to be $122 million per year, with about 80% due to distribution damage. Therefore, the estimated societal benefits of annual ground-based inspection programs are $122 million x 80% x 5% = $4.9 million per year.

5 Infrastructure Hardening Programs

This section evaluates the costs and benefits of implementing the following requirements in hurricane-prone areas (i.e., within 50 miles of the Texas coast): constructing new substations above the 100-year floodplain, constructing new COs above the 100-year floodplain, providing backup generators for substations and COs, hardened new transmission structures, the use of non-wood structures, underground distribution, underground transmission, and targeted hardening programs.

5.1 New Facilities above the 100-Year Floodplain

This section addresses the costs and benefits that may accrue if new electric substations and/or new telephone central offices (COs) are built above or outside the 100-year floodplain. The analysis does not address relocation of existing substations or COs that may currently exist within a floodplain.

The costs for design and construction of electric power substations and telephone central office facilities will typically be higher if it is being sited within a 100-year floodplain and is designed to be flood resistant. These costs additional costs are typically weighed against other factors when making a siting decision such as proximity to customers, proximity to transmission facilities, and the availability of suitable sites outside of the 100-year floodplain.

5.1.4 Substations

When considering the cost of design and construction of a substation on a site outside of a 100-year floodplain, the substation cost is typically more due to flood mitigation costs. For example, Figure 5-1 shows CenterPoint's West Bay substation on Galveston Island, which had its site elevated before construction. It did not flood during Ike like some other substations on Galveston.

If, other than flooding reasons, the site in the 100-year floodplain is optimal, incremental site-specific costs will be incurred. These are primarily based on the following:

- Higher land cost,
- Higher cost for transmission line taps, and
- Higher cost for feeder extensions.

These variable costs in substation siting and design can be higher or lower at any specific site, and are independent of the flood risk of a site. A utility will not choose a site with higher risk of flooding over a lower risk site if all other parameters are equal. Location of utility facilities in sites with flood risk are driven by specific needs or cost considerations that make the site preferred.

The benefits of locating substations outside of 100-year floodplains are a reduced chance of flooding, reduced damages due to flooding, and reduced outages due to flooding. As part of this analysis, information on outages of substations within 50 miles of the coast of Texas has been provided. Outages and damage due to flooding has also been specifically identified as part of the information. Data provided shows:

Figure 5-1. CenterPoint's West Bay Substation.

- Of the four IOUs providing service in the region (AEP, CenterPoint, Entergy Texas, and TNMP), there are an estimated 146 substations located within a 100-year floodplain.
- Since 1998, with occurrence of 14 named storms (hurricanes and tropical storms), utilities reported 125 incidents of substation damage.
- 11.6% of the reported substation damage incidents were attributed to flooding.

Because of the low number of incidents reported, the data do not support statistical analysis and simulation to develop flood-related failure rates for the substations in the area. The 100-year floodplains are developed based on long-term weather analysis which includes all weather conditions. The effect of hurricanes and other severe weather events are included in the analysis that defines a 100-year floodplain. By definition, a 100-year floodplain has a 1% chance per year of flooding and is therefore used as the probability of substation flooding in the coastal region. If the substation is constructed outside the 100-year floodplain but in the same general area, it is assumed to be in the 500-year floodplain. Hence the probability of flooding in that location is projected to be 0.2% (i.e., 1 chance in 500 years).

The simple economic analysis shown in Figure 5-2 is based on a first cost of $6,000,000 for a substation in either location and a $2,000,000 repair cost if flooded. The analysis shows that the new benefit of building the same substation outside the 100-year floodplain is $16,000 per year. Assuming a 10% discount rate and a 40-year substation life, the present value of avoided restoration costs is $156,465.

New substation	$6,000,000	$6,000,000
Probability of damage in floodplain (100 yr flood)	1.0%	
Probabililty of damage outside floodplain (500 yr flood)		0.20%
Repair cost if flooded	$2,000,000	$2,000,000
Expected annual value of flood repair cost	$20,000	$4,000
PV of repair cost of 40 yr life of substation (@10%)	($195,581)	($39,116)
Net benefit		$156,465

Figure 5-2. Substation cost analysis.

A basic assumption in the analysis of substation flooding in coastal Texas is that the cause of the flooding is storm surge associated with hurricanes. The damage from storm surge flooding is typically more extensive than inland flooding because 1) it is more widespread and 2) the salt and sand exposure from the flooding causes more facility damage. Additionally, the utility facilities in coastal storm surge regions are generally more exposed than inland facilities.

This example assumes only damage avoidance and/or repair costs as benefits and is positive with that limitation. Obviously, the reduced chance of flooding also has benefits in terms of outage recovery for the entire storm restoration. The overall duration of a storm recovery is primarily a function of repair and replacement of transmission and distribution lines, not substations. Therefore, societal benefits in terms of faster restoration time are assumed to be negligible.

If a utility decided to construct a new substation in a 100-year floodplain, it can spend additional money to reduce the flood risk. For example, the entire site can be raised, waterproof equipment can be specified, control cabinets can be raised, and so forth.

In 2007, Entergy conducted a study to evaluate various infrastructure hardening initiatives. That report[7] includes cost estimates for design and construction of substation modifications to raise finished elevations of certain station components to levels that would minimize the risk of flooding. The Entergy report estimates an additional first cost of approximately $825,000 to increase substation elevation by 8 feet for flood risk reduction. A quick comparison shows that this flood mitigation cost is high when compared to the present value of avoided flood costs ($156,465). Therefore, additional considerations beyond equipment damage must exist for a utility to locate a substation in a 100-year floodplain. For example, substations on Galveston Island essentially have to be located within a 100-year floodplain. It would be very expensive to serve these customers without substations on the island due to the resulting high distribution system costs.

[7] "Entergy Hurricane Hardening Study" December 14, 2007, Public Utilities Commission of Texas Project 32182, Item 163.

5.1.5 Telephone Central Offices

Similar to substations, the cost of design and construction of a CO on a site within a 100-year floodplain is typically more due to flood mitigation costs. If, other than flooding reasons, the site in the 100-year floodplain is optimal, incremental site-specific costs will be incurred. These are primarily based on the following:

- Higher land cost
- Higher cost for facility extensions away from the CO

These variable costs in CO siting and design can be higher or lower at any specific site, and are independent of the flood risk of a site. A utility will not choose a site with higher risk of flooding over a lower risk site if all other parameters are equal. Location of utility facilities in sites with flood risk are driven by specific needs or cost considerations that make the site preferred.

The benefits of locating COs outside of 100-year floodplains are a reduced chance of flooding, reduced damages due to flooding, and reduced outages due to flooding. As part of this analysis, information on outages of COs has been provided. Outages and damage due to flooding has also been specifically identified as part of the information. Data provided shows:

- Since 1998, with the occurrence of 14 named storms (hurricanes and tropical storms), companies reported 17 incidents of central office damage.
- Eight of the reported central office damage incidents were attributed to flooding.
- Five of the eight flooding incidents were from storm surges during Rita and Ike.

A cost-benefit analysis for telephone central offices is essentially the same as electric substations with the same expected result. For the same facility, at essentially the same cost, on a site outside a floodplain compared to inside the 100-year floodplain, it is beneficial to be in the lower risk location. Based on similar probabilities of 1% risk of flooding in the floodplain vs. 0.2% risk of flooding outside the floodplain, the benefits are positive to be in the lower risk location. This analysis assumes a first cost of approximately $1.5 million for a central office facility with repair/restoration costs at 33% of first cost.

Because of the low number of incidents reported, the data do not support statistical analysis and simulation to develop flood-related failure rates for the COs in the area. By definition, a 100-year floodplain has a 1% chance per year of flooding and is therefore used as the probability of CO flooding in the coastal region. If the CO is constructed outside the 100-year floodplain but in the same general area, it is assumed to be in the 500-year floodplain. Hence the probability of flooding in that location is projected to be 0.2%.

The simple economic analysis shown in Figure 5-3 is based on a first cost of $1,500,000 for a CO and a $500,000 repair cost if flooded. The analysis shows that the benefit of building the same CO outside the 100-year floodplain is $4,000 per year. Assuming a 10% discount rate and a 40-year substation life, the present value of avoided restoration costs is $39,116.

New Telephone Central Office	$1,500,000	$1,500,000
Probability of damage in floodplain (100 yr flood)	1.0%	
Probabililty of damage outside floodplain (500 yr flood)		0.20%
Repair cost if flooded	$500,000	$500,000
Expected annual value of flood repair cost	$5,000	$1,000
PV of repair cost of 40 yr life of substation (@10%)	($48,895)	($9,779)
Net benefit		$39,116

Figure 5-3. Central Office cost analysis.

The reduced chance of flooding also has benefits in terms of outage recovery for the entire storm restoration. The overall duration of a storm recovery is primarily a function of repair and replacement of overhead and underground cables, not COs. Therefore, societal benefits in terms of faster restoration time are assumed to be negligible.

A utility should always try to locate central offices outside of floodplains. When this is not possible, it is worth spending about $40,000 if the risks associated with being in a 100-year floodplain can be reduced to the risks associated with being in a 500-year floodplain.

5.2 Backup Power for Central Offices and Substations

This section evaluates the costs and benefits of providing backup power for central offices and substations.

5.2.1 Substations

In storm conditions, substations are exposed to outages from direct damage to the facility itself, or the more common outage caused by damage to transmission lines that are the source of power for the substation. In either case, a backup power source to the substation for station service (i.e., auxiliary power) can be beneficial but does not ensure that the substation outage will be shortened or its impact lessened in any way. Most substations are equipped with batteries for auxiliary power as well as redundant station service power sources. This standard equipment for auxiliary power in the substation is adequate for most conditions. The station service transformers are energized from the station itself. In most cases, if the substation is in service, the power supply to the substation control house and protection and communication systems is also available.

If an independent auxiliary power supply is required in a substation, it would normally be provided through an emergency generator. The cost of backup power in a substation includes the cost of installing a backup generator, automatic transfer switch, and fuel source or supply. Size of the generator can vary depending upon how much of the station service load is to be carried by the generator. For example, the generator may be sized to carry the entire station service load or it may be sized to provide power to lighting and battery charging only. Since the generator is the bulk of the cost for the entire system, the size of the unit is highly influential on total cost. For the purpose of this analysis, a 10-kW generator is considered. Maintenance costs of the generator system are not considered although they can be significant.

Benefits derived from backup station power are dependent upon the nature of the outage. If transmission service to the substation is interrupted, auxiliary power is less beneficial. If line protection and communications must be maintained from a particular substation, backup power is critical and is normally supplied by the batteries. As outlined earlier, auxiliary station service power is of primary benefit for a station service supply outage. When the entire substation is out of service due to internal damage or transmission line damage, the benefit of backup station service power is lessened.

To estimate the cost-to-benefit ratio of adding emergency generators to substations, the following assumptions are made:

- Substation damage incidents reported are assumed to require backup power beyond the existing substation capability 30% of the time.
- Avoided cost is based on the reduction of substation service power outage by one-half day and valued at daily GDP rate for the area.
- Generator cost assumes generator capacity capable of full backup of station service with an automatic transfer switch.

Table 5-1 shows the cost-to-benefit ratio for each company based on the above assumptions. The cost and benefit assumptions here are at a macro level acting as a filter to determine if more detailed investigation is justified. It is Quanta Technology's belief that a detailed study, including load information, outage data, existing backup power capability, and other specific inputs would make the cost-to-benefit ratios worse rather than better. A detailed analysis by individual substation would be needed to appropriately assess cost and benefits. Considering the level of backup power already available in a typical substation and the low incidence of loss of station power (even in storm conditions), it is unlikely that incremental benefit can be shown for additional backup generation.

Table 5-1. Emergency generator benefit estimate.

Company	# of SS	Damage rate (/yr)	Societal Benefit (/yr/site)	PV of Societal Benefits (10 yr, 10%)	Emergency Generator cost	Net Present Value
Entergy (Beaumont-Port Arthur)	378	2.65%	$387	$2,400	$20,000	($17,600)
CenterPoint & TNMP (Houston)	389	0.87%	$3,181	$19,500	$20,000	($500)
AEP (Victoria) 20%	65	0.00%	0	$0	$20,000	$0
AEP(Corpus & Brownsville) 80%	262	0.00%	0	$0	$20,000	$0

In aggregate, there are 1,094 substations in the area under consideration, 6 currently with backup generators. Therefore, the total cost to provide backup generators to the remaining is 1,088 x $20,000 = $21.8 million. The total annual benefit for the Entergy area is 378 x $387 = $146,286 per year. The total annual benefit for the CenterPoint area is 389 x $3,181 = $1,237,409 per year. The annual benefit for the AEP areas is negligible due to low substation flooding rates, resulting is a total societal benefit of $1,383,695 per year. Even with the generous assumptions used in this analysis, the broad deployment of backup generators in substations is not cost-effective.

5.2.2 Telephone Central Offices

Backup power to a telephone CO can have significant benefit during storm conditions if the utility power to the facility is lost. Assuming no other damage to the CO, backup power would allow full, continuous operation of the CO until utility power is restored. The degree of continuous telephone service provided to the community, however, is still at risk due to damage to aerial facilities in the field from trees, wind, broken poles, etc. and/or damage to underground facilities due to storm surge or flooding. Backup power at a CO is equivalent to having an electrical substation in service, available to supply service to customers if the downstream facilities are operable.

Most COs are built with emergency generation capability, either through permanently located generators or through the capability to easily connect a portable generator to the main power panel. All COs have battery systems to backup power for an initial four to eight hour period following a utility power interruption. In those cases where portable generators are the contingency to supply backup power, the telephone companies have established procedures to deploy and maintain the generators including refueling.

For the purpose of this report, an analysis of the cost and benefit of adding permanent generators to the telephone central offices is provided. This analysis assumes:

- Batteries are the only current source of backup power.
- Current CO locations have available space to accommodate installation of a generator and fuel supply.
- The incidence of utility power outage is 50% of the damage rate reported by the telephone companies.
- Avoided cost is based on reduction of CO power outage by one-half day and valued at daily GDP rate for the area.

Table 5-2 provides the cost-to-benefit calculation based on the above assumptions. As with earlier examples in this report, this is a macro level analysis based on the information provided by telephone companies on historical storm damage. It should also be noted that the information provided in this project was oriented toward damage of facilities, i.e., physical damage of a CO during a storm, with the cause of damage identified as flooding, wind, trees, etc. For the purpose of evaluating the addition of permanent generators, an issue to be further investigated is the number and duration of utility power outages the facility has experienced (see assumptions). In order to accurately evaluate cost and benefit of generator additions, the specific power outage history of each CO should be evaluated as well as the actual contribution of each facility to the area economy.

As part of the ongoing PUCT project on storm hardening, the telephone companies have filed responses to interrogatories on the subject of providing backup generators at COs. In one response[8], Verizon provided a cost of $860,000 for installation of emergency generators and fuel tanks at eight COs. Using an average cost based on this estimate results in the cost-to-benefit calculations shown in Table 5-2.

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[8] Comments of Verizon Southwest, May 30, 2006; Public Utilities Commission of Texas Project 32182, Item 56.

Table 5-2. Estimated cost-benefit for generators at COs.

Metropolitan Statistical Area	# of COs	Damage rate (/yr)	Societal Benefits ($/yr/site)	PV of Societal Benefits (10 yr, 10%)	Emergency Generator cost	Net Present Value
Beaumont-Port Arthur	20	0.50%	$2,308	$14,200	$107,000	($92,821)
Brownsville	17	2.94%	$7,768	$47,700	$107,000	($59,271)
Corpus Christi	30	0.33%	$1,591	$9,800	$107,000	($97,223)
Houston	119	0.84%	$16,663	$102,400	$107,000	($4,610)
Victoria	8	0.00%	$0	$0	$107,000	($107,000)

The number of COs in the analysis area is 194, with an estimated 80% already having a permanent back-up generator. Therefore, the cost to supply the remaining 20% with backup generators is 194 x 20% x $107,000 = $4,151,600. The annual benefit for an area is computed by taking 20% of the number of COs in the area and multiplying this number by the societal benefits. The sum of societal benefits amounts to $441,777 per year.

Although this macro analysis does not result in a positive net present value, the annual hurricane benefits of compare favorably with the program cost. However, the analysis assumes that 20% of COs do not have any backup generation capability. In reality, these COs are supported by mobile backups which currently supply most of these benefits.

5.3 Hardened Transmission Structures

This section evaluates the costs and benefits of constructing new transmission lines and/or replacing existing structures designed to meet NESC wind loading standards in effect on December 1, 2008.

The 2007 version of the National Electric Safety Code incorporated “extreme wind and ice” considerations into the loading criteria for utility structures. The NESC adopted the standards for wind loading of structures from ASCE 7-98, “Minimum Design Loads for Buildings and Other Structures” as part of the 2007 revision. Generally, these extreme wind loading requirements only apply to structures over 18 meters (60 ft.) above ground or water. As most transmission line structures exceed this height, the extreme wind loading criteria is currently required for new construction in extreme wind regions.

Electric utilities with facilities within 50 miles of the coastline have provided estimates of costs to upgrade existing lines in that region to current NESC standards. The total estimated cost for transmission tower upgrades by Entergy, CenterPoint, TNMP, and AEP (TCC) is $23 billion. The average cost per mile to upgrade is $459,000, or an average per structure of $61,000.

The same utilities provided damage information for named storms for the past ten years. The damage reports indicated that during the ten year period, a total of 1,947 transmission structures were damaged or replaced. The total cost for transmission structure repair or replacement over the ten year period is estimated at $110 million (some of the costs for the recent Hurricane Ike are not yet final). It is assumed that when a structure is replaced following a storm, it is replaced with the same class and/or strength materials. This means that the design strength of the structure does not increase.

Benefits potentially accruing from the upgrade of existing structures to extreme wind criteria are based on the probabilistic hurricane model described in Appendix A. The model simulates the number and intensity of storms that can be expected to impact the Texas coast in future years. Based on damage reports from previous storms, weather data on previous storms, and the likelihood of occurrence, the expected failure rate of structures can be modeled. By applying typical outage duration and expense to the projected failure rate, an estimation of costs avoided by less damage to the transmission lines can be made. This avoided outage cost is the estimated benefit to be measured against the cost of the structure upgrades.

Analysis of damage data from utilities and failure rate modeling produces the failure rate curve for existing structures shown in Figure 5-4.

Existing transmission structures are designed and constructed to meet NESC Grade B requirements and are therefore equivalent to a wind loading standard of 105 mph. If the structures are replaced or rebuilt to the current NESC extreme wind loading criteria, they would need to meet a wind load requirement of up to 130 mph. The failure rate curve based on 130 mph design for transmission structures is shown in Figure 5-5.

The potential benefit from using the extreme wind criteria for structure design comes from the ability of the structure to withstand stronger forces and thereby reduce outages resulting from damaged poles or line spans. There are, however, multiple variables in any storm scenario that must be considered. Falling trees and flying debris are two prime examples of elements that can damage overhead lines even if the structures are designed to withstand the wind. Additionally, the age and the maintenance of structures can have a major impact on the overall strength and ability to resist damage in storms.

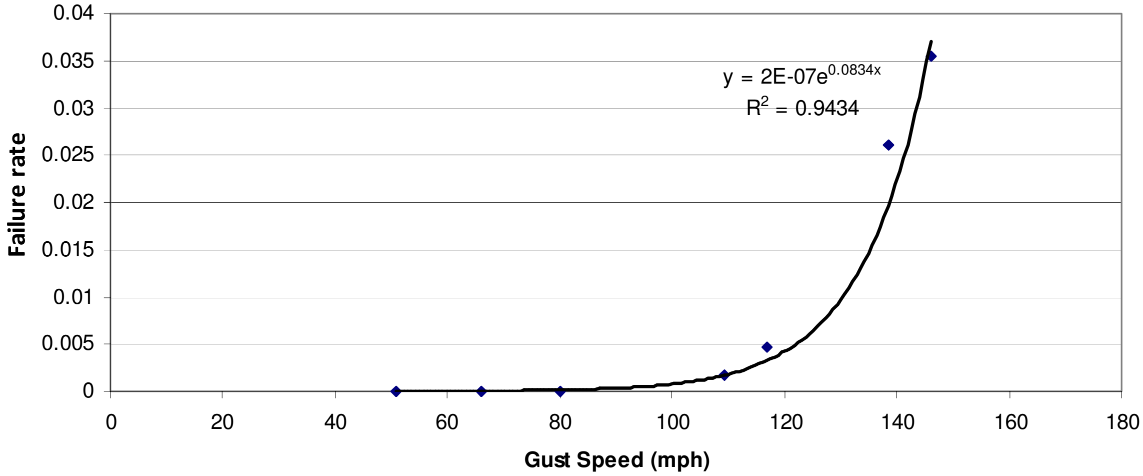

Figure 5-4. Existing transmission structure failure rate

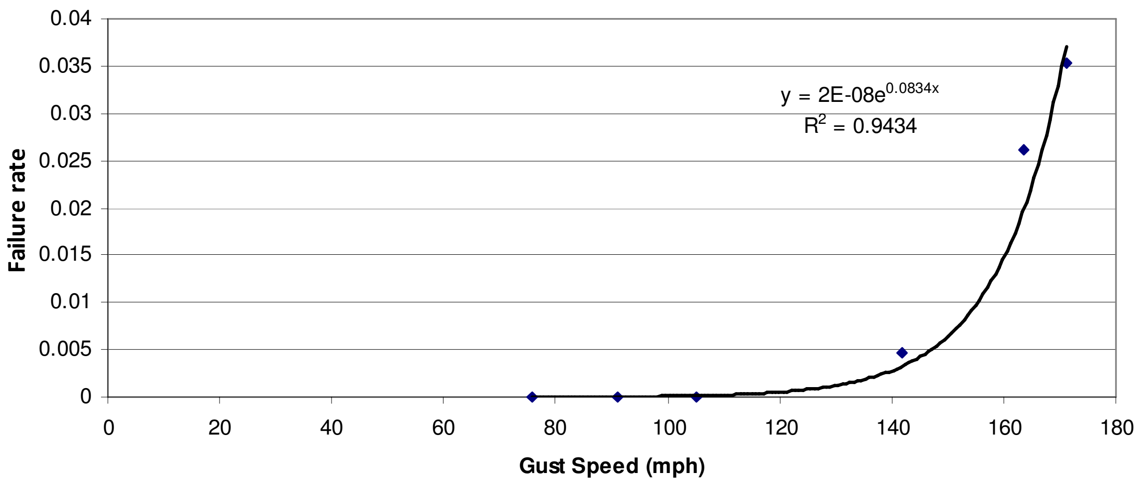

Figure 5-5. Hardened transmission structure failure rate

For analysis of the impact of upgrading structures to NESC extreme wind ratings, the following steps and assumptions were applied:

- Utility territories in the coastal region were aligned with Metropolitan Statistical Areas (MSAs) for the purpose of relating GDP losses from extended outages to specific regions.
- The number of transmission structures within the coastal region (50 miles of coast) was proportioned to the miles of transmission line reported in that region.
- Hurricane probabilities by category of storm by approximate company territory were computed from hurricane simulation model.
- An average direct cost of $60,000 per structure for restoration was applied based on the cost of upgrade provided by the utility companies. Direct costs were doubled to account for storm resto-

ration overheads and premiums. That is, the total direct and indirect cost for each damaged transmission structure is assumed to be $120,000.

- All data on line miles, structures, etc. is based on the region within 50 miles of the Texas coastline.
- Outage time reduction is based on the proportion of transmission damage to total system damage.

The base data used for the analysis is shown in Table 5-3. The detailed analysis by company for each category of hurricane is provided in Appendix D. The summary information for benefit to cost comparison is provided in Table 5-4.

As illustrated in Table 5-4, the cost to upgrade existing transmission structures to NESC extreme wind standards far outweighs the potential benefits derived from damage reduction in hurricanes, including the storm restoration costs and societal benefits. The low probabilities of storm occurrence coupled with the failure rates do not justify the expense. It is clear, however, that higher wind loading standards will result in fewer damaged structures.

A recommended approach to the application of NESC extreme wind standards is through a targeted process to determine those structures and facilities that are most important to system integrity and operation and to focus hardening efforts on those system components. This targeting hardening approach can be applied to optimize the benefit and cost ratio within a specific budget. Identification of key infrastructure that has major impacts on the extent and duration of a system outage can be conducted and addressed through targeted hardening techniques. As demonstrated by this analysis, wholesale upgrade of existing facilities is not cost-effective. It is further demonstrated that the expected benefit of hardening programs diminishes rapidly in the circumstance of category 4 or 5 hurricanes, since storms of this strength exceed the NESC extreme wind criterion for the Texas coast.

Table 5-3. Utility company data.

Utility	OH Transmission Line Miles	No. of Transmission Structures	Cost to upgrade lines to NESC Extreme Wind ($000s)	Cost per mile to upgrade ($000s)	Cost per tower to upgrade ($000s)
Entergy (Beaumont-Port Arthur)	1,450	15,660	1,064,850	734	68
CenterPoint & TNMP (Houston)	2,744	19,465	1,274,271	941	107
AEP (Victoria) 20%	477	3,559	250,400	105	14
AEP(Corpus & Brownsville) 80%	1,906	14,238	1,001,600	420	56

Table 5-4. Summary cost-to-benefit findings.

Utility	Weighted Savings Damage Reduction ($000s)	GDP Loss Reduction - Transmission ($000s)	Cost to Upgrade ($000s)	Discounted Annual Cost ($000s, 60 yrs, 10%)	Cost-to-Benefit Ratio
Entergy (Beaumont-Port Arthur)	2,050	6,060	1,064,850	106,836	131
CenterPoint & TNMP (Houston)	863	40,690	1,274,271	127,847	31
AEP (Victoria) 20%	202	620	250,400	25,123	304
AEP(Corpus & Brownsville) 80%	2,691	3,450	1,001,600	100,490	163

5.4 Non-Wood Structures for New Transmission

This section evaluates the costs and benefits of deploying particular types of utility structures, specifically wood, concrete, and steel for new construction or expansion of existing lines. The focus is on transmission structures, but distribution is discussed as well.

Transmission line structures are engineered for their specific location and application. The design criteria are multiple and include the basic elements of span length, required height or clearance, loads (mechanical, wind, ice), terrain and geology. In some applications aesthetics are the primary criteria and in all cases costs are a major issue. The use of non-wood structures is an option for the designer to consider in how to best meet all the primary objectives under consideration when designing a line. From a strength or structural integrity standpoint, the material is not the major consideration. A wood structure can be designed to be equally strong as steel or concrete for the same application.

Larger pole sizes must be used in order to achieve similar or equal strength between wood and engineered materials such as concrete or steel. The variation in strength that occurs in natural fibers (wood) as compared to engineered materials must be allowed. This allowance is a factor in NESC strength calculations. The NESC employs an overload capacity factor (OCF) of 4.0 for wood poles (Grade B construction) while concrete poles have an OCF of 2.5. This means that a wood pole must be 60% stronger, on average, to carry the same load as a concrete pole. The additional strength can only be gained through using a larger size wood pole.

For the purpose of this cost-benefit analysis, it is assumed that the wind rating of the structure is the primary design element. The NESC requirement for extreme wind loads as well as the specific company's design and engineering standards will determine what strength requirement the structure must meet. Once the mechanical and wind loads are defined, the designer must then determine how to economically meet the requirements. From an engineering perspective, the alternatives are equal: they all meet the requirements for use. The life cycle cost of the line design then becomes a primary decision element. But from a reliability or storm hardening perspective, the alternatives should be equal.

In addition to the cost data in Table 5-4, the Entergy report included some typical incremental costs for concrete and steel poles compared to wood. The incremental cost for concrete over wood was approximately $24,000 per mile, while steel carried an additional $16,000 to $39,000 per mile.[9] Recent material costs for equivalent wood, concrete, and steel structures are approximately as follows[10]:

Wood Pole, 95' H4	$ 6,500
Concrete, 105' G120	$ 8,300
Steel monopole (light duty), 90' LD8	$11,000
Steel lattice tower, 90'	$14,500

The final benefit of using one material over another is a factor of the total line design and the associated costs. The total number of structures, the design wind rating, the soil conditions and location of the structure are all variable factors in the total economic analysis that would need to be performed to determine the preferred material for a specific job.

[9] Ibid, pp 33.

[10] Moving average material (only) prices provided by CenterPoint based on no specific application or design.

Table 5-5. Approximate line costs.

Pole or Tower Type	Approximate Span (ft.)	Structures per mile	Pole or Tower Cost ($000s)	Cost per Mile ($000s)
Wood Single Pole, 95' H4	375	14	89	180
Concrete single pole, 105' G120	500	11	91	250
Steel monopole, 90' LD8	400	13	143	240
Steel lattice tower, 90' DT800	450	12	174	375

A cost-benefit analysis of the structure material alone has limited value without a specific design application or set of parameters to compare. In an effort to demonstrate generic cost differences, however, a simple study of transmission line cost per mile using different structure material has been completed. Table 5-5 provides the cost per mile of a transmission line where all parameters are the same with the exception of the structures. Each line is designed to 130 mph NESC using the same conductor, structure configuration, hardware, etc.

Because the examples above are all based on the same wind design rating, there is no significant benefit to be evaluated between the alternatives. In reality, issues of maintenance, overheads, and other elements of life cycle costs would need to be considered. For the purpose of this general analysis, however, only first costs are considered. This is an illustrative example of cost comparisons by material. A detailed cost study of a specific line design or material application would be necessary to thoroughly evaluate alternatives.

Wood poles will naturally degrade in strength over time due to wood deterioration and other factors. The NESC accounts for this deterioration by specifying the overload factor to be used to determine when pole replacement is required. For example, the 250B Grade C overload factor is 2.67 for initial installation, but is 1.33 at replacement. This implies that a fully loaded Grade C wood pole can lose 50% of its initial strength before replacement is required. Similarly, the Grade B overload factor is 4.0 for initial installation, but is 2.67 at replacement. This implies that a fully loaded Grade B wood pole can lose 33% of its initial strength before replacement is required.

To prevent deterioration, new wood poles are typically treated with decay-resistant substances. Older poles were typically treated with coal-tar creosote. Popular treatments today include pentachlorophenol ("penta") and chromated copper arsenate ("CCA"). Both creosote and penta poles will deteriorate after time, and require periodic inspections and supplemental preservative treatments to prevent excessive loss of strength. CCA poles have not generally shown signs of decay, but must still be specified assuming decay will occur (utilities may choose to periodically inspect CCA poles for reasons other than decay).

If a pole shows excessive signs of rot, it should be replaced. It the rot is less severe, it may be possible to take remedial actions. This will include removing all existing rot, fumigating the pole, and possibly filling internal cavities with a filler paste. If the pole has lost strength, it can be reinforced with an adjacent wood stub, a steel brace, or a fiberglass wrap.

In part due to deterioration considerations, some utilities are beginning to use non-wood poles for transmission structures. The following is a summary of the most viable candidates.

Spun Concrete. These poles are similar in characteristics to cast concrete, but are circular in cross-section and have a hollow interior. They are manufactured in a circular mold that is spun at a high rate so that the centrifugal force compresses the concrete against the inner wall of the mold. Spun concrete poles have the advantage of being essentially maintenance free. Spun concrete poles should be pre-drilled since they are very difficult to drill in the field.

Steel. Round steel poles are commonly used for transmission structures. Steel has an excellent strength-to-weight ratio and can be used to make very strong structures that can still be installed with standard equipment and methods. Drawbacks to steel include high price, climbability, poor electrical insulation qualities, and susceptibility to corrosion.

Composite. Composite poles are made by injecting an epoxy resin into a matrix of reinforcing fibers such as fiberglass, carbon fiber, and Kevlar. The result is exceptional strength-to-weight ratio, no susceptibility to corrosion, and good electrical insulation qualities. Manufacturers also claim that new technologies prevent deterioration due to high sun exposure. The use of composite poles is becoming more common in areas subject to woodpecker and insect damage.

5.5 Underground Distribution

The conversion of overhead electric power facilities to underground has been a topic of discussion for more than twenty years. The topic has been studied, discussed, and debated many times at the state, municipal, and local levels. A detailed assessment of publically available documentation can be found in the report *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*, submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI.

Analyses and investigations consistently find that the conversion of overhead electric distribution systems to underground is costly, and these costs are far in excess of the quantifiable storm benefits, except in rare cases where the facilities provide particularly high reliability gains or otherwise have a higher than average impact on community goals. This conclusion is reached consistently in many reports, which almost universally compare the initial cost of undergrounding to the expected quantifiable benefits. No prior cost-benefit study recommends broad-based undergrounding, but several recommend targeted undergrounding to achieve specific community goals.

As a rough estimate, the cost of converting existing overhead electric distribution lines and equipments to underground is expected to average about $1 million per mile. In addition, there are costs required to convert individual home and business owner electric service and meter facilities so they will be compatible with the new underground system now providing them with electricity. Further, there are separate, additional costs associated with site restoration and placing third-party attachments underground.

When only considering the direct utility cost of a conversion from overhead to underground, studies find that undergrounding distribution facilities in residential neighborhoods served by investor-owned utilities would cost an average of about $2,500 per residential customer affected. Undergrounding residential main-trunk feeders (those lines leading to residential neighborhoods) would cost an average of about $11,000 per residential customer affected. Undergrounding all main trunk commercial feeders (those feeding business and office areas, etc.) would cost an average of about $37,000 per commercial customer affected.

Costs in any particular situation could vary widely from these estimates depending upon electric system design, construction standards, customer density, local terrain, construction access issues, building type, and service type. Existing studies estimate the wholesale conversion of overhead electric distribution system to underground would require that electricity rates increase to approximately double their current level, or possibly more in areas with a particularly low customer density.

In return for the considerable expense, electric customers can receive a number of potential benefits from the undergrounding of their overhead systems. The following is a list of benefits most often mentioned in undergrounding reports and studies:

Potential Benefits of Underground Electric Facilities

- Improved aesthetics;
- Lower tree trimming cost;
- Lower storm damage and restoration cost;
- Fewer motor vehicle accidents;
- Reduced live-wire contact;
- Fewer outages during normal weather;
- Far fewer momentary interruptions;
- Improved utility relations regarding tree trimming; and
- Fewer structures impacting sidewalks.

There are a number of potential disadvantages which need to be considered whenever the conversion of overhead facilities to underground is evaluated. The following is a list of potential disadvantages most often mentioned in undergrounding reports and studies:

Potential Disadvantages of Underground Electric Facilities

- Stranded asset cost for existing overhead facilities;
- Environmental damage including soil erosion, and disruption of ecologically-sensitive habitat;
- Utility employee work hazards during vault and manhole inspections;
- Increased exposure to dig-ins;
- Longer duration interruptions and more customers impacted per outage;
- Susceptibility to flooding, storm surges, and damage during post-storm cleanup;
- Reduced flexibility for both operations and system expansion;
- Reduced life expectancy
- Higher maintenance and operating costs; and
- Higher cost for new data bandwidth.

The amount of overhead distribution within 50 miles of the Texas coastline is 28,263 miles. Assuming an average underground conversion cost of $1 million per mile, the total conversion cost for this area amounts to an initial cost of $28 billion. Assuming a 40 year life for underground facilities and a 10% discount rate, this amounts to an annual cost of $2.9 billion per year.

The average total electric facilities restoration cost of hurricanes over the last ten years for Texas is $180 million per year. The total societal cost of hurricanes is estimated at $122 million per year (see Appendix B). Even if undergrounding eliminated all electric system damage and eliminates all societal cost (neither close to true), underground conversion is not even close to being cost-effective. These results are similar to other analyses that have been done in other states.

Underground conversion can actually be detrimental in areas subject to storm surge damage. Overhead distribution facilities are generally much faster to repair compared to underground equipment that has been flooded, eroded away, or otherwise damaged by storm surges.

Undergrounding of new facilities is potentially cost-effective, provided the location is not subject to storm surge, depending upon the cost differential of overhead construction versus underground. A typical distribution structure costs about $4000 to replace during hurricane restoration. The failure rate of poles can be approximated by the following equation:

Wood Pole Failure Rate = 0.0001 x exp(0.0421 x W)

W is sustained wind speed in miles per hour.

This equation is explained in the report *Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling*, submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI.

Using these assumptions, the cost per year in restoration costs can be computed for each of the hurricane prone areas. This analysis is shown in Table 5-6. The highest annual expected restoration cost is $1.69 for the Corpus Christi area. Assuming a wood pole life of 60 years and a discount rate of 10%, this amounts to a present value of about $16.85. With 40 distribution poles per mile, this amounts to $674 per mile. Therefore, installing new facilities underground is worthwhile if the incremental cost per mile is less than $674 per mile. This amount will vary based on region and distribution span length, but in any case will be small as a percentage of total construction cost since typical new overhead distribution facilities cost between $100,000 and $200,000 to construct.

Greater societal benefits will not result from hardening of new facilities since the percentage of hardened facilities is small and total storm restoration time is not likely to be affected.

Although the undergrounding of new distribution may not be justified purely on reduced hurricane damage, underground may be desirable for other reasons. If the primary issue is hurricane damage, hardening the overhead design may be more cost-effective. For example, a Class 1pole is 50% stronger than a Class 5 pole, but typically only costs about $200 more. At 40 poles per mile, this amounts to $8000 per mile for a much stronger system. Because of these economics, some utilities in hurricane-prone areas design their distribution systems to Grade B construction rather than Grade C.

Table 5-6. Annual restoration cost of wood distribution poles.

	Hurricane Category					
	1	2	3	4	5	
	Annual Probability of Occurrence					
Beaumont-Port Arthur	4.45%	1.18%	0.38%	0.11%	0.01%	
Brownsville-Harlingen	1.61%	0.30%	0.08%	0.01%	0.01%	
Corpus Christi	4.34%	1.09%	0.42%	0.09%	0.07%	
Houston-Sugar Land-Baytown	3.54%	0.83%	0.17%	0.03%	0.00%	
Victoria	3.87%	0.75%	0.37%	0.03%	0.00%	
Sustained wind speed (mph)	84.5	103	120.5	143	168	
Failure rate	0.35%	0.76%	1.60%	4.12%	11.79%	
	Annual Restoration Cost ($/yr)*					Total ($/yr)
Beaumont-Port Arthur	0.62	0.36	0.24	0.18	0.05	1.46
Brownsville-Harlingen	0.23	0.09	0.05	0.02	0.05	0.43
Corpus Christi	0.61	0.33	0.27	0.15	0.33	1.69
Houston-Sugar Land-Baytown	0.50	0.25	0.11	0.05	0.00	0.91
Victoria	0.54	0.23	0.24	0.05	0.00	1.06

* -Annual restoration cost is equal to the restoration cost per structure ($4,000) multiplied by the failure rate multiplied by the probability of occurrence. For example, the annual restoration cost in Beaumont-Port Arthur due to Category 1 hurricanes is $4,000 x 0.35% x 4.45% = $0.62 per year.

In terms of total conversion, there are 28,263 miles of overhead distribution within 50-miles of the Texas coast. At $1 million per mile, total overhead to underground conversion is estimated to cost $28 billion. Assuming that 70% of hurricane damage is eliminated (80% is due to distribution), annual reductions in utility restoration costs are $126 million and annual societal benefits are $85.4 million.

5.6 Underground Transmission

Underground transmission is extremely expensive. New underground transmission is roughly ten times the cost of overhead, and presents other technical challenges due to the high phase-to-ground capacitance. Hardening existing transmission structures has already been examined in Section 5.3, and has been shown to not be cost-effective. New transmission is already required to be built to NESC extreme wind criteria. Therefore, any incremental benefit in moving from an extreme-wind-rated overhead transmission design to underground will be minimal, although the additional cost will be substantial.

Using the hardened transmission failure rate assumptions represented in Figure 5-5, the cost per year in restoration costs can be computed for each of the hurricane-prone areas. This analysis is shown in Table 5-7. The highest annual expected restoration cost is $25.18 for the Corpus Christi area. Assuming a transmission structure life of 60 years and a discount rate of 10%, this amounts to a present value of about $251. With 10 transmission structures per mile, this amounts to $2510 per mile. Therefore, installing new transmission facilities underground is worthwhile if the incremental cost per mile is less than $2510 per mile. This amount will vary based on region and transmission span length, but in any case will be small as a percentage of total construction cost since typical new overhead transmission facilities cost $1 million per mile or more.

Table 5-7. Annual restoration cost of wood transmission poles.

	Hurricane Category					
	1	**2**	**3**	**4**	**5**	
	Annual Probability of Occurrence					
Beaumont-Port Arthur	4.45%	1.18%	0.38%	0.11%	0.01%	
Brownsville-Harlingen	1.61%	0.30%	0.08%	0.01%	0.01%	
Corpus Christi	4.34%	1.09%	0.42%	0.09%	0.07%	
Houston-Sugar Land-Baytown	3.54%	0.83%	0.17%	0.03%	0.00%	
Victoria	3.87%	0.75%	0.37%	0.03%	0.00%	
Sustained wind speed (mph)	84.5	103	120.5	143	168	
Failure rate	0.12%	0.13%	0.77%	8.74%	34.64%	
	Annual Restoration Cost ($/yr)					**Total ($/yr)**
Beaumont-Port Arthur	3.20	0.92	1.76	5.77	2.08	13.73
Brownsville-Harlingen	1.16	0.23	0.37	0.52	2.08	4.37
Corpus Christi	3.12	0.85	1.94	4.72	14.55	25.18
Houston-Sugar Land-Baytown	2.55	0.65	0.79	1.57	0.00	5.55
Victoria	2.79	0.59	1.71	1.57	0.00	6.65

* -Annual restoration cost is equal to the restoration cost per structure ($60,000) multiplied by the failure rate multiplied by the probability of occurrence. For example, the annual restoration cost in Beaumont-Port Arthur due to Category 1 hurricanes is $60,000 x 0.12% x 4.45% = $3.20 per year.

Like the case for distribution, greater societal benefits will not result from hardening of new facilities since the percentage of hardened facilities is small and total storm restoration time is not likely to be affected.

In terms of total conversion, there are 6,577 miles of overhead transmission within 50-miles of the Texas coast. At $5 million per mile, total overhead to underground conversion is estimated to cost $33 billion. Assuming that 15% of hurricane damage is eliminated (20% is due to transmission), annual reductions in utility restoration costs are $27 million and annual societal benefits are $18.3 million.

5.7 Targeted Storm Hardening

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 extreme wind speed.

There are four primary motivations for targeted storm hardening:

Primary motivations for targeted storm hardening

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.

There are a variety of ways to reduce the probability of a structure failing in a hurricane. Not all tactics are possible in all situations, but the following describes the major available approaches:

Stronger Structures. Structure strength is one of the most important factors for extreme wind rating. This is true for new construction, where stronger structures allow for longer spacing between structures, and upgrading of existing construction, where extreme wind ratings can be increased by upgrading existing structures with stronger structures. When selecting a structure, there are several important factors that must be considered. These factors include weight, visual impact, wind performance, insulating qualities, corrosion, and climbability.

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.

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 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 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 removes extreme wind as a design factor. This is almost always more expensive than bringing the overhead system up to extreme wind ratings.

Increased performance expectations for major storms will result in certain utilities choosing to exceed safety standards in an effort to reduce storm damage. This decision to harden the system is potentially expensive. 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.

Cost-to-Benefit of Targeted Hardening of Transmission

For cost-to-benefit calculations, it is assumed that utilities harden 5% of transmission structures at a cost of $60,000 per structure. This amounts to 40,000 hardened structures at a cost of $2.4 billion. Historically, transmission has amounted to about 20% of restoration costs, or about $36 million per year. It is assumed that each of the hardened transmission structures previously contributed to proportionally five times more to restoration times than typical structures. Therefore, the estimated savings in utility restoration costs is $36 million x 25% = $9 million per year.

The societal cost of hurricanes is estimated to be $122 million per year, with about 20% due to transmission damage. Therefore, the estimated societal benefits of targeted transmission hardening is $122 million x 20% x 25% = $6.1 million per year.

Since Entergy Texas has experienced high transmission structures in several Hurricanes, a separate cost-to-benefit analysis is warranted. Entergy Texas has 27,000 transmission structures. Hardening 5% of these structures at $60,000 per structure will cost $81 million. With an expected life of 60 years and a discount rate of 10%, $81 million is equal to $8.13 million per year for sixty years.

It is assumed that targeted hardening can reduce transmission damage at Entergy Texas by 50%. The average transmission damage to Entergy Texas since 1998 is $13.5 million per year, resulting in estimated restoration savings of $6.8 million per year. Societal cost of hurricanes in the Beaumont-Port Arthur MSA is $6.15 million per year. Transmission accounted for 14% of Entergy Texas restoration costs. Assuming that targeted hardening can reduce total restoration time by 7% results in a societal benefit of $430,500 per year.

Based on this analysis, targeted hardening of the Entergy Texas system is potentially cost-effective and should be investigated in more detail.

Cost-to-Benefit of Targeted Hardening of Distribution

For cost-to-benefit calculations, it is assumed that utilities harden 10% of distribution circuits and 10% of poles within these targeted circuits. This amounts to 160,000 hardened distribution poles. At an assumed $2,000 per hardened pole, this amounts to $320 million. With an expected life of 40 years and a discount rate of 10%, $320 million is equal to $33 million per year for forty years.

Historically, distribution has amounted to about 80% of restoration costs, or about $144 million per year. It is assumed that each of the hardened distribution poles previously contributed to proportionally ten times more to restoration times than typical poles (including higher failure rates and higher impact to repair times). Therefore, the estimated savings in utility restoration costs is $144 million x 10% = $14.4 million per year.

The societal cost of hurricanes is estimated to be $122 million per year, with about 80% due to distribution damage. Therefore, the estimated societal benefits of targeted distribution hardening is $122 million x 80% x 10% = $9.8 million per year.

This high-level analysis estimates a cost of $33 million per year and benefits of $14.4 million + $9.8 million = $24.2 million. This analysis has used many broad assumptions that will vary by utility and by region. For example, the societal benefits for the Houston area are higher in absolute terms than the Brownsville-Harlingen area. By its very nature, targeted hardening avoids broad assumptions, performs detailed analyses to find the most cost-effective way to spend hardening dollars, and will only spend money when it is deemed cost-effective. Therefore, targeted hardening for distribution is cost-effective by definition, but may involve more or less hardening than the assumed 1% of current distribution poles.

6 Technology Impact

This section evaluates the impact that changes in technology would have on electric service restoration following a hurricane. This includes transmission technologies, distribution technologies, communications, advanced metering, and systems that allow all of these technologies to work together.

6.1 Background

Recognizing that technologies could help in reducing the restoration times after a storm hits, the PUCT has opened a filing that essentially asked utilities this very question in 2006.[11] Responses indicated a wide array of technologies. This section presents the technologies that could be used to reduce the restoration time after a major storm and an estimate of the potential impacts for the Texas utilities.

These technologies usually involve automation, computers, and communications. They cover the transmission, distribution, and customer sectors. They comprise what is currently loosely labeled as smart grid technology solutions. In order to support these solutions, as is common in smart grid, there is a need for enabling technologies. But quantifying the benefits of each of such enabling technologies is often difficult. However, they do enable the realization of benefits as provided by each of these smart grid applications.

6.2 Technologies for Transmission

6.2.1 Phasor Measurement Units

As reported in Entergy's response to PUCT's Filing #32182, a Phasor Measurement Unit (PMU) system was able to forewarn Entergy of a pending islanding problem. Entergy reported that it avoided an islanding problem because of what they observed from their PMU data during Hurricane Gustav. Indeed, PMUs can provide a time-synchronized snapshot state of the power system every 1/30th of a second. The availability of such synchronized state data is made possible because of the GPS clock technology, albeit somewhat expensive. The data collected by the PMUs are continuously sent back to the central processing unit at system control centers. Monitoring the data streams and analyzing them with different data mining methodologies, system operators will be alerted of imminent system security or instability problems. This will give sufficient time for operators to respond to such incipient problems.

With a typical Energy Management System (EMS), utilities receive data on the system state every few seconds via Remote Terminal Units (RTUs). However, the latency of a few seconds is usually too long for system dispatchers to respond to fast moving grid instability events. In addition, because of time skew problems, the data from various points are not synchronized to give an accurate snapshot of the system state. PMUs can provide data at a much faster rate, which can then be processed by systems (e.g., Wide Area Monitoring, Protection and Control Systems, or WAMPACS) to provide information on pending

[11] PUCT opened a filing #32182 in 2006 to request all utilities of the possible utilization of technologies in combating the storm restoration problem.

contingencies of the power grid and even suggest remedial actions for system operators. It is this fast responding capability that helped Entergy avoid a major islanding event.

This same capability can also evaluate and select the appropriate system restoration schemes as the grid is restored. As a result, the chance of executing an inappropriate grid restoration scheme is minimized. Any prolonged restoration time will be reduced. The reduction is estimated to be 3% to 5% of the normal restoration time in the absence of such PMU systems because this system would optimize the restoration scheme. This translates into about 3-5 hours reduction of an average restoration time of 3-4 days for restoring service to 95% of the customers after a major hurricane.[12]

6.2.2 Automatic Fault Location

By monitoring and analyzing the real-time voltage and current data from metering devices (e.g., Intelligent Electric Devices, IEDs, at substations) throughout the grid, a data mining engine at the EMS master can determine where a fault is probably located on the grid. This application leverages the existing EMS communications infrastructure to allow for this data retrieval. IEDs monitor voltage and current values at selected transmission substations. These IEDs are primarily protective relays, but they also monitor all these grid parameters on fine time intervals (e.g., 5-second intervals) that are amenable to signature analyses to detect faults on the system. Such data is transmitted back to the EMS master at the control center via the communications infrastructure (e.g., digital microwave).

Another technology solution is to install faulted circuit indicators (FCIs) along transmission lines. These FCIs are equipped with communications frontend, which can communicate over a public or private wireless radio frequency (RF) network to send the status data back to the system control centers. In so doing, system dispatchers will know instantly where a fault is if it happens. Dispatchers will also know as service is restored, whether a general area has been restored or not. This could shorten the restoration time somewhat since utilities do not need to send patrol crews to ascertain whether the service at a certain area has been restored or not. The impact is not major since utilities usually know which transmission regions experience service interruptions.

[12] Data obtained from a report prepared by Keys Energy Services: "*Storm Preparedness Implementation Plan, Keys Energy Services - Key West," June 1, 2006*

6.3 Technologies for Distribution

The bulk of the technologies for distribution systems is focused on distribution automation – a set of core smart grid technologies. Such technologies include the following:

- **Fault Location, Isolation, and Service Restoration (FLISR) –** This function uses remote-controlled feeder switches equipped with appropriate sensors and fault indicators to automatically isolate the faulted feeder section and quickly (within a couple of minutes) restore service to customers that are served from healthy (unfaulted) sections of the feeder.
- **Remote Monitoring of FCIs –** Faulted Circuit Indicators (FCIs) mounted at various locations along distribution feeders can provide indications of "downstream" fault conditions when monitored remotely via communication infrastructure. This is especially useful when the detected fault is displayed in an electrical network model (tied to a GIS system) so that operators can immediately see the location of faults.
- **Remote Activation of "Fuse Saving" –** This function allows system operators to remotely activate the "fast curve" in the substation feeder breakers so as not to burn out fuses at the branch circuits in stormy conditions where momentary outages (e.g., tree branches falling on and off the circuits) occur frequently.
- **Feeder Load Balancing –** Peak load on some substations may be reduced by automatically and remotely transferring load to adjacent feeders served by the same or other substations. This function involves conducting load flow studies using the real-time monitored load data at various locations along feeder lines and substations to determine the optimal load switching scheme among feeders. Through this smart grid application, utilities can determine the optimal scheme for re-energizing customers by taking into account the available feeder capacity on a real-time basis and what end-use loads can be controlled via the AMI-based demand response programs.
- **Distribution Management System (DMS/SCADA System) –** Implementing DMS is an enabler to the above-listed applications and to others. It provides the over-arching visibility and controllability of the entire distribution system. Through sensors and controllers that communicate over a communications infrastructure with the computer master, the DMS operators can have a real-time view of the entire distribution system and decide how to best restore services through the switch order management. That will help reduce the time to restore services to customers.

These applications are built upon a system architecture configuration as shown in Figure 6-1. This figure shows what a utility ideally should have for implementing smart grid. For shortening the service restoration time after storms, the focus will be on the distribution system. The above listed applications need this integrated technology solution. The DMS/SCADA system will oversee and control essentially all the major control (e.g., switches and reclosers) and monitoring devices at substations and along distribution lines, whether overhead or underground. A master DMS/SCADA computer would be located at a district control center, which communicates with RTUs or data concentrators at substations, and with line control and monitoring devices along distribution lines over a wide area network (WAN) that could utilize point-to-point or point-to-multipoint communications (e.g., power line carrier communications, 900 MHz multiple address radio, IP-addressable meshed radio network or WiMax to access the Internet). The master computer would have the following application software:

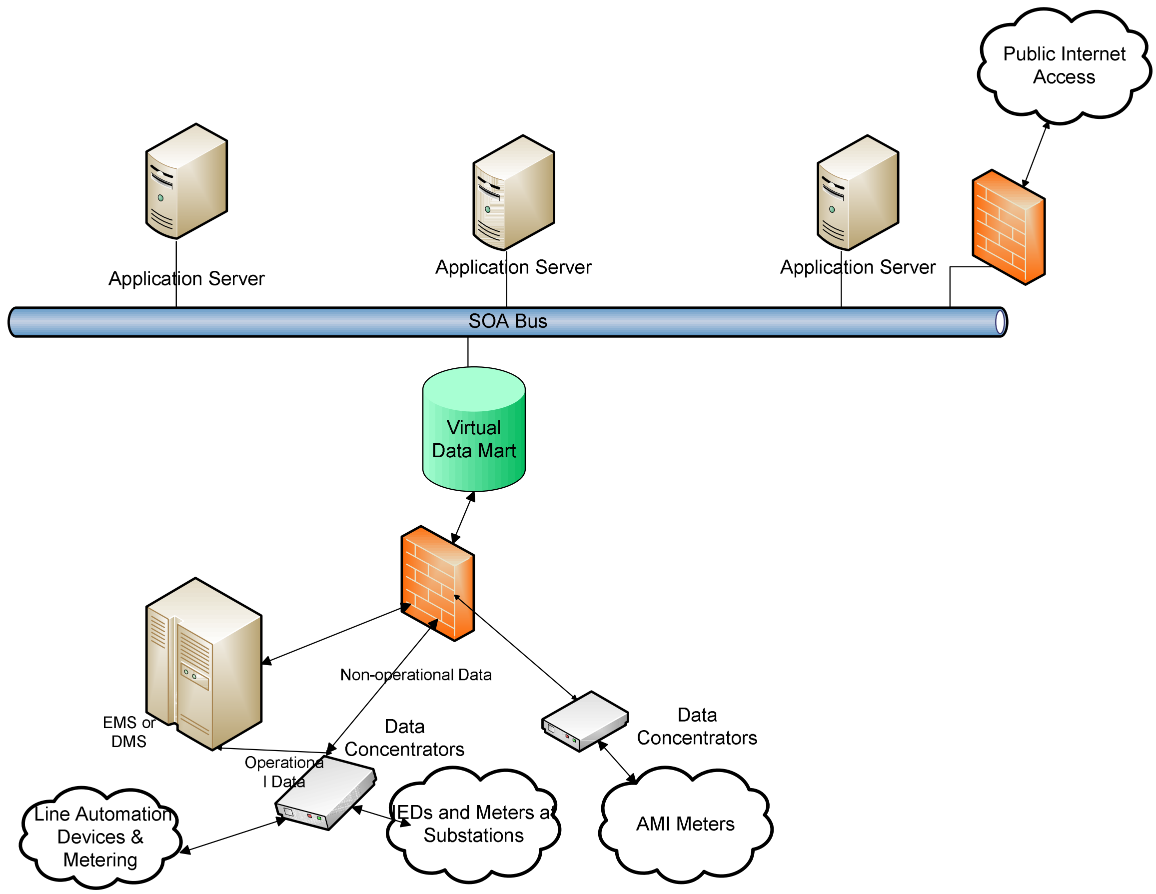

Figure 6-1. System Architecture for An Integrated Data Management System

Master Station Application Software

- Switch order management so that a switching plan can be developed based on the circuit connectivity data and service restoration criteria (e.g., critical loads or critical care customers). This switching plan will be transmitted to Work Management Systems at the business system to generate work orders.
- Circuit network model to be maintained for currency in circuit connectivity configuration so that operators can run load flow studies to determine the optimal switching plan. The optimal switching plan can thus be developed to accelerate service restoration.
- Monitor the status of different line switches, tie switches and reclosers to know whether the FLISR function is operating properly, based on local intelligence. Should the system operator decide that there is a better scheme than what the local intelligent FLISR devices are doing, the system operator can override their local operations. Thus FLISR could quickly restore services, while this system's view reduces the likelihood of entering into a major regional system fault situation, thus reducing the overall restoration time.
- Monitor the state of remotely monitored FCIs along distribution lines to be alerted of the fault status at different line and cable sections. This will quickly allow dispatchers to dispatch field crews to check out faults and administer repairs accordingly.

- Remotely activate the fast-curve feature at circuit breakers for feeders at substations. This is accomplished through remote SCADA monitoring and control of these CBs. Through a coordinated effort of this application and service restoration function by the crew, while the tree branches may be momentarily falling on the lines, customers on fused circuit laterals will not have to experience service interruptions due to blown fuses. This will speed up the service restoration process.
- Optimize the use of feeder load capacities in restoring services by using the FLISR function to offload sections of the circuit to neighboring feeders that have the accommodating load diversity, and then restoring the remaining feeder load. This will reduce the restoration time compared with the option of restoring the entire feeder load the supply resource might be limiting. This will be even more effective if demand response or distributed generators, as supported by the AMI system, are integrated into this dispatch.

In the field, a communications infrastructure will cover the entire distribution system from master station to substations and along feeder lines. Two types of communications technologies will be in place: peer-to-peer communications and point-to-point or point-to-multipoint systems. The former is set up for the FLISR function, which is a local intelligence application. Its operation involves groups of switches, reclosers and circuit breakers that form an intelligent local area network (LAN). Each device has communications frontend and firmware. Such devices would communicate over this peer-to-peer communications network (usually relatively short distance of about a mile or so) to decide among themselves how a collection of feeder sections should be optimally switched in case of faults. Each group does not rely on directives from the central master DMS computer, though the group would be linked to the master computer so that the system operator knows what these FLISR groups are doing. This peer-to-peer communication could be a meshed radio network. The communications protocols would tend to be an industry standard (e.g., DNP 3.0) to facilitate integration with a variety of vendor products.

The other communications technology is point-to-point or to multi-point design. This is of the more classical hub-and-spoke type architecture for the field devices to communicate with a data concentrator at a substation, which in turn would communicate with the master computer at a control center through backhaul communications. Alternatively, the field devices could communicate directly with the master computer.

All the field devices have monitoring and control capabilities. They are also equipped with communications interface frontends so that they can communicate with other system components or field devices.

With all these distribution automation functions, it is expected that about 10-15% of the system restoration time can be reduced during non-hurricane conditions. These functions quickly identify where the faults are without the need for patrolling rather hazardous areas after storms. In the case of faults, FLISR could restore services almost instantly at locations where FLISR could work. The bulk of the restoration time is spent on scheduling the properly trained crews and executing the repair work with the right parts.

6.4 Customer Sector Applications

6.4.1 AMI System

The proliferation of Advanced Metering Infrastructure (AMI) systems opens up the possibility of helping assure that all customer services are restored. What usually happens is that a utility might have restored services to customers served by main feeders and majority of the branch laterals. Perhaps a lateral might have been missed and those customers still experience service interruptions. Usually a utility may not be aware of the issue until customers call about their continuing service interruption. Only then are their services restored. This unnecessarily prolongs the system restoration time.

If the utility has installed an AMI system, it will have the capability to "ping" each customer's smart meter remotely to ensure that their services are restored. By incorporating this step into their service restoration process, a utility could reduce its total (100%) system restoration time. That reduction could be as high as 25% of the total restoration time during normal conditions, depending on the utility's procedures for service restoration.

An AMI system involves smart meters at customer premises. These smart meters are capable of monitoring interval load data (e.g., 15-minute intervals) and service continuity. They have a communications frontend that provides two-way communications capability with the headend computer at utility headquarters. Thus every customer is connected to the utility company. The status on service continuity can be remotely monitored by the utility at the MDMS (Meter Data Management System) at the utility operations centers. The MDMS would be linked to the Customer Information System (CIS) and the Geographical Information System (GIS) to show where the meters are located and electrically connected, using connectivity data from a DMS.

In addition to meter reading, a smart meter can perform other functions. A smart meter could be equipped with a Zigbee chip to allow it to communicate with different end-use loads on customer premises to shift peak load to other times (e.g., demand response programs). It can also monitor and report service disruptions and service thefts. It can also be part of a Home Area Network (HAN), which would display all the information for customer energy management use. If one adds some software to the smart meter, one can change the meter to be a smart controller within the customer premise to manage the use of customer-owned generation (e.g., rooftop solar PV), battery storage (or flywheel storage), PHEV's batteries, intelligent end-use appliances, and electricity from the grid, which is priced differently each hour. The AMI system infrastructure would deliver the hourly energy price data to the smart controller. The smart controllers would manage the energy use accordingly. The same AMI system infrastructure would deliver a signal to "ping" the meters. The meters' responses would tell the operations center whether they are "alive" or not.

The AMI system infrastructure involves access communications system – from meters to data collectors, and backhaul communications – from data collectors to the headend master system at the operations center. Access communications could be delivered by two-way wireless technologies such as GPRS cellular, WiMax and meshed radio networks, and terrestrial ones such as fiber optics and BPL. Backhaul communications could be delivered by technologies such as digital microwave, fiber optics, frame relay and satellites.

Because AMI systems are dependent on communications infrastructure, their effectiveness is compromised if communications is unavailable. Thus, the impact of this technology on shortening restoration time – the ability to ping meters to assure service restoration – is diminished if the storm also damages the communications infrastructure. In addition, its impact further depends on the metrics used to measure system restoration time. If the metrics are defined as total (100%) system restoration time, then the AMI system can play a very major part in ensuring the last customer is restored. But if the metrics are 95% of customers restored, the AMI system would have minimal impact on the system restoration time.

6.4.2 Distributed Generation

Distributed generation (DG) is defined as small sources of generation connected to the utility distribution system. Commercial and industrial customers may have relatively large DG units, but smaller units are becoming more popular at residential sites (e.g., solar panel, small wind turbines). DG can be owned both by customers and by utilities.

When penetration is small, DG does not pose a large problem for distribution system. When penetration becomes greater than 10% to 15% of peak load, Smart Grid technologies become necessary to avoid system problems. Therefore, Smart Grid technologies, among other things, can be considered an enabler of widespread DG deployment. This is likely to become a critical issue as more people begin to purchase plug-in hybrid electric vehicles (PHEVs), where two PHEVs is equivalent to adding an additional house to the utility distribution system.

With Smart Grid technologies, DG has the potential to restore customers more quickly after a hurricane strikes. This is accomplished by creating an "electrical island" where DG units completely supply the island load without any connection to a utility supply. These benefits will increase with the severity of the hurricane. For example, a Category 5 hurricane can completely destroy an overhead utility system. A neighborhood with underground distribution and sufficient DG may be able to be restored in days, even though the normal utility connection is not restored for weeks.

6.4.3 Net Zero Energy Buildings/Communities

As described in the prior section, customers are beginning to strive to be self sufficient with regards to energy. They could install solar photovoltaic (PV) systems at their rooftops, locate flywheel or battery storage in their basements, purchase PHEVs, install intelligent appliances (e.g., refrigerators, dishwashers, clothes washers and dryers), and participate in demand response programs (e.g., real-time pricing) through the smart meters in their homes. The smart meters, with the aid of smart controllers and in-home displays, will optimize the energy use and minimize the energy bill. Depending on the electricity prices at a certain hour, the controllers may decide to let the solar PV charge up the flywheel storage, and then when the electricity price is low from the utility company (usually in the evening) the PHEV battery is charged. All these energy management schemes could result in a situation that the customers do not need to purchase electricity from the grid and thus become "net zero energy customers." In some situations, a number of customers could band together electrically to form a "net zero energy community."

This technology may seem far away in the future. But other parts of the world are adopting this concept. For instance, Abu Dhabi is building such a "net zero energy city" called Masdar City[13]. Essentially independent of the central grid, such a city would have its supply resources right at the load centers. Through intelligent energy management systems and utilizing renewable resources, storage technologies, energy efficient building design and infrastructure to support electric vehicles, such a community would have a shorter service restoration time after a storm. There is less dependence on a central supply point, and thus less exposure to a large-scale service disruption. At the same time, the dispersed nature of supply resources also makes it easier to restore services and thus shorter restoration time for the majority of the customers. This technology could reduce the restoration time by as much as 90%.

6.5 Communications Technologies

Communications technology is the major enabler of all these above-mentioned smart grid applications. Damage to communications will diminish the ability of those smart grid applications to shorten service restoration time. Two technologies should be considered: satellite communications and GPS (Global Positioning System).

6.5.1 Satellite Communications

Satellite communications is less dependent on the terrestrial structure. As a result, it would result in less coverage loss than the terrestrial telecommunications systems. This is especially so if the satellite base stations are located outside of the storm surge areas and even the 50-mile strip to the coastline. In a hurricane, cellular towers, microwave towers, and poles with the telecommunications attached devices are highly vulnerable to damages. Satellite communications have much fewer structures; the communications transponders are located in space. Therefore, the satellite communications infrastructure is less affected by storms.

By employing satellite communications during the system restoration time, utilities will be assured of better and more extensive coverage with their field crews. This should shorten the system restoration time, which could be in the order of 5-10% of the restoration time during normal conditions.

6.5.2 GPS Tracking System

Using a GPS Tracking System allows utilities to know where their field crews are during a storm restoration process, where situations could become quite chaotic. This is especially critical when utilities have to schedule a large fleet of crews, some from mutual assistance programs, and direct them to go to locations where the crews are not familiar or the roads do not have streetlights. In most utilities, their trucks are usually equipped with GPS. To be able to bring all these internal and external trucks under one system and track them can reduce the restoration time, especially when they also have Logistics Management and Work Scheduling System, as part of the enterprise Work Management System. The benefits could translate into 20% reduction in restoration time during normal conditions.

[13] http://www.masdar.ae/en/home/index.aspx. Masdar Initiative is a bold vision launched by Abu Dhabi to build the first carbon neutral city in the world.

6.5.3 Communications Restoration

There are a wide variety of communications possibilities for Smart Grid, and it is not possible to discuss the hurricane issues of each in this report. However, communications is critical for the operation of a Smart Grid. After a hurricane, traditional restoration plans focus on the restoration of utility service to customers. With Smart Grid, full realization of hurricane benefits requires an additional restoration plan for the damaged communications systems. It may be beneficial to initially focus on the restoration of communications so that the Smart Grid functionality can be used during power restoration. In any case, the power restoration plan and communication restoration plan should be carefully coordinated.

6.6 Logistics Management and Work Scheduling System

During a storm, to be able to track who is doing what, who is qualified and trained to do what, where the parts are, where the crews are, and who needs rest, etc. is a critical task. Having a back office system that can perform these functions is critical. Such a system can be called Logistics Management and Work Scheduling System, which would include the following applications:

- Track crews and trucks
- Spare parts inventory management
- Expertise matching and scheduling
- Work management (generate work orders and track their progress)
- Workforce management
- Resource management

Such a system will have to interface with the GIS (Geographical Information System) and CIS (Customer Information System). When the work order is issued, it will contain the customer information and the asset data, and a vector map for the asset in question. In so doing, the Mobile Data Terminals, with the GPS tracking system, will be able to receive the work orders. The crew will also be able to upload the status of the work order when done, including the as-built drawings of the asset in question. That will make the restoration work flow that much more smoothly, and in the process reduce the restoration time.

As indicated above, this technology could reduce the restoration time by 20% during normal conditions.

It should be noted that restoration benefits are not additive. The total benefit in terms of percent reduction will be less than the sum of each technology evaluated separately.

6.7 Impacts of Technologies on System Restoration Time

The expected impact of six key smart grid technologies has been estimated as a percentage of restoration time reduction. Percentages are shown in Table 6-1. These percentages are best guesses, but could vary widely based on the type of hurricane damage, the damage to communications infrastructure, and other factors. For example, many hurricanes will not cause significant transmission damage beyond what the system is designed to accommodate. In these situations, there is very little benefit attributable to PMUs. In contrast, some storms may result in electrical separation of the bulk power system, in which case the availability of PMUs will be beneficial.

Appendix B describes the annual GDP due to hurricanes of each category. For example, Category 1 hurricanes results in an average of $75.11 million per year in lost GDP. Technology benefits are computed based on expected reductions to these values. These benefit calculations are shown in Table 6-1.

Societal benefits range from $0.61 million per year for PMU deployment to $16.9 million for distribution automation and related functions. These benefits assume that the technologies are deployed fully along the entire Texas coastline, and are integrated into a comprehensive Smart Grid system. Benefits for individual stand-alone systems will be less.

The benefits shown in Table 6-1 are societal benefits and do not necessarily translate into reduced direct restoration costs for the utility. The same amount of damage will still be incurred, perhaps more since the advanced technologies might also be damaged. Even the societal benefits are not enough in themselves to fully justify these technologies. However, advanced technologies are deployed for a variety of reasons and it is appropriate to consider these societal benefits when examine total benefits.

Table 6-1. Hurricane Benefits of Smart Grid Technologies.

	Hurricane Category					Total
	1	2	3	4	5	
	Reduction in restoration time					
PMU	0.5%	0.5%	0.5%	0.5%	0.5%	
Automatic Fault Location	1.0%	1.0%	1.0%	1.0%	1.0%	
DA, DMS, FLISR, FCI, Fuse Saving, Feeder Load Balancing	15.0%	13.0%	11.0%	9.0%	7.0%	
AMI System	10.0%	8.0%	6.0%	4.0%	2.0%	
20% DG penetration	10.0%	12.0%	14.0%	16.0%	18.0%	
GPS, MDT, Advanced Logistics & Work Scheduling System	5.0%	5.0%	5.0%	5.0%	5.0%	
Total lost GDP ($M/yr)	75.11	29.50	13.15	3.65	0.66	122.08
	Societal Benefits ($ millions per year)					
PMU	0.376	0.148	0.066	0.018	0.003	0.61
Automatic Fault Location	0.751	0.295	0.132	0.036	0.007	1.22
Total for Transmission Technologies						**1.83**
DA, DMS, FLISR, FCI, Fuse Saving, Feeder Load Balancing	11.267	3.835	1.447	0.328	0.046	16.92
AMI System	7.511	2.360	0.789	0.146	0.013	10.82
20% DG penetration	7.511	3.540	1.841	0.584	0.119	13.60
GPS, MDT, Advanced Logistics & Work Scheduling System	3.756	1.475	0.658	0.182	0.033	6.10
Total for Distribution Technologies						**47.44**

7 Conclusions

Hurricanes can cause significant damage to utility infrastructure, resulting in large restoration costs for utilities (ultimately borne by customers) and further societal costs due to reduced economic activity. Despite these costs, hardening utility infrastructure so that it is less susceptible to hurricane damage is very expensive.

This report examines the costs, utility benefits, and societal benefits for a variety of storm hardening programs (see Table 7-1). Based on data provided by utilities and other assumptions, the following programs are found to be cost-effective:

<u>Cost-effective Storm Hardening Programs</u>

1. **Improved post-storm data collection.** Most damage data available to utilities is from accounting and work management systems. A much better understanding of infrastructure performance can result from carefully designed post-storm data collection programs that capture key features at failure sites and are statistically significant. Improved storm data allows for more cost-effective spending on hardening programs.
2. **Hazard tree removal.** Hazard trees are dead and diseased trees outside of a utility's right-of-way that have the potential to fall into utility lines or structures. Removing dead and diseased trees is desirable from a societal perspective in any case and can significantly reduce hurricane damage. Further benefits can result from the removal of healthy "danger trees" that are at risk of falling into utility facilities. Many utilities already attempt to address these issues but often encounter resistance from property owners.
3. **Targeted electric distribution hardening.** This approach targets spending to high-priority circuits, important structures, and structures that are likely to fail. Since all spending must be justified based on a cost-to-benefit analysis, targeted distribution system hardening is cost-effective by definition. The targeted hardening of about 1% of distribution structures is likely to be cost-effective for Texas utilities.

In general, the targeted hardening of transmission structures is not cost-effective. However, the transmission structures of Entergy Texas experienced extremely high failure rates during both Hurricanes Rita and Ike. Based on these high failure rates, an analysis shows that the targeted hardening of Entergy Texas transmission structures is potentially cost-effective and should be investigated further.

Findings and conclusions are based on (1) hurricane damage and cost data provided by the utilities and (2) a hurricane simulation model. Utility data is never perfect, and many assumptions are used within the hurricane simulation model and the cost-to-benefit analysis. Therefore, the findings and conclusions are necessarily broad and may or may not be applicable to specific situations. Brief descriptions of major findings and conclusions are now provided.

Table 7-1. Summary of Findings.

#	Hurricane Mitigation Program (a)	Incremental Utility Cost ($1000s)	Utility Hurricane Benefit ($1000s/yr)	GDP Hurricane Benefit ($1000s/yr)	Cost Effective (b)
Vegetation Management					
1. -	Annual patrols for transmission	$136 /yr	$0	$0	No
2. -	Annual patrols for distribution	$2,760 /yr	$0	$0	No
3. -	Hazard tree removal program	Not examined	$13,800	$9,200	Yes
Ground-Based Patrols					
4. -	Annual patrols for transmission	$15,400/yr	$0	$0	No
5. -	Annual patrols distribution	$32,700/yr	$7,500	$4,900	No
Substations & Central Offices					
6. -	New substations outside of 100-yr floodplain	Site specific	$16 per site	$0	Depends
7. -	New COs outside of 100-yr floodplain	Site specific	$4 per site	$0	Depends
8.	Backup generators for substations within 50 miles of coast	$21,800	$0	$1,384	No
9. -	Backup generators for COs within 50 miles of coast	$4,152	$0	$442	Yes (c)
Infrastructure Hardening					
10. -	Improved post-storm data collection	Not examined	Not examined	Not examined	Yes
11. -	Non-wood structures for new transmission	Varies	$0	$0	No
12. -	Harden new transmission	$0 (d)	$0	$0	No
13. -	UG conversion of existing transmission	$32,885,000	$27,000	$18,300	No
14. -	UG conversion of existing distribution	$28,263,000	$126,000	$85,400	No
15. -	Targeted hardening existing transmission	$2,400,000	$9,000	$6,100	No (e)
16. -	Targeted hardening existing distribution	$320,000	$14,400	$9,800	Yes
Smart Grid Technologies					
17. -	Technologies for transmission	Not examined	Not examined	$1.8	No
18. -	Technologies for distribution	Not examined	Not examined	$47.4	No

(a) - Unless otherwise stated, these mitigation programs are evaluated on a broad basis with the assumption of widespread deployment. Even if widespread deployment is not cost-effective, there may be certain specific situations where the approach is cost-effective.

(b) - The cost-effective rating is based on hurricane benefits only. There may be other benefits that make these mitigation programs cost-effective.

(c) - Most COs already have backup generator capability in addition to battery backup.

(d) - Targeted hardening of the Entergy Texas transmission system is potentially cost-effective and should be investigated in more detail.

(e) - New transmission is already required to meet NESC extreme wind criteria.

Electric Utility Restoration Costs

Fifteen named storms struck Texas from 1998-2008. Seven of these were hurricanes. These storms caused electric utilities in Texas to incur $1.8 billion in restoration costs, an average of about $180 million per year. About 80% of these costs are attributed to distribution and 20% to transmission. Nearly all of the restorations costs are attributed to wind damage, tree damage, and flying debris. Storm surge damage is occasionally a major concern in specific areas, but generally represents a low percentage of restoration costs. Other findings in the report include:

- All utilities design transmission to NESC Grade B and distribution to NESC Grade C.
- By far, the largest number of transmission failures occurred on the Entergy Texas system with Rita and next with Ike.
- Excluding outliers, distribution structures fail about five times more during hurricanes than transmission structures. This is expected since transmission is built to higher strength standards, and transmission rights-of-way are typically wider.

Telecom Utility Restoration Costs

Since 1998, telecom utilities in Texas have incurred about $181 million in restoration costs due to hurricanes and tropical storms, an average of about $18 million per year. This is about 10% of the electric utility restoration costs over the same time period. Telecom utilities attribute a higher percentage of hurricane damage to storm surge and flooding when compared to electric utilities, but a majority of damage is still due to wind damage, tree damage, and flying debris. Other findings in the report include:

- During the last ten years, eleven telecom utilities reported at least some tropical storm damage and twenty-one reported no damage. Those reporting no damage tended to be smaller utilities.
- By far, the most expensive hurricane events were experienced by AT&T Texas – $79.9 million after Ike in 2008 and $71.7 million after Rita in 2005. The next most costly experience was only $7.8 million to Verizon after Ike.

Hurricane Simulation

A hurricane simulation model has been developed that simulates hurricane years. This model is based on data from NOAA and mathematical approached by FEMA. It has also been calibrated to the ASCE extreme wind map. For each year, the model determines the number of hurricanes that make Texas landfall. It then simulates each hurricane including size, strength, landfall location, path, infrastructure damage, restoration time, and other key factors. The average results of 10,000 simulation years are used for cost and benefit calculations. The model extends 50-miles inland from the coastline.

Societal Cost

Societal costs are based on GDP for metropolitan statistical areas along the Texas coastline (Beaumont-Port Arthur, Brownsville-Harlingen, Corpus Christi, Houston-Baytown-Sugar Land, and Victoria). Annually, GDP for these areas is $384 billion. Based on the hurricane simulation model, lost GDP due to hurricanes is an average of $122 million per year. Most of this is due to the Houston-Baytown-Sugar Land area.

Vegetation Management

Annual vegetation patrols apart from normal vegetation management activities will not result in significant hurricane benefits. During hurricanes, most vegetation damage is from falling trees located outside of the utility right-of-way. Typical vegetation patrols focus on clearance violations, which is not a major hurricane issue. As stated previously, a cost-effective hurricane vegetation program must focus on the removal of hazard trees and potentially danger trees. Other findings in the report include:

- Most of the electric IOUs reported a minimum of one annual patrol of their entire transmission system to inspect for potential vegetation problems. Generally, this is an aerial patrol, supplemented with ground or foot patrols as deemed necessary.
- Most Texas IOUs do not perform separate distribution vegetation management patrols.

Ground-Based Patrols

Ground-based patrols are used by utilities to visually inspect structures from the ground and identify maintenance needs, including problems that may result in poor hurricane performance (inspections for groundline deterioration is typically performed separately). Comprehensive ground-based patrol programs for transmission are common, but not generally cost-effective to perform annually. Comprehensive ground-based patrol programs for distribution are less common, with inspections typically occurring as part of daily operations.

Substations & Central Offices

Substations and central offices have relatively low failure and damage rates during storms and have low contributions to total restoration costs. Locating a particular new substation and/or CO outside of the 100-year floodplain will have both benefits and costs, and the cost-effectiveness will vary with each situation. Loss of substation auxiliary power has not been a major factor for utilities after hurricanes, and the installation of backup generators in substations for auxiliary power is generally not cost-effective. In contrast, backup generators at COs are cost-effective. In practice, large COs already have permanent backup generators and smaller COs have the ability to utilize portable generators. The incremental benefits of placing permanent backup generators at small COs typically do not justify the incremental costs.

Infrastructure Hardening

Infrastructure hardening is expensive, and most general approaches are not cost-effective. However, targeted distribution hardening is cost-effective by definition, since a specific hardening activity is only performed if analyses show that it is cost-effective. A targeted program will typically identify and address high priority circuits, critical structures in these circuits, and structures with a very high probability of failing during a hurricane. The cost-effectiveness of distribution hardening can be significantly increased through the use of data collected through a well-designed post-storm data collection process. Other findings in the report include:

- Utilities reported a very small number of damage incidents due to substation and CO flooding.
- For substations, backup generators are only of value if an independent source of auxiliary power is required.
- Most COs are already built with emergency generation capability, either through permanently located generators or through the capability to easily connect a portable generator to the main power panel.
- New transmission is required by the NESC to meet extreme wind loading criteria, and is therefore already hardened.
- Structures are engineered to a specific strength. Therefore, there is no hardening benefit for using non-wood structures, although there may be other benefits.

Smart Grid Technologies

There are many potential storm restoration benefits that can be derived from a variety of Smart Grid technologies. These benefits are magnified if a comprehensive suite of technologies are integrated and work together seamlessly. This said, technology components located on poles are of little use if the pole blows over, and technology components requiring communications are of little use if the communications system is destroyed. Therefore, the restoration benefits of Smart Grid technologies require a Smart Grid plan that specifically addresses issues related to major storms. Even if this is done, the hurricane benefits of Smart Grid are small compared to the costs. However, these benefits should be included in the overall Smart Grid cost-to-benefit analysis that will include many other benefits. Other findings in the report include:

- Smart Grid technologies will not reduce hurricane damage.
- Since Smart Grid technologies rely heavily upon communications systems, utilities wishing to use Smart Grid functionality during storm restoration will have to develop and coordinate a communications restoration plan along with its power restoration plan.

Summary

Recent Texas hurricanes have caused a significant amount of utility infrastructure damage and other societal costs. However, damage is unpredictable and small as a percentage of total installed infrastructure. Broad prescriptive approaches to hurricane hardening are generally not cost-effective since many structures must be hardened for every failure that is eventually prevented. However, certain targeted vegetation and hardening approaches can be cost-effective, especially if they are based on detailed post-storm data collection and analyses.

Appendix A – Probabilistic Hurricane Model

A.1 Introduction

This appendix describes the probabilistic hurricane simulation model, which is customized specifically for the areas within 50 miles of the Texas Gulf Coast. This proposed probabilistic hurricane simulation model is able to determine the number of hurricanes landing in Texas each simulated year and assign landfall characteristics to each simulated hurricane. The modeled hurricane landfall features include:

- Landing positions,
- Approach angle (or direction),
- Translation velocity (or forward speed),
- Central pressure difference,
- Maximum wind speed,
- Radius of maximum wind, and
- Gust factor (used to estimate the peak gust speed).

The evolving inland features while the simulated hurricane moves into Texas territories are also modeled such as:

- Maximum wind speed decay rate,
- Central pressure difference filling rate,
- Radial wind field profile.

Although it can produce detailed landfall and inland information for each simulated hurricane, this probabilistic hurricane simulation module is designed to generate an expected effect, which is derived from a large number of simulations, as opposed to reproducing the effect of a specific historical hurricane.

This hurricane simulation module is developed in Microsoft Excel with the extensive use of Visual Basic for Applications (VBA) programming.

A.2 Available Data

The model development as well as the parameter calibration of individual hurricane characteristics heavily relies on the historical information. The North Atlantic Hurricane Data Base (HURDAT) [1], compiled by the Atlantic Oceanographic and Meteorological Laboratory at National Oceanic & Atmospheric Administration (NOAA), is the most complete and reliable source of data for North Atlantic and Gulf Coast hurricanes currently available[14]. This database has been widely employed by various hurricane researchers and cited in many meteorological publications.

HURDAT consists of position and intensity estimates for tropical cyclones (including hurricanes, tropical storms, and subtropical storms) at six hour intervals dating back to 1851. The information in HURDAT is less reliable during the nineteenth and early twentieth centuries, and is increasingly reliable from the early twentieth century to present day. The key hurricane features recorded in HURDAT are:

- Central position (to the nearest 0.1 degree latitude and longitude),
- Direction (to the nearest 5 degree with North),
- Translation speed (or forward speed),
- Maximum sustained wind speed (1-minute at 10-m height) ,
- The Saffir-Simpson category, (the Saffir-Simpson scale is shown in Table A1), and
- Central pressure for some latest hurricanes.

Table A1. Saffir-Simpson Scale

Category	*Minimum Central Pressure (mb)*	*Maximum Sustained Wind Speed (mph)*	*Storm Surge (ft)*
5	<920	≥155	≥18
4	920-944	130-155	13-18
3	945-964	110-130	9-12
2	965-979	94-110	6-8
1	≥980	74-94	4-5
Tropical Storm	-	39-74	0-3
Tropical Depression	-	0-39	0

HURDAT contains tropical cyclone records up to 2007. The relevant features of three tropical cyclones that made landfall in Texas in 2008 (Hurricane Dolly, Tropical Storm Edouard, and Hurricane Ike) are extracted from the Tropical Cyclone Reports [2, 3, 4] issued by the National Hurricane Center.

The average number of landfall tropical cyclones in Texas is around 4 per decade, as shown in Figure A1. As recorded in the database, there are 64 tropical cyclones (of which 54 are hurricanes) that made landfall in Texas from 1851 to 2008. The summary statistics of the occurrence of tropical cyclones that impacted Texas are listed in Tables A2 and A3.

[14] HURDAT is currently undergoing re-analysis in order to improve the data quality, but it still is the best available data source so far.

Table A2. Hurricane Occurrence in Texas

Tropical Storm	*Category 1*	*Category 2*	*Category 3*	*Category 4*	*Category 5*	***Total***
10	25	14	9	4	2	64

Table A3. Annual Hurricane Occurrence in Texas

Years with no storms	*Years with 1 storm*	*Years with 2 storms*	*Years with 3 storms*	*Years with 4 storms*	***Total***
105	46	4	2	1	158

For each historical hurricane[15], the exact landing information such as time and position (in terms of latitude and longitude) is usually not available since HURDAT records the storm information every 6 hours. The hurricane landing information is estimated from the database according to the approximated Texas coastline. Figure A2 shows the approximated Texas coastline (as well as partial LA coastlines) and the areas within 50 miles of the coast implemented in Excel. Among the hurricane central positions recorded on six-hour interval for a landfall hurricane, the one closest to the approximated coastline is treated as the landfall position and the corresponding record is considered as the one containing the landfall information so that other features including approach angle, translation velocity, and maximum wind speed can be identified for model development and parameter calibration.

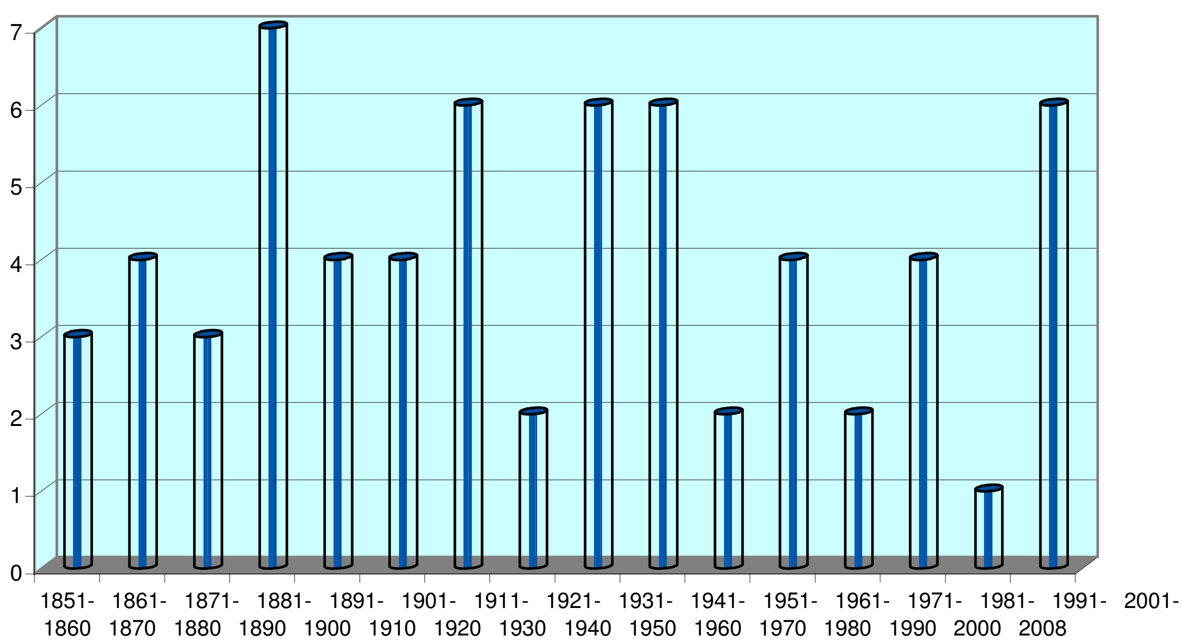

Figure A1. Histogram of Landfall Hurricane Frequency in Texas (by Decade).

[15] Only the landing information of hurricane is included in HURDAT, the landing information of tropical storms and subtropical storms is not included.

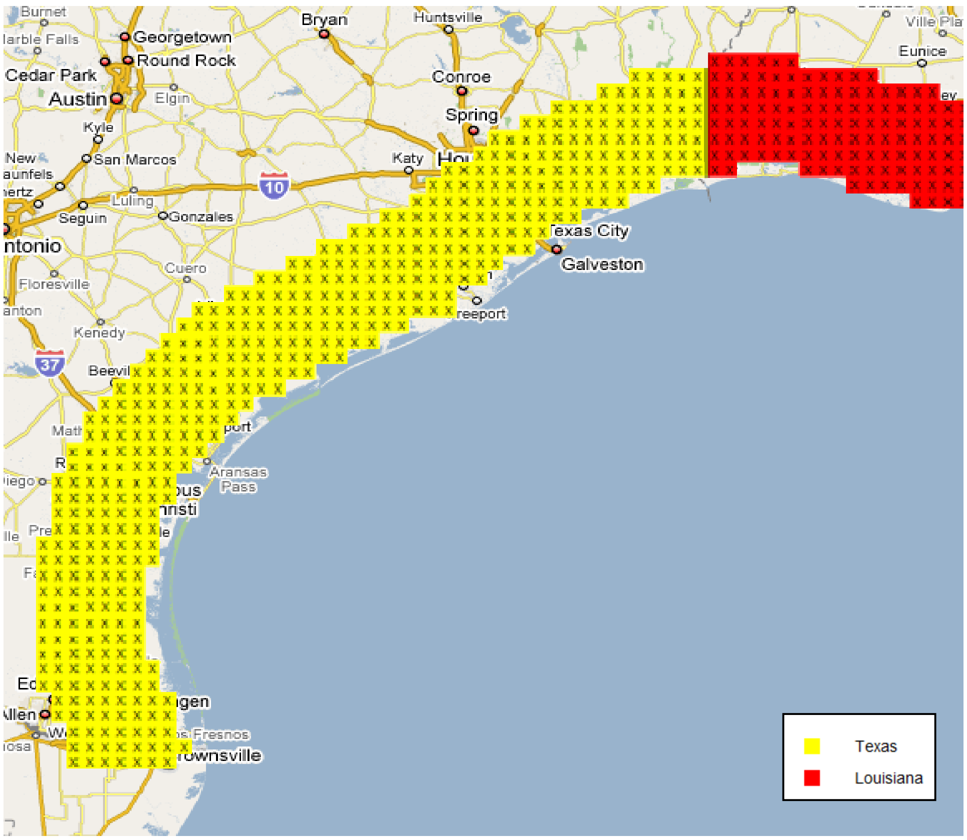

Figure A2. Approximate Texas Coastline.

A.3 Probabilistic Hurricane Modeling

Method Selection

Only few complete hurricane simulation models are available in the public domain. HAZUS-MH hurricane model developed by Federal Emergency Management Agency (FEMA) is the most popular one; it is currently designed for potential residential structural damage estimation. Since HAZUS-MH hurricane model aims to assess the economical loss instead of simply simulating hurricane information, the hurricane simulation model is embedded in the tool with limited intermediate results such as sustained and peak gust wind speed. The lack of full control of the hurricane simulation inevitably causes certain difficulties in applying the HAZUS-MH to assess hurricane damage to utility infrastructures, which is not its original target population.

The proposed probabilistic hurricane simulation module is based on the same hurricane database HURDAT as the HAZUS-MH hurricane model uses, applies similar assumptions, and adopts the same research findings for a large portion of hurricane characteristics. All these are done to ensure the soundness of the methodology. On the other hand, this module is different from the HAZUS-MH hurricane simulation model in handling local information in order to better serve the purpose of this specific project and to reduce the computational demand (the detailed technical difference between these two models will be discussed in the subsequent sections). This hurricane module is customized for the specific purpose of this project and offers more flexibility since all the features can be modified or adjusted by the users as needed.

Hurricane Characteristics Modeling

Various probabilistic and empirical models have been developed or applied to capture hurricane characteristics in order to simulate a complete hurricane. The modeled characteristics include:

Modeled Hurricane Characteristics
- Annual hurricane frequency
- Landfall position expressed in latitude and longitude
- Approach angle at landfall (or direction)
- Translation velocity (or forward speed)
- Central pressure difference at landfall and its filling
- Maximum wind speed at landfall and its decay
- Gust factor
- Radius of maximum wind
- Radial wind field profile

Hurricane features and effects may be highly idiosyncratic. For example, the complete hurricane trajectory may not follow a straight line, or some hurricanes make more than one landfall. However, this hurricane module is designed to determine the average impact of a large number of simulations rather than track every single possible hurricane scenario; in addition, this project aims to determine the costs and benefits associated with storm hardening efforts within 50 miles of the Texas coast instead of the entire Texas territory; therefore, certain assumptions have been made to simplify the model and minimize the computational intensity.

1. When extracting information from HURDAT, only the hurricanes impacting Texas and west Louisiana are included.
2. Only one landfall is considered for each hurricane.
3. The hurricane wind speed is assumed constant until landfall; in other words, the wind speed before landfall is always the same as when it lands. The wind speed decays after its landfall due to frictions and insufficient continuous moisture.
4. The hurricane translation speed is held constant for each simulated storm.
5. Hurricanes travel along a straight path when they move across the areas within 50 miles of the Texas coast.

One major difference between this simulation approach and HAZUS-MH hurricane model is the simulation starting point. HAZUS-MH model starts from sampling the historical hurricane originating positions while this hurricane module starts from modeling the landfall position in Texas. HAZUS-MH is designed for the entire North Atlantic coastal region instead of specifically for one state, so many of its simulated hurricanes may not affect Texas at all, which significantly increases its computational demands. In addition, with hurricanes simulated from their origination positions, there may be a larger variance in the landing frequency and landfall characteristics for those hurricanes that eventually land in Texas. As explained in the HAZUS-MH technical manual [5], the simulated landfall rate in different regions of Florida (Florida is used as an example) may deviate from the actual historical information. The proposed simulation module starts directly from the historical data related to Texas, which not only reduces the computational time but also fits the local landfall patterns better.

Occurrence

Annual hurricane frequency has been successfully modeled parametrically using Poisson distribution and negative binominal distributions [6, 7, 8, 9]; the difference between Poisson distribution and negative binominal distribution in modeling annual hurricane frequency is negligible [6]. The Poisson distribution is chosen due to its simplicity.

The Poisson distribution expresses the probability of a number of events occurring in a fixed period of time if these events occur with a known average rate and independently of the time since the last event; it is modeled as:

$$f(h) = \frac{e^{-\lambda}\lambda^{h}}{h!}; \quad h = 0,1,2,...,$$

where h is the number of landfall hurricanes per year, λ equals to the expected (average) number of hurricanes that land in Texas during a given year, and f(h) is the probability of h hurricanes landed in Texas in a given year. The probability mass function of Poisson distribution is shown in Figure A3, where the horizontal axis is h. The function is discrete, the connecting lines are only guides for the eye and do not indicate continuity. There are several ways to estimate the parameter λ; the maximum likelihood estimator (best estimate) of λ is simply the mean value of the sample data.

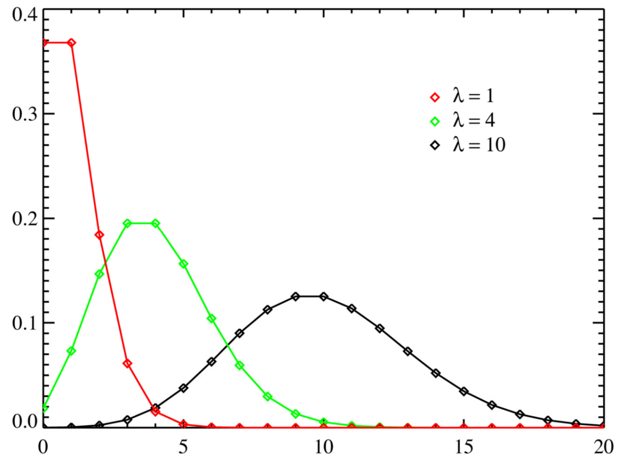

Figure A3. Probability Mass Function of Poisson Distribution.

Landing Position

The landing position of a simulated hurricane is proportionally assigned according to the distribution of historical hurricane landing positions in Texas with certain smoothing mechanisms. The coastline of Texas is divided into a certain number of sections, which are equally sized in terms of the range of latitude or longitude. The distribution of historical hurricane landing positions among those sections becomes the base for assigning the landfall position to each simulated hurricane such that the simulated landing positions is consistent with the distribution of historical data. The sections without any historical records are assigned a small probability in order to avoid absolute safe zone. When the landfall section is determined for a simulated hurricane, a uniform distribution is applied to determine the exact landing location within the zone.

Approach Angle

The approach angle indicates the heading direction of a hurricane when it comes ashore; it is expressed to the nearest 5 degrees with North as 0 degree in the HURDAT data, as shown in Figure A4.

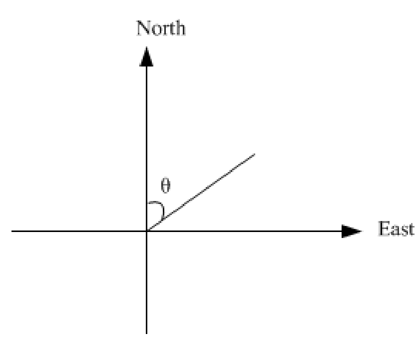

Figure A4. Approach Angle.

The approach angle is modeled as a normal distribution:

$$f(\theta) = \frac{1}{\sqrt{2\pi}\sigma} \exp\left[-\frac{1}{2} \left(\frac{\theta - m}{\sigma} \right)^2 \right]$$

where m is the mean and σ is the standard deviation, these parameters are to be identified from historical data.

Since the trajectory of a hurricane within 50 miles of the Texas coast is assumed to be a straight line, it can be described as

$$y = kx + b$$

with x denoted as the hurricane longitude at a time and y denoted as the latitude of the hurricane at the same time. Once the landing position (*landing_latitude* and *landing_longitude*) and the approach angle θ (with necessary transformation) are determined, both k and b can be calculated to determine the hurricane trajectory:

$$k = \tan(\theta)$$

$$b = \frac{landing\_latitude}{\tan(\theta) * landing\_longitude}$$

Translation Velocity

The translation velocity of a hurricane (m/s) upon landfall can be modeled as a lognormal distribution [9, 10]:

$$f(c) = \frac{1}{c\sqrt{2\pi}\sigma_{\ln c}} \exp\left[-\frac{1}{2} \left(\frac{\ln c - m_{\ln c}}{\sigma_{\ln c}} \right) \right]$$

where c is the translation velocity, $m_{\ln c}$ is the logarithmic mean, and $\sigma_{\ln c}$ is the logarithmic standard deviation; both $m_{\ln c}$ and $\sigma_{\ln c}$ are to be identified from historical data.

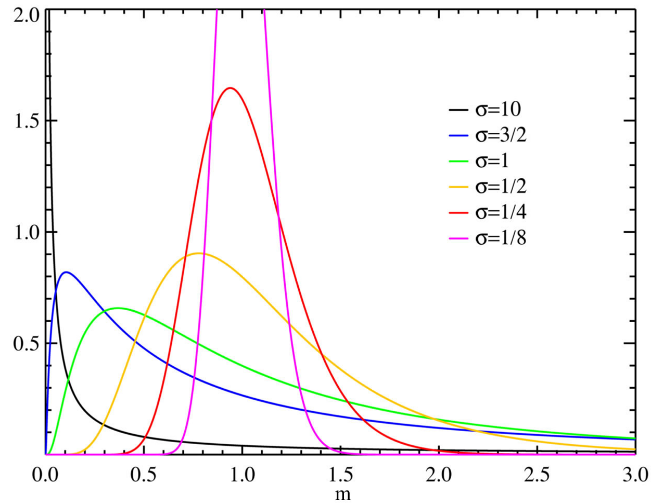

Figure A5. Probability Distribution Function of Lognormal Distribution.

Central Pressure Difference

The difference between atmospheric pressures at the center and at the periphery of a hurricane, denoted as Δp, plays a very important role in determining the maximum wind speed. The central pressure difference (millibar) is modeled as the Weibull distribution [9, 10]:

$$f(\Delta p) = \frac{k}{C}\left(\frac{\Delta p}{C}\right)^{k-1} \exp\left[-\left(\frac{\Delta p}{C}\right)^{k}\right]$$

where k and C are parameters to be identified from historical data.

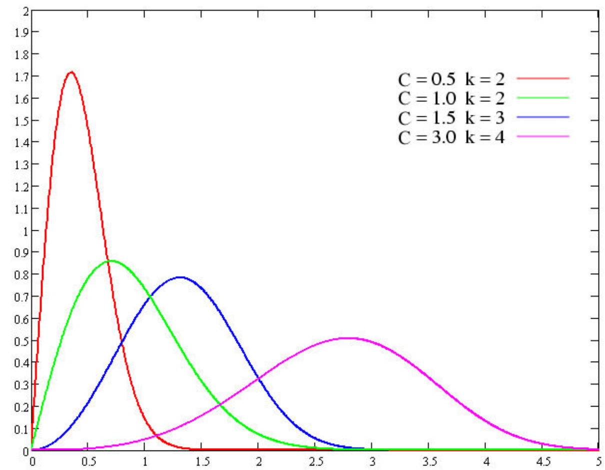

Figure A6. Probability Distribution Function of Weibull Distribution.

Instead of recording the central pressure difference Δp, HURDAT records the central pressure p. The conversion from the central pressure p to the central pressure difference Δp is fairly straightforward given the atmospheric pressure at a distance beyond the effect of the hurricanes having a typical value of 1,013 millibars [11].

Maximum Wind Speed

The maximum wind speed models in recent meteorological researches are usually complicated and involve sensitive and difficult-to-determine parameters. In this work, the maximum wind speed is roughly modeled based on its minimum central pressure p at its landfall.

The simulated minimum central pressure p at landfall determines the Saffir-Simpson category of the corresponding hurricane (it has been investigated that using minimum central pressure to categorize a hurricane leads to fewer errors than using wind speed [5]). Then, the maximum wind speed is proportionally calculated in that specific Saffir-Simpson category.

For instance, the central pressure difference for a simulated hurricane is 45mb at its landfall, i.e., the minimum central pressure is 1013 – 45 = 968mb. According to the Saffir-Simpson scale shown in Table A1, it is a Category 2 hurricane, and the maximum sustained wind speed for this hurricane upon landfall is calculated as 106.6mph (47.4m/s) proportionally in the range from 94mph (41.8m/s) to 110mph (48.9m/s).

Gust Factor

The wind speed produced in hurricane simulations are maximum sustained wind speed based on 1-minute duration. However, the structural damage is closely related with peak gust speed, which is the highest "instantaneous" wind speed during a specified period (usually 3 seconds). The gust factor can be used to estimate the most likely peak gust speed from sustained wind speed. It is demonstrated that ESDU[16] model [12, 13] provides an adequate model for hurricane gust factors, both over water and land.

In the ESDU approach, the peak wind speed at height z averaged over time period τ occurring over an observation time of 3600s (1 hour) is given as:

$$\hat{U}(\tau, z) = U(3600, z)[1 + g(\upsilon, \tau, z) I_u(z)]$$

where:

$U(3600, z) = 2.5u_* \ln(z / z_0)$;

$I_u(z) = \dfrac{\sigma_u(z)}{U(3600, z)}$ is longitudinal turbulence intensity, in which:

$\sigma_u(z) = \dfrac{u_* 7.5\eta[0.538 + 0.09\ln(z / z_0)]^{\eta^{16}}}{[1 + 0.156\ln(u_* / fz_0)]}$ is the standard deviation of wind speed

$\eta = 1 - 6fz / u_*$,

$f = 2\Omega \sin\phi$ is the Coriolis parameter,

$\Omega = 7.292 \times 10^{-5}\, rad / s$ is the Earth's angular velocity [14],

ϕ is the local latitude,

z_0 is the terrain roughness (a value of 0.05 is used in this work [15]);

$g(\upsilon, \tau, z) = \left[\sqrt{2\ln(T_0\upsilon)} + \dfrac{0.557}{\sqrt{2\ln(T_0\upsilon)}}\right] \dfrac{\sigma_u(z, \tau)}{\sigma_u(z)}$ is the peak factors, in which:

T_0 is observation period which is set to 3600s,

$\upsilon = \dfrac{0.007 + 0.213(3.13z^{0.2} / \tau)^{0.654}}{3.13z^{0.2}}$,

$T_u = 3.13z^{0.2}$,

$\sigma_u(z, \tau) = \sigma_u(z)[1 - 0.913(T_u / \tau + 0.1)^{-0.68}]$.

Given the simulated maximum sustained wind speed as well as the values of $\hat{U}(\tau, z)$, τ, z, f, and z_0, the value of friction velocity u_* can be determined using iterative approaches. The Newton-Raphson method [16] is used in this work.

[16] ESDU is an acronym of "Engineering Sciences Data Unit", which is an engineering advisory organization based in the United Kingdom.

Based on 1000-year simulation (for 3-s peak gust at roughness length of 0.05m) using Newton-Raphson method, it is observed that the distribution of the calculated values of the gust factor is highly concentrated around 1.287 with standard deviation of 0.002. In this work, the value of 1.287 is used to replace the ESDU model in order to reduce the computational intensity, especially for Monte Carlo simulation.

Radius to Maximum Winds

Radius to maximum winds describes the range of most intensive hurricane wind speed. The radius of maximum winds $R_{\max}$ is empirically modeled in [5] as:

$$\ln R_{\max} = 2.556 - 0.000050255\Delta p^2 + 0.042243032\psi$$

where ψ is the storm latitude, Δp is the center pressure difference.

Maximum Wind Speed Decay Rate

Hurricanes' intensity decays and dissipates after their landfall because large land masses cause frictions and the terrain cuts off hurricanes' circulation and squeezes out the storm's moistures. There are two widely accepted models to model the decay of hurricanes: one estimates the decayed wind speed and the other model is for estimating the change in minimum central pressure.

KD95[17] [17, 18] is the most widely used model for simulating the decay of hurricane maximum wind speed inland; it has been used in many real-time forecasting and emergency preparedness scenarios. KD95 is for storms south of 37°N (Texas coastline is located south of 30°N). KD95 model is based on the assumption that hurricanes decay at a rate proportional to their landfall intensity and decay exponentially with time after landfall.

$$V(t) = V_b + (RV_0 - V_b)e^{-\alpha t}$$

where R=0.9 is a factor used to account for the sea-land wind speed reduction, V_b=13.75m/s, α=0.095h^{-1}, V_0 is the maximum sustained 1-min surface wind speed at the time of landfall.

Central Pressure Filling Rate

The filling rate module for evolvement of the minimum central pressure [19] is modeled as following:

$$\Delta p(t) = \Delta p_0 e^{-at}$$

where the filling constant a is defined as:

$$a = a_4 + a_5 \Delta p_0 + \varepsilon$$

[17] KD95 is named after the authors John Kaplan and Mark Demaria, the related paper was published in 1995.

The values of parameters for the Gulf Coast are defined in [19]: a_4=0.006, a_5=0.00046, and ε is a normally distributed error term with a mean of zero and a standard deviation of 0.025.

Both the maximum wind speed decay module and the central pressure filling module will be used since the direct link between the central pressure difference and the maximum sustained wind speed is not available.

Wind Field Profile

The most intensive wind of a hurricane generally occurs at the eye wall; wind speed decreases as the location moves away from the hurricane's center. The wind field model developed by Holland [20] describes the radial profile of winds in a hurricane.

$$V_g = \left[\frac{AB\left(p_n - p\right)e^{-A/r^B}}{\rho r^B} + \frac{r^2 f^2}{4} \right]^{1/2} - \frac{rf}{2}$$

where V_g is the gradient wind at radius r, ρ=1.15kg/m^3 is the air density, p is the central pressure, p_n is the ambient pressure (with typical value of 1013mbars), and f is the Coriolis parameter:

$$f = 2\Omega \sin\phi$$

where Ω=7.292× 10^{-5}rad/s is the Earth's angular velocity [14], and $\emptyset$ is the local latitude.

The parameters A and B in the model are scaling parameters. For actual hurricanes, they are empirically estimated from observations; while for a simulated hurricane, A and B can be determined climatologically as:

$$V_m = \sqrt{\frac{B}{\rho e}\left(p_n - p\right)}$$

$$R_{\max} = A^{1/B}$$

where V_m is the maximum wind speed, e is the base of natural logarithm with a value of 2.718, and $R_{\max}$ is the radius to maximum wind.

This calculated gradient wind is considered as the upper level wind and needs to be adjusted to surface level (10m) in order to assess the power system infrastructure damage caused by hurricanes. A simple approach in [19] applies a 17.5% reduction for r<2$R_{\max}$ and a 25% reduction for r>4$R_{\max}$ with a smooth transition curve used for intermediate values of r. These parameters are for wind speed adjustment over water; the reduction of wind speed is larger over land. This approach is utilized, while the parameters are calibrated towards the ASCE 7 wind map.

Complete Hurricane Simulation

Individual hurricane characteristics have been modeled either statistically or empirically. A complete hurricane and then a general hurricane year for the areas within 50 miles of Texas coast can be simulated by compiling those components together.

The first step is to simulate the annual hurricane frequency in Texas. Then, the landing features, including landfall position, approach angle, translation velocity, central pressure difference, maximum wind speed, and radius to maximum wind, are probabilistically generated for each simulated hurricane using corresponding modules. The hurricane landing information further determines its inland movement. Since the trajectory of a hurricane within 50 miles of the Texas coast is assumed as a straight line, the landing position and the approach angle determine its inland path.

The central pressure filling rate module updates the central pressure difference at any location along the hurricane path, and then the corresponding radius to maximum wind speed is calculated. On the other hand, KD95 model tracks the maximum wind speed at any point along the hurricane path. With the maximum wind speed and the radius to maximum wind speed updated along the hurricane path, parameters A and B for the radial wind field model are calculated so that the current radial profile of hurricane wind can be described.

Given the wind speed in any specific location, the gust factor is applied to convert the sustained wind speed to the most likely 3-second peak gust in order to help assess the hurricane-induced utility structural damage.

A.4 Parameter Estimation

In order for the proposed probabilistic hurricane simulation module to capture the actual hurricane characteristics shown in historical data, the module parameters should be carefully calibrated. Among various models for hurricane characteristics, some are empirical models with parameter provided such as the model for the radius to maximum winds, the maximum wind decay rate, and central pressure filling rate. Some are probabilistic distribution models with parameters estimated from historical data such as the Poisson distribution for the hurricane frequency, and some models use a sampling approach so that the parameter extraction is not needed such as the approach for getting landing position and maximum wind speed at landfall.

There are 64 historical tropical cyclones included in the HURDAT, but it may not be sufficient to support good parameter estimation for those statistical distribution models, especially when the historical data for some characteristics are not always available. For example, the central pressure at landfall was not recorded until recently due to the technology limitation (only 37 storms have central pressure at landfall recorded.)

The parameters have been extracted using probabilistic distribution fitting and empirical studies. Due to the fact that insufficient historical data are available to generate statistically well-representative parameters for some weather characteristics, the estimated parameters during the calibration process are allowed to be slightly changed in order to better represent the actual hurricane patterns. The parameters are calibrated towards the Texas portion of the ASCE 7 Wind Map.

Table A4 lists the parameters used in the algorithm.

Table A4. Region-Specific Parameters

Hurricane Characteristics	Parameter	Value
Occurrence	λ	0.68
Approach Angle	m	-27.63
	σ	44.13
Translation Velocity	m	3.1
	σ	0.35
Central Pressure Difference	C	33
	K	1.4

A.5 Hurricane Simulation Validation

Hurricanes are complex phenomena influenced by a variety of physical factors; their developments involve extensive uncertainties. The best approach to treat the situations with large degree of uncertainties is the probabilistic modeling through the use of a Monte Carlo simulation. The probabilistic approach accounts for variances in the data and the probabilistic approach via multiple iterations can reproduce the scenarios close to the actual cases in the long run.

The ASCE 7 Wind Map represents the 3-second gust speed with a mean recurrence interval of 50 years. This map is derived from statistical analysis of peak gust data collected at weather stations and mathematical predictions of hurricane wind speeds in coastal areas. Through a Monte Carlo simulation, the worst 3-second peak gust of 50 years from the proposed hurricane simulation methodology can be compared against the ASCE 7 Wind Map to validate the algorithm.

The key step in accurately reproducing the ASCE 7 Wind Map is calibrating the hurricane simulation module parameters. Among the various models for adverse weather characteristics, some are empirical models, such as the model for the radius to maximum winds, with easily obtained parameters from published resource; some are well-developed models, such as the Poisson distribution for the hurricane frequency, with parameters easily determined from historical data. Several models have parameters that are not easily obtained either because of the insufficient data or the lack of theoretical support.

The hurricane simulation module can best be calibrated by adjusting two parameters:

- HURDAT contains historical hurricane data (back to 1850). However, the central pressure has not been systematically recorded until recently (around 1960s). The parameters for the Weibull distribution that is used to model the central pressure difference at hurricane landfall extracted from the limited historical data may not be as accurate as the parameters for some other hurricane characteristics.
- In the proposed hurricane simulation methodology, the landing location sampling approach divides the Texas coastline into a number of segments (fifteen in this case) and then uses the number of historical hurricane landed in each segment as the foundation for assigning simulated landfall position. The choice of the number of segments can affect the accuracy of simulation. If too few bins are assigned, it may be too coarse to include enough details; however, it may be too sensitive to data noise if too many segments are assigned, especially when the historical landing information is estimated from the six-hour interval records and the approximated Florida coastline.

By focusing on the calibration of these two parameters, a map presenting the worst 3-second peak gust in fifty years for areas within 50 miles of Texas coast is generated, which is based on a 10,000-run Monte Carlo simulation of the proposed hurricane method. The simulated wind map is shown in Figure A7, comparing with the actual ASCE 7 Wind map using the same color scheme is shown in Figure A8.

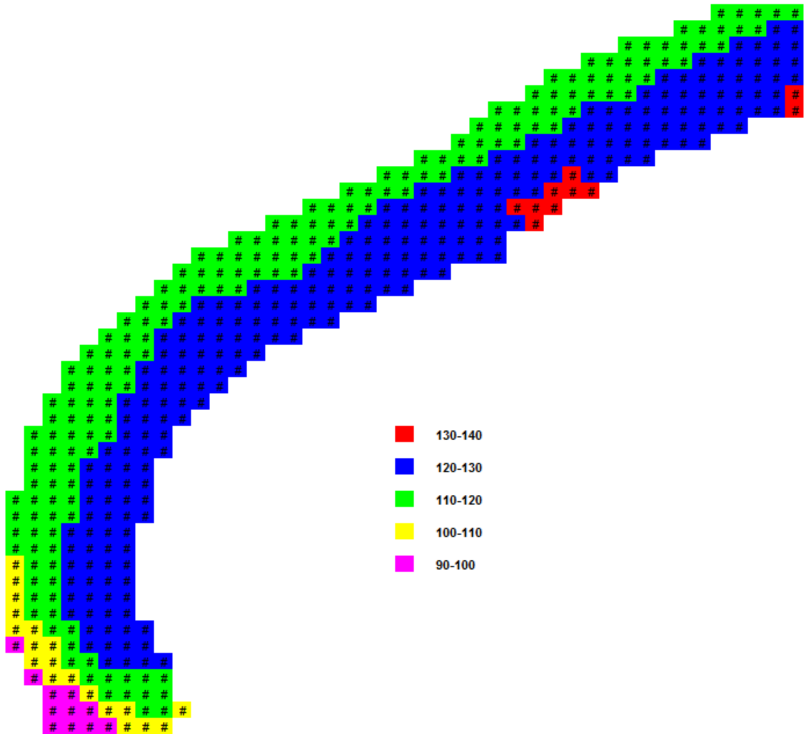

Figure A7. Simulated Wind Map for Areas within 50 Miles of Texas Coast.

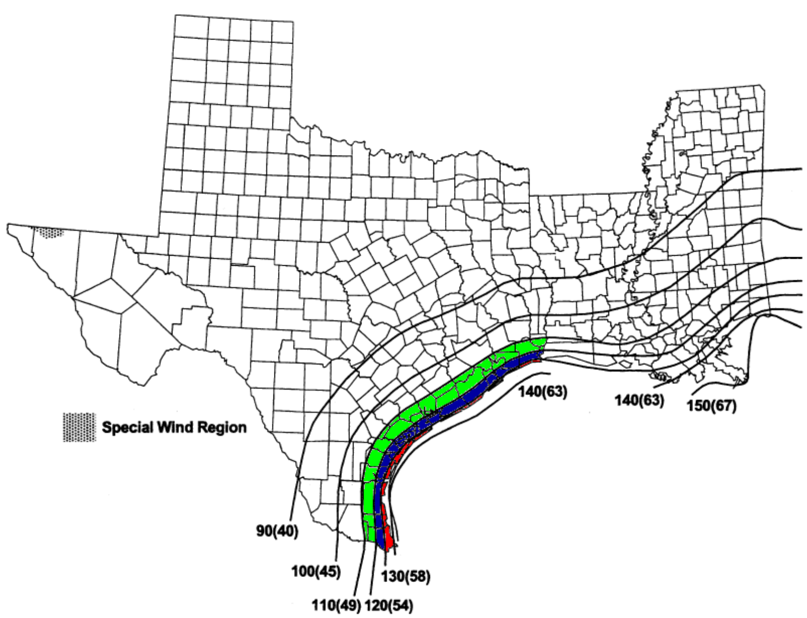

Figure A8. ASCE 7 Wind Map for Texas.

Figure A7 shows the simulated wind map within the 50 miles of Texas coast and Figure A8 presents the Texas portion of the actual wind map in which not all of the green colored band is within the 50 miles of Texas coast, so the green band in the actual wind map appears wider than that in the simulated wind map.

The simulation generally reproduces the Texas portion of ASCE 7 Wind Map with lower simulated peak gusts at the southern region. Mexico has not been included in the model due to the unavailability of relevant hurricane data. In this simulation, the areas around the border of Texas and Mexico are not impacted by simulated hurricanes coming from the southeast; therefore this causes the simulation results to be lower than the actual situation. West Louisiana has been included in the model, so the wind map of the eastern section of the 50 miles of Texas coast is consistent with the actual wind map.

It is also noticed that the simulated wind map is missing some of the red color band along the southern coastline. This is partially because the Texas coastline is approximated by linear sections, and the resolution is limited by the Excel presentation. When examining the wind speed simulated, the wind speed within those areas is very close to 130 mph, many of the girds have the worst wind speed in 50 years recorded at around 129mph.

The ASCE 7 Wind Map presents the average effect of thousands of hurricane simulations; the good reproduction of the Texas portion of this map demonstrates that the proposed hurricane simulation approach is able to estimate hurricane activities along the Texas coast and hurricane-induced distribution system damage with proper system damage model.

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Appendix B: Societal Cost Analysis

When a customer experiences an interruption, there is an amount of money that the customer is willing to pay to have avoided the event. This amount is referred to as the customer cost of reliability. In the U.S. alone, EPRI estimates that power interruptions result in more than $119 billion annually.[18]

The customer cost of reliability is typically estimated based on surveys. These surveys capture information about tangible costs, opportunity costs, and intangible costs. Tangible costs include items such as computer crashes, ruined processes, scrapped product, spoiled food, overtime pay, and the cost of going out to eat. Opportunity costs include lost production and lost sales. Intangible costs include inconveniences such as water pump failures, difficulties in getting ready for work, impact on leisure time, and needing to reset digital clocks.

The cost of an interruption varies widely from customer to customer and from country to country. Other important factors include duration, time of year, day of the week, time of day, and whether advanced warning is provided. Customers will also be impacted less if they have backup generators, uninterruptible power supplies and other on-site interruption mitigation equipment. Good customer surveys attempt to capture as much of this information as possible, but the quantity and interaction of parameters makes complete models difficult to achieve.

Estimates of customer cost are well-documented by a host of surveys. The Pacific Northwest National Laboratory chose to use the results of surveys of Canadian electricity users in 1992 and in 1996.[19,20,21] Costs of a typical one-hour interruption, normalized to peak load, are provided for a variety of commercial and industrial customers and shown to vary from virtually zero cost to more than $276 per kW. On average, industrial customers incur about $8.40/kW for a 1-hr interruption and commercial customers incur about $19.38/kW for a 1-hr interruption. Based on these results, large customers with high costs can easily incur millions of dollars per interruption hour.

The cost of an interruption is highly dependent on its duration. Short interruptions can result in computer crashes, ruined processes, and broken equipment. Longer interruptions result in lost production and ruined inventory. For specific customers, curves tend to be highly nonlinear. A semiconductor factory may incur a high initial cost due to a ruined process and a small time-dependent cost due to lost production. A plastic extrusion facility may incur small costs for short interruptions, but incur an extremely high cost if the interruption is long enough for plastic to solidify within the extrusion equipment. A refrigeration warehouse may not incur any cost for short interruptions. At a certain point, food will begin to spoil and severe economic losses will occur. After all of the food is spoiled, additional interruption time will not harm this particular customer much more.

[18] Consortium for Electric Infrastructure to Support a Digital Society (CEIDS), *The Cost of Power Disturbance to Industrial and Digital Economy Companies*, Electric Power Research Institute (EPRI), 2001.
[19] P. J. Balducci, J. M. Roop, L. A. Schienbein, J. G. DeSteese, M. R. Weimar, *Electrical Power Interruption Cost Estimates for Individual Industries, Sectors, and U.S. Economy*, Pacific Northwest National Laboratory (PNNL), Feb. 2002.
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[21] R. Billinton, "Methods to Consider Customer Interruption Costs in Power System Analysis," CIGRE, Paris, France, 2001.

There are many problems with customer surveys, the biggest being their tendency to overestimate the customer's willingness to pay. The bigger issue for hurricanes is that the surveys are based on short-duration interruptions that do not affect the broader local economy. A typical survey will ask questions based on 1-hour and 4-hour interruptions. These results are probably not representative of multi-day interruption costs. They also do not reflect that the surrounding local economy is severely impaired. For these reasons, survey data is not suitable for hurricane societal cost assessment and other methods are needed.

The two options besides customer surveys for estimating societal costs are case studies and GDP analysis. A case study looks at a widespread event, estimates the societal cost of the events, and uses this result as a basis for estimating the societal cost of similar events that may occur in the future. Unfortunately, hurricane GDP studies are not common and are difficult to generalize to different geographic areas and to different storm characteristic. Because the case study method is also not suitable, societal cost analysis is done using the GDP method.

The most common measure for the size of an economy is gross domestic product (GDP). GDP measures the market value of the total output of an economy. Total output includes all final goods and services, but excludes intermediate goods and services. The final GDP value must adjust for investment and net exports as follows:

GDP = consumption + investment + exports – imports

GDP is typically reported for countries. For example, the 2007 GDP for the U.S. was about $13.8 trillion as computed by the International Monetary Fund.[22] The contribution of country GDP is also computed for each state. The 2007 GDP for Texas was $1.14 trillion according to the U.S. Department of Commerce. Last, the contribution of GDP is computed for metropolitan statistical areas(MSAs). The GDPs of Texas MSAs are shown in Table B1 (2006 values as computed by the U.S. Bureau of Economic Analysis).

Five of the MSAs have been designated as prone to hurricane damage. These are the areas that have exposure within 50 miles of the Texas coastline. The designated hurricane prone MSAs are Beaumont-Port Arthur, Brownsville-Harlingen, Corpus Christi, Houston-Sugar Land-Baytown, and Victoria.

The total GDP of hurricane prone MSAs is $384 billion. This amounts to $1.1 billion dollars per day. That is, a total shut down of all economic activity in the designated hurricane-prone MSAs will result in a societal impact of $1.1 billion dollars per day, not including storm damage, the cost of evacuation and temporary relocation, or the cost of inconvenience, suffering, or human life.

Of course, a hurricane does not impact the entire Texas coastline and does not necessarily cause all economic activity to cease. Nor is the entire societal cost due to utility infrastructure damage. To account for these issues, the following assumptions are made when assessing societal cost:

[22] http://www.imf.org/external/country/USA/index.htm.

Societal Cost Assumptions

- Hurricane-prone MSAs in Texas generate economic activity as shown in Table B1.
- Hurricanes strike Texas with a frequency and severity corresponding to the probabilistic model described in Appendix A.
- Total electric power restoration times are assumed to be constant for a given hurricane category. These values are shown in Table B2.
- Average economic activity during restoration is equal to daily total economic activity multiplied by one-third of the total electric power restoration time. This recognizes that restoration efforts focus on restoring as many customers and businesses as quickly as possible.
- Only the direct cost of lost GDP is considered. The cost of human inconvenience, suffering, and life is real but difficult to directly attribute to the unavailability of utility service.

Table B1. GDP of Texas Metropolitan Statistical Areas (MSAs)

Texas MSA	GDP ($ millions)	Hurricane Prone
Abilene	4,927	
Amarillo	8,435	
Austin-Round Rock	71,176	
Beaumont-Port Arthur	**13,476**	**Yes**
Brownsville-Harlingen	**6,555**	**Yes**
College Station-Bryan	5,669	
Corpus Christi	**14,352**	**Yes**
Dallas-Fort Worth-Arlington	338,493	
El Paso	23,563	
Houston-Sugar Land-Baytown	**344,516**	**Yes**
Killeen-Temple-Fort Hood	12,286	
Laredo	5,450	
Longview	8,238	
Lubbock	8,389	
McAllen-Edinburg-Mission	12,026	
Midland	8,700	
Odessa	4,776	
San Angelo	3,216	
San Antonio	72,738	
Sherman-Denison	3,009	
Tyler	7,593	
Victoria	**4,766**	**Yes**
Waco	7,095	
Wichita Falls	5,403	
Texarkana	3,922	
Texas GDP (All MSAs)	998,769	
Texas GDP (Hurricane Prone MSAs)	383,665	
Daily Hurricane Prone GDP	1,051	

Table B2. Annual Expected Societal Cost of Hurricanes.

	Hurricane Category 1	2	3	4	5	GDP ($ millions)
	Annual Probability of Occurrence					
Beaumont-Port Arthur	4.45%	1.18%	0.38%	0.11%	0.01%	13,476
Brownsville-Harlingen	1.61%	0.30%	0.08%	0.01%	0.01%	6,555
Corpus Christi	4.34%	1.09%	0.42%	0.09%	0.07%	14,352
Houston-Sugar Land-Baytown	3.54%	0.83%	0.17%	0.03%	0.00%	344,516
Victoria	3.87%	0.75%	0.37%	0.03%	0.00%	4,766
Days to full restoration	6	10	20	30	60	
Days of economic loss	2.0	3.3	6.7	10.0	20.0	
Lost GDP ($millions)	**Lost GDP ($millions)**					**Total**
Beaumont-Port Arthur	3.29	1.45	0.94	0.41	0.07	6.15
Brownsville-Harlingen	0.58	0.18	0.10	0.02	0.04	0.91
Corpus Christi	3.41	1.43	1.10	0.35	0.55	6.85
Houston-Sugar Land-Baytown	66.83	26.11	10.70	2.83	0.00	106.47
Victoria	1.01	0.33	0.32	0.04	0.00	1.70
Total	**75.11**	**29.50**	**13.15**	**3.65**	**0.66**	**122.08**

Table B2 shows the probability of hurricanes of each category striking each hurricane prone MSA (determined by the probabilistic model). Using the restoration time assumptions, the expected annual GDP loss for each MSA due to each hurricane category is calculated. For example, Victoria has an annual GDP of $4,766 million. It has a 3.87% chance of being struck by a Category 1 hurricane. A Category 1 hurricane is expected to have a societal impact of two days worth of GDP. Therefore, the expected impact of Category 1 hurricanes on Victoria is equal to $4,766 x 3.87% x 2 days ÷ 365 = $1.01 million per year. This calculation is then repeated for all hurricane categories and totaled to result in the expected impact of all hurricanes on Victoria, in this case $1.7 million per year. This is then repeated for each hurricane prone MSA. The total for all areas is $122 million with the bulk of this coming from the greater Houston MSA ($106 million).

It should be emphasized that the probabilities listed in Table B2 do not necessarily include the number of hurricanes of each category. Rather, they represent the probability of winds within a specific hurricane category affecting the metropolitan area. For example, a Category 3 hurricane will cause Category 3 winds in some areas, but may cause Category 2 winds in some areas and Category 1 winds in others.

The typical size of hurricanes, as measured by the radius of hurricane-force winds, is shown in Table B3. A visual representation of these sizes is shown in Figure B1. Due to their large size, hurricanes are assumed to impact an entire metropolitan area when the center of the area experiences hurricane-force winds.

Hurricane benefits are computed by estimating the impact of activities on the number of days to full restorations. The calculations are repeated and the difference between the original analysis and the updated analysis represents the societal benefit, broken down by metropolitan area, of the hurricane mitigation activity.

Table B3. Typical Hurricane Sizes

Saffir – Simpson Hurricane Category	Radius of Hurricane-Force Winds (mile)
1	69.4
2	92.5
3	121.3
4	144.4
5	161.9

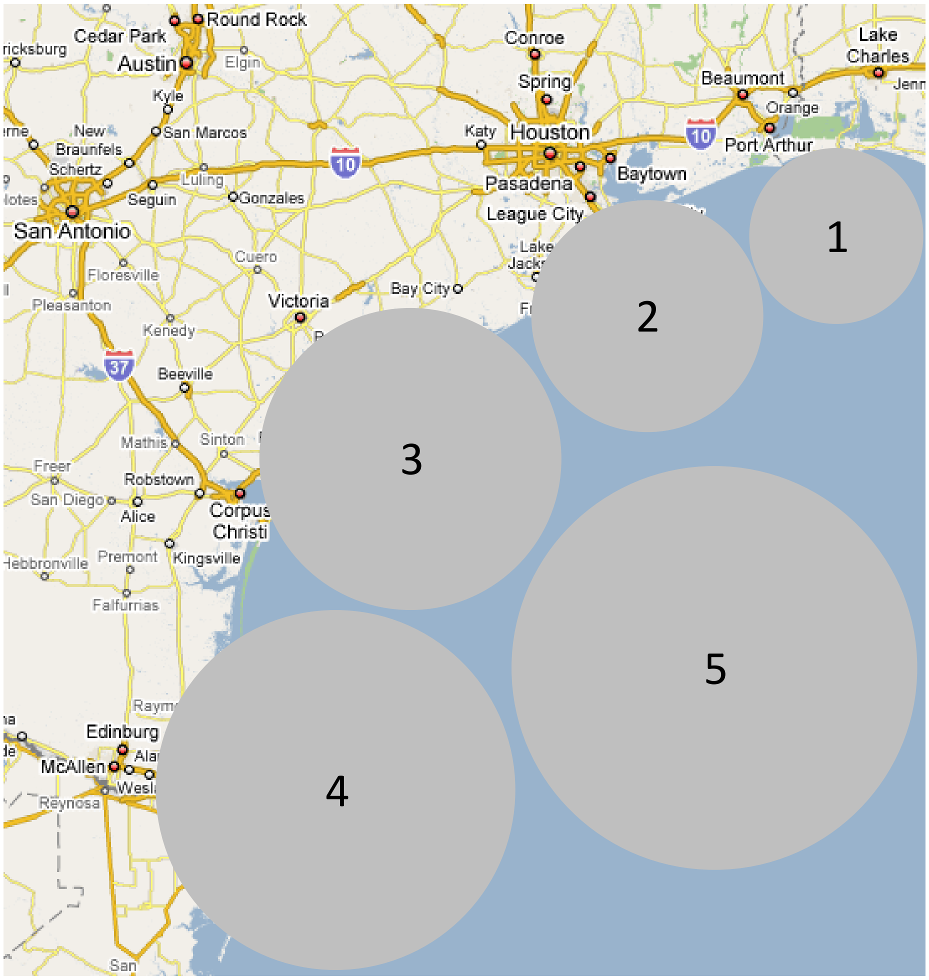

Figure B1. Typical Hurricane Sizes by Category.

Appendix C: Electric Utility Questionnaire

1. How many retail customers do you serve?
2. What wind loading standards are used for overhead transmission and distribution (e.g., NESC Grade B for transmission and Grade C for distribution)?
3. About how many circuit miles do you have of the following:
    a. Overhead distribution
    b. Underground distribution
    c. Overhead transmission
    d. Underground transmission
4. About how many of the following are in your system:
    a. Distribution poles
    b. Transmission structures
    c. Substations
5. About what percentages of the following are within 50 miles of the gulf coast (rough estimates are OK)?
    a. Overhead distribution
    b. Underground distribution
    c. Overhead transmission
    d. Underground transmission
6. About what percentages of the following are vulnerable to hurricane storm surge damage (very rough estimates are OK)?
    a. Overhead distribution
    b. Underground distribution
    c. Overhead transmission
    d. Underground transmission
7. About how many miles of vegetation management were performed in 2008 for:
    a. Overhead distribution
    b. Overhead transmission
8. About how much was spend on patrolling for vegetation management performed in 2008 for :
    a. Overhead distribution
    b. Overhead transmission
9. About how much was spent on vegetation management in 2008 for:
    a. Overhead distribution
    b. Overhead transmission
10. About how many miles of ground-based circuit inspections were performed in 2008 for:
    a. Overhead distribution
    b. Overhead transmission
11. About how much was spent on ground-based circuit inspections in 2008 for:
    a. Overhead distribution
    b. Overhead transmission
12. How many substations are within a 100 year floodplain:
13. How many substations within 50 miles of the gulf coast have back-up power?

Appendix D: Transmission Structure Damage Estimates

Category 1								
Current Trans Struct Fail Rate	0.15%							
Hardened Trans Struct FR	0.12%							
	Prob of Occurrence	Projected Structure Failures- Current	Projected Structure Failures- Hardened	Reduction in Structure Failures	% Damage Reduction	Direct Savings @ $60k per structure ($000s)	Weighted Savings ($000s)	Days Restoration Reduced
Entergy (Beaumont-Port Arthur)	4.45%	23	19	5	20%	282	25.1	0.24
CenterPoint & TNMP (Houston)	3.54%	29	23	6	20%	350	24.8	0.09
AEP (Victoria) 20%	3.87%	5	4	1	20%	64	5.0	0.10
AEP(Corpus & Brownsville) 80%	5.95%	21	17	4	20%	256	30.5	0.10

Category 2								
Current Trans Struct Fail Rate	1.04%							
Hardened Trans Struct FR	0.13%							
	Prob of Occurrence	Projected Structure Failures- current	Projected Structure Failures- Hardened	Reduction in Structure Failures	% Damage Reduction	Direct Savings @ $60k per structure ($000s)	Weighted Savings ($000s)	Days Restoration Reduced
Entergy (Beaumont-Port Arthur)	1.18%	163	20	143	88%	8,550	201.8	1.43
CenterPoint & TNMP (Houston)	0.83%	202	25	177	88%	10,628	176.4	0.50
AEP (Victoria) 20%	0.75%	37	5	32	88%	1,943	29.2	0.59
AEP(Corpus & Brownsville) 80%	1.39%	148	19	130	88%	7,774	216.1	0.59

Category 3								
Current Trans Struct Fail Rate	6.29%							
Hardened Trans Struct FR	0.76%							
	Prob of Occurrence	Projected Structure Failures- current	Projected Structure Failures- Hardened	Reduction in Structure Failures	% Damage Reduction	Direct Savings @ $60k per structure ($000s)	Weighted Savings ($000s)	Days Restoration Reduced
Entergy (Beaumont-Port Arthur)	0.38%	985	119	866	88%	51,960	394.9	2.18
CenterPoint & TNMP (Houston)	0.17%	1,224	148	1,076	88%	64,584	219.6	0.75
AEP (Victoria) 20%	0.37%	224	27	197	88%	11,810	87.4	0.87
AEP(Corpus & Brownsville) 80%	0.50%	896	108	787	88%	47,240	472.4	0.87

Category 4								
Current Trans Struct Fail Rate	71.90%							
Hardened Trans Struct FR	8.74%							
	Prob of Occurrence	Projected Structure Failures- current	Projected Structure Failures- Hardened	Reduction in Structure Failures	% Damage Reduction	Direct Savings @ $60k per structure ($000s)	Weighted Savings ($000s)	Days Restoration Reduced
Entergy (Beaumont-Port Arthur)	0.11%	11,260	1,369	9,891	88%	593,451	1305.6	2.30
CenterPoint & TNMP (Houston)	0.03%	13,995	1,701	12,294	88%	737,632	442.6	0.77
AEP (Victoria) 20%	0.03%	2,559	311	2,248	88%	134,887	80.9	0.90
AEP(Corpus & Brownsville) 80%	0.10%	10,237	1,244	8,992	88%	539,548	1079.1	0.90

Category 5								
Current Trans Struct Fail Rate	100.00%							
Hardened Trans Struct FR	34.64%							
	Prob of Occurrence	Projected Structure Failures- current	Projected Structure Failures- Hardened	Reduction in Structure Failures	% Damage Reduction	Direct Savings @ $60k per structure ($000s)	Weighted Savings ($000s)	Days Restoration Reduced
Entergy (Beaumont-Port Arthur)	0.01%	15,660	5,425	10,235	65%	614,123	122.8	4.61
CenterPoint & TNMP (Houston)	0.00%	19,465	6,743	12,722	65%	763,325	0.0	1.57
AEP (Victoria) 20%	0.00%	3,559	1,233	2,326	65%	139,585	0.0	1.84
AEP(Corpus & Brownsville) 80%	0.08%	14,238	4,932	9,306	65%	558,342	893.3	1.84