MAINE PUBLIC UTILITIES COMMISSION

REPORT RELATED TO PUBLIC LAW 2017, CHAPTER 448

Presented to the
Joint Standing Committee on
Energy, Utilities and Technology
February 1, 2019

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Mark A. Vannoy
CHAIRMAN

R. Bruce Williamson
Randall D. Davis
COMMISSIONERS

Harry Lanphear
ADMINISTRATIVE DIRECTOR

February 1, 2019

Honorable Mark W. Lawrence, Senate Chair
Honorable Seth A. Berry, House Chair
Energy, Utilities and Technology Committee
100 State House Station
Augusta, Maine 04333

Re: Report Related to Public Law 2018, c. 448

Dear Senator Lawrence and Representative Berry:

During the 2018 legislative session, An Act To Restore Confidence in Utility Billing Systems was enacted (Act).[1] Section 4 of the Act directed the Public Utilities Commission (Commission) to submit a report to the Committee by February 1, 2019 related to whether investor-owned utilities are doing enough to protect and strengthen their systems in light of storm events, whether it is in ratepayers' interests to require them to do more, and, with respect to utility operations, what can be done to improve public safety during storm events and what lessons have been learned from recent storm related outages. Attached is the Commission's Report for the Committee's consideration.

If you have any questions, please do not hesitate to contact us.

Sincerely,

Mark A. Vannoy, Chairman

On behalf of the Chairman
R. Bruce Williamson, Commissioner
Randall D. Davis, Commissioner
Maine Public Utilities Commission

cc: Energy, Utilities and Technology Committee Members
Lucia Nixon, Legislative Analyst

[1] P.L. 2018, c. 448.

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I. INTRODUCTION

During the 2018 session, An Act to Restore Confidence in Utility Billing Systems, P.L. 2017, c. 448 (Act), became law. Section 4 of the Act directed the Public Utilities Commission (Commission) to submit a report to the Energy, Utilities and Technology Committee by February 1, 2019 that addresses the following issues:

1. Whether investor-owned transmission and distribution utilities are doing enough to protect and strengthen their systems, especially with what appears to be an increase in high-intensity storm events;

2. Whether it is in the ratepayers' interest to require investor-owned transmission and distribution utilities to do more to strengthen and protect their systems against damage in order to prevent and decrease the number and duration of power outages; and

3. With respect to utility operations, what can be done to improve public safety during storm events and what lessons have been learned from recent outages due to storm events.

With respect to question 3, the Act directed Commission to consult with the Maine Emergency Management Agency (MEMA) and to review what other states are doing to improve emergency planning and preparedness. The Commission submits this report in accordance with the Legislature's directive.

II. BACKGROUND

On October 29, 2017, a rain/wind storm moved into the State which caused significant outages in both the territories of Central Maine Power Company (CMP) and Emera Maine. Specifically, service to approximately 404,000 CMP customers and 90,000 Emera Maine customers was interrupted as a result of this storm. In a number of cases, customers were without power for more than a week.

Given the extent of and duration of the outages which resulted from this storm, the Commission found it appropriate to initiate a summary investigation to gather information on the transmission and distribution (T&D) utilities preparedness and response to the October 2017 storm and to review what steps T&D utilities have taken, or should be taking in the future, to prepare their systems for the effects of future storms. *Public Utilities Commission, Investigation into the Response by Public Utilities to the October 2017 Storm*, Docket No. 2017-00324, Notice of Investigation (December 19, 2017) ("*October Storm Investigation*").

In its Order issued on October 4, 2018, the Commission concluded that, based on weather forecast information and availability of storm restoration crews, both CMP and Emera Maine acted reasonably in their preparation for and in their response to the major wind and rain storm in October 2017. The Commission's Order, however, noted that the information collected during the investigation indicated areas for improvement for future utility storm performance including coordination with other entities including county Emergency Management Agencies (EMAs) and MEMA. Therefore, as part of the utilities' overall Improvement Plans, which were required to be filed on December 1, 2018, the Commission required CMP and Emera Maine to report on the steps that they had taken and plan to take to improve coordination with other entities, including EMAs, during storms or other emergency situations. *October Storm Investigation*, Order at 1, 10.

To address the other aspect of the Commission's investigation (steps utilities have taken, or should be taking in the future to prepare for future storms), as well as to address questions one and two set forth in the Act, on August 9, 2018, the Hearing Examiner in the *October Storm Investigation* issued a Procedural Order which required CMP and Emera Maine to provide the following information to the Commission:

1. A description of how the design and strength of the utility's current system compares to the requirements of the National Electric Safety Code (NESC) and other applicable national or regional codes and standards with particular focus on performance and resiliency related to storm events;

2. A description of the utility's existing or planned programs or programs to strengthen its system against high intensity storm events;

3. The utility's plan to minimize the number and duration of power outages in storm events, including high intensity storm events;

4. A description of any plans that the utility's parent has to address the issues set forth in the Act on a corporate-wide basis or across multiple utility affiliates;

5. With respect to the prior question, a description of how and why the utility's plans differ from those of the utility's parent;

6. The projected costs, revenue requirement, and rate impacts of implementing the plans identified in response to the prior questions;

7. A cost/benefit analysis of any of the plans and investments identified in response to the prior questions, including (1) all evidence relied on by the utility which demonstrates that the plans and investments will reduce the number and/or duration of outages, and (2) all evidence or analysis relied on by the utility to determine the benefits to customers from avoiding or reducing the duration of outages; and

8. In addition to the investments and/or procedures that are identified in response to the prior questions, a description of additional investments and/or procedures that could strengthen the T&D system to minimize or reduce the duration of outages. Please fully describe such investments and/or procedures, estimated costs, and provide the analysis or rationale that lead the utility to conclude such that options should not be pursued.

III. ISSUES ONE AND TWO

CMP and Emera Maine filed their reports in response to the Procedural Order on September 7, 2018. A technical conference on the reports was held on September 12, 2018.

Both the CMP and Emera Maine Reports indicated that their construction standards are in conformity with the NESC. In its report, CMP noted that the NESC takes into account the regional impact of weather and provides a design that will meet the majority of operating conditions that the assets should experience over their lifetime. Emera Maine noted that depending on the type of line and other individual factors, design margins above the NESC minimums are often applied, based on engineering discretion, to increase line performance for storm resiliency and overall reliability.

Emera Maine also noted that as part of its ongoing effort to improve reliability, Emera Maine has developed the following initiatives to reduce outages:

1. Vegetation Management – Emera Maine noted that it moved from a six-year cycle trim program to a five-year program on July 1, 2018. At the same time, Emera Maine enhanced its Danger Tree Removal Program by going from Danger Tree Removals on line sections serving 1,000 or more customers every six years to removals on line sections serving 200 or more customers every three years.

2. Line Rebuilds Using Covered Conductor – Emera Maine notes that it evaluates the use of covered conductor on a case by case basis. Covered conductor can reduce customer interruptions by preventing faults when branches or small to medium size trees lean on distribution lines.

3. T&D Inspection Repairs – Emera Maine notes that it has a schedule for the inspection of its lines and that the repairs from these inspections have an impact on storm resiliency.

4. Protection and Coordination – This includes the installation of sectionalizers and reclosers which reduce outage impacts in terms of customers interrupted and hours of interruption.

Emera Maine noted that it does not have a definitive plan or program constructed just for large storm events and has not done a cost/benefit analysis for such a program. Emera Maine states that its approach is to improve reliability as measured by the Service Area Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI) for small storms and normal operating conditions. However, benefits for large storm events can be expected as a result of Emera Maine's reliability efforts. Emera Maine concluded that it is already using cost effective storm resiliency methods on an individual project basis. Emera Maine goes on to note that a dedicated high intensity storm hardening program would substantially improve reliability during such events and it is willing to undertake such investments if ratepayers desire that the Company pursue such investments.

In its Report to the Commission, CMP noted that similar to most utilities, tree-related issues were the most common cause of outages on CMP's system which were at least in part, location driven. CMP noted that tree-caused outages represented 40% of the interruptions and, out of CMP's 475 distribution circuits, 113 circuits (or approximately 24%) are responsible for 75% of the outages.

As part of its response, CMP stated that it was currently in the process of developing a new Resiliency Plan which would focus on improving several characteristics of CMP's network. Specifically, the Plan would focus on improving performance in the following areas:

1. Network Topology – Designed to improve connectivity between circuits and substations and allowing for alternate supply possibilities. CMP noted here that there are 42 circuits (out of the total of 475 circuits on its network) that are over 100 miles long, and which are responsible for 30% of the SAIFI performance.

2. Automation Level – Increasing the number of recloser and SCADA switches. CMP noted that this increased automation will minimize the number of customers affected by an outage, isolate the area impacted by the outage quicker and accelerate customer restoration.

3. Vegetation Management – "ground-to-sky" trimming on selected circuits with high reliability issues.

4. Proactive Distribution Renewal – The Plan proposes to increase improvements to the distribution system through targeted class upgrades and replacements.

5. Construction Standards – Use of more robust construction standards including the use of large class poles, increased use of covered tree-wire and composite dead-end crossarms.

As part of its submission, CMP noted that it intended to fully set forth its proposed Resiliency Plan, including projected costs, as part of its rate case filing to be submitted in the Commission's current rate investigation, *Public Utilities Commission, Investigation of Central Maine Power Company's Rates and Revenue Requirements*, Docket No. 2018-00194. On October 15, 2018, the Company submitted its Rate Case filing which included testimony regarding proposed improvements in its operations and capital investment programs. Specifically, the Company proposed modifications to its vegetation management program designed to reduce tree-related outages and proposed modifications to its reliability programs. In addition, as part of its proposal, the Company submitted additional details on its proposed $24 million resiliency related plant additions set forth below:

TABLE #1

Resiliency Planned Capital Forecast by Category for 2019-2020
($'s in thousands)

Description	2019 Forecast	2020 Forecast	Total
1. Circuit Segmentation	$ 1,000	$ 5,000	$ 6,000
2. Feeder Ties	2,000	5,000	7,000
3. Circuit Upgrades	2,000	2,000	4,000
4. Incremental Automation	3,000	4,000	7,000
5 Total	$ 8,000	$ 16,000	$ 24,000

The Company's Resiliency Plan proposals are now subject to review and adjudication in the rate case. *Central Maine Power Company, Commission Initiated Investigation into Rates and Revenue Requirements*, Docket No 2018-00194. Thus, the Commission will necessarily address in the rate case proceeding the questions of whether CMP is doing enough to protect and strengthen its systems and whether it is in ratepayers' interest to pay for investments that would do so. As such, it would not be appropriate for the Commission to comment on these issues as part of this report since such comments would essentially amount to a prejudgment of issues in a pending rate case.[1]

Although the Commission cannot specifically comment on questions one and two, we are providing with this Report three studies on the issue of storm hardening and resilience which were obtained during the *October Storm Investigation*. The first report was prepared for the Public Utilities Commission of Texas by Quanta Technology (Attachment A); the second study was a computation of storm hardening and resiliency studies, programs and policies prepared by the Edison Electric Institute (EEI) (Attachment B); and the third study is the Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018, prepared by the Florida Public Service Commission (Attachment C). As noted above and in the attached reports, evaluating the need for investments and expenditures to increase the reliability and resiliency of a T&D utility's system requires consideration of the costs that would be incurred (and recovered from ratepayers) to achieve these reliability and resiliency increases.

[1] The Commission would also note that Emera Maine has filed a notice with the Commission, pursuant to the provisions of 35-A M.R.S. § 307, of its intent to file for a general rate increase. The Commission expects that the issues set forth in questions one and two of P.L. 2017, c. 448 § 4 will also be raised during the course of this rate proceeding.

IV. ISSUE THREE

A. The Commission's October 2017 Storm Order

The Commission's *October Storm Investigation* Order found that:

> "Information collected during the summary investigation indicated a lack of a coordinated, commonly understood, and consistently followed set of protocols for information exchange and responsibility for action among the utilities, municipalities, county EMAs and MEMA. This appeared to have resulted in delays in addressing unsafe conditions, e.g., wires in the road, making roads passable, and, generally, introduced uncertainties and inefficiencies that may have impeded restoration efforts."

The Commission noted that, during the investigation, CMP and Emera Maine recommended that utility employees be present at MEMA during future events involving significant power outages and both utilities expressed a desire to improve coordination with county EMAs during major events, such as substantial storms. The Commission found that these were positive and constructive recommendations and required CMP and Emera to report and provide additional details on these and other steps that could be taken to improve emergency response coordination in their December Improvement Plan Reports to the Commission.

The Commission's Order also addressed storm response coordination with telecommunications and cable providers. Here, the Commission noted that although Charter (a/k/a Time Warner Cable) communicates with utilities during storms, it does not typically have any formal communications with governmental officials such as county EMAs. Charter agreed that there were situations during the October Storm where a lack of communication between utilities, pole attachers and governmental entities meant that in some cases companies were not informed that their facilities were blocking roads and that this lack of communication contributed to the duration of road closures since the right crews could not be located to repair or move downed wires.

Consolidated Communications (formerly FairPoint Communications) told the Commission that during major storm events, Consolidated does not communicate directly with county or State governmental officials. Similarly, the Telephone Association of Maine (TAM) also stated that it did not believe that its members communicate with county emergency groups during storms though they are in contact with county sheriffs. Both Consolidated and TAM stated, however, that they would be willing to work more closely with MEMA or county EMAs during major storm events.

B. Consultation with MEMA

Pursuant to the Legislature's directive, the Commission Staff has had several phone calls with MEMA personnel and on August 21, 2018, Commission Staff hosted a meeting between MEMA Director, Suzanne Kraus, MEMA Deputy Director, Peter

Rogers, and other MEMA staff members to discuss MEMA's perspective on the storm restoration effort and areas identified for improvement.

At that meeting, MEMA described its storm response approach as following the Federal Emergency Management Agency (FEMA) model which it described as "federally supported, state managed and locally executed." Thus, under this paradigm, emergency management services are intended to be provided at the local level to the greatest extent possible.[2] Local service providers work with emergency centers at the county level when they do not have the resources or expertise to adequately respond to emergency situations. When the county is unable to respond, they contact MEMA to facilitate a more robust response using other nearby county or state resources. According to MEMA, each town or municipality is supposed to have someone acting as a local emergency manager who is responsible for deciding when to seek assistance from the county EMA and for submitting the request. MEMA indicated that while most municipal and town responders were aware of their roles and responsibilities, there were some who did not follow the proper emergency response protocol to route their requests through the county EMA. Failure to do so added confusion and inefficiency to the restoration effort.

During the meeting, MEMA referenced a report it had issued, October 2017 Storm/ Power Outages After Action Report and Improvement Plan, (MEMA Report) (Attachment D) which critiqued the overall storm recovery effort. As part of the overall effort to improve communications as discussed above, the MEMA Report stated that the electric and telecommunications / cellular utilities are "critical infrastructure during a response and recovery event." MEMA Report at 9. As such, the primary utilities should have personnel assigned to staff the State Emergency Operations Center (SEOC) when it is activated. Additionally, MEMA noted a need to coordinate training with the utilities to better understand roles and responsibilities.

Another key area addressed in the MEMA Report related to improving public safety during storm events was the need to improve the road closure accuracy process. MEMA relies on a "Road Closures" board within their online communications portal (referred to as WebEOC). This board allows for the documentation and tracking of closures, status reports, and detours during an event. The emergency response providers and county EMAs stated that the information was "inconsistent, inaccurate or at times non-existent." Further, MEMA reported that, "team members were unclear as to who provided road status and clearing updates (Utilities or DOT)" MEMA Report at 11. The MEMA Report concluded that additional training and performing simulation exercises would be beneficial.

[2] The term "local level" refers to the town or municipality.

C. CMP Plan for Storm Restoration Improvement

In its December 3, 2018 filing, CMP responded to the Commission's concern regarding improving public safety during a storm response through the submission of its CMP Improvement Plan. CMP noted that it has taken numerous steps to improve the coordination and communication with many emergency management partners, including first responders and U.S. Customs and Border Protection. One positive result of these discussions was to have a more stream-lined pre-approval process for Canadian storm crews crossing the border enacted by the federal authorities. Another important result included working with Kennebec and York counties to develop and implement a new road clearing policy for storm restoration. Under this new policy, CMP will assign a limited number of crews to each affected county for the purpose of clearing roads and undertaking safety related activities prior to beginning restoration work. The impacted communities will be required to follow the Incident Command System (ICS) system to coordinate the road clearing requests through the County Emergency Management Agency (CEMA) or MEMA centers. This policy has been implemented on a state-wide basis.

Additionally, CMP has also been involved in a number of training presentations. In its response, CMP highlighted a meeting it held with all 16 county emergency management directors and MEMA where they addressed standardization and development of common practices to improve storm response efforts. CMP has indicated that it intends to commit to on-going communication efforts with partnering agencies.

D. Emera Maine Response

Emera Maine's report to the Commission also indicated its plan to address communication and coordination with state and local emergency agencies. Like CMP, Emera Maine noted that it has undertaken a series of steps to improve the communication with the EMAs. In addition to attending training exercises and meetings, Emera Maine has developed a process for storm planning communication, designated personnel to timely respond to the EMA and developed Memoranda of Understanding with the EMAs that define the communication and coordination plans.

The Emera Maine report details two additional projects the utility is advancing. The first initiative is to work with the EMAs to prioritize service restorations to critical infrastructure using the Emera Maine GIS system. Emera Maine noted that Penobscot and Bangor EMAs have provided Emera Maine with their prioritized lists. The second initiative is with MEMA to embed Emera Maine personnel in the SEOC when it is activated.

E. Activities In Other States

As requested, the Commission has reviewed other state efforts with respect to storm response. This survey confirmed that states generally follow the federal model discussed above. As part of this process, the Commission Staff reached out to the other New England state commissions to ascertain what their public safety role is during storm recovery situations. All states that responded indicated that their Commission's coordinate with their version of MEMA during storms, supply staff to their Emergency Operations Centers, and utilize the FEMA model discussed previously. Appendix 1 to this Report is a general summary of the information provided by each state in regard to storm restoration efforts as well as ongoing activities related to emergency management public safety.

F. Conclusions

Following the October 2017 storm, MEMA, CMP and Emera Maine have all developed plans to enhance their storm restoration policies and procedures. Additionally, both utilities have investigated their prior actions and have developed plans to make improvements. With regard to improving safety during major storm events, all parties have advanced efforts to define roles and responsibilities and better coordinate and communicate recovery information. CMP and Emera Maine both reported improved performance throughout 2018 and provided testimonials from partner agencies. A promising development is that there appears to be a shared commitment by all parties to continue the cross-agency engagement and process improvement efforts.

As evidenced by the information provided by MEMA, the utilities and the other New England states, Maine's process is consistent with regional best practices. Since the October 2017 storm, there has been a concerted effort to develop processes and standards for communicating among agencies, prioritizing safety and restoration efforts, and improving outage information to the public. The commitment to ongoing training will further strengthen roles and responsibilities.

The Commission is now in the process of scheduling a stakeholders meeting to ensure improvements discussed above are in fact in place and that the stakeholders have the same expectations as to what conduct is expected and the communication protocols during storm event situations. In addition, at such time, stakeholders can share additional thoughts that they may have regarding ways to further enhance emergency storm response efforts.

Appendix 1

1. The Rhode Island Public Utilities Commission (RI PUC) opened a docket (Docket No. D-17- 45) to review National Grid's October 2017 storm response and commissioned Power Services to prepare a post storm report (http://www.ripuc.org/eventsactions/docket/D_17_45_Final_report.pdf). Beyond the numerous communication and reporting issues, the authors of the report recommend that "the Division perform a separate evaluation of the Mutual Aid process and NAMAG to determine if Rhode Island is consistently being provided resources in an appropriate priority scheme and at proportional levels to requests from other regional utilities.

2. Connecticut PURA Train staff in the ESF and the web-based emergency management tool for tracking/coordinating resources/events. Additionally, Commissioners and staff meet at least once a year with their utilities to discuss storm response performance. Every two years, PURA reviews the utilitys' emergency response plans.

3. The New Hampshire Safety Division participates as a subject matter expert for the Energy and Communications Sector– two important sectors of the States Emergency Operation Plan. The Safety Division assists with revisions to the States Emergency Operation's Plan and related annexes. During state wide emergency in which the Emergency Operations Center is activated, representatives of the Safety Division collect and distribute emergency response activities of the affected utilities. (https://www.puc.nh.gov/Safety/safety.htm) The New Hampshire Public Utilities Commission (Commission) conducted extensive after-action reviews following three of its largest storms; the December 2008 Ice Storm, the October 2011 snowstorm, 2014 Thanksgiving snowstorm, to assess utility preparedness and emergency response capabilities in New Hampshire.

4. Massachusetts: The annual storm and emergency restoration report details the company's storm and emergency plans ("ERPs") to respond to any emergency event such as hurricanes or snowstorms. The companies are required to file their ERPs annually, including actions taken to prepare for an emergency event. The ERPs are established pursuant to 220 C.M.R. § 19.00, Standards of Performance for Emergency Preparation and Restoration of Service for Electric Distribution and Gas Companies, and Emergency Response Plan Guidelines for electric companies. In addition, the Department closely monitors storm events and assigns staff to the Massachusetts Emergency Management Agency ("MEMA") bunker when necessary. (https://www.mass.gov/files/documents/2018/01/26/DPU%202017%20AR%20-%20Final.pdf)

5. Vermont: Tree trimming and emergency preparedness are reviewed every three years as part of the Integrated Resource Plan process. Vermont Electric Power Company (VELCO), which is owned by all of the Vermont electric distribution

companies, coordinates and maintains a call list of agencies for storm management; and hosts calls storm response calls similar to the other states. Many of the events are not at the level necessary to open the SEOC but operate in a similar manner.

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**

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March 4th 2009

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Quanta Technology's Background on Similar Projects

Similar Projects

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

Florida Undergrounding Study, Florida Electric Utilities
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]

Reliability Improvement Roadmap, Puget Sound Energy
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.

Hurricane Hardening Roadmap, Florida Power & Light
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.

Extreme Wind Hardening Benchmark Survey, BC Hydro
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.

QUANTA TECHNOLOGY

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 wide-spread 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

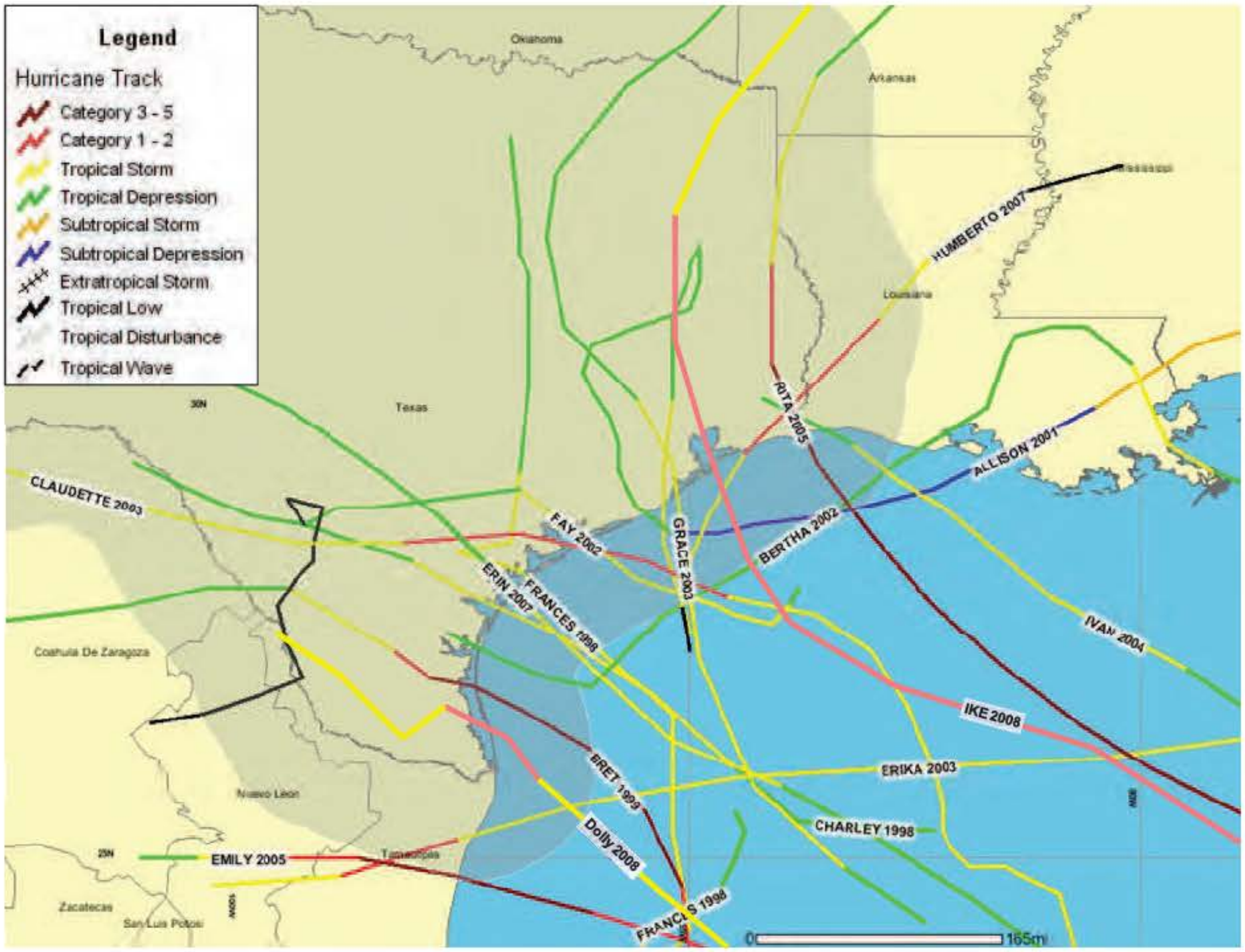

Figure 2-3. Tracks of hurricanes making Texas landfall in the last ten years.

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.

QUANTA TECHNOLOGY

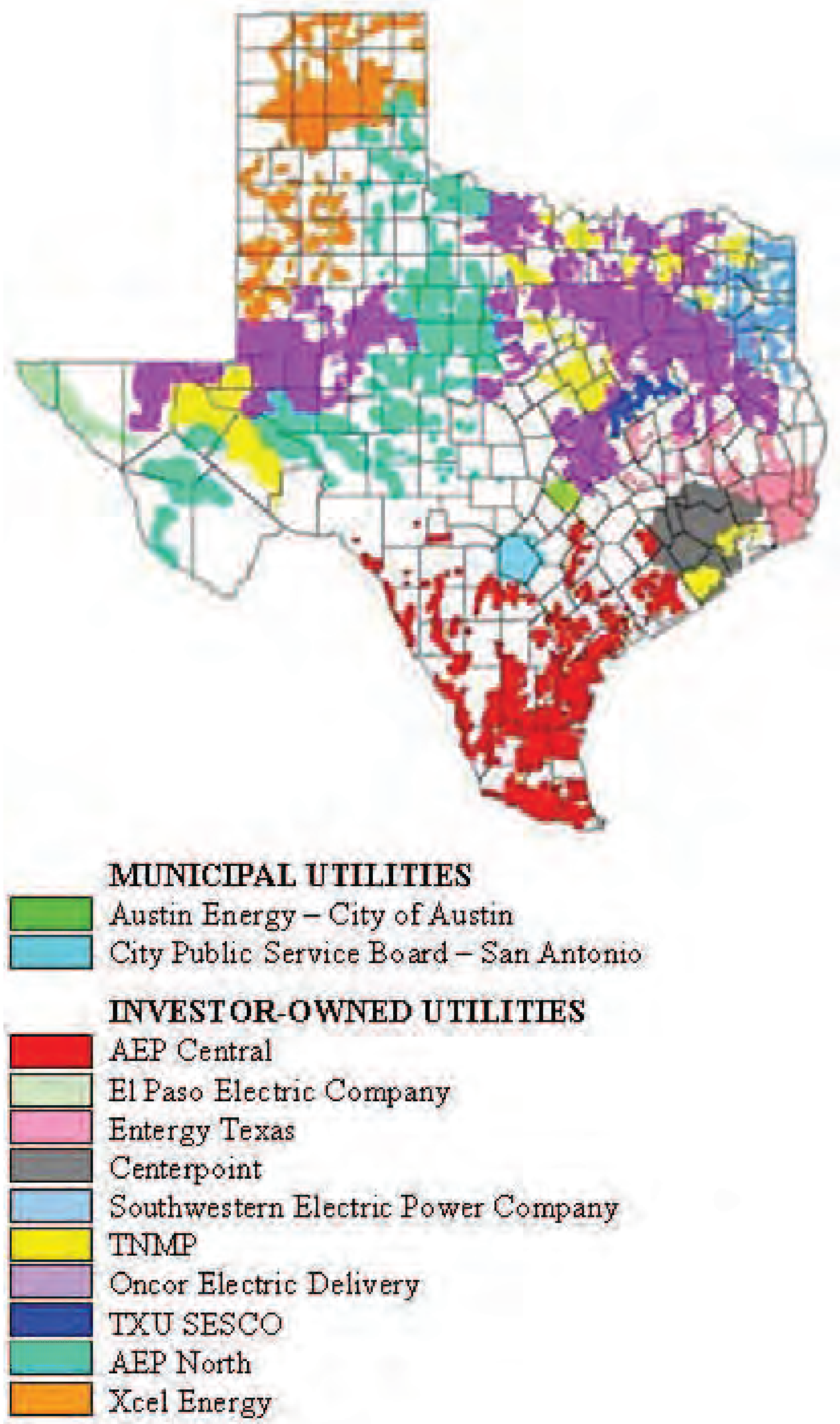

Figure 2-6. Electric IOU and municipal utility service territories in Texas.

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.

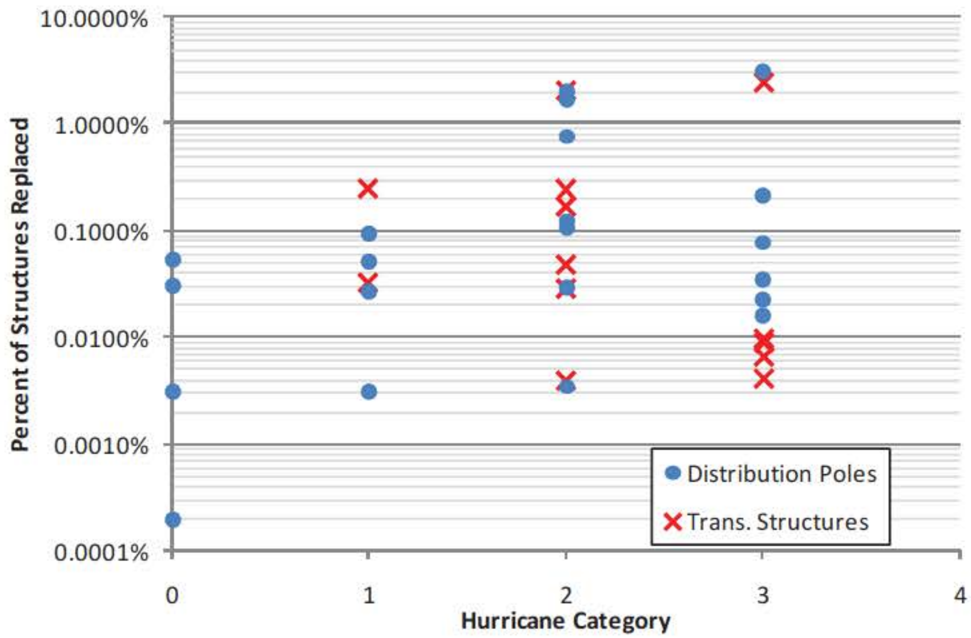

Figure 2-7. Structure replacement versus Hurricane Strength

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.

<u>Electric Utilities</u>

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.

[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.

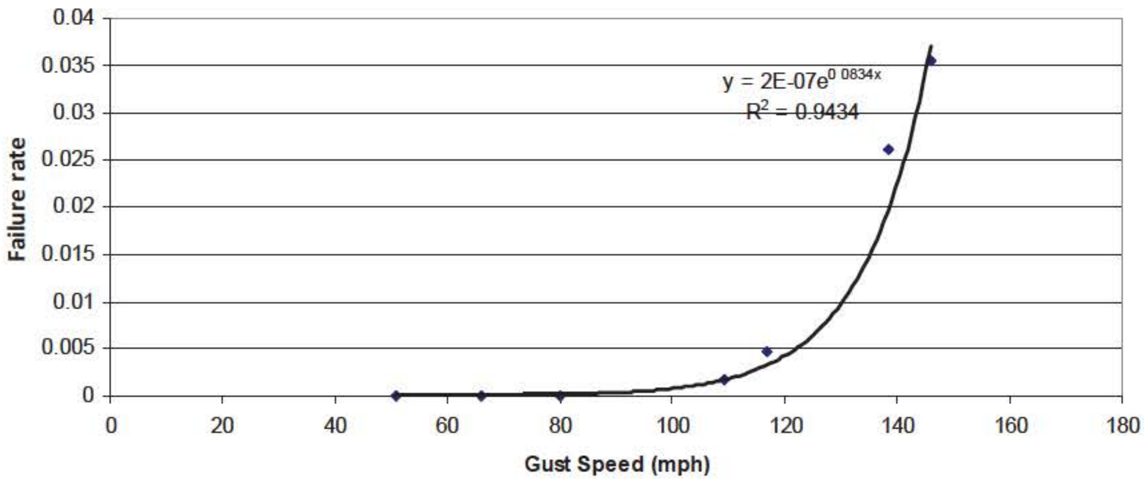

Figure 5-4. Existing transmission structure failure rate

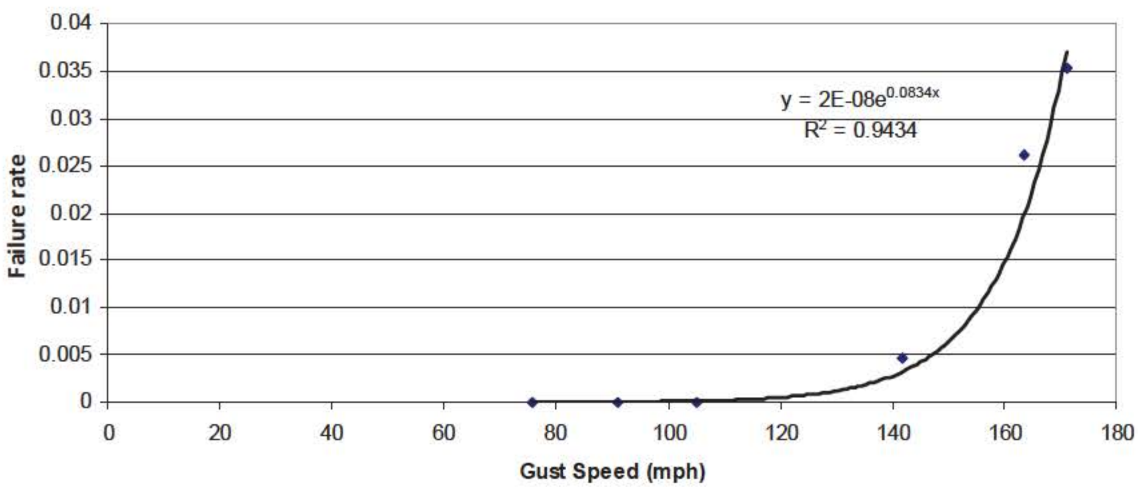

Figure 5-5. Hardened transmission structure failure rate

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:

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

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

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

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

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

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

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:

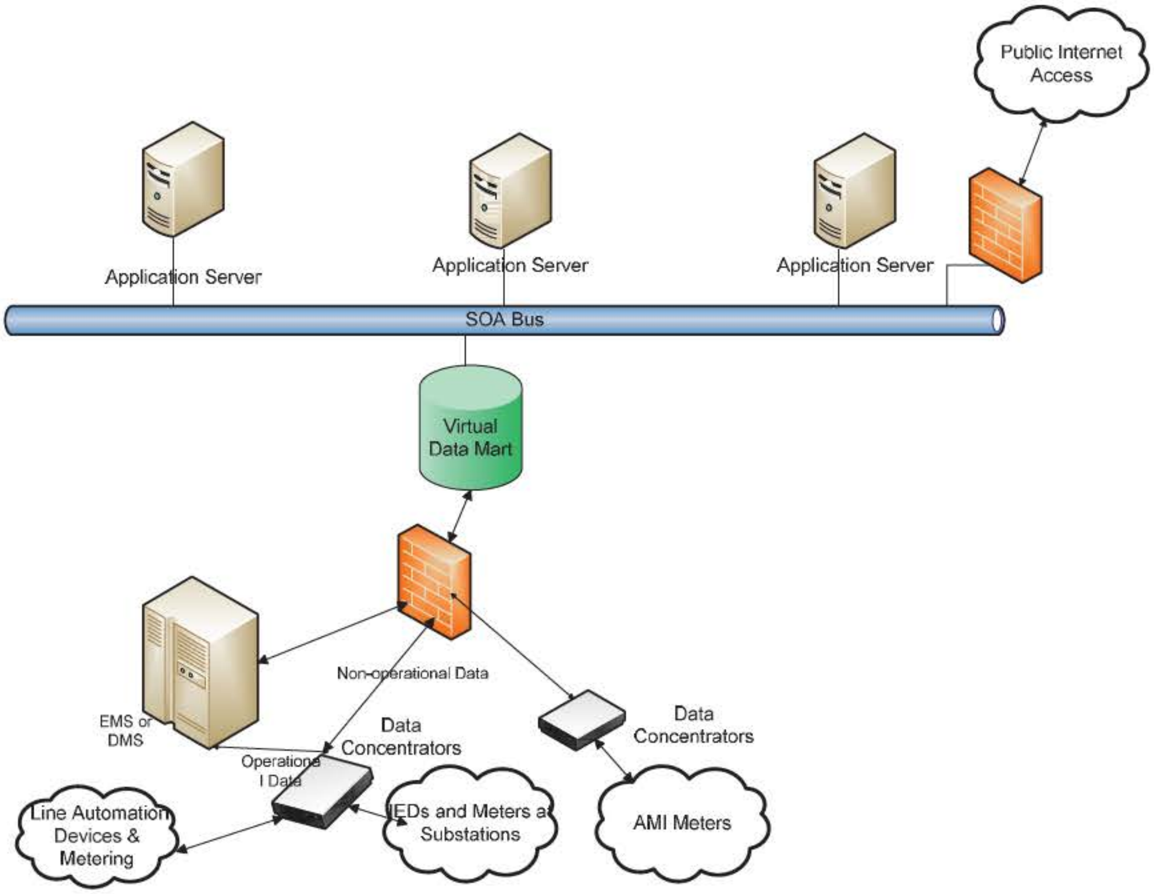

Figure 6-1. System Architecture for An Integrated Data Management System

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 as-set 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:

Cost-effective Storm Hardening Programs

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 wide-spread 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.

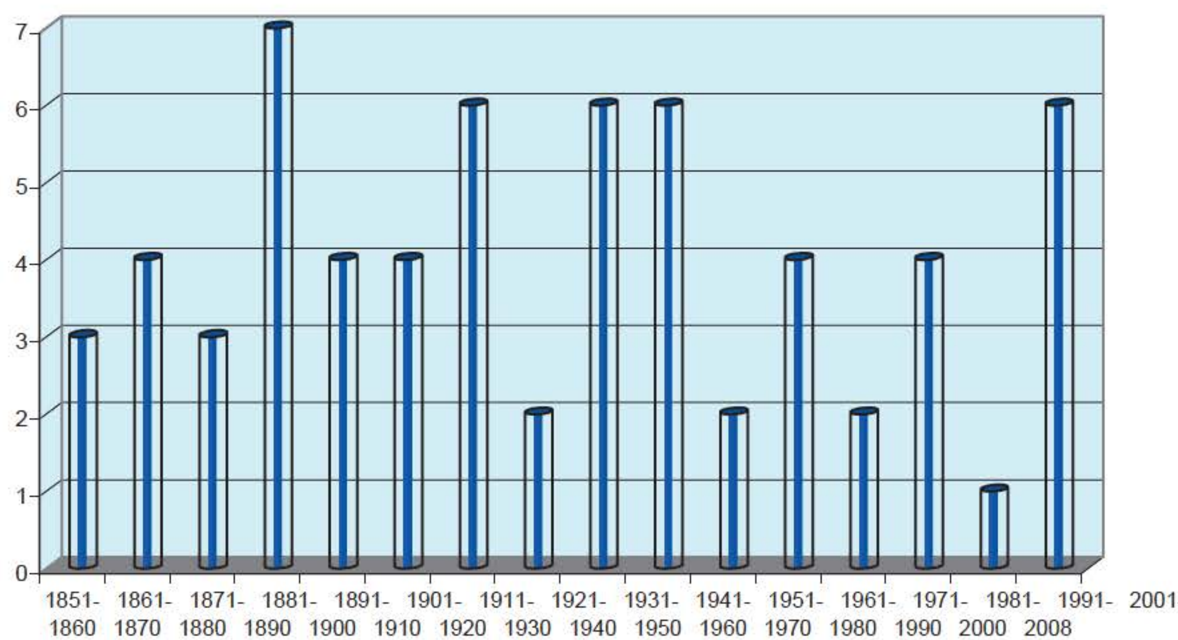

Figure A1. Histogram of Landfall Hurricane Frequency in Texas (by Decade).

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

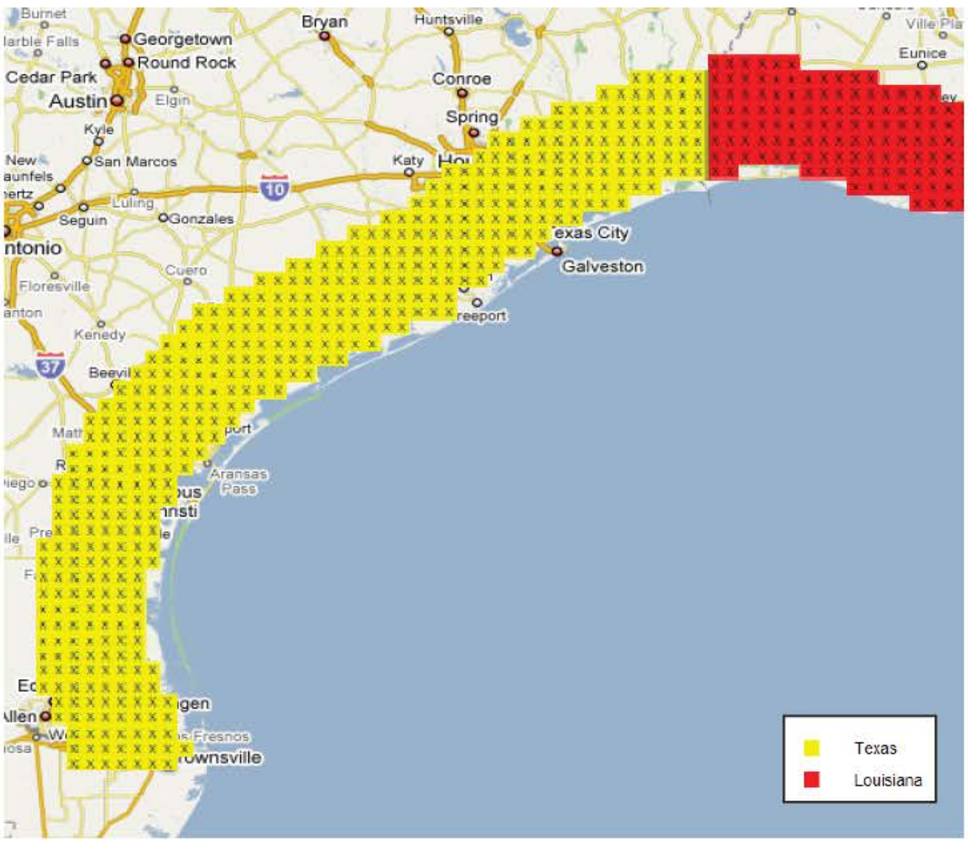

Figure A2. Approximate Texas Coastline.

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.

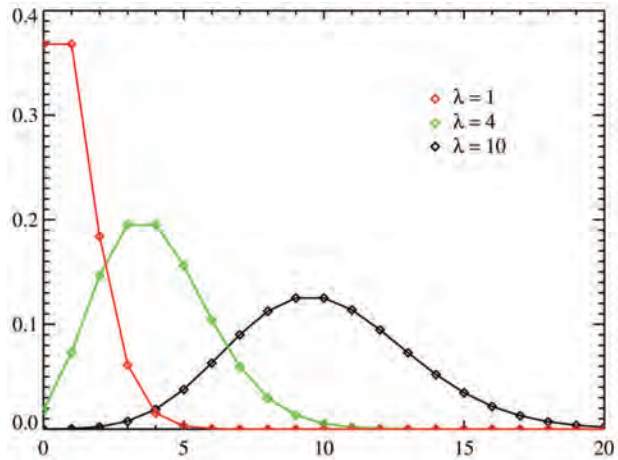

Figure A3. Probability Mass Function of Poisson Distribution.

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.

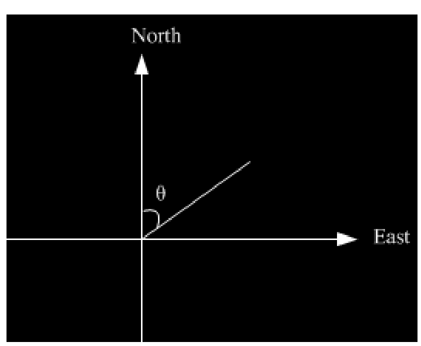

Figure A4. Approach Angle.

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.

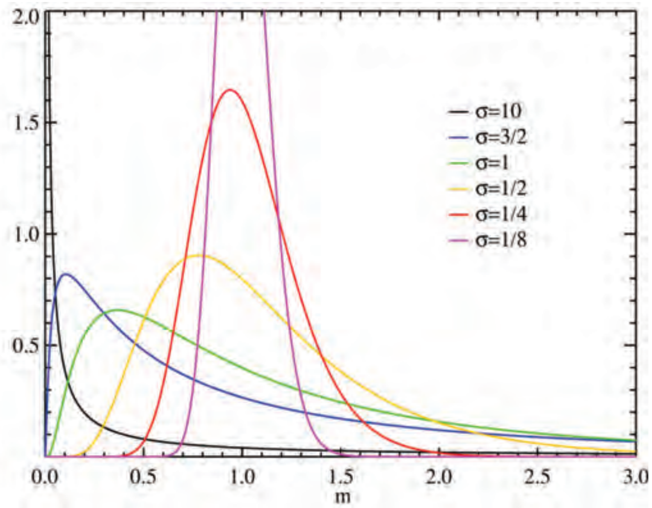

Figure A5. Probability Distribution Function of Lognormal Distribution.

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.

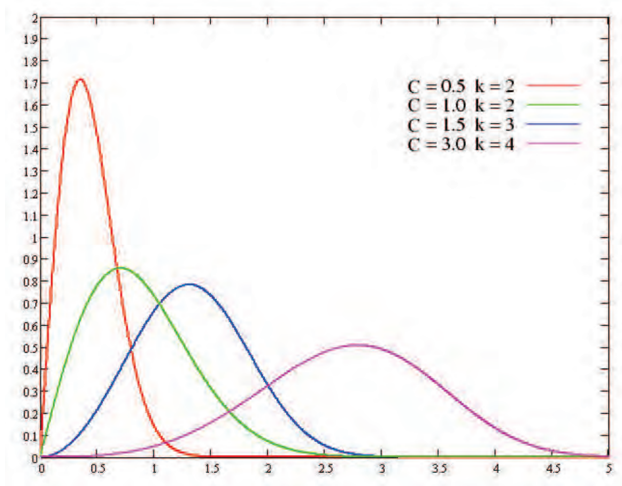

Figure A6. Probability Distribution Function of Weibull Distribution.

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$\times$ 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 $r<2R_{\max}$ and a 25% reduction for $r>4R_{\max}$ 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.

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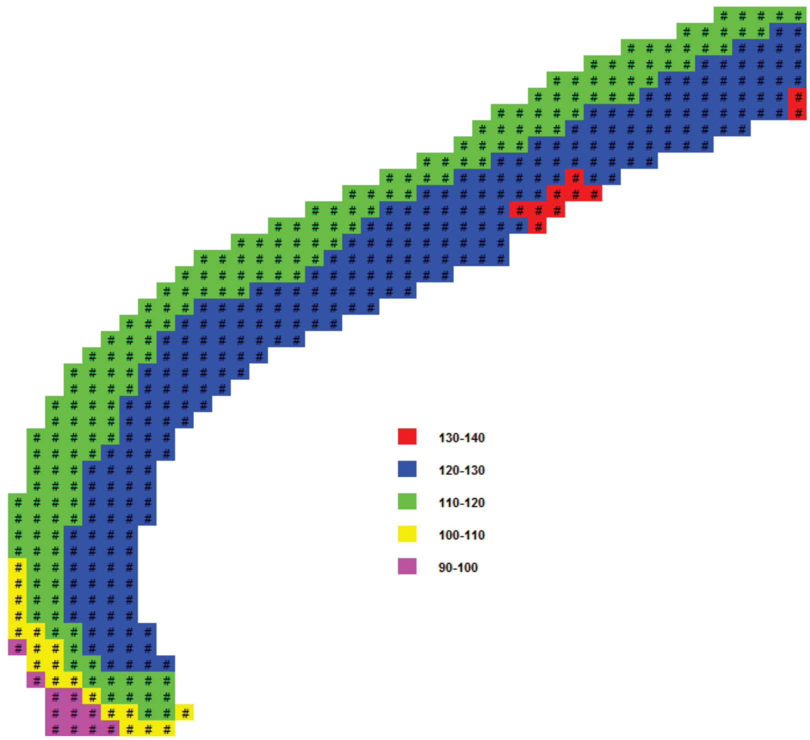

Figure A7. Simulated Wind Map for Areas within 50 Miles of Texas Coast.

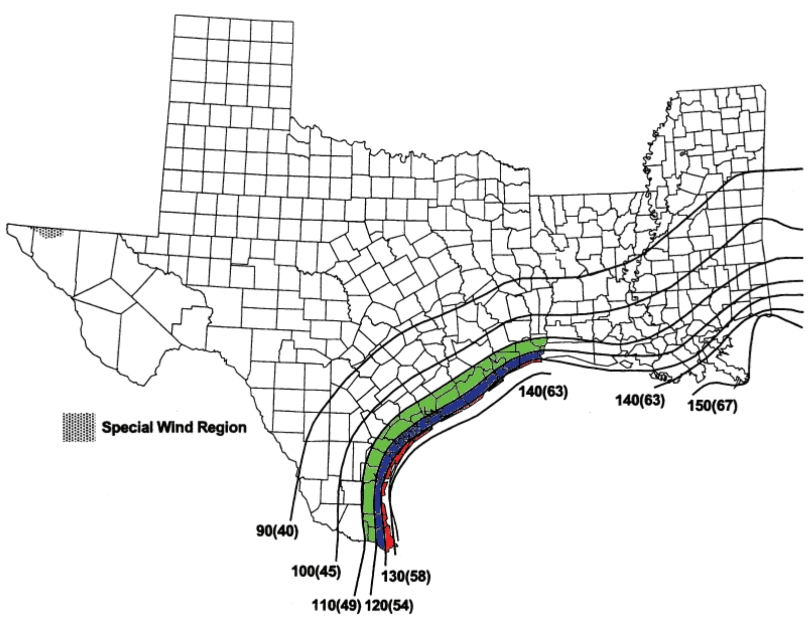

Figure A8. ASCE 7 Wind Map for Texas.

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.

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[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.
[20] R. Billinton, E. Chan, G. Tollefson, and G. Wacker, “A Canadian Customer Survey to Assess Power System Reliability Worth.” *IEEE Transaction on Power Systems*, Vol. 9, No. 1, pp. 443-450, 1994.
[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.

QUANTA TECHNOLOGY

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

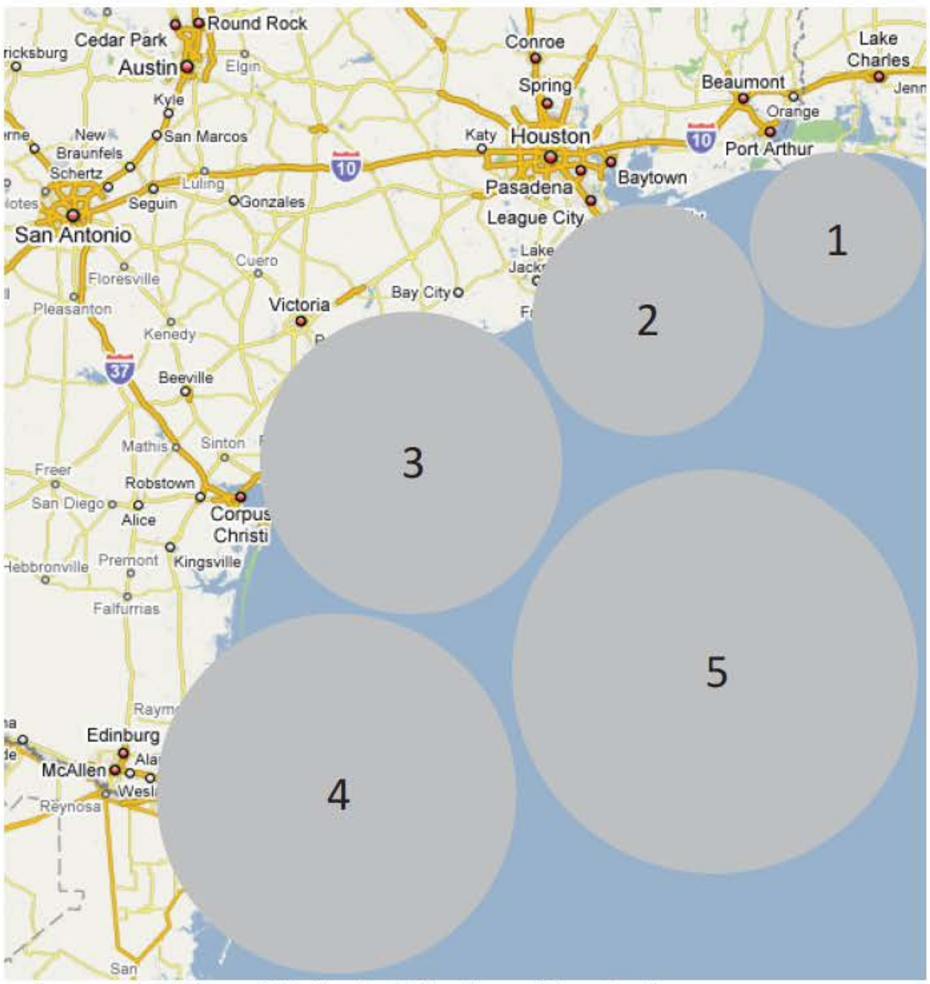

Figure B1. Typical Hurricane Sizes by Category.

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

Edison Electric Institute

Power by Association℠

Before And After The Storm

A compilation of recent studies, programs, and policies related to storm hardening and resiliency

UPDATE March 2014

Edison Electric Institute

Before and After the Storm - Update

A compilation of recent studies, programs, and policies related to storm hardening and resiliency

Prepared by:
Edison Electric Institute

March 2014

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Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
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INTRODUCTION AND PURPOSE

The United States has experienced a number of large storms within the last ten years ranging from ice and snow, hurricanes, storm surges and strong winds. After each storm, there is an increased focus on investor-owned utility response to widespread customer outages and the infrastructure's ability to withstand devastating weather events. Inevitably, state officials and public utility commissions call for investigations into utility practice and standards, often requiring testimony, appearances before the commission, filings and written reports.

Edison Electric Institute ("EEI") has been asked by its members to update its January 2013 report to incorporate newly released studies on recommendations and best practices with regard to hardening the distribution infrastructure and creating a more resilient system, especially since the impact of Superstorm Sandy in the Fall of 2012. As part of EEI's review, we have also looked at available cost recovery mechanisms and a representative cross-section of state regulatory and legislative actions initiated to address storm resiliency. The updated report also describes the efforts of the industry to enhance and formalize the mutual assistance program, which is a voluntary partnership of electric utilities from across the country, to respond to events that require a national, industry-wide response such as experienced in Superstorm Sandy.

The purpose of this compilation is to provide members with a centralized source of recent studies, reports, and other information regarding options for system hardening and resiliency measures in response to storm related outages of electric distribution facilities. The compilation provides a menu of infrastructure hardening and resiliency options, the relative cost impact of such measures, information on the various cost recovery mechanisms utilized, and a representative overview of various state programs addressing system hardening, resiliency and cost recovery. The compilation is aimed to serve as a reference tool to assist members in addressing state commissions and legislatures as they investigate possible regulatory reforms with respect to how electric utilities combat and respond to storm related outages.

The report does not attempt to make any recommendations regarding the viability or effectiveness of the reported measures and regulatory frameworks. There is no one solution to hardening the infrastructure or creating a more resilient system. Rather, utilities and their regulators must look at the full menu of options and decide the most cost-effective measures to strengthening the grid and responding to storm damages and outages. This report will hopefully serve as a starting point to that conversation.

CHAPTER 1: SYSTEM HARDENING AND RESILIENCY MEASURES

The recent increase in storm activity and extreme weather events has highlighted the need for reinforcing and upgrading the electric distribution infrastructure. EEI has focused its review on potential solutions for combating and mitigating storm damage and outages – system hardening and resiliency measures. **System hardening**, for purposes of this report, is defined as physical changes to the utility's infrastructure to make it less susceptible to storm damage, such as high winds, flooding, or flying debris. Hardening improves the durability and stability of transmission and distribution infrastructure allowing the system to withstand the impacts of severe weather events with minimal damage. **Resiliency** refers to the ability of utilities to recover quickly from damage to any of its facilities' components or to any of the external systems on which they depend. Resiliency measures do not prevent damage; rather they enable electric facilities to continue operating despite damage and/or promote a rapid return to normal operations when damages and outages do occur.[1]

1.1 Hardening Measures

1.1.1 Undergrounding

The undergrounding of transmission and distribution lines has been one of the most often cited measures for mitigating storm damage in recent years as evidenced by the number of reports published over the past seven to eight years. With images of trees and ice bringing down power lines on a 24 hour news cycle after each storm, the common reaction among consumers and regulators is to eliminate poles and bury distribution lines underground shielding them from the effects of extreme weather. Coupled with the aesthetic benefits of having a major portion of the distribution system out of sight, undergrounding has been a major focus of attention after major weather events. However, the costs associated with converting overhead systems underground have made widespread use of such measures cost prohibitive. Of the studies EEI reviewed, there was not a single study that recommended a complete conversion of overhead distribution infrastructure to underground facilities. In fact, none of the studies could identify a single state requiring complete conversion of its distribution system as the costs, estimated to be in the billions of dollars, were not economically feasible and would severely impact customer rates. And although undergrounding distribution and transmission can reduce the frequency of outages, the studies often showed that restoration times actually increased due to the complicated nature of the systems and the inability of restoration crews to visually pinpoint the cause of the disruption. Images of flooded substations and damaged underground facilities after Superstorm Sandy also highlighted the vulnerabilities of undergrounding. However, despite multiple studies citing the prohibitive cost of widespread undergrounding, lawmakers and regulators continue to examine undergrounding opportunities and are closely examining the metrics and data used for developing cost estimates.

The common conclusion among the reviewed studies was that undergrounding could be a viable solution to hardening the infrastructure through targeted or selective undergrounding rather than a total conversion. This

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[1] *Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons* (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, p. v.

might include placing the worst performing feeders, or feeder portions, underground or placing substation feeders that affected numerous customers underground. Targeted undergrounding was also recommended for those feeders supplying areas that were vital to the community such as police and fire departments, gas stations, hospitals, pharmacies and stores. Coupling such installations with other major excavation projects (such as roadwork, fiber optic cable installation and other construction) could also reduce the costs and disruptive impacts of undergrounding. Reiterating that converting overhead systems to underground systems are anywhere from five to ten times as costly as overhead equipment (estimated to cost between $80,000 and $3 million per mile), the studies recommend targeting the areas where undergrounding would provide the most benefit. The majority of the studies emphasized that undergrounding was not impervious to weather events and that environmental factors must be taken into account when considering underground systems. In coastal areas prone to storm surge, as demonstrated by Superstorm Sandy, underground systems are much more susceptible to damage from flooding and even risk further damage during clean-up efforts. Therefore, it is recommended that any utility or state looking into the possibilities of undergrounding take into account relative costs, environmental factors and actual causes of outages to ensure that undergrounding provides the most cost effective benefit to its electric consumers.

Reports Referencing Undergrounding:

Moreland Commission on Utility Storm Preparation and Response - Final Report (June 22, 2013) delivered to New York Governor Andrew Cuomo.
http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Florida Power & Light Company 2013 – 2015 Electric Infrastructure Hardening Plan (May 1, 2013) filed with the Florida Public Service Commission in Docket No. 130132-EI.
http://www.psc.state.fl.us/library/FILINGS/13/02408-13/02408-13.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI).
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Out of Sight, Out of Mind 2012: An Updated Study on the Undergrounding of Overhead Power Lines (January 2013) prepared by Kenneth, L. Hall, P.E. of Hall Energy Consulting, Inc. for Edison Electric Institute. http://www.eei.org/ourissues/electricitydistribution/Documents/UndergroundReport.pdf

Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15.
http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Underground Electric Transmission Lines (2011) prepared by the Public Service Commission of Wisconsin.
http://psc.wi.gov/thelibrary/publications/electric/electric11.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the

District of Columbia Order No. 15568 (September 2010). http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia (July 1, 2010) prepared by Shaw Consultants International, Inc. submitted to the Public Service Commission of the District of Columbia pursuant to Formal Case No. 1026. http://www.dcpsc.org/pdf_files/hottopics/Study_Feasibility_Reliability_Undergrounding_Electric_Distribution_Lines.pdf

The Power to Change The Face of America: Converting Overhead Utilities to Underground (2009) prepared by Underground 2020. http://www.governor.maryland.gov/documents/eOverheadToUnderground.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma (June 30, 2008) prepared and submitted by Oklahoma Corporation Commission Public Utility Division Staff. http://www.occeweb.com/pu/PUD%20Reports%20Page/Underground%20Report.pdf

Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling (May 5, 2008) prepared by Quanta Technology for Florida Public Utilities. http://www.quanta-technology.com/sites/default/files/doc-files/PURCPhase3FinalReport.pdf

Undergrounding Assessment Phase 2 Final Report: Undergrounding Case Studies (August 6, 2007) prepared by Quanta Technology for Florida Electric Utilities. http://www.quanta-technology.com/sites/default/files/doc-files/QuantaPhase2FinalReport.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888). http://www.floridapsc.com/publications/pdf/electricgas/stormhardening2007.pdf

Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion (February 28, 2007) prepared by Quanta Technology for Florida Electric Utilities. http://www.quanta-technology.com/sites/default/files/doc-files/QuantaPhase1FinalReport.pdf

Evaluation of Underground Electric Transmission Lines in Virginia (November 2006) report of the Joint Legislative Audit and Review Commission to the Governor and The General Assembly of Virginia. http://jlarc.virginia.gov/reports/Rpt343.pdf

Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida (March 2005) prepared by the Florida Public Service Commission. http://www.psc.state.fl.us/publications/pdf/electricgas/Underground_Wiring.pdf

A Review of Electric Utility Undergrounding Policies and Practices (March 8, 2005) prepared by Navigant Consulting, Inc. for the Long Island Power Authority. http://www.lipower.org/pdfs/company/papers/underground_030805.pdf

Placement of Utility Distribution Lines Underground, (January 2005) report of the State Corporation Commission to the Governor and The General Assembly of Virginia. http://www.scc.virginia.gov/comm/reports/report_hjr153.pdf

The Feasibility of Placing Electric Distribution Facilities Underground (November 2003) report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force. http://www.ncuc.commerce.state.nc.us/reports/undergroundreport.pdf

1.1.2. Vegetation Management

Vegetation management is most likely already incorporated into the operations and maintenance activities and budgets of most utilities. However, the various studies reviewed by EEI have explained that the emphasis being placed solely on maintaining specific clearances may not be as effective for every situation. The majority of the reports have had two overarching recommendations: (1) find the true cause of outages and employ necessary vegetation management and (2) coordinate with property owners and local officials to plant and replace downed vegetation that is most conducive to system reliability. Employing targeted vegetation trimming and removal versus strict vegetation clearance cycles was echoed in several of the reports. The prior practice seemed to focus unnecessarily on ensuring specific branch clearances from power lines instead of "danger" trees and branches. As a majority of outages cited were caused by trees or heavy branches falling on lines and bringing down poles rather than tree branches brushing up against power lines, maintaining clearances alone did not address all possible measures to improve reliability. Local officials can assist in mitigation of "danger" tree effects by establishing and enforcing ordinances that require the removal of dead or dying trees from private property near power lines. A second emerging theme in the studies that were reviewed was the usefulness of a concerted effort to plant vegetation near distribution systems that would pose the least reliability issues. In the past, property owners, businesses and local municipalities planted vegetation with little consideration as to the impacts on surrounding utility systems. Again, it is suggested that local officials assist by requiring trees to be labeled as appropriate for planting under power lines or requiring informational brochures at the point of sale. The studies recommended looking at vegetation with shorter heights and longer lifecycles but were careful to reiterate that utilities must staff trained arborists and work closely with customers to ensure a workable outcome for all parties. In fact, the studies showed that direct communication and coordination with regard to vegetation management resulted in higher customer satisfaction rates when it came to utility relationships.

Recognizing that vegetation management represented the highest recurring maintenance cost, the studies were careful to point out that deferral of vegetation management tended to be more costly in the long run. Although specific vegetation costs were not a focal point of the studies, there was a general consensus that vegetation management was one of the more cost effective hardening mechanisms, especially when compared to the relative high costs of undergrounding.

Reports Referencing Vegetation Management:

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15. http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

State Vegetation Management Task Force Final Report (August 28, 2012) issued to the Connecticut Department of Energy & Environmental Protection. http://www.ct.gov/dep/lib/dep/forestry/vmtf/final_report/svmtf_final_report.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Report of the Two Storm Panel (January 2012) presented to Connecticut Governor Dannel P. Malloy. http://www.ct.gov/dep/lib/dep/forestry/vmtf/two_storm_panel_final_report.pdf

Report on Transmission Facility Outages During the Northeast Snowstorm of October 29-30, 2011: Causes and Recommendations (May 31, 2012) prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

Best Practices in Vegetation Management for Enhancing Electric Service in Texas (November 11, 2011) submitted by Texas Engineering Experiment Station to the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/projects/electric/38257/Russell_Report.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the District of Columbia Order No. 15568 (September 2010). http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia (July 1, 2010) prepared by Shaw Consultants International, Inc. submitted to the Public Service Commission of the District of Columbia pursuant to Formal Case No. 1026. http://www.dcpsc.org/pdf_files/hottopics/Study_Feasibility_Reliability_Undergrounding_Electric_Distribution_Lines.pdf

New Hampshire Public Utilities Commission After Action Review – December '08 Ice Storm (December 3, 2009).
http://www.puc.nh.gov/2008IceStorm/Final%20Reports/PUC%20IceStorm%20After%20Action%20Report%2012-03-09.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas.
http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

Reliability Based Vegetation Management Through Intelligent System Monitoring (September 2007) prepared by Power Systems Engineering Research Center.
https://www.google.com/url?q=http://www.pserc.wisc.edu/documents/publications/reports/2007_reports/russell_2007_pserc_report_vegetation_management_report_t-27.pdf&sa=U&ei=Q4-3UPXvA4WUiQf2uIG4BQ&ved=0CAcQFjAA&client=internal-uds-cse&usg=AFQjCNGuPbjs4cFbOdcoGaWm9yIjEDiQxQ

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888).
http://www.floridapsc.com/publications/pdf/electricgas/stormhardening2007.pdf

Report on the Workshop for Best Practices in Vegetation Management (April 17, 2007) sponsored by the Florida Electric Utilities.
http://www.floridapsc.com/utilities/electricgas/EIProject/docs/VegetationManagementWorkshopReport.pdf

The Neglected Option for Avoiding Electric System Storm Damage & Restoration Costs – Managing Tree Exposure (2005) prepared by Siegfied Guggenmoos of Ecological Solutions, Inc.
http://www.ecosync.com/Avoided%20Storm%20Costs.pdf

Utility Vegetation Management Final Report (March 2004) prepared by CN Utility Consulting, LLC for the Federal Energy Regulatory Commission to support the federal investigation of the August 14, 2003 Northeast Blackout. http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/uvm-final-report.pdf

1.1.3. Higher Design and Construction Standards

As with undergrounding and vegetation management, the key to finding the right design and construction standards should be based on the local conditions of the facilities. The studies reviewed provide a myriad of hardening measures for pole designs to withstand high winds as well as suggestions for how to mitigate widespread outages due to tear-down situations from vegetation. Other reports, especially those in coastal areas, emphasized the importance of elevating substations and other vulnerable facilities that are susceptible to flooding. Submersible equipment, isolation switches, waterproof sealants, moats and flood walls are also recommended in recent studies especially given the damage from floodwaters experienced in New York and New Jersey during Superstorm Sandy. Placement of facilities is another critical component of design and must be updated periodically to account for changing geography, such as flood level potentials and vegetation growth. Several reports also noted that it is imperative when replacing grid components to consider stronger hardening measures rather than replacing the same units in kind or at minimum code requirements.

As to the relative costs of the various hardening choices, prices vary significantly depending on the specific hardening measure, the materials being used, soil and other environmental conditions and the skill needed to implement the hardening mechanism. The studies generally recommended, as with undergrounding, that widespread system hardening is cost-prohibitive and that the most effective use of hardening tools is through a targeted approach. The recommendations are to identify the most critical elements, the worst performing components, those units that have aged and weakened or those elements most in danger of failure and work to replace them with improved system designs such as composites, guying, stronger pole classes or relocation to name a few. Of course, the key to identifying and mitigating potential structural problems lies with robust inspection and maintenance plans. The reports highlight that infrastructure hardening should not come only as a result of storm damage and tear-downs, but as part of a regular maintenance schedule. As newer designs come to market and older designs and equipment are retired, the distribution grid will naturally become more resilient and require fewer replacements and rebuilds in the future.

Reports Referencing Higher Design and Construction Standards:

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather (July 2013) prepared by the U.S. Department of Energy. http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf

Moreland Commission on Utility Storm Preparation and Response - Final Report (June 22, 2013) delivered to New York Governor Andrew Cuomo. http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Florida Power & Light Company 2013 – 2015 Electric Infrastructure Hardening Plan (May 1, 2013) filed with the Florida Public Service Commission in Docket No. 130132-EI. http://www.psc.state.fl.us/library/FILINGS/13/02408-13/02408-13.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf
Structural Hardening for the Northeast Utilities – CL&P Distribution System (August 22, 2012) prepared by Quanta Technology for Northeast Utilities – CL&P.
http://www.dpuc.state.ct.us/DOCKCURR.NSF/e59368b7c12f537e852573ee005bff7f/2784a7687318599a85257a640067f367/$FILE/Q-EN-006%20Quanta%20storm%20hardening%20%20report%20%208_22_12%20final.pdf

Report on Transmission Facility Outages During the Northeast Snowstorm of October 29-30, 2011: Causes and Recommendations (May 31, 2012) prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

Report of the Two Storm Panel (January 2012) presented to Connecticut Governor Dannel P. Malloy. http://www.ct.gov/dep/lib/dep/forestry/vmtf/two_storm_panel_final_report.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the District of Columbia Order No. 15568 (September 2010).
http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas.
http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

Report on Transmission System Reliability and Response to Emergency Contingency Conditions in the State of Florida (March 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Senate Bill 888.
http://www.psc.state.fl.us/publications/pdf/electricgas/transmissionreport2007.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888).
http://www.floridapsc.com/publications/pdf/electricgas/stormhardening2007.pdf

The Hardening of Utility Lines – Implications for Utility Pole Design and Use (2007) North American Wood Pole Council, Technical Bulletin VII prepared by Martin Rollins, P.E. http://products.construction.com/swts_content_files/1475/593089.pdf

1.1.4. Smart Grid

As smart grid technologies are still being developed and have yet to experience a long history of widespread deployment, there is only anecdotal literature on how smart grid has effectively hardened the distribution system against outages. At least one utility has reported that mapping smart meter outages allowed it to expedite recovery and response after a tornado by precisely identifying the path of the storm damage.[2] Although, smart grid is becoming a featured part of the discussion regarding storm restoration and resiliency and has been cited in many of the studies referenced in this document, the benefits have yet to be tested in a widespread storm scenario. In the context of infrastructure hardening, the most cited benefits are the ability of the system to detect outages and remotely reroute electricity to undamaged (unfaulted) circuits and feeders. Through automated distribution technologies utilizing reclosers and automated feeder switches, faults can be isolated for greater system reliability and fewer customers affected. A key element of successfully utilizing these technologies is designing the distribution system as a looping system that provides for the rerouting of power rather than a radial linear system. However, as some studies have pointed out, smart grid relies on portions of the distribution system remaining intact. In cases of large tear-downs with many poles and wires out of service, there may be simply nowhere to reroute the power to. Therefore, in order for smart grid technologies to work adequately, it may need to be paired with other system hardening mechanisms.

As federal assistance has been made available for smart grid development and the technologies continue to develop, there has been little discussion regarding the relative costs of integrating smart grid technologies into the distribution system.

Reports Referencing Smart Grid:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather (July 2013) prepared by the U.S. Department of Energy. http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Powering New York State's Future Electricity Delivery System: Grid Modernization (January 2013) prepared by the New York State Smart Grid Consortium. http://nyssmartgrid.com/wp-content/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

[2] *See Improving the Reliability and Resiliency of the US Electric Grid* (2012) from Metering International Issue – 1 authored by Debbie Haught and Joseph Paladino of the U.S. Department of Energy, p. 2.

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

Improving the Reliability and Resiliency of the US Electric Grid (2012) from Metering International Issue – 1 authored by Debbie Haught and Joseph Paladino of the U.S. Department of Energy. http://energy.gov/sites/prod/files/Improving%20the%20Reliability%20and%20Resiliency%20of%20the%20US%20Electric%20Grid%20-%20SGIG%20Article%20in%20Metering%20International%20Issue%201%202012.pdf

Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15. http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the District of Columbia Order No. 15568 (September 2010). http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

The Value of Distribution Automation (March 2009) prepared by Navigant Consulting for the California Energy Commission – Public Interest Energy Research Program. http://www.ilgridplan.org/Shared%20Documents/CEC%20PIER%20Report%20-%20The%20Value%20of%20Distribution%20Automation.pdf

Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma (June 30, 2008) prepared and submitted by Oklahoma Corporation Commission Public Utility Division Staff. http://www.occeweb.com/pu/PUD%20Reports%20Page/Underground%20Report.pdf

Value of Distribution Automation Applications (April 2007) prepared by Energy and Environmental Economics, Inc. and EPRI Solutions, Inc. for the California Energy Commission – Public Interest Energy Research Program. http://www.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF

1.1.5. Microgrids

The concept of "microgrids" is still in the study phase and like smart grid has yet to see widespread deployment or demonstrated its resiliency capabilities during a major storm; however, recommendations highlighting microgrids increased dramatically after Superstorm Sandy. The concept of the microgrid is that it functions as an isolatable distribution network, usually connected to one or more distributed generation sources, that can seamlessly connect and disconnect from the main grid (referred to as "island-mode") in times of widespread outages. Similar to smart grid applications, if major portions of the main grid or the microgrid are torn-down or destroyed in a major weather event, the microgrid capabilities are rendered less effective. There are limited studies of micogrid capabilities, especially as a hardening option. New York, Connecticut and California as well as the U.S. Department of Energy have begun to look into microgrid capabilities and some of the current regulatory frameworks hindering widespread deployment. Although microgrid applications are generally end-user driven and funded, the studies do address areas where utilities can and should be involved, especially with ensuring systems are optimized for interoperability and security. Utilities would also act as an active partner with customers and generators to facilitate and manage the aggregation of loads and the deployment of generation on the microgrid.

As previously mentioned, most microgrid deployment would be funded by the end-users rather than the utility (with estimated returns on investment over 15 years), however, microgrids can provide some cost benefits. By precisely controlling interconnected loads and managing customer voltage profiles, utilities can reduce the cost of providing reactive power and voltage control at microgrid participants' locations. As microgrids remove some of the load that would otherwise be served by the utility on the main grid, microgrids can reduce peak demand or area load growth and similarly help utilities avoid or defer new power delivery capacity investments. As one study points out "[s]uch deferrals can produce financial value to both utilities (e.g., reduced capital budget, lower debt obligations, a lower cost of capital) and ratepayers (i.e., lower rates)."[3] However, it should be noted that in situations where microgrids fail or are damaged and thus rely on the utility as a back-up, stranded investments and hurdles for cost recovery can become problematic for the utility.

Reports Referencing Microgrids:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather (July 2013) prepared by the U.S. Department of Energy. http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf

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[3] *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State* (September 2010) prepared for the New York State Energy Research and Development Authority, p. S-5.

A Stronger, More Resilient New York (June 11, 2013) from the City of New York Mayor Michael R. Bloomberg. http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_spreads_Lo_Res.pdf
Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance. http://www.gridwise.org/documents/ImprovingElectricGridReliabilityandResilience_6_6_13webFINAL.pdf

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Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15. http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Microgrids (September 12, 2012) prepared by Lee R. Hansen, Legislative Analyst for the Connecticut General Assembly, Office of Legislative Research. http://www.cga.ct.gov/2012/rpt/2012-R-0417.htm

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

The Business Case for Microgrids (2011) white paper on the new fact of energy modernization prepared by Robert Liam Dohn of Siemens AG. http://www.energy.siemens.com/us/pool/us/energy/energy-topics/smart-grid/downloads/The%20business%20case%20for%20microgrids_Siemens%20white%20paper.pdf

DOE Microgrid Workshop Report (August 30 – 31, 2011) prepared by the Office of Electricity Delivery and Energy Reliability, Smart Grid R&D Program. http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf

Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State (September 2010) prepared for the New York State Energy Research and Development Authority. http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CD4QFjAA&url=http%3A%2F%2Fwww.nyserda.ny.gov%2F~%2Fmedia%2FFiles%2FPublications%2FResearch%2FElectic%2520Power%2520Delivery%2F10-35-microgrids.ashx%3Fsc_database%3Dweb&ei=0tC8UN2ZH4rh0QGg4oC4CA&usg=AFQjCNEMLDVWvr-RMvdfopz1FSAbn6bK3w&sig2=dUz2rZfgMcCr4AWDzm6rGQ

The Value of Distribution Automation (March 2009) prepared by Navigant Consulting for the California Energy Commission – Public Interest Energy Research Program. http://www.ilgridplan.org/Shared%20Documents/CEC%20PIER%20Report%20-%20The%20Value%20of%20Distribution%20Automation.pdf

Value of Distribution Automation Applications (April 2007) prepared by Energy and Environmental Economics, Inc. and EPRI Solutions, Inc. for the California Energy Commission – Public Interest Energy Research Program. http://www.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF

Microgrid: A Conceptual Solution (June 2004) prepared by Robert H. Lasseter and Paolo Piagi of the University of Wisconsin-Madison. http://energy.lbl.gov/ea/certs/pdf/mg-pesc04.pdf

1.1.6. Advanced Technologies

Many of the advanced technologies currently being studied and rolled out are closely related to smart grid applications in the areas of communication and circuit auto-reconfiguring. Other technologies being used to bolster utilities information gathering and control are various mapping technologies such as Geographic Information Systems ("GIS") and Automated Mapping and Facilities Management ("AM/FM"). There is very limited literature on other technologies outside of smart grid applications; however, there has been some investigation into hydrophobic, nano-particle coatings on distribution lines and other facilities to enhance waterproofing, prevent ice formation on power lines, and combat corrosion and shorting caused from saltwater. Installation of self-healing cables reduces damage to wires by incorporating sealant between insulation layers that flow into any insulation breaks and seals them permanently to prevent further exposure. Of the studies reviewed, the relative cost of these advanced technologies was not included.

Reports Referencing Advanced Technologies:

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

America's Next Top Energy Innovator Challenge – SH Coating, LP, Oak Ridge National Laboratory. http://energy.gov/americas-next-top-energy-innovator/sh-coatings-lp

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

1.2 Resiliency Measures

In the body of research that we reviewed, most of the resiliency measures were considered together in the recommendations and best practices and therefore we only include one "Sources" section that encompasses the storm response and restoration efforts utilized by utilities. Many of the sources cited have also been referenced in the "Hardening" section above as well.

Although the industry as a whole responded well to the massive restoration effort following Superstorm Sandy, utilities quickly agreed that the mutual assistance program should be enhanced and formalized. As described more fully in Appendix C, the electric industry has instituted a formal process for responding to major outage events involving multiple regions that addresses many of the resiliency recommendations in this section.

1.2.1. Increased Labor Force

Sufficient restoration crews are essential to storm response and restoration. Of the studies reviewed by EEI, the major element of securing enough crew members in preparation for major storms is advanced planning. This includes adequate weather prediction paired with advanced reservation of additional crews whether through mutual assistance or outside contractors. All impacted stakeholders should bear in mind that widespread storms encompassing large areas and multiple service territories will lead to increased competition for resources and thus adequate planning is essential. Part of the planning includes securing shelter, food, first aid, shower and toilet facilities, parking and other essentials for crews working around the clock for days on end.

When securing crews, these additional costs should also be taken into consideration. Several studies warned that it is not always cost-effective, and increasingly subject to scrutiny by state officials, to cut full-time staff in favor of attempting to secure additional crews during emergency situations only. Utilities must measure the costs of having available crews compared with the costs of extended outages due to insufficient numbers of prepared crews.

1.2.2. Standby Equipment

Another key consideration in proper storm restoration and recovery, as documented in several studies, is to consider necessary arrangements for response equipment to be on standby (for example strategic alliances or material consignment). Extra trucks, supplied with necessary materials including maps, flashlights, mapping software, communication devices, to name a few, could be readily available to utilities without needing to secure such equipment from outside locations thus slowing response activities. In addition to equipped trucks, crews should be armed with GPS devices as many will be unfamiliar with local roads and service territories. As demonstrated during Hurricane Katrina and Superstorm Sandy, fuel can become scarce after extreme weather events and thus utilities must secure enough fuel for its service trucks, either through on-hand reserves or emergency fuel contracts with suppliers. Other standby equipment to be considered are mobile transformers, mobile substations and large generators that can enable temporary restoration of grid service, circumventing damaged infrastructure, to enable repair of grid components without extended interruptions to customers.

1.2.3. Restoration Materials

As part of storm response and restoration, multiple studies suggested that utilities must have adequate back-up restoration supplies such as poles, wires, transformers and other system components that are on location in storage or are easily obtained through contracts with suppliers. As with securing adequate labor and equipment, large storms with widespread outages may result in competition for materials. The State of New York launched a review of a potential equipment-sharing, inventory and stockpile programs and determined that such programs could facilitate improvement to individual utility practices and help coordinate utilities' response to major events. It was recommended that New York State utilities leverage existing stockpiles at utility and vendor locations statewide and develop a sharing agreement among utilities for deployment of restoration materials during major outage events. In November 2013, the State of New York Public Service Commission directed utilities to finalize the protocols, procedures and plans for sustaining a shared equipment and supplies stockpile.[4]

[4] Order Instituting a Process for the Sharing of Critical Equipment, State of New York Public Service Commission Docket No. 13-M-0047 (November 19, 2013).

As with other recommendations, costs of such back-up restoration materials need to be compared with the costs of extended outages and lost restoration time while waiting for supplies to become available.

1.2.4. Enhanced Communication, Planning and Coordination

Several of the studies reviewed highlighted the many complications and logistical challenges associated with moving multiple crews to large areas all the while keeping customers, regulators and news agencies up-to-date with the latest restoration information. As stressed in one study, utility response must be scalable so that restoration efforts run smoothly whether there are 5,000, 50,000 or 500,000 customer outages.[5] A crucial element in utility plans for major storm events is pre-staging. Having crews, equipment and resources safely positioned before the storm allows for a quicker response and avoids waiting for crews to arrive from outside the affected areas. However, for those crews that do arrive from out of town, standby equipment and restoration materials are already gathered and organized for immediate response. Certain utilities have commissioned new mobile command centers to accommodate response teams. These mobile command centers typically have state-of-the-art technology, including satellite and cellular communications, dispatcher workstations, video monitors with video switcher, SMART boards, and telescoping masts with cameras. These mobile command centers provide utilities with extended capability to manage restoration on location and closer to the customers experiencing outages. Recognizing the importance of pre-staging, some utilities are looking into hiring outside vendors to evaluate and map out staging areas to maximize resource flow and use of space. Part of this pre-staging effort entails coordinating with federal and state agencies to quickly obtain emergency permits and waivers for traveling crews and heavy equipment to bypass tolls and access normally restricted bridges and roadways. Procedures must be in place prior to large outage situations in order to avoid delays in getting mutual assistance crews to assist with restoration.

As several studies pointed out, response times are unnecessarily delayed as outage coordinators are unsure where their crews have been dispatched, what outages remain and where to dispatch crews that have completed a restoration project to ensure the least amount of driving or "windshield" time. Thus, coordination and constant communication is vitally important. As one study suggested, relying on satellite communications is a beneficial option for crew coordination as they are less reliant on terrestrial structures which may have been damaged during the storm or weather event.[6]

In addition, utility communications with its customers is vital. A key frustration, cited in the reports, was out-of-date information and inaccurate restoration estimates. Utilities are taking new and innovative steps to keep the communities and customers informed at all times. These include designating a central contact person or working team to serve as the "one voice" communicator with crews, state and federal government officials, news agencies and customers to ensure the continuity of communication and information for the most accurate assessments and response estimates. Some utilities have implemented storm communication guidelines to ensure consistent communication across all customer channels during the various phases of a storm. These guidelines provide for tailoring communication outreach by taking into account the magnitude of the storm and subsequent customer sentiment. The guidelines include monitoring of customer feedback and scripting for customer service representatives, interactive voice response, text messaging, mobile application notifications, utility websites, Twitter, Facebook, Flickr and YouTube. A number of new technologies have been developed such as text messaging programs and fully functional mobile applications that allow customers to report an outage, view outage information, and receive proactive push notifications with outage status updates.

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[5] *See Report of the Two Storm Panel* (January 2012) presented to Connecticut Governor Dannel P. Malloy, p. 12.

[6] *See Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs* (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas, p. 74.

Though the studies did not explore specific costs attached to communication and coordination efforts, again the general consensus is that utilities must weigh these various costs against the costs of slower restoration and extended outages.

1.2.5. Advanced Technologies

Much of the conversation regarding advanced technologies, in the context of storm response, has centered on smart grid/smart meters. The two-way communication capabilities of smart meters allows utilities to monitor service continuity, identify outages and "ping" customer meters to ensure service has been restored. In the wake of Superstorm Sandy, advanced technologies involving outage management systems and developing better weather and damage forecast models has gained prominence in the discussion surrounding large outage events. An effective outage management system linking load and outage data with GIS allows restoration crews to isolate the areas where outages have occurred and focus their efforts solely on restoration rather than on truck roll-bys to identify damage and customer outages. Some software allows utilities to track restoration crews, equipment and fuel consumption to better manage logistics and allocate resources. Outage Management Systems are being used to detect and report reliability issues in addition to crews using infrared scanning equipment for surface and airborne damage assessment. Infrared scanning detects temperature variances which can indicate damaged or failed equipment. Airborne damage assessment allows technicians to survey damage where traditional vehicles are blocked due to downed trees, flooded roads and other obstacles thereby reducing response time by hours. Automated storm damage information can be instantaneously shared with restoration crews to speed up response and repairs, limiting the need for extra scouting crews. Utilities are recognizing the importance of integrating such data with data from local municipalities, police and fire departments to better coordinate restoration to critical areas.

A cost assessment for smart meters and other automated technologies is contained within the broader context of smart grid programs and differs by region and level of federal assistance. Although costs for many of the recommended advanced technologies may be costly, it is important to remember that those costs should be measured against the costs of delayed restoration when advanced capabilities are not being utilized. As one utility reported during Superstorm Sandy, use of advanced technologies reduced the number of truck rolls during Superstorm Sandy by over 6,000 resulting in a savings of least one million dollars in restoration costs.[7]

Reports Referencing Resiliency Measures:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology.
http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Hurricane Sandy Rebuilding Strategy: Stronger Communities, A Resilient Region (August 2013) prepared by the Hurricane Sandy Rebuilding Task for and presented to the President of the United States.
http://portal.hud.gov/hudportal/documents/huddoc?id=HSRebuildingStrategy.pdf

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[7] See Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance, p. 12.

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

Moreland Commission on Utility Storm Preparation and Response - Final Report (June 22, 2013) delivered to New York Governor Andrew Cuomo. http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

A Stronger, More Resilient New York (June 11, 2013) from the City of New York Mayor Michael R. Bloomberg. http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_spreads_Lo_Res.pdf

Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance. http://www.gridwise.org/documents/ImprovingElectricGridReliabilityandResilience_6_6_13webFINAL.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Powering New York State's Future Electricity Delivery System: Grid Modernization (January 2013) prepared by the New York State Smart Grid Consortium. http://nyssmartgrid.com/wp-content/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

The October 2011 Snowstorm: New Hampshire's Regulated Utilities' Preparation and Response (November 20, 2012) prepared by the New Hampshire Public Utilities Commission. http://www.puc.state.nh.us/2011OctSnowstorm/October%202011%20Snowstorm%20(11-20-12)%20final.pdf

Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15. http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Performance Review of EDCs in 2011 Major Storms (August 9, 2012) prepared by Emergency Preparedness Partnerships for the New Jersey Board of Public Utilities. http://www.nj.gov/bpu/pdf/announcements/2012/stormreport2011.pdf

January 2012 Pacific Northwest Snowstorm – After Action Review (June 19, 2012) prepared by KEMA for Puget Sound Energy. http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=120231

Report on Transmission Facility Outages During the Northeast Snowstorm of October 29-30, 2011: Causes and Recommendations (May 31, 2012) prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

State of Rhode Island Division of Public Utilities and Carriers Review of National Grid Storm Preparedness, Response, and Restoration Efforts (February 2012) prepared by Power Services. http://www.ripuc.org/eventsactions/docket/D_11_94_Booth.pdf

Report of the Two Storm Panel (January 2012) presented to Connecticut Governor Dannel P. Malloy. http://www.ct.gov/dep/lib/dep/forestry/vmtf/two_storm_panel_final_report.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the District of Columbia Order No. 15568 (September 2010). http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

New Hampshire Public Utilities Commission After Action Review – December '08 Ice Storm (December 3, 2009). http://www.puc.nh.gov/2008IceStorm/Final%20Reports/PUC%20IceStorm%20After%20Action%20Report%2012-03-09.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

CHAPTER 2: COST RECOVERY MECHANISMS

2.1 Types of Costs

Utility costs incurred to respond to storms before, during and after the event—collectively referred to as storm hardening and resiliency—are of two types: Operational and maintenance expenses, which are typically the costs of labor and consumable materials used in the process, and capital costs, which include replacement power poles, wires, transformers, and trucks driven by repair crews.

Traditionally, operational expenses are recovered in base rates after they are reviewed by state regulatory authorities. Capital expenses are usually included in a utility's rate base and depreciated over time. When included in rate base, utilities are allowed to earn a return on these investments and the depreciation expense is included in rates.

Rate base additions and operational expenses traditionally have been considered in the context of general rate cases. However, for a variety of reasons, including the increasing costs involved and unpredictability, utilities and regulators are increasingly turning to other means to deal with cost recovery for storm response, as discussed in this section.

2.2 General Rate Case Recovery

The normal practice by which most investor-owned electric utilities recover costs is through a general rate case, where the utility seeks to change its rates based on either new plant additions or changes in expenses or both. The utility typically presents its costs in a defined "test year." The test year often is an historical test year that ends before the rate case is filed. However, many states are using or moving toward use of current or future test years or hybrids.[8] After reviewing the costs, the state regulatory commission approves or disallows costs and sets an authorized rate of return for the utility's assets. Storm response expenses can be considered in the context of a general rate case, but there may be significant problems with this path for storm cost recovery.

First, if any of the storm costs were incurred outside the utility's test year, they would not be eligible for recovery even if they were prudently incurred and legitimate expenses, except in some cases when post-test year additions are allowed under specified circumstances. Second, many states have prohibitions against single-issue ratemaking, meaning that all costs incurred by the utility must be considered together in a general rate case. A utility that does not have a general rate case scheduled in the near future would have no recourse to recover its costs, perhaps for years.

Moreover, rate cases can be very contentious and take years to resolve, depending on state rules, and they often result in at least some costs being disallowed as a compromise to reach a conclusion. All of this regulatory delay and uncertainty can add to the business risk of the utility and may harm its financial health, exposing it to potential credit downgrades by rating agencies and thus increasing its cost of capital, which in turn can lead to higher rates for customers.

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8 *Innovative Regulation: A Survey of Remedies for Regulatory Lag* (April 2011) prepared by Pacific Economics Group Research LLC for Edison Electric Institute

The length of time for rate cases to resolve in many states also means that a utility may incur additional storm damage before the costs of previous storms are recovered, resulting in a pancaking effect.

Utilities may not have the capability to finance recovery of costs resulting from multiple storms, especially if storms are large and costly. General rate case recovery may be reasonable for storms with minor damage but can create problems when storms are large or frequent in nature. Many utilities have classifications for major versus minor storms and handle minor storms under regular accounting and cost recovery procedures.[9] In addition, many utilities already collect revenue in base rates for "normal" storm damage based on test year data, which may be based on an historic average.

General rate case recovery may be a more viable method of cost recovery for known, approved capital expenses, such as pre-storm hardening of facilities or undergrounding. In these cases, it is appropriate that costs be capitalized and added to a utility's rate base. Certain operational and maintenance costs are also appropriate for consideration in general rate cases. Routine vegetation management costs are an example of a normal, predictable expense that would typically be included and recovered in base rates.

General rate cases that employ mechanisms other than a historical test year or that use methodologies resulting in a higher rate base valuation than would occur under a traditional averaging method provide additional ways in which storm cost recovery can be achieved in a timely manner. An example is use of a future test year that allows projected capital expenditures (capex) to be included in base rates, thus reducing problems due to regulatory lag or the need for multiple rate cases.

Another example is application of end-of-test-year or "terminal" values to rate base, where rate base is set based on values at the end of the normal test period rather than on averaging values over the period. Use of terminal rate base can better reflect the level of investment during the period rates will be in effect, especially during times of high investment levels. For example, a utility that is in the midst of a large capex spending program for reliability improvement, system hardening, or storm damage resiliency measures might propose a future test year or terminal rate base valuation to ensure that the increased capital spending over historical averages is properly reflected in base rates. States that have allowed use of terminal test year include **Illinois**, **Maryland** and **Texas**.

2.3 Cost Deferral

Because immediate recovery of storm response costs—whether investments to harden systems to prevent storm damage or the costs of recovering from storm damage—may be too much of a burden to place on customers at the time such costs are incurred, often some or all of the costs are deferred. The accounting process for deferrals involves treatment of the costs as a regulatory asset (under-recovery) or regulatory liability (over-recovery). The state regulatory authority essentially allows the utility to place the costs on its balance sheet as an asset or liability, so it does not have to appear on the company's balance sheet and be charged against current revenues (or credited against current costs). The utility maintains the asset or liability on its balance sheet until the costs are recovered from or refunded to customers. The value of the asset or liability does not have to be considered either as income or an expense for tax purposes until there is actually some activity with the asset.

Once the regulatory asset or liability is established, the ultimate cost recovery decision can be deferred until the next general rate case, where an asset can be recovered through base rates or through a multi-year rate

[9] *After the Disaster: Utility Restoration Cost Recovery* (February 2005) prepared by Bradley W. for Edison Electric Institute, p. 9.

plan that negates the need for the utility to continually seek new rate cases. Or, as described below, costs associated with the regulatory asset can be recovered through a rate adjustment mechanism outside of a general rate case.

An issue that often arises with respect to cost deferral is whether utilities can charge the carrying costs associated with the asset to customers. This is important because there is an opportunity cost to the utility from delaying cost recovery, and investors are harmed if the opportunity cost is not reflected. The issue of cost deferral and carrying costs has been dealt with in many different ways.

States that have authorized individual utilities to defer storm-related costs include **Arkansas**, **Kentucky**, **Maryland**, **Massachusetts**, **New Jersey**, **New York**, **Ohio** and **Texas**. (See Appendix A.)

2.4 Rate Adjustment Mechanisms

Rate adjustment mechanisms refer to trackers, riders, adders, cost recovery factors and similar terms (that are usually used interchangeably) for a customer surcharge that recovers the costs of one or more specific cost items or categories outside of base rates. These surcharges may be permanent or temporary charges that are approved by regulatory commissions to recover costs that were unforeseen in previous general rate cases, costs that are imposed on the utility and not within its control, costs that are particularly volatile and difficult to predict, costs that are substantial and non-recurring, and/or costs for which the regulatory authority wants to establish a separate line item on customer bills apart from base rates. The most common form of rate adjustment mechanism is a fuel adjustment clause, which allows utilities to collect their most volatile and significant cost as fuel costs change.

Rate adjustment mechanisms have become more prevalent in recent years because they allow utilities and regulators to target specific costs without the need for frequent rate cases, allow customers some transparency as to the components of the rates they pay when the charge appears on the bill as a separate line item, and are favored by the financial community as a means to ensure that utilities are not financially harmed due to slow cost recovery, as can occur when general rate cases are not filed at frequent intervals.

The level of a rate adjustment mechanism may be fixed in advance (usually with scheduled true-ups to reflect actual costs within certain defined periods) or may vary as costs change (usually subject to periodic reviews to ensure the costs were prudently incurred). In any event, there are almost always regulatory proceedings to ensure that the level of the surcharge is equal to actual, prudently incurred costs expended (or saved).

Rate adjustment mechanisms can be designed to end when the specific amount of cost recovery is satisfied and thus are particularly useful for storm response. Rate adjustment mechanisms are also typically used when a charge applies only to a certain set of customers or only for certain periods of the year, such as seasonal adjustments. Many times these mechanisms are used to collect costs imposed by other governmental agencies, such as tax collection riders, environmental riders, and economic development riders. They also may be used to implement special programs such as smart meter and smart grid programs or grid hardening projects.

Rate adjustment mechanisms may or may not include a return to the utility on the assets for which costs are being recovered. While there are exceptions, it is common for capital investments recovered in this way to include a return component while operations and maintenance expenses usually do not include a return.

These mechanisms also may be used to track and recover costs from (or return savings to) ratepayers that commissions have previously allowed to be deferred as regulatory assets (or liabilities). Agreement by regulators to allow costs to be deferred for possible future recovery that would not have been reflected in a test year provides additional confidence to investors that costs will be recovered. Such use of rate adjustment mechanisms allows utilities flexibility, especially where storm costs are substantial and immediate recovery would severely harm utility customers. By obtaining regulatory approval to defer such costs as a regulatory asset (or liability), utilities also can avoid having to write off those expenses in the current period, which would cause harm to investors and increase the risk profile of the utility.

The operational details of rate adjustment mechanisms for deferred costs vary by state jurisdiction. In some cases, the utility is assured estimated cost recovery in a future period at the time the account is approved, subject to prudence review and true-up(s). In other cases, the commission may approve only the rate adjustment mechanism and require the utility to seek approval later of actual costs. Some jurisdictions may limit further additions to the account, while others will allow expenses pertinent to the mechanism's purpose to continue to be accumulated but impose limitations such as a cap to prevent excess earnings.

States that have authorized use of rate adjustment mechanisms include **Florida**, **Mississippi**, **Missouri**, **New Hampshire**, **Ohio**, **Oklahoma**, **Pennsylvania** and **Texas**. (See Appendix A.)

2.5 Lost Revenue and Purchased Power Adjustments

Another potential storm-related cost for which rate adjustment mechanisms may be relevant is an adjustment for lost revenues. Utilities set their rates based on a revenue requirement established by the state regulatory authority and forecasted (or recent historical) sales. If a utility loses customers for extended periods following a storm, its revenues from customers will fall short, and the utility may be unable to pay its fixed costs that are unavoidable with or without customer sales. State regulatory authorities have in some cases approved a lost revenue adjustment clause to allow utilities to recover some or all of these costs.

- While there do not appear to be any lost revenue adjustment mechanisms that are directly targeted at recovering revenues lost because of storms, there are several utilities around the country that have similar mechanisms that automatically adjust rates to reflect changing weather conditions. For example, in September 2009, the **District of Columbia** Public Service Commission approved the implementation of a bill stabilization adjustment (BSA) for Pepco. The BSA is a "decoupling" mechanism applied monthly in order to mitigate the volatility of revenues and customer bills caused both by abnormal weather and customer participation in energy efficiency programs. A similar BSA mechanism in **Maryland** was ended by the regulator as it applied to major storms in October 2012 following a June 2012 "derecho" storm in response to complaints from citizens and elected officials.[10]

Along similar lines, if a utility's generating facilities become unavailable due to storm damage, it may have to purchase power from other sources at rates higher than expected in its cost forecast. Purchased power adjustment clauses are sometimes approved to recover some or all of these additional costs. Purchased power transactions also may be approved to address other storm-related circumstances.

- **Florida** approved a fuel and purchased power cost recovery clause (FPPCRC) that provides for the recovery of both prudently incurred fuel and purchased power costs. Costs of power purchased during storm recovery would be recoverable under this clause if found to be prudent by the Florida Public Service Commission. Florida also has a capacity cost recovery clause (CCRC) in place. The capacity component of purchase power agreements and post-2001 power plant security costs are

[10] Maryland PSC, Case No. 9257 (October 26, 2012).

flowed through this clause.

- The **Texas** Public Utility Commission allowed Entergy Gulf States (EGS) to recover costs, via its fuel adjustment clause, of purchasing both surplus capacity and energy from affiliate Entergy New Orleans (ENO), which lost significant load as a result of Hurricane Katrina. The commission waived a rule restricting such recovery to energy-only costs. The transaction was intended to ease ENO's financial burden resulting from the hurricane, help facilitate restoration by the Entergy system, and save fuel costs for EGS customers. (See Appendix A.)

2.6 Formula Rates

Formula rates are another way of allowing utilities to recover unforeseen costs between general rate cases. Formula rates simply allow utilities to adjust rates between general rate cases because of changes in costs so that they may continue to earn their authorized returns. Some formula rate plans only allow changes if rates fall outside a specific band (either above or below) the rate set in the general rate case.

In almost all cases, utilities still need to present their cost changes and receive regulatory approval before changing their rates. To the extent that a general rate case includes storm-related expenses, and the formula rate allows those costs to change to reflect additional costs, formula rates can be a way to get more immediate recovery of storm damage costs than would be available through the general rate case process.

States that have approved formula rates for individual utilities include **Illinois** and **Louisiana.**

2.7 Storm Reserve Accounts

Storm reserve accounts are a form of self-insurance used by many utilities to "collect in advance" for costs incurred to recover from storms. A storm reserve is an accounting technique that allows utilities to smooth out the earnings impact of storms.[11] Traditionally, a utility would credit a fixed amount from its earnings to a storm reserve account. Storm recovery costs, typically when they are incurred, are charged against the balance in the storm reserve account, subject to review by commissions. In this case, the storm reserve account does not provide any cash to pay the storm costs but rather lessens the earnings impact due to the cost impact of the storm. This only works if there have been sufficient accruals to the storm reserve account to pay the incurred costs.

There are exceptions where storm reserves are funded with cash rather than by accrual. In these cases, cash is withdrawn from the storm reserve account to pay for storm damage as it is needed. Florida Power & Light, for example, has funded storm reserves with cash.

The impacts of recent major storms often have far exceeded amounts available in storm reserves. In some cases, state regulatory authorities allowed utilities to account for the excess as a negative balance in the storm reserve account as a temporary solution. But regulators in many cases have begun allowing utilities to charge customers either to establish or replenish storm reserve accounts in advance of incurring storm recovery costs. In some cases, such customer-funded storm reserve accounts have been permitted by state legislation.

States that have authorized use of storm reserve accounts include **Arkansas**, **Florida**, **Louisiana**, **Massachusetts**, **Mississippi**, **New Hampshire**, **New Jersey**, **New York** and **Texas**. In response to severe

[11] Johnson. op. cit., p. 11.

storms over the past few years, states such as **New York** have approved increases in annual funding of storm reserves. (See Appendix A.)

2.8 Securitization

Securitization is a financial tool that essentially packages bonds backed by secure revenue streams (usually supported by state legislation) and then sells the bonds on the market. By ensuring that the money being invested from the proceeds of these bonds has a high probability of being paid back—usually because a state legislature has mandated that the costs associated with repayment will be placed on customer bills as a surcharge—the bonds can be rated highly and thus get much lower interest rates than the utility would obtain by financing the investments itself. These lower interest costs then translate into lower costs for customers when they pay the servicing costs of the bonds through surcharges.

The first uses of this mechanism in the investor-owned electric utility segment were for so-called "stranded cost" bonds, where utilities—authorized by state legislatures—would set up a stranded cost securitization account, replenished by a surcharge on customer rates to pay whatever amount of stranded costs were allowed by the state. The state or utility would issue securitization bonds and the proceeds would be used by the utility to accelerate the depreciation on portions of their stranded plants to their market levels, with the bonds repaid from the customer surcharges.

The first use of securitization for recovering costs of damages to utility systems occurred after the terrorist acts of September 2001. Consolidated Edison Company of New York used securitized bonds to recover costs of damage to its systems. Since that time, and particularly following Hurricane Katrina, securitization has become an increasingly common method of recovering costs for major storms, especially in hurricane-prone states.

Securitization is not always a preferred mechanism for dealing with storm cost recovery. First it requires the legislature to act in most cases, followed by a favorable ruling from the regulator and then the underwriters. And the administrative costs can be significant. In most cases of securitization, the utility cannot earn on whatever investment results from the proceeds. For example, if a utility is using securitization to finance the reconstruction of a large part of its system, it might not be able to earn on that investment in the future and thus could face a reduced rate base.

While securitization has not been used to date to pay for hardening of facilities to prevent storm damage, it has been suggested as a possible tool for that purpose. For example, a recent report by the State of Maryland suggests securitization as an option for paying for the costs of undergrounding utility systems in the state.[12] Moreover, there may be some precedent for this type of use on the environmental side. For example, in **West Virginia**, securitization was authorized by the commission per a state statute to finance a flue gas desulfurization system at a utility generating plant. In this case, the bonds were backed by a nonbypassable environmental control charge.[13]

States that have authorized securitization of storm-related costs include **Arkansas**, **Florida**, **Louisiana**, **Mississippi**, **Ohio** and **Texas**.

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[12] *Weathering the Storm: Report of the Grid Resiliency Task Force* (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15, pp. 67-68.

[13] West Virginia PSC, Case No. 05-0402-E-CB, et al. (April 7, 2006), decided pursuant to WV Code § 24-2-4e.

2.9 Customer or Developer Funding/Matching Contributions

Where customers, groups of customers, or developers are interested in gaining protection against storm damage, they are often interested in the undergrounding or hardening of transmission and/or distribution lines. The costs of such hardening can be substantial as discussed elsewhere in this report. Some states such as Florida have begun to establish programs whereby utilities harden their systems and recover costs over time through base rates. In some cases, utilities will cover the costs of undergrounding for new residential developments where lines can be put in as excavation is done for other utilities. However, in other cases, the undergrounding of lines must be paid for in full or in part by the customer.

Almost every utility has a slightly different rule as to determining the costs of undergrounding for which the customer is responsible. The most common is that the customer pays for the difference in cost between overhead and underground lines for new installations, and the cost of undergrounding plus the cost of removing overhead lines, less any salvage value for the overhead equipment. In some cases—particularly for new installations—the utility will do a revenue analysis for the customer and reduce the cost of undergrounding if projected revenues are sufficient to cover some of the additional costs. Utilities in some circumstances might also match customer contributions.

With respect to transmission undergrounding, because transmission costs are seldom associated with a particular set of customers, utilities will need to seek regulatory approval for including the costs in rate base. Because of the substantial costs of undergrounding transmission, it is usually only done when circumstances dictate, such as in areas that are particularly environmentally or aesthetically sensitive, or where the terrain requires it.

There are situations where utilities can share costs with other utility providers that are undergrounding (such as gas pipelines or distribution lines or water mains), or take advantage of situations where roads or tunnels are being built and the incremental cost of undergrounding is much less than normal.

Where customers or other entities such as another utility provider pay for or contribute to the costs of undergrounding or other hardening measures, the payment by the contributor is referred to accounting-wise as a contribution in aid of construction (CIAC). Such contributions are generally not allowed to be recovered in a utility's rate base and may be considered as taxable income to the utility. In such cases, the amount to be collected from contributors is grossed up to collect any state or federal taxes that will be paid by the utility.

Florida is an example of a state that has authorized use of CIAC for storm-related investment.

2.10 Federal Funding

The Robert T. Stafford Disaster Relief and Emergency Assistance Act (the Stafford Act) authorizes the Federal Emergency Management Agency (FEMA) to provide federal aid to individuals and families, certain nonprofit agencies, and public agencies upon declaration of a state of emergency by the President.[14] Stafford Act funding is thus available to municipal, state, and rural electric cooperatives but not to investor-owned utilities. Over the past decade, there have been several unsuccessful attempts to amend the Stafford Act to include investor-owned utilities.

Federal funding has been made available, however, in very limited circumstances to investor-owned utilities under the Community Development Block Grant (CDBG) program of the U.S. Department of Housing and

[14] Federal Stafford Act Disaster Assistance: Presidential Declarations, Eligible Activities, and Funding" (June 7, 2011) prepared by the Congressional Research Service.

Urban Development (HUD). CDBG funds are actually provided to the states, and the utilities wishing to utilize the funds for disaster recovery must do so through agreements with the state government. States must satisfy one or more of three grant objectives:

1. Principally benefit low and moderate income persons
2. Aid in eliminating or preventing slums or blight
3. Meet urgent community development needs because existing conditions pose a serious or immediate threat to the public[15]

It is the third of these requirements that is usually satisfied by storm recovery needs.

CDBG funds can only be used for activities not covered by FEMA or the Small Business Administration, which qualifies investor-owned utilities because they cannot take advantage of these other sources. CDBG funds can be used for short-term relief, mitigation activities to lessen the impact of future disasters, and long-term recovery activities. While there are multiple rules covering the use of CDBG funds, the HUD secretary has fairly broad discretion to waive requirements in emergencies. The CDBG program generally requires matching funds from the state, but those requirements can also lessened or waived in emergencies.

Mississippi is an example of a state that certified storm restoration costs as eligible to receive CDBG funds.

2.11 Insurance

Up until the early 1990s, most utilities carried commercial insurance policies that covered storm damage up to the limits of the policy and after a deductible was met. But new commercial insurance policies to cover storm damage became difficult if not impossible to obtain following the destruction caused by Hurricane Andrew in 1992. Nonetheless, many utilities do carry legacy policies—usually small in amount and with high deductibles. For example, Connecticut Light and Power had a $15 million policy (with a $10 million deductible) in effect at the time of Tropical Storm Irene in 2011.[16] Most utilities also have insurance that covers generating station damage and damage to the facilities immediately surrounding those stations.

Storm reserve accounts (discussed above) represent a form of self-insurance by electric utilities. Funds are collected in advance through customer surcharges and held in reserve by the utility for future storms. Utilities still must obtain approval to apply actual costs against the reserve.

Another form of insurance that has been discussed off and on for years by utilities—particularly those in storm-prone areas—is the idea of a mutually funded insurance reserve that would receive premiums from member companies and pay for damages to members' systems when needed according to pre-determined formulas. The proposed insurance fund would work similarly to NEIL (Nuclear Electric Insurance Limited), which provides insurance coverage to domestic and international nuclear utilities. To date, efforts to establish such an insurance fund have not come to fruition but it remains a possibility for the future.

[15] Ibid., p. 1.
[16] http://www.ctnewsjunkie.com/ctnj.php/archives/entry/assessment_of_storm_response_can_wait

CHAPTER 3: CROSS-SECTION OF STATE REGULATION

As the frequency and intensity of major storm events have increased in recent years in many areas, so too has state regulatory activity, including post-storm reviews of electric utility preparation and response. Many of these reviews have resulted in legislation, new rules or increased regulatory activity under existing authority to strengthen utility storm readiness and response capability, mitigate risk, and enhance reliability and resiliency of electric systems.

This chapter provides a brief overview of state regulation and a cross-section of key state regulatory activities involving utility storm hardening and resiliency. Recent policy and regulatory activities of 16 states are highlighted below. Regulatory actions in 28 states are described in more detail in a matrix in Appendix A, EEI Cross-Section of State Regulatory Decisions on Storm Hardening and Resiliency. The matrix is not comprehensive but rather provides a snapshot of recent regulatory actions.

3.1 Regulatory Focus on Hardening and Resiliency

The review of states shows that regulatory attention to storm hardening and resiliency to help prevent and mitigate outages has strengthened since Superstorm Sandy. However, regulatory approaches to storm hardening and resiliency – and related cost recovery – continue to vary from state to state and depend on the particular circumstances of the state and utility.

The effects of Sandy have prompted regulators in states such as **New Jersey**, **New York** and **Pennsylvania** to look more comprehensively and strategically at reliability and storm hardening and resilience. Other states have taken more incremental approaches post-Sandy such as **West Virginia**, which directed utilities to focus on expanded vegetation management programs in light of extensive forest growth in the rural state.

Many of these and other states such as **Florida** already had begun to consider or implement changes before Sandy as a result of previous severe weather events and/or out of recognition of electric service reliability issues arising from aging distribution and other infrastructure.

An example of a different approach to cost recovery can be found in **Maryland**, where regulators in several rate cases departed from their longstanding practice of using a historic test year and conditionally allowed test year adjustments to reflect actual and certain forecasted reliability investment. (See Appendix A.) The actions came in recognition of increased reliability spending by utilities – with regulatory encouragement – and of the public need for such investment to reduce the risk of outages and mitigate their impacts.

Even with encouragement of increased utility spending to meet public need, cost recovery from ratepayers is not a given for system hardening and resiliency initiatives, which often mean higher costs for ratepayers. Utilities must, as they have always done, demonstrate the prudence of investments and provide assurance that spending is proportionate to the benefits delivered.

In some cases utilities must meet higher standards for performance that are aligned with higher customer expectations of reliability, as well as perform detailed recordkeeping to aid in assessments of the need for, and costs and benefits of, reliability and resilience investments. For example, the **Maryland** approvals of test year adjustments came with the condition that utilities must meet enhanced reliability performance metrics.

3.2 Changing Regulatory Frameworks

Some states have broadened their regulatory frameworks to enable regulators to give utilities more incentive and flexibility to address storm events and reliability infrastructure needs. The potential for financial and other penalties also is increasing in some states.

Examples of regulatory framework changes, which are more fully detailed in state highlights below and Appendix A and B, include:

- A **Connecticut** law requiring state regulators to review a utility's performance in responding to storms, set new performance standards, and identify the most cost-effective levels of tree trimming and system hardening needed to achieve maximum system reliability and minimize outages. Financial penalties may be imposed for non-compliance with the performance standards.
- A **District of Columbia** law authorizes financing via issuance of revenue bonds to back a public-private partnership between the District and Pepco. The partnership is planning to implement a program to strategically underground feeders that are particularly susceptible to storms.
- An **Illinois** law authorizing use of performance-based formula rates and requiring participating utilities to invest large specified amounts in transmission and distribution systems, with cost recovery addressed in annual formula rate plan proceedings. Utilities file grid modernization plans with performance metrics that carry penalties for non-compliance.
- A **Massachusetts** law that expands the authority of the Department of Public Utilities to oversee utility storm restoration and set performance standards for emergency preparation and restoration of utility service. Financial penalties may be imposed for non-compliance with the performance standards.
- Development by **New York** regulators of a process to change the regulatory model for achieving policy objectives that include assurance of system reliability and resiliency. The regulatory model will include performance and outcome-based incentives.
- **Indiana**, **Pennsylvania** and **Texas** laws authorizing the use of innovative rate adjustment mechanisms to allow more timely cost recovery for eligible distribution investments between general rate cases.

Even in the absence of authority to levy financial penalties, state commissions have authority to determine whether and to what extent utilities may recover storm-related costs from ratepayers, determine the value of rate base, and set an allowed return on capital investments in storm hardening, reliability improvements, and other infrastructure projects. Some commissions have considered utility preparedness and performance in major storms in making such determinations. In determining cost recovery, regulators look to whether costs were prudently incurred and are reasonable in accord with the statutory and regulatory frameworks of each state.

3.3 After Action Reviews: Mixed Results

State public utility commission oversight will continue to be a critical part of initiatives on storm hardening and resiliency. As part of this oversight, regulators conduct post-storm audits—on their own motion or in response to complaints—that often result in new requirements for utilities.

Several investigations that reviewed utility response to Sandy, including proceedings in Connecticut, New York and Pennsylvania, had mixed results. (More details can be found in the state sections below and Appendix A.)

- **Connecticut:** The Public Utilities Regulatory Authority found utilities performed in a "generally acceptable manner" in response to Sandy but also ordered certain improvements, e.g., in training and communications.
- **New York:** A report by the governor-appointed Moreland Commission found utilities unprepared to manage the perceived growing threat from major storms and recommended many changes to state and utility policies.
- **Pennsylvania:** The Public Utility Commission issued a report that was positive about utility response to Sandy and made recommendations for further improvements, e.g., in communications.

3.4 Distribution Reliability Improvements

Many states have taken steps to improve general distribution reliability to prevent or mitigate outages regardless of cause. Distribution reliability measures can include infrastructure inspection and maintenance, vegetation management, and other programs as discussed in Chapter 1 of this report. While the Federal Energy Regulatory Commission (FERC) regulates transmission power lines, including reliability standards that apply to transmission, it is up to state regulators to set vegetation management and other reliability standards for distribution facilities in their states.

Many regulators believe vegetation management and infrastructure inspection are key to improved reliability based on evidence that trees constitute the main cause of storm-related outages in most states. The **Missouri** Public Service Commission pointed to improved reliability as a result of new rules for enhanced vegetation management. In addition to Missouri, states that have directed improvements and/or authorized increased funding for vegetation management include **California**, **Connecticut**, **Maryland**, **Massachusetts**, **New Hampshire, North Carolina**, **Oklahoma** and **West Virginia**. (See Appendix A.)

Other programs encompassing distribution reliability improvement such as infrastructure upgrades have been approved in states such as **California**, **New Hampshire** and **North Dakota**. (See Appendix A.)

3.5 The Roles of Distributed Energy Resources and Smart Grid

The roles of smart grid technologies and distributed generation (DG) in grid resiliency and their interdependence with measures to protect critical infrastructure are the focus of heightened policy and regulatory discussion.

For example, Massachusetts is acting on a stakeholder grid modernization report urging regulators to provide guidelines to utilities to invest in grid modernization to improve system reliability and resiliency. The report linked distributed generation, grid modernization and grid resiliency, including recommendations for measures that improve a utility's ability to reduce the impact of outages. Measures including hardening, distributed generation and storage, aging infrastructure replacement and vegetation management.[17]

Connecticut, New York and **New Jersey** are examples of other states embracing development of microgrids, expanding distributed generation, and/or stepping up grid modernization with smart grid technologies. (See state highlights below and Appendix A).

[17] Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee (July 2, 2013), Final Report; Massachusetts DPU Case No. 12-76-A (December 23, 2013), order presenting straw proposal for grid modernization.

3.6 Rate Impact Mitigation

Even as many state regulatory commissions are taking a more proactive stance to address storm hardening and resiliency and/or general distribution reliability, they are recognizing that customers have become increasingly resistant to rate increases. State regulators generally are expected to continue seeking to avert or mitigate the impact of rate increases as many utility customers continue to struggle financially in the current economic climate. Pressure to keep rates from increasing comes despite the wide recognition that infrastructure is aging and must be replaced, and that new infrastructure may be needed to better respond to increasingly severe and unpredictable weather events.

Although potential rate impacts are uppermost in the minds of many regulators and policymakers, rate case filings have significantly increased in recent years to reflect needed infrastructure investment and other reliability measures undertaken by utilities on their own initiative to maintain and improve electric service or in response to mandates such as storm hardening requirements in **Florida** and **Texas**. In addition, storms feature prominently in many recent rate case filings.[18] This trend has continued post-Sandy.

3.7 State Highlights: AR, CA, CT, DC, FL, IL, IN, LA, MD, MA, MS, NJ, NY, NC, OH, PA

Arkansas

Securitization of Storm Costs: In March 2009, the Arkansas legislature passed Act 729, the Electric Utility Storm Securitization Recovery Act of 2009,[19] in response to a January 2009 ice storm which caused hundreds of millions of dollars of damage to Arkansas utilities. Unlike some other states, under Act 729 utilities would issue storm bonds themselves, but could not be considered by the Arkansas Public Service Commission (PSC) to be debt of the utility other than for tax purposes. By the same token, revenues collected to repay the bonds could not be considered utility revenue. Act 729 included a requirement that in Financing Orders to be issued by the PSC under the statute, provisions would be made for costs to be recovered using a formula-based mechanism for making expeditious periodic adjustments in the storm recovery charges that customers are required to pay and for making any adjustments that are necessary to correct for any projected over-collection or under-collection of the charges. In its request to recover costs from the January 2009 ice storm, Entergy Arkansas availed itself of the securitization provisions of Act 729 and received approval from the PSC to recover the costs of securitized bonds through a non-bypassable rider on utility bills. The PSC also allowed the company to recover carrying costs during the time between when the costs were incurred and when the bonds securitized.

Storm Reserve Accounting: In a rate case that was filed in 2006, Entergy Arkansas attempted to establish a storm reserve account and to increase rates to begin building up that account. The company noted that the commission had previously approved reserve accounting for storm damage. However, in a decision in June 2007, the PSC rejected the company's request to establish a storm reserve account, stating that it amounted to retroactive and single issue ratemaking, contrary to PSC rules.[20] Following the January 2009 ice storm, concerned about the financial impact on the company of not being able to defer $80-$100 million in new costs, Entergy Arkansas sought the PSC's permission to defer the expense portion of the storm restoration costs pursuant to accounting standards, thereby removing the expense from the income statement and avoiding the reporting of a financial loss in the first quarter earnings report. The commission approved Entergy's request.[21]

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[18] Rate Case Summary, Q4 2011 Financial Update, prepared by Edison Electric Institute
[19] Arkansas Code Annotated 5 23-18-901.
[20] Arkansas PSC Docket No. 06-101-U, Order No. 10 (June 15, 2007).
[21] Arkansas PSC Docket No. 09-018-U (March 6, 2009).

Meanwhile, in 2009 the Arkansas legislature passed a bill specifically allowing Arkansas utilities to use storm reserve accounting.[22] Entergy Arkansas made another filing after this bill was enacted to establish a storm reserve account, which was approved by the PSC in April 2010.[23]

California

Storm Investigations: In December 2011 a windstorm in Southern California caused widespread outages and sparked criticism by local governments regarding pre-emergency planning and coordination. The California Public Utilities Commission (PUC) launched an investigation that resulted in a preliminary report that cited pole failure and flaws in emergency planning among other findings.[24] The windstorm also gave rise to legislation (AB 1650) that was signed into law in September 2012. The law requires the PUC to establish standards for disaster and emergency preparedness plans within an existing proceeding. The law also requires electric utilities to develop, adopt, and update an emergency and disaster preparedness plan every two years. Cities and counties must participate in the development such plans.[25]

Distribution Reliability: The PUC in June 2010 adopted with modifications Pacific Gas and Electric's proposed Cornerstone program aimed at improving distribution system resiliency and reliability to provide customer benefits such as reduced frequency and duration of outages. Cornerstone capital costs and expenses are being recovered through a balancing account outside of general rate cases and are trued-up annually to reconcile actual with forecasted costs.[26]

System Hardening and Cost Recovery Related to Wildfires: Effects of wildfires increasingly are being treated at local, state and national levels in a manner similar to treatment of disasters such as hurricanes and tornadoes, including funding assistance. The CPUC in 2009 undertook a broad review of fire hazards following a series of destructive wildfires in 2007 that the commission thought linked to electric and communications facilities. The commission concluded three phases of the proceeding with decisions that first focused on preparations for the autumn 2009 fire season, then revised rules to improve vegetation management practices, avoid pole failure and improve fire planning, and finally revised rules to incorporate use of modern materials and technologies such as smart grid as well as design and construction practices.[27] New tools were provided, such as giving utilities the ability to address situations where property owners seek to block access to their sites for tree trimming. Under the rules, utilities have authority to turn off power to such properties, subject to specified conditions.

Recovery of costs related to utility wildfire response that exceed insurance proceeds has been a controversial issue in the state. The PUC in late 2012 issued a final decision denying utility applications for recovery of uninsured expenses related to a series of 2007 wildfires through a separate, dedicated balancing account outside of a rate case.[28] The commission was concerned that the applications by an electric utility and a gas utility did not adequately address the possibility that limitless potential for ratepayers to fund third-party claims, including fire suppression and environmental damage, could invite a host of claims by others such as

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[22] Act 434 of 2009, "An Act to Require the Arkansas Public Service Commission to Permit Storm Cost Reserve Accounting for Electric Public Utilities When Requested; and for Other Purposes."
[23] Arkansas PSC Docket No. 09-031-U (April 16, 2010).
[24] *Investigation of Southern California Edison Company's Outages of November 30 and December 1, 2011,* Preliminary Report (February 1, 2012) prepared by California PUC Consumer Protection and Safety Division.
[25] AB 1650, enacted September 23, 2012, http://www.leginfo.ca.gov/pub/11-12/bill/asm/ab_1601-1650/ab_1650_bill_20120923_chaptered.pdf
[26] California PUC Application 08-05-023 (June 24, 2010).
[27] California PUC Rulemaking 08-11-005 (August 20, 2009; January 12, 2012; February 5, 2014).
[28] California PUC Proceeding for Application 09-08-020, *Decision Denying Application* (December 20, 2012).

government entities. The commission also cited concern about the need to ensure that utilities are incentivized to defend against third-party claims and manage risk appropriately.

Grid Modernization: California also has been in the forefront of grid modernization efforts with approvals in recent years of smart grid-related programs for all three major investor-owned utilities in the state. Pacific Gas and Electric in its required annual update to the PUC detailed continued progress toward enhancing the reliability of its transmission and distribution systems. Activities include widespread deployment of smart meters, which have enabled implementation of an outage management integration project to better detect outage areas and "ping" individual meters to determine whether service has been restored. The result has been quicker and more accurate service restoration, the utility reported. San Diego Gas & Electric and Southern California Edison in their 2013 annual reports in the same proceeding highlighted similar developments.[29] In its 2013 annual report to the governor and legislature, the CPUC cited improved system resiliency and other benefits from smart grid investments.[30]

Connecticut

Distribution reliability: In the wake of Tropical Storm Irene and an October 2011 snowstorm that caused widespread outages, Connecticut in June 2012 enacted SB 23, An Act Enhancing Emergency Preparedness and Response.[31] The law requires the Public Utilities Regulatory Authority (PURA) to review the performance of utilities when more than 10 percent of its customers are without service for more than 48 consecutive hours. Utilities must file an emergency plan every two years. The law also established a pilot program to provide up to $15 million in grants and loans for the development of microgrid infrastructure that supports 65 MW of onsite generation at critical facilities. The law also required PURA to establish emergency performance standards and to allow utilities to recover reasonable costs incurred for maintaining or improving infrastructure resiliency pursuant to their approved emergency plans. The PURA implemented performance standards in November 2012.[32] In other related action, the PURA conditioned its approval in April 2012 of a merger of Northeast Utilities and NSTAR with requirements related to distribution reliability, including a directive to spend an incremental $300 million on system resiliency and to develop microgrid infrastructure in collaboration with the state.[33]

Distributed Energy Resources: The Act directed establishment of a first-of-its-kind statewide pilot program for the development of microgrid infrastructure to help protect critical facilities and increase the safety and quality of life of citizens during outages. A first round of the program, which is administered by the Department of Energy and Environmental Protection, awarded a total $18 million to nine projects, which are expected to become operational within 18 months of the July 2013 announcement. A second round was announced a few months later by the governor in which $15 million will be awarded. Selection is expected to be announced in September 2014.

Refrigerated Spoilage Loss: Another investigation directed by the Act resulted in a PURA report to the legislature describing a potential program to compensate customers for spoilage of refrigerated food and medications due to a verified outage. Ratepayers would fund the program through the existing systems benefit charge. The program would reflect a departure from traditional utility liability rules and an extra ratepayer expense, PURA found. Such a program would require legislation and "create a risk of some

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[29] California PUC Rulemaking 08-12-009: annual reports filed by Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison (October 1, 2013).
[30] *Report to the Governor and the Legislature: California Smart Grid – 2012,* California PUC (May 2013).
[31] Public Act 12-148.
[32] Connecticut PURA Docket No. 12-06-09 (November 1, 2012).
[33] Connecticut PURA Docket No. 12-01-07 (April 2, 2012).

unknown magnitude that reimbursement payments will change the role of the [electric distribution companies] to customers. That change will create a precedent that will affect future regulatory and public policy decisions," PURA said in its decision.[34] Citing a National Regulatory Research Institute report, PURA said only five other states have similar reimbursement programs: **California**, **Illinois**, **Michigan**, **Minnesota** and **New York**.[35]

Storm Investigations: A panel convened by the governor to evaluate the state's response to Tropical Storm Irene and the October 2011 snowstorm issued its report ("Two Storm Report") in January 2012.[36] The report included 82 recommendations, many of which addressed areas affecting electric utilities, including tree trimming, storm hardening and communication issues. The PURA later investigated the performance of utilities in preparing and responding to Sandy, finding that utilities performed "in a generally acceptable manner." The PURA also recommended areas for additional improvement, including communications and estimated restoration times.[37]

Vegetation Management: The Two Storm Report found that Connecticut has one of the densest tree canopies in the country and that fallen trees and limbs caused most of the downed wires during Irene. A PURA investigation of tree trimming practices is currently under way in response to the governor's directives. In a draft decision, PURA said utilities already are implementing most recommendations and requirements to make their infrastructure more resilient to storm damage and to promote shorter restoration time following outages from major storms.[38] Electric utilities have approved vegetation management plans with significantly increased budgets over the next five to eight years. The current PURA investigation is aimed at reviewing and clarifying the practices, procedures and requirements for utility vegetation management to comply with the Governor's directives and legislative mandates. The PURA was set to hold a technical meeting and hear public comments in March 2014 before rendering a final decision.

District of Columbia

Reliability Regulations: In July 2012, the District of Columbia Public Service Commission (PSC) formally adopted comprehensive reliability standards related to major outages.[39] The regulations include requiring electric utilities to develop and implement plans to improve the performance of low performing feeders, and to develop a Major Service Outage Restoration Plan detailing internal and external communication policies concerning outage notifications; utility early storm detection and tracking efforts; staffing, materials and logistical information; and lists of restoration priorities.

Undergrounding: In the District of Columbia, the undergrounding of electric distribution lines has been a hot topic due to the reliability concerns related to major storm outages. In 2009, the PSC engaged a consulting firm, Shaw Consultants International, Inc., to conduct an independent study of the economic and technical feasibility and reliability implications of undergrounding electric distribution lines in the District of Columbia. The firm released its study in July 2010 making several recommendations to the PSC including the continued use of undergrounding when new residential developments are introduced; not undergrounding all existing circuits and selective undergrounding in specific situations where undergrounding can be

[34] Connecticut PURA Docket No.12-06-12 (January 8, 2013).
[35] *Should Public Utilities Compensate Customers for Service Interruptions?* Ken Costello, Principal Researcher, National Regulatory Research Institute, Report No. 12-08 (July 2012).
[36] *Report of the Two Storm Panel* (January 9, 2012) presented to Governor Dannel P. Malloy.
[37] Connecticut PURA Docket No. 12-11-07 (November 16, 2012).
[38] Connecticut PURA Docket No. 12-01-10, draft decision (November 19, 2013).
[39] *D.C. Mun. Regs.*, Title 15, § 3603 (2012).

bundled with infrastructure investments, such as road expansion efforts, and large scale water and sewer replacement.[40]

A public-private partnership between D.C. and Pepco was subsequently announced in May 2013. The partnership plans to implement a $1 billion program to strategically underground feeders that are particularly susceptible to storms. Enabling legislation was needed for the financing, and in February 2014 the D.C. Council passed a bill authorizing the district to issue revenue bonds to finance part of the project.[41] The remainder would be financed through a surcharge mechanism also authorized by the bill.

Florida

Storm Hardening and Resiliency: Florida is probably unique in that it has adopted the most comprehensive program to date for hardening existing (and future) infrastructure to reduce damage from future storms. Florida has utilized a multifaceted approach that includes the development of new rules and regulations regarding vegetation management and other hardening activities, the development of overhead and underground construction standards, requirements for the filing of utility plans—including cost estimates—for hardening options, and required investments by utilities with predetermined cost recovery, subject to a prudence review. The Florida Public Service Commission (PSC) has also encouraged the filing of tariffs that reduce the costs of undergrounding to customers. The Florida effort also has included the initiation of several research programs at Florida universities to look at new methods to reduce storm damage costs and methods to assess the costs and benefits of various measures.

The Florida initiatives began in early 2006, when the legislature enacted a statute[42] that among other provisions, required the PSC to determine what should be done to increase the reliability of the state's transmission and distribution systems during extreme weather events. The state's legislative action came in response to a series of devastating hurricanes (Dennis, Katrina, Wilma and Rita) in 2005 and 2004 (Charley, Frances, Ivan and Jeanne). The legislature requested recommendations from the PSC in the following areas:

- Encouraging underground electric distribution for new utility service or construction
- Encouraging the conversion of existing overhead distribution facilities to underground facilities, including any incentives for local-government-sponsored conversions
- Utility participation in local-government-sponsored conversion costs as an investment in grid reliability, with such investment recognized as a new plant in service for regulatory purposes
- Encouraging the use of road rights-of-way for the location of underground facilities in any local-government-sponsored conversion project, provided the customers of the public utility do not incur increased liability and future relocation costs.

The PSC initiated its efforts in January 2006 with a workshop on lessons learned from the hurricane seasons of 2004 and 2005. The commission then decided on its multifaceted, multiyear approach to investigate actions needed to harden systems and reduce the amount of future storm damage, including:

- Annual hurricane preparedness briefings by Florida utilities
- A formal electric utility pole inspection program

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[40] *Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia* (July 1, 2010) prepared by Shaw Consultants International, Inc. submitted to the District of Columbia PSC pursuant to Formal Case No. 1026.
[41] The Electric Company Infrastructure Improvement Financing Act of 2013, Bill No. 20-0387.
[42] Chapter 2006-230, Sections 19(2) and (3), Laws of Florida.

- An annual assessment of comprehensive reliability reports by the electric utilities
- Ten storm-hardening initiatives that include Florida specific research
- University research on the measurement and effects of storm wind speeds on infrastructure
- University research on best practices for vegetation management
- Development of rules governing utility storm restoration costs
- A rulemaking regarding overhead and underground storm hardening construction standards
- A rulemaking to expand the calculation of contribution-in-aid-of-construction (CIAC) for new underground facilities and conversion of existing overhead facilities to underground to reflect the cost impacts of storm hardening and storm restoration
- Tariffs promoting underground electric distribution facilities
- University research to develop cost benefit methodologies to identify areas and circumstances to facilitate the conversion of overhead distribution facilities to underground facilities

The first related PSC rulemaking dealt with an inspection program for wood poles, requiring an eight-year mandatory wooden pole inspection program, including reporting, for all investor-owned electric utilities and local exchange telephone companies. [43] The commission next adopted a set of rules strengthening reporting requirements.[44] Prior reporting requirements allowed for the exclusion of reliability data that is typically related to power outages that were viewed as being outside the utility's control. Thus, absent the rule change, the reports provided no insight into storm-related impacts on reliable electric service in Florida. The rule changes also specifically require the utilities to retain records and data supporting annual reports.

In another proceeding the commission required utilities to file storm hardening plans and estimated implementation costs by June 1, 2006.[45] The following components were to be considered:

- Three-year vegetation management cycle for distribution circuits
- Audit of joint-use attachment agreements
- Six-year transmission structure inspection program
- Hardening of existing transmission structures
- Transmission and distribution geographic information system
- Post-storm data collection and forensic analysis
- Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
- Increased utility coordination with local governments
- Collaborative research on effects of hurricane winds and storm surge
- Natural disaster preparedness and recovery program

The commission approved most aspects of the utility storm preparedness initiative plans but required revisions in some areas.[46] The commission also required the companies to file updates to their storm

[43] Florida PSC Docket No. 060078-EI (February 27, 2006).
[44] Florida PSC Docket No. 060243-EI (July 31, 2006).
[45] Florida PSC Docket No. 060198-EI (April 4, 2006).

hardening plans by March 1, 2007. The commission did not address cost recovery for the approved initiatives, leaving those issues for the utility rate cases or other actions.

The overall effort by the commission also initiated several research programs by Florida universities on issues such as how to measure the costs and benefits of storm hardening activities, measuring the effects of storms on infrastructure, and best practices for vegetation management. In reviewing the utility storm hardening plans, the commission noted that the utilities were not, but needed to be, involved with these research programs. The effort to date has resulted in the publication of several research studies that have been made available on the PSC's web site.[47]

In a final rulemaking initiated in 2006, the commission issued a series of rules and requirements for storm hardening[48]. First, utilities were to file within 90 days a detailed storm hardening plan (different from the "storm response initiatives plan" requirements discussed above), containing a detailed description of the construction standards, policies, practices, and procedures employed to enhance the reliability of overhead and underground electrical transmission and distribution facilities. Such standards, practices and policies were to be in conformance with the provisions of the rule. Each utility storm hardening plan needed to explain the systematic approach the utility will follow to achieve the desired objectives of enhancing reliability and reducing restoration costs and outage times associated with extreme weather events. The hardening plan was also to include pole attachment standards. The PSC held public workshops on the plans filed by utilities in October 2007, and ultimately approved those plans.

The PSC summarized all these activities pursuant to the Florida statute in a required report to the legislature and governor submitted July 2, 2007.[49] In February 2008 an addendum to that report was issued[50] and in July 2008, an update to the 2007 report was provided to the legislature and the governor.[51] These reports reflect the comprehensive and detailed nature of the commission's and the Florida utilities' efforts to improve the ability of the state's transmission and distribution infrastructure to withstand the large number of severe storms faced by the state.

The commission has continued to approve utility storm updates filed every year, finding that they are largely continuations of previously approved plans. The PSC also has noted the unavailability of data to evaluate the effects of the plans because of the dearth of named storms that have affected the state in more recent years.

Securitization of Storm Costs: Following the tremendous damage caused by the 2004 hurricanes, the Florida legislature in early 2005 enacted a statute giving utilities the ability to recover their storm damage costs and replenish storm reserve accounts by selling securitized bonds.[52] Before bonds were issued to cover the 2004 costs, the utilities suffered additional damage from the 2005 hurricanes. With respect to Florida Power &

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[46] Florida PSC Docket No. 060198-EI (September 19, 2006).
[47] http://www.psc.state.fl.us/utilities/electricgas/eiproject/index.aspx
[48] Florida PSC Docket Nos. 060172-EU and 060173-EU (January 17, 2007).
[49] *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather* (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888).
[50] *Addendum to the July 2007 Report to the Legislature On Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather*; Summary of Commission Actions; May 1, 2007 - December 15, 2007 (http://www.psc.state fl.us/utilities/electricgas/eiproject/docs/SHaddendum.pdf)
[51] *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather* (July 2008) submitted by the Florida Public Service Commission to the governor and legislature.
[52] Title XXVII, Section 366.8260, Florida Statutes.

Light in particular, the PSC approved issuance of up to $708 million in storm-recovery bonds, provided the initial average retail cents per kWh for the storm recovery charge would not exceed the average retail cents per kWh for the 2004 storm surcharge that was currently in effect.[53]

Storm Reserve Accounting: In 2007, the PSC issued an Order allowing utilities to establish storm reserve accounts and capitalize the costs of storm recovery to that account.[54] It is the utility's option whether to expense storm recovery costs or credit them to a storm reserve account. A utility may petition the commission for the recovery of a debit balance in reserve account plus an amount to replenish the storm reserve through a surcharge, securitization, or other cost recovery mechanism. If a utility seeks a change to either the target accumulated balance or the annual accrual amount for the storm reserve, it must file a study with the commission.

Following approval of its storm hardening plan, Progress Energy Florida requested that it be allowed to recover approved storm hardening costs through its storm reserve account. The PSC denied the request,[55] saying it did not meet the purposes specified for storm damage reserve accounts under Florida's rules. In a separate proceeding, the PSC established a uniform procedure by which investor-owned electric utilities were to calculate amounts due as CIAC from customers who request new facilities or upgraded facilities in order to receive electric service.[56]

Illinois

Infrastructure Investment: Illinois in 2012 enacted the Energy Infrastructure Modernization Act (EIMA), a law authorizing and incentivizing investment in upgrades and modernization of the electric grid to provide consumer benefits such as reduced duration of frequency of service outages, improved overall service reliability, and improved power restoration following storms.[57] Under the law, participating utilities may use performance-based formula rates and in return are required to make investments in transmission and distribution systems, including smart grid systems, over 10 years as follows: Commonwealth Edison must invest $2.6 billion and Ameren Illinois must invest $625 million. Electric system upgrades include storm hardening, underground residential distribution cable injection and replacement, and wood pole inspection and replacement. Smart grid investment includes distribution automation, substation microprocessor relay upgrades, and smart meters and related data communications network.

The law sets reliability, customer benefit and vendor diversity metrics. Utilities must file annual work plans and undergo annual rate reviews. The law specifies a formula for calculating ROE in the annual rate reviews and requires adjustments if earned ROE falls outside a 100-basis-point deadband around the authorized ROE. The program terminates in 2014 if the total residential bill increases by more than 2.5 percent per year. The program also may terminate in 2017 if additional spending cannot be justified, and it automatically sunsets in 2022. A "trailer bill," HB 3036, also was enacted that refines the EIMA program, including redirecting of $200 million toward targeted infrastructure investments including undergrounding, storm hardening and other measures.[58]

In 2013, S.B. 9 was enacted to further clarify EIMA provisions by specifying that in rate reconciliations in formula rate plan proceedings, the ICC must use terminal, or year-end, rate base values, year-end capital

[53] Florida PSC Docket No. 060038-EI (May 30, 2006).
[54] Florida PSC Docket No. 070011-EI (May 23, 2007).
[55] Florida PSC Docket No. 090145-EI (July 6, 2009).
[56] Florida PSC Docket Nos. 060172-EU and 060173-EU (January 17, 2007).
[57] SB 1652 (Public Act 97-0616), Energy Infrastructure Modernization Act, enacted October 31, 2011
[58] HB 3036 (Public Act 97-0646), enacted December 30, 2011

structures, and weighted average cost of capital.[59] Enactment occurred via legislative override of a veto by Governor Pat Quinn, who viewed the measure as a circumvention of longstanding regulatory precedent.

Formula Rate Plans: The Illinois Commerce Commission's (ICC) application of EIMA in decisions on initial formula rate plans prior to passage of S.B. 9 left both filing utilities, Commonwealth Edison and Ameren Illinois, with lower revenue prospects than anticipated.[60] This result led to a scaling back of the utilities' investment plans under EIMA. The cases highlighted the importance of methodologies for calculating rate base, capital structure, and interest for purposes of reconciliation adjustments in formula rate plans. The treatment specified by S.B. 9 is intended to better reflect the value of infrastructure investments than the treatment previously used by the ICC, which applied average rate base value, average capital structure, and inclusion only of debt return for reconciliation adjustments.

Following enactment of S.B. 9, the ICC issued a decision in Commonwealth Edison's general distribution rate case in late 2013 that approved use of year-end rate base treatment and capital structure and weighted average cost of capital as interest for purposes of reconciliation adjustments.[61] The provisions of S.B. apply not only to future rate reconciliations under formula rate plans but also to past reconciliation proceedings. The ICC accordingly adjusted, in June 2013, a previous decision for Commonwealth Edison that resulted in a lower revenue requirement. Ameren had not yet gone through a reconciliation by the time of passage.

Refrigerated Spoilage Loss: For the first time under a 15-year-old statute,[62] the ICC found that a utility, Commonwealth Edison, may be liable for damages such as food spoilage and other economic losses experienced by customers in relation to one of a series of storms in summer 2011. In other similar cases, the ICC has consistently waived utility liability for such damage, typically on the basis of findings that damage was unpreventable due to severity of weather. After being denied rehearing, Commonwealth Edison filed a compliance report with confidential information on customers or areas that could be entitled to compensation.

Indiana

Infrastructure Investment: In April 2013, Indiana joined the ranks of states such as **Pennsylvania** and **Texas** that allow distribution infrastructure investment riders for cost recovery for such projects outside of general rate cases. S.B. 560 was enacted to encourage transmission, distribution and energy storage infrastructure investment by utilities, including projects to improve safety and reliability and modernize the grid.[63] The law allows utilities to implement a transmission, distribution, and storage system improvement rider (TDSIC), conditioned on approval by the Indiana Utility Regulatory Commission (URC) of an accompanying seven-year project plan, which is subject to hearings and public comment. The TDSIC can be used to recover no more than 80 percent of capital expenditures related to the plan; 20 percent must be deferred until the next rate case. Utilities with approved TDSIC riders must file a base rate case every seven years. The URC approved the first electric utility TDSIC mechanism for Northern Indiana Public Service in February 2014.[64]

The law also established shorter timeline (300 days) for general rate cases and included other provisions to reduce regulatory lag. The law allows utilities to use a historic test year, forward test year, or hybrid test year

[59] Public Act 098-0015
[60] ICC, Commonwealth Edison Docket No. 11-0721 (May 29, 2012, rehearing, October 3, 2012); Ameren Docket No. 12-0001(September 19, 2012).
[61] ICC, Commonwealth Edison Docket No. 13-0318 (December 18, 2013).
[62] Public Utilities Act, Section 16-125(e).
[63] Public Law 133
[64] URC Docket Nos. 44370 and 44371 (February 17, 2014).

in general rate cases. Under specified circumstances, utilities also may implement interim rate increases to facilitate cost recovery before a final decision is rendered in a rate case.

Storm Reserve Accounting: The URC approved a major storm damage restoration reserve for Indiana Michigan Power. While it reduced the base amount, it allowed IMP to use a tracking mechanism to record variations in O&M expenses from the base amount as a regulatory asset or liability, to be recovered from or refunded to ratepayers in a future rate case. In its decision, the URC said that in the past it has allowed a utility to seek recovery of extraordinary storm restoration costs through a separate proceeding, but only when the related storm was a worst-case scenario. The commission found, however, that these stand-alone cases are often heavily litigated and highly contentions. The approved tracking mechanism will serve to "smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm," the commission said.

Louisiana

Securitization of Storm Costs: There have been two bills passed by the Louisiana legislature that deal with securitization of utility storm damage costs, both of which resulted from the unprecedented damage caused to the Gulf Coast by Hurricanes Katrina and Rita. A 2006 Louisiana statute authorizing securitization of storm recovery costs, referred to as Act 64, required the companies to establish "special purpose entities" to sell securitization bonds. The Act simply stated that the Louisiana PSC must judge proposed bond issuances on the basis of whether it would result in lower overall costs or would mitigate the impact of storm recovery costs on customers. Rather than institute a separate surcharge for storm recovery, the statute provides that the utility recover its costs of the bonds in general rates. This statute also made clear that the bonds were not backed by the state of Louisiana.

Entergy Louisiana and Entergy Gulf States Louisiana applied for a financing order shortly after passage of the new statute to securitize its costs from Hurricanes Katrina and Rita. (The companies had already received permission to recover the unreimbursed costs in rates.) They received Commission approval,[65] but after over two years were unable to securitize storm costs at what the PSC considered to be favorable rates terms and conditions. Among the possible reasons cited were lack of transparency and the fact that Act 64 did not rely on a separate surcharge or rider for cost recovery, and the state of the securities markets at the time.[66] In 2007, the legislature passed a new law, Act 55, which established the Louisiana Utilities Restoration Corporation to serve as a co-applicant with the utility companies in requesting the sale of bonds for storm recovery by the Louisiana Public Facilities Authority. By establishing the Louisiana Utilities Restoration Corporation, and having the bonds issued by a state authority, the companies were able to successfully sell securitized bonds for storm cost recovery, and at a lower cost to consumers than was possible under Act 64. Act 55 was used again in 2010 to recover damage costs from Hurricanes Ike and Gustav through the sale of securitized bonds. In this case, the PSC established a rider for the collection of funds from customers to repay the bonds.[67]

Storm Cost Recovery by Formula Rate: In 2009, Entergy New Orleans, which is regulated by the City Council of New Orleans Utilities Committee, requested and received approval to implement formula rates which included the recovery of costs due to storm damage, for a three-year period beginning in 2010.[68] The

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[65] Louisiana PSC Docket Nos. U-29203- B, - C and –D (August 15, 2007).

[66] *February 2008 Cumulative Update – Critical Electric Power Infrastructure and Reconstruction: New Policy Initiatives in Four Gulf Coast States After 2005's Catastrophic Hurricanes*, prepared by George Mason University School of Law, Critical Infrastructure Protection Program, p. 27.

[67] Louisiana PSC Docket Nos. U-30981 and U-309812 –A, -B and –C (April 21, 2010).

[68] New Orleans City Council Resolution R-09-136 (April 2, 2009).

formula rates include a rider that collects both for the costs of storm damage and replenishes the company's storm reserve fund.

Storm Investigations: Following Hurricanes Katrina and Rita, the PSC initiated an investigation into the appropriate level of cost recovery for Entergy Louisiana and Entergy Gulf States. Recognizing the catastrophic nature of the storm and the financial position that storm recovery expenditures was placing the companies in, the commission approved interim cost recovery in March 2006 and allowed the company to recover additional forecasted expenses through September of that year.[69] Recovery amounts were to be recovered as an extraordinary cost surcharge which would end when the full amount was collected. The PSC also ordered that after an investigation of the companies' full costs, it would develop a revenue requirement, to be added to rates, for permanent storm recovery.

In an order issued in August 2007, the PSC approved the level of permanent cost recovery for storm damage from Rita and Katrina at $187 million for Entergy Gulf States and $545 million for Entergy Louisiana.[70] Both companies were ordered to establish storm reserve accounts to cover costs of future storms. The PSC requested that the companies seek financing orders to securitize unreimbursed costs from storm damage.

Maryland

Storm Investigations: Maryland has been active in investigating and regulating the actions of investor-owned electric utilities in preparing for and responding to major storms. For example, in February 2011, the Maryland PSC initiated a proceeding to investigate whether the decoupling mechanisms approved for Maryland investor-owned-utilities inadvertently eliminated the incentive for the companies to quickly restore lost service to customers by authorizing the recovery of revenues foregone during extended outages, and if so, whether the decoupling mechanisms should be modified to prevent that outcome. In response to this investigation, the commission issued an order finding that the decoupling mechanisms as currently designed do not appropriately align company financial incentives with reliability goals, and therefore, the commission will require the modification of the decoupling mechanism to prevent collection of decoupling revenue if service is not restored to pre-major storm levels within 24 hours of the commencement of a Major Storm.[71] In October 2012, the commission reaffirmed the January 2012 order and extended the prohibition on collecting decoupling revenue during the first 24 hours of a major outage.[72]

The PSC more recently investigated utility response to the derecho storm of June 29, 2012 and found that the grid is not resilient enough to withstand unscathed a storm the magnitude of the derecho. The commission also found a "disconnect" between the public's expectations for distribution system reliability and the ability of the system to meet those expectations, and it directed utilities to take various steps, including development of shorter term as well as long-term plans to improve reliability. The PSC did not, however, find cause for civil penalties or further action.[73]

The PSC directive built on other work that arose out of an Executive Order[74] issued by Maryland Governor Martin O'Malley initiating a task force to solicit recommendations on how to improve the resiliency and reliability of the Maryland electric distribution system. This task force issued 11 recommendations

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[69] Louisiana PSC Docket No. U-29203–A (March 3, 2006).
[70] Louisiana PSC Docket Nos. U-29203- B, - C and –D (August 15, 2007).
[71] Maryland PSC Case No. 9257, *et al.* (January 25, 2012).
[72] Maryland PSC Case No. 9257, *et al*. (October 26, 2012).
[73] Maryland PSC Case No. 9298 (July 26, 2012).
[74] Executive Order 01.01.2012.15 (July 25, 2012).

concerning how specific technology, infrastructure, regulatory, and process improvements can improve the resiliency of Maryland's distribution grid, including allowing a tracker cost recovery mechanism for accelerated and incremental investments.[75]

Reliability Regulations: In 2011, the Maryland Electricity Service Quality and Reliability Act was signed into law requiring the PSC to adopt regulations imposing service quality and reliability standards on electric utility companies, and raising the maximum penalty for failure to comply with the regulations from $500 to $25,000 per violation. Then, in April 2012, the PSC adopted the regulations implementing the service quality and reliability standards in Rule Making 43 (RM43). RM43 set minimum reliability metrics for each utility based on past performance, established a mandatory annual performance reporting system, set up a customer communication survey, and mandated vegetation management and periodic inspections. Also, under RM43, utilities are required to submit a major outage event report within three weeks of a major outage, as well as a restoration plan detailing the utilities' response to a major event. Finally, RM43 provides the PSC the authority to enact civil penalties and disallow costs based on non-compliance with the regulations.

Cost Recovery: In recent rate proceedings the PSC has departed from precedent by allowing application of end-of-test year values to reliability capital investments and post-test year reliability spending adjustments of up to three months in rate cases. The commission also has conditionally approved a reliability spending surcharge for three utilities, known as a grid resiliency charge, which the governor's task force said may be appropriate and that is linked to specific projects such as expansion of poorest performing feeders.[76] Use of these tools, which better reflect for ratemaking purposes the level of investment during the rate period, was approved in recognition of the need to make and accelerate incremental infrastructure investments for safety and reliability. However, the commission has continued to reject longer-term post-test year adjustments, including proposals related to RM43 compliance. The commission cited concern about the estimated nature of such adjustments, including the limited experience with implementation of RM43 so far.[77]

Undergrounding: Maryland has required undergrounding of distribution lines in new commercial and industrial buildings and residential structures since August 1969.[78] In addition, the governor's grid resiliency task force held a session focusing on undergrounding Maryland's electricity distribution system. The discussion touched broadly on the economic feasibility of undergrounding, whether undergrounding truly increases reliability, and the effect of undergrounding on grid resiliency. While the task force issued no specific recommendations concerning undergrounding or other, the consensus among the roundtable participants was that while undergrounding can significantly reduce outages caused by falling vegetation and high winds, due to costs considerations, selective undergrounding is preferable to complete undergrounding of the electric distribution system. The PSC remains cautious about undergrounding, approving half of a utility-requested selective undergrounding project and requiring more detailed information for the approved components.[79]

[75] *Weathering the Storm: Report of the Grid Resiliency Task Force* (September 24, 2012), delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15, pp. 67-68.
[76] *See, Delmarva Power and Light*, Case No. 9317 (September 3, 2013); *Potomac Electric Power Company*, Case No. 9311 (July 12, 2013); and *Baltimore Gas and Electric*, Case No. 9326 (December 13, 2013).
[77] *Baltimore Gas and Electric*, Case No. 9299
[78] COMAR 20.85.01, and COMAR 20.85.03.
[79] *Baltimore Gas and Electric*, Case No. 9326 (December 13, 2013).

Massachusetts

Storm Response: Massachusetts in November 2009 enacted H 4329, a law that expands the authority of the Department of Public Utilities (DPU) to oversee utility storm restoration.[80] The DPU in April 2010 adopted regulations to implement the law. Under the law, the DPU set performance standards for emergency preparation and restoration of utility service and established financial penalties to be applied for failure to meet the standards. Penalties for failing to meet emergency response plans required of each utility range up to $250,000 per day per incident, with the maximum penalty for a series of violations capped at $20 million. Penalties may not be recovered from ratepayers and instead must be credited to ratepayers of the affected utility in a single billing period, although utilities may petition for a longer period if the credit exceeds $10 million.

The law also authorizes the DPU to issue extraordinary temporary orders for utilities to expend funds and redeploy service to restore service, and it gives the state attorney general the power to appoint a temporary receiver for small utilities (fewer than 100,000 customers) based on a determination that the utility has materially violated DPU standards or on evidence that compliance will not be possible without a receivership. The law was enacted following an investigation by the DPU of a utility's performance in a 2008 ice storm that resulted in findings of shortcomings. Enactment came during a DPU investigation of the response of several utilities to Tropical Storm Irene and an October snowstorm in 2009. The results of the investigation of Irene and the 2009 storm were announced in December 2012 and included financial penalties.[81]

Another law, S 2143, was enacted in August 2012 to establish a Storm Trust Fund, funded by a charge assessed utilities by the DPU that is not recoverable from ratepayers. The funds are used by the DPU to conduct investigations of utility storm response.

Storm Reserve Accounting: Through rate settlements, the DPU has adopted storm funds for various electric distribution companies.[82]

Distribution Reliability: The DPU in late 2012 began reviewing utility service quality (SQ) and SQ guidelines. The department recognized that the attorney general was developing recommendations, which were submitted into the docket. The AG cited concerns that included recent storms and outages, and infrastructure investments and related rate increases. The DPU has solicited input on metrics, benchmarks, offsets and penalty levels.

Distributed Energy Resources: As part of the SQ proceeding above, which is still underway, the DPU has sought input on the possibility of creating a clean energy performance metric. In another initiative, Governor Deval Patrick on January 14, 2014, announced a climate change preparedness plan that includes a $40 million municipal resiliency grant program to be funded by utilities via alternative compliance payments under the state renewables standard. The governor said DPU will work with utilities to accelerate storm hardening and deploy microgrids and resiliency projects for transmission and distribution.

Grid Modernization: The DPU in October 2012 opened an investigation of policies relating to grid modernization, a topic the DPU said has received increased attention in recent years as a result of customer outages following several severe storms. In support of the inquiry, the DPU cited the storm response law

[80] St. 2009, c. 133; 220 CMR § 19
[81] Massachusetts DPU Docket No. DPU 11-119 (December 11, 2012).
[82] Massachusetts DPU, Western Massachusetts Electric Docket No. DPU 06-55 (2006); Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric/NSTAR Gas Docket No. DTE 05-85 (2005).

discussed above and another recently enacted law, S. 2395, An Act Relative to Competitively Priced Electricity in the Commonwealth.[83] The DPU in December 2013 presented a straw proposal for grid modernization following a publication earlier in the year of a working group report.[84] The DPU directed utilities to submit within six months 10-year strategic grid modernization plans that contain infrastructure and performance metrics toward meeting four broad objectives, including reduction of outage effects.[85]

Mississippi

Rate Adjustment Mechanism: In 2007, the Mississippi PSC approved Rider Schedule SRC for Entergy Mississippi as a mechanism to recover securitized and other funds authorized by the PSC.[86] The rider was designed to be applied as a nonbypassable surcharge to all customers. It includes a formula-based mechanism to allow expeditious adjustments intended to correct over- or under-recovery of costs. A similar order was issued for Mississippi Power Company. In 2011, the PSC approved changes in the storm damage rider to reflect an increase in frequency and severity of storms.[87] Rider collections were increased to allow companies to recover their deficit in storm damage reserves that occurred due to Hurricanes Gustav and Ike in 2010, and additional storms of April 2008. The cap on the storm reserve fund was also increased.

Securitization of Storm Costs: In June 2006, the Mississippi PSC issued financing orders permitting both Mississippi Power and Entergy Mississippi to issue securitized storm bonds to recover the costs of Hurricane Katrina that were not otherwise reimbursed by Community Development Block Grants or other payments.[88] The order was issued pursuant to the Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act of 2006 passed by the state legislature. By issuing the order, the State Bond Commission (also established by the 2006 legislation) was authorized to issue the bonds to finance recovery costs. Bond debt service is repaid via a system restoration surcharge on customer bills, to be reset by the companies annually to recover 110% of required annual debt service.

Storm Investigations: In approving the issuance of bonds to recover damage costs associated with Katrina, the PSC also determined that certain actions should be taken to reduce future storm damage, and in particular the jurisdictional Mississippi companies were ordered to harden their locations to withstand hurricane force winds approximately 10 miles inland from potential flooding. In addition, Mississippi Power was authorized to use proceeds of its bond sale to build a new storm operations center further from shore.

New Jersey

Storm Hardening and Resiliency: Following Sandy, the New Jersey Board of Public Utilities (BPU) opened various generic proceedings. In one proceeding, the BPU is investigating possible avenues to support utility infrastructure in withstanding major storms and it has asked for utility proposals for infrastructure upgrades.[89] In another proceeding the BPU is investigating the prudence of costs related to 2011 and 2012 major storms for which utilities are seeking rate recovery. Among the responses to the first investigation was Public Service Electric and Gas' proposed Energy Strong program, which is awaiting BPU action. The

[83] St. 2012, c. 209 (August 3, 2012).
[84] *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee*, Final Report (July 2, 2013).
[85] DPU Docket No. 12-76-A (December 23, 2013).
[86] Mississippi PSC Docket No. 2006-UA-350 (May 22, 2007).
[87] Mississippi PSC Docket No. 2010-UN-436, et al. (October 7, 2011).
[88] Mississippi PSC Docket No. 2006-UA-82 (June 28, 2006).
[89] New Jersey BPU Docket No. AX13030197 (March 20, 2013).

proposal is for a 10-year, $3.9 billion investment program that includes deployment of smart grid technologies, strengthening of distribution infrastructure, and undergrounding in certain areas.

Storm Investigations: The BPU released a report that investigated the restoration efforts by New Jersey's electric distribution companies (EDCs) prior to, during and after Hurricane Irene and the October 29, 2011 snowstorm.[90] The recommendations to the BPU included more detailed development of a vegetation management program; development of an Incident Command System; use of company websites and social media to provide more granular outage details and estimated time of restoration; conducting annual training and exercise drills; and use of benchmarking and external analysis of each company's restoration experiences. This report served as a follow-up to a preliminary report issued by the NJ BPU on December 14, 2011 concerning major storm event planning and emergency response by New Jersey's four EDCs.[91] As a result of another investigation, the BPU imposed new requirements relating to communication among utilities, municipal officials, customers and the Board.[92]

The Board also asked staff to work with Rutgers' Center for Energy, Economic and Environmental Policy (CEEEP) to analyze specific areas that raise concerns and affect restoration efforts in the wake of Sandy. The areas include infrastructure investment such as selective undergrounding and substation protection, expansion of distributed generation, evaluation of smart grid technologies, and identification of best practices for vegetation management.

Distributed Energy Resources and Grid Modernization: New Jersey is focusing more attention on the roles that distributed generation, microgrids, and smart grid technologies may play in grid resiliency. The U.S. Department of Energy and the state last year announced a partnership to develop an advanced microgrid for the New Jersey transit system.[93] See also the discussion above for additional focus on distributed generation and smart grid via a CEEEP study.

Vegetation Management: The state of New Jersey has comprehensive vegetation management regulations for its EDCs.[94] The regulations provide for penalties up to a $100 per day for each violation.[95] See discussion above for additional focus on vegetation management via a CEEEP study.

Undergrounding: In New Jersey, undergrounding of distribution lines is governed under Section 14:3-8.4 of the New Jersey Administrative Code.[96] Under the regulations, distribution lines are required to be constructed underground for new residential developments and streets that are constructed after August 2005.[97] See discussion above for additional focus on selective undergrounding via a CEEEP study.

New York

Storm Hardening and Resiliency: The New York Public Service Commission (PSC) in February 2014 approved multiyear rate plans for Consolidated Edison Co. of New York (Con Edison) that provide for major capital investment in storm hardening and resiliency, including strategic undergrounding and flood

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[90] *Performance Review of EDCs in 2011 Major Storms* (August 9, 2012).
[91] New Jersey BPU Docket No. EO11090543 (December 14, 2011).
[92] New Jersey BPU Docket No. EO12111050 (May 29, 2012).
[93] Department of Energy press release (August 26, 2013).
[94] *Electric Utility Line Vegetation Management*, N.J.A.C. § 14:5-9.2 and 9.6
[95] N.J.A.C. § 14:5-9.10.
[96] *Regulation for Residential Electric Underground*, N.J.A.C. § 14:3-8.4.
[97] *Id*. at § 14:3-8.4(d).

protection projects to protect against coastal storm surge.[98] Concurrent with the rate proceeding was a collaborative track addressing storm hardening and resiliency issues. The PSC in the rate order adopted many of the collaborative's recommendations, which were included in the docket, and approved Phase 2 work, including a voluntary Con Edison climate change vulnerability study in 2014 and review of 2015-16 storm hardening initiatives.

Storm Investigations: New York Governor Andrew Cuomo in late 2012 issued an Executive Order establishing a commission under the Moreland Act to investigate the response, preparation, and management of New York's power utility companies with major storms hitting the state over the previous two years, including Hurricanes Sandy and Irene, and Tropical Storm Lee.[99] The Moreland Commission issued its final report on June 22, 2013, recommending a series of changes to state and utility policies. Recommendations included using public benefit funds and redirecting energy efficiency funds to use for better protecting the electric grid, as well as levying penalties and other measures. The report identified perceived deficiencies in utility storm preparation and restoration as well as best practices by some utilities that the commission said should be adopted statewide. The commission also made recommendations to reform the overlapping responsibilities and missions of the New York Power Authority, the Long Island Power Authority, the New York State Energy and Research Development Authority and the PSC.[100] In response to a request by Governor Cuomo, the PSC in late 2013 adopted a scorecard to serve as guidance to utilities as to what the PSC expects of them and for assessing utility performance related to major storm events.

Distributed Energy Resources: The Moreland Commission's recommendations included using public benefit funds and redirecting energy efficiency funds to use for better protecting the electric grid. In response, the PSC in late 2013 issued an order making changes to the state energy efficiency portfolio standard.[101] The order also started a process for making significant regulatory changes that would address deployment and use of customer-based resources in a more comprehensive policy context. Among the core policy outcomes articulated by the PSC was assurance of system reliability and resiliency. As part of its order approving Con Edison's capital investment program, as discussed above, the PSC directed the utility to pursue development of a plan for a microgrid project as well as a plan to address significant load growth in a section of Brooklyn by offering distributed generation as an alternative to traditional infrastructure. In addition, Phase 2 of the Con Edison resiliency collaborative discussed above will include identification of potential alternative resilience strategies such as additional microgrid and distributed generation projects.

Smart Grid: In New York, while investor-owned electric utilities are making investments designed to modernize the electric power grid, no utility has undertaken mass deployment of smart meters. However, the PSC issued a Smart Grid Policy Statement[102] where the commission recognized that smart meters could "[f]urnish utilities with additional outage management tools."[103]

Vegetation Management: Under 16 NYCRR Part 84 of the New York PSC's Rules of Procedure and an order from Case 04-E-0822, each utility must develop and implement a long-range vegetation management plan for the utilities' right-of-ways. The PSC requires that a utility's long-range plans provide for vegetation management planning in right-of-way corridors for transmission facilities consisting of 34 kV and above, except where located entirely on public streets or roads in right-of-way corridors.

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[98] New York PSC, Case No. 13-E-0030 (February 21, 2013).
[99] Executive Order No. 73 (November 13, 2012).
[100] *Final Report*, Moreland Commission on Utility Storm Preparation and Response (June 22, 2013).
[101] New York PSC, Case No. 07-M-0548 (December 26, 2013).
[102] New York PSC Case Number 10–E–0285 (August 19, 2011).
[103] *Id*. at 32.

Undergrounding: In New York, undergrounding is governed under both 16 NYCRR Part 98 and Part 101. New York was a very early adopter of distribution line undergrounding and since 1969, has required that extensions of electric distribution lines to most new residential subdivisions be placed underground with initial costs up to be borne by the utility up to 60 ft. per customer, with remaining costs to be borne by developers.[104]

North Carolina

Storm Investigations: As a result of a 2002 ice storm that caused significant damage and disruptions, the North Carolina Utilities Commission (UC) initiated an investigation into the response of electric utilities that resulted in a report to the North Carolina Disaster Preparedness Task Force.[105] The UC found that the ice storm was unprecedented in North Carolina history in terms of customer outages for Duke Energy and almost unprecedented for Progress Energy. The report also found that while some government officials faulted companies for their communications during the storm, improvements have since been made. The report further found that utilities have adopted proper procedures for advance planning and getting aid from other utilities, but that the circumstances of this particular storm made things more difficult. The report recommended that utilities examine their tree trimming practices to determine whether improvements were possible.

Undergrounding: In a study conducted in conjunction with the investigation into the December 2002 ice storm noted above, the Public Staff of the UC conducted an examination regarding the feasibility of undergrounding electric distribution facilities.[106] Staff concluded that replacing overhead lines with underground would be prohibitively expensive (about six times the current value of the companies' current distribution assets) and result in higher operations and maintenance costs. The Public Staff did, however, recommend that companies identify the overhead facilities in each region they serve that repeatedly experience reliability problems, determine whether conversion to underground is a cost-effective option for those facilities, and, if so, develop a plan for undergrounding those facilities. In the interim, Public Staff recommended that the companies continue their current practices of: 1) placing new facilities underground when the additional revenues cover the costs or the cost differential is recovered through a contribution in aid of construction, 2) replacing existing overhead facilities with underground facilities when the requesting party pays the conversion costs, and 3) replacing overhead facilities with underground facilities in urban areas where factors such as load density and physical congestion make overhead service impractical.

Vegetation Management: As part of a settlement agreement in a general rate case, Duke Energy Carolinas agreed to review its vegetation management policies and procedures and develop a clear, comprehensive, consistent and publicly available policy description, and file it for review by the UC within 90 days.[107] The settlement agreement provision was based on Public Staff testimony regarding public complaints on the company's vegetation management practices. These complaints generally concerned removal of trees that customers did not want removed, the failure to remove trees that are interfering with power lines, and tree cutting debris being left on customer premises. Public staff believed that the company's practices and procedures were not well-defined or publicly available and therefore had recommended they be filed for commission review. The UC reviewed both Duke's policy description and detailed response to customer

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[104] *In the Matter of Sleepy Hollow Lake, et al. v. Public Service Commission of the State of New York*, 352 NY Supp 2d 274, 43 A.D. 2d 439 (1974).

[105] *Response of Electric Utilities to the December 2002 Ice Storm* (September 2003) report of the North Carolina Public Utilities Commission and the Public Staff to the North Carolina Disaster Preparedness Task Force.

[106] *The Feasibility of Placing Electric Distribution Facilities Underground* (November 2003) report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force.

[107] North Carolina UC Docket No. E-7, Sub 989 (January 27, 2012).

concerns and found that the company implemented its vegetation management policies in a reasonable manner. However, the commission imposed additional reporting requirements.[108]

Ohio

Distribution Reliability: The Public Utilities Commission (PUC) of Ohio requires investor-owned electric utilities in the state to file an annual report of their distribution reliability performance based on specified measures and criteria. Each utility also must file performance standards for approval. The approved standards are minimum performance levels, and missing a standard for two consecutive years constitutes a rule violation.[109] Performance standards can be revised under specified procedures. The PUC has encouraged electric utilities in the state to proactively replace aging distribution infrastructure to improve the reliability of electric service to customers. In deciding a case in 2012, the commission said: "We believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs."[110]
Vegetation Management: Enhanced vegetation management is seen by the PUC as a critical factor in distribution reliability. Utility vegetation management budgets have increased in the years following the Northeast blackout of August 2003, which implicated vegetation management practices as one of the root causes.[111] Reliability rules provide for the inspection, maintenance, repair and replacement of utility transmission and distribution system facilities (circuits and equipment), including vegetation management along rights of way.[112]
Rate adjustment mechanisms: The commission has approved numerous rate adjustment mechanisms that enable timely recovery of investment costs between rate cases to facilitate improved service reliability and to better align utility and customer expectations. Among the riders approved by the PUC in recent years are distribution reliability-related riders for AEP, Duke Energy and First Energy; a vegetation management rider for AEP; and a grid modernization rider for AEP's gridSMART program.

Deferrals: The PUC has allowed several utilities to defer costs related to specific storms for possible future recovery via base rates or storm riders. However, the commission has not always allowed full recovery of deferred costs.

Securitization of Storm Costs: Ohio in December 2011 enacted H.B. 364, which provides electric distribution companies with a mechanism to securitize, through the issuance of phase-in-recovery (PIR) bonds, certain debt previously approved by the PUC.[113] An intended benefit of securitization is customer savings and rate impact mitigation because of lower interest rates on PIR bonds as compared to authorized carrying charges on deferred assets. Deferred assets may include costs related to storm restoration, infrastructure, fuel, environmental cleanup and other areas. In one of the first cases decided under the law, the PUC allowed American Electric Power-Ohio Power to securitize approximately $298 million in previously approved deferred costs, including storm restoration costs related to a Hurricane Ike windstorm in September 2008.[114] The bonds will be backed with a phase-in-rider, which will replace an existing deferred

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[108] North Carolina UC Docket No. E-7, Sub 1014 (June 3, 2013).
[109] Rule 4901:1-10-10 (Rule 10) O.A.C.
[110] Ohio PUC Case No. 11-346-EL-SSO, *et al*. (August 8, 2012).
[111] *Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations* (April 2004) U.S.-Canada Power System Outage Task Force.
[112] Rule 4901:1-10-27 O.A.C.
[113] Establishes Sections 4928.23-4928.2318 of the Revised Code (December 21, 2011).
[114] Ohio PUC Case No. 12-1969-EL-ATS (March 20, 2013).

asset recovery rider (DARR). The DARR was approved previously to collect costs related to the storm and other approved regulatory assets.

Undergrounding: Cost allocation for undergrounding distribution lines has been an issue in the state. A PUC decision in 2011, which was upheld by the state Supreme Court in 2012,[115] found that AEP appropriately applied a tariff under which it charged a city for costs of relocating overhead distribution lines underground because the city had required such relocation. The city challenged the decision, saying a local ordinance supersedes the tariff. The state high court found that the ordinance was an exercise of police power to promote the health, safety and welfare of the public and did not overcome the "general law" of the state that is attached to the tariff.

Pennsylvania

Rate adjustment mechanism: The state in February 2012 enacted HB 1294 (Act 11) to reduce regulatory lag and provide more ratemaking flexibility for recovery of prudently incurred distribution and other infrastructure costs.[116] The measure is aimed at improving utility access to capital at lower rates and to accelerate improvement and replacement of aging, unreliable infrastructure. The Pennsylvania Public Utility Commission (PUC) in August 2012 issued a final order implementing the new law, which allows electric and other utilities to petition for a voluntary distribution system improvement charge (DSIC) to recover fixed costs related to specific infrastructure projects between general rate cases.[117] The DSIC is capped at 5 percent of distribution rate revenue and is subject to audit. As a pre-requisite, a utility must submit a five- to 10-year long-term infrastructure improvement plan that the PUC must review at least once every five years. The law also allows utilities to use a fully projected test year in rate cases. In May 2013, the PUC approved the first DSIC for an electric utility, PPL Electric, after first approving its long term infrastructure plan to which the DSIC is linked.[118]

Cost deferral: The PUC has approved deferral by utilities of extraordinary storm-related costs for regulatory accounting and reporting purposes, including a recent case where it made clear that future cost recovery of deferred amounts is not guaranteed and that approving a deferral does not constitute a ruling on the reasonableness of costs.[119]

Storm Investigations: The PUC in May 2013 released its report on utility response to Hurricane Sandy, finding that utilities applied lessons learned from 2011 storms with a positive result, especially in communicating with customers and officials and liaising with county 911 and emergency operations centers. The PUC recommended action steps for utilities to continue improvements in these and other areas, such as management of estimated restoration times. In addition, the PUC recommended that its staff continue ongoing work with utilities to reduce the duration and number of outages on worst performing circuits.

In separate action, the PUC issued a proposed policy statement that would revise existing response, recovery and public notification guidelines based on experience gained in recent significant storm-related service outages.[120] The PUC in issuing the proposal also established and sought comment on a Critical Infrastructure Interdependency Working Group in recognition of the need for different types of utilities and other entities to

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[115] Ohio Supreme Court, *In re Complaint of Reynoldsburg*, Docket No. 2011-1274 (November 15, 2012).
[116] Public Utility Code (66 Pa.C.S.).
[117] Pennsylvania PUC Docket No. M-2012-2293611 (August 2, 2012).
[118] Pennsylvania PUC Docket No. P-2012-2325034 (May 23, 2013).
[119] Pennsylvania PUC Docket No. P-2011-2270396 (December 15, 2011).
[120] Pennsylvania PUC Docket No. M-2013-2382943 (September 26, 2013).

coordinate restoration of critical infrastructure. The working group will meet at least once a year to identify mission critical facilities and discuss interdependencies and best practices.

CHAPTER 4: CROSS-SECTION OF STATE LEGISLATION

As with state regulatory activity, inevitably after each major storm or outage event, there is increased executive and legislative activity by governors and other state policymakers. Action in this area tends to focus on reliability standards, emergency preparedness and response plans, infrastructure hardening, and cost recovery issues. As of this report, Connecticut and Massachusetts have passed legislation that allows certain penalties to be assessed to utilities should certain reliability standards and storm response measures not be met.

This section provides a brief overview of recently proposed or enacted state legislation involving utility storm resiliency and response. A more detailed description is included in a matrix in Appendix B, EEI Cross-Section of State Legislative Proposals on Storm Hardening and Resiliency. The matrix will be expanded and updated as additional information is obtained or as developments occur. The matrix is not comprehensive but rather provides a snapshot of recent legislative activity which usually serves as the basis for new regulatory proposals.

4.1 State Highlights: CA, CT, IL, MA, MD, MS, NJ, NY, VT, WI

California

Following the extreme windstorm that occurred in December 2011 in Southern California, the state legislature passed two bills in September 2012 addressing deficiencies in utility outage response. The new legislation requires the California Public Service Commission to establish standards for disaster and emergency preparedness plans for utilities and requires public utilities to preserve all records and evidence collected after any unplanned outages.

Connecticut

The combined effects of Hurricane Irene in August 2011 followed by the October 2011 snowstorm caused significant damage to utility infrastructure in the Northeast with the majority of electrical outages caused by weakened and fallen trees. In June 2012, the Governor signed Senate Bill 23, Public Act No. 12-148, requiring the Connecticut Public Utilities Regulatory Authority to investigate utility practices and establish reliability and emergency response standards for electric utilities as well as identify the most cost-effective means for system reliability. The newly enacted legislation allows for the Public Utilities Regulatory Authority to grant cost recovery in a future proceeding for utility investment in improved resiliency.

District of Columbia

After a series of severe weather events in 2012 that caused widespread outages and left extensive wind damage across the region, Washington D.C. Mayor Gray established the Mayor's Power Line Undergrounding Task Force to study the feasibility of undergrounding major portions of Washington's distribution network. In March 2014, Mayor Gray signed into law the recommendations of the Task Force which authorizes the issuance of revenue Bonds to finance the undergrounding of the 60 most vulnerable overhead distribution power lines and their ancillary facilities.

Illinois

After several major storms and widespread outages in the Chicago area in 2011, several bills were proposed in the Fall of 2011 regarding utility emergency preparedness, communication protocols and vegetation management. In December 2011, the Governor signed into law certain requirements for utility upgrade investments pursuant to an infrastructure investment program and provided for utilities to recover the reasonable costs incurred to maintain or improve the resiliency of its infrastructure necessary to meet established standards.

Massachusetts

Several bills were introduced during the 2013 session proposing hardening measures including vegetation management, infrastructure upgrades and undergrounding. In August 2012, the Governor signed a law establishing the Department of Public Utilities Storm Trust Fund to be used by the department of public utilities to fund investigations into the preparation for and responses to storm and other emergency events by electric companies doing business in the commonwealth. The funds will come from annual assessments made by the department proportional to each electric utility's annual revenues. Any penalties levied against the utilities for any violations of storm response and emergency preparedness will be credited back to utility customers. The law also required electric utilities to file an annual emergency response plan.

Maryland

In August 2012, proposed emergency legislation prohibiting the Public Service Commission from authorizing an adjustment to an electric company's rates to recover profits lost during a disruption in electrical service was introduced to the state Senate; however, there has been no movement on this proposal since its introduction.

Mississippi

Following the devastation of Hurricane Katrina in 2005, the state enacted the Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act which provides that the state may issue system restoration bonds with proceeds to be used to securitize the system restoration costs and storm damage reserve levels of those electric utilities affected by Hurricane Katrina, thereby providing electric utility customers relief from traditional methods of recovering system restoration costs.

New Jersey

In the wake of Superstorm Sandy, the legislature has introduced numerous bills in 2013 and 2014 mostly calling for the New Jersey Board of Public Utilities (BPU) to establish performance standards in emergency situations and require utilities to file emergency preparedness plans with the BPU. Other bills have been introduced that require inspections and hardening of the existing infrastructure looking towards the necessity for certain facility construction standards. Prior to Superstorm Sandy, bill A.B. 2760 was introduced giving authority to the BPU to authorize the recovery of all reasonable and prudent costs incurred by an electric utility in repairing, improving, and replacing its equipment and property reasonably associated with the improvement of utility service reliability. This measure was reintroduced in the 2014 session.

New York

Also widely affected by Superstorm Sandy, the New York state legislature introduced several bills aimed at requiring new standards for utility emergency preparedness and response. The proposed "Natural Disaster

Preparedness and Mitigation Act" (S.B. 3761) establishes a disaster preparedness commission consisting of commissioners from each of the New York public sectors, including the chair of the public service commission, to oversee and coordinate state emergency preparedness and response activities. The proposal also calls for the disaster preparedness commission to "utilize, in rate setting proceedings, to recover the reasonable costs incurred to maintain and improve the resiliency of the utility's infrastructure necessary to comply with [established standards]."

Vermont

Citing the devastating effects of Hurricane Irene, Governor Peter Shumlin signed Executive Order 04-13 in April 2013 establishing the Governor's Emergency Preparedness Advisory Council which will review the state emergency preparedness system. Governor Shumlin ordered that the Council must take into consideration the interdependencies between federal, state and local government as well as public service sectors serving the community and provide recommendations on ways to bolster such relationships in emergency preparedness policies and communications.

Wisconsin

In December 2013, Governor Scott Walker signed into law an act creating a State and Province Emergency Management Assistance Compact providing for several states and Canadian provinces to participate in mutual assistance operations such as the sharing of emergency operations plans, resources and communications in responding to an emergency affecting several participating jurisdictions.

Edison Electric Institute
Power by Association

APPENDIX A

EEI Cross-Section of State Regulatory Decisions on Storm Hardening and Resiliency

March 2014

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
AR (Public Service Commission)	Generic	• Decided 1/30/09 • Case 09-12-U • Order No. 1	• To facilitate/encourage restoration efforts during Jan 2009 ice storm, grants temporary waiver of certain general service rules, e.g., those governing daily meter reading and customer billing, until utilities are able to resume full compliance	• Invites all public utilities to file in this docket specific proposals for recovery of extraordinary storm restoration expenses related to recent ice storms (see entries below)	
AR	Entergy Arkansas	• Decided 12/30/13 • Case 13-028-U • Order		• Approves $5.8m increase in annual storm reserve • Approves $20.1m related to 2013 winter storm • Approves co.-requested $2m increase in test-year vegetation management expense based on 3-yr. average of known & measureable costs • Rejects co. proposal for $2.3m to shorten vegetation management cycle time, saying costs are not yet known & measureable	
AR	Entergy Arkansas	• Decided 5/25/10 • Case 10-008-U • Order No. 5		• Approves co. request to securitize costs related to damage from Jan 2009 ice storm • Authorizes cost recovery to back bonds, including carrying charges & upfront financing costs, via new Storm Recovery Charges Rider (Rider SRC) • Rider SRC rates to be calculated using demand (kW) for Large General Service customers & energy (kWh) for all other customer classes • Reduces requested $121.9m increase by $293K to	Financing order issued pursuant to Arkansas Electric Utility Storm Securitization Recovery Act of 2009 (AR Code Annotated 5 23-18-901) (Act 729)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				avoid potential double-recovery regarding plant that was damaged by ice storm and retired rather than replaced • Costs to be recovered from all existing and future customers receiving transmission or distribution service from co. • Regarding carrying cost recovery, notes significant time lag between incurrence of storm recovery costs and filing to recover those costs - Finds delay not unreasonable considering the law authorizing securitization was neither adopted nor in effect till months after storm • Caps interest rate on securitized bonds @4.4% • Requires co. to reduce amt. to be securitized by any credit balance in storm reserve account	
AR	Entergy Arkansas	• Decided 4/16/10 • Case 09-031-U • Order No. 3		• Approves request to establish storm reserve account, w/initial amount of $14.449 to be accrued monthly as of Jan 2009 per new Act 434 • Authorizes co. to charge reserve account for O&M storm restoration costs that are reasonable/prudent and not otherwise recovered • Requires quarterly reports • Staff to audit/adjust all storm restoration costs to ensure only reasonable/prudent storm restoration costs are included in reserve account consistent w/statutory provisions	Filing made under provisions of Act 434 of 2009, An Act to Require the Arkansas Public Service Commission to Permit Storm Cost Reserve Accounting for Electric Public Utilities When Requested; and for Other Purposes
AR	Entergy Arkansas	• Decided 3/6/09 • Case 09-018-U • Order		• Allows co. to defer $80m-$100m in storm recovery O&M expenses resulting from Jan 2009 ice storm • Allows co. to defer expense portion of storm restoration costs per accounting standards, thereby removing expense from income statement and avoiding the reporting of financial loss in 1Q earnings report	• Co. stated that w/o accounting order authorizing deferral of storm recovery costs, "there will be a significant negative impact on earnings"
AR	Entergy Arkansas	• Decided 6/15/07 • 06-101-U • Order No. 10		• Rejects co.-proposed use of reserve accounting for rate purposes for both storm damage reserve & storm damage expense, saying co. proposal would constitute retroactive ratemaking by crediting almost $50m of storm costs incurred in	• Co. had proposed that storm-related O&M costs are appropriately booked using reserve accounting; it argued that "(t)he use of reserve

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				prior periods to rate base or CAOL (Current Accrued & Other Liabilities) account and amortizing prior period costs as current expense; says co. method also would constitute single issue ratemaking by isolating one component of revenue requirement for proposed ratemaking treatment w/o taking other components into account - Accepts staff recommendation for inclusion of normal expected annual level of storm damage costs of $14.5m based on historical average; requires co. to reduce amount in storm reserve account to zero	accounting for storm costs is appropriate because of the nature of storm costs ... (given that) ... (t)he severity and number of storms are clearly out of the Company's control." Co. also asserted that normalization vs. use of reserve method "would improperly provide no recovery of previously incurred storm costs above the current level of accrual."
CA (Public Utilities Commission)	Generic	• Decided 2/5/14 • Case R08-11-005 • Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electric Utility Facilities and Aerial Communications Facilities	• Revises General Order 95 to incorporate new and modified rules, including: - Communications facilities in proximity to lines must be built w/higher safety standards - Overhead facilities must be able to support higher vertical loads to reflect increased weight of workers & their equipment - Incorporation of use of modern design & construction materials /standards • Approves consensus plan for utilities to report fire incidents to CPUC enforcement staff for identification of systemic fire safety risks and development of measures to mitigate risk	• Authorizes utilities to track related costs for future recovery in general rate cases	• This decision concludes Phase 3 of docket. Phase 2 concluded with 1/12/12 decision (below). Phase 1 concluded with 8/20/09 decision (below.)
CA	Generic	• Decided 1/16/14 • Case R08-11-005 • Decision Approving the Work Plan for the Development of Fire Map 1	• Approves work plan for design, development & adoption of statewide fire-threat map depicting physical & environmental conditions associated with an elevated risk of power-line fires. PG&E, SDG&E and SCE to jointly provide up to $250K for state to obtain consultants.	• Establishes rebuttable presumption that utility payments (per previous column) are reasonable and may be recovered in rates.	•
CA	Generic	• Decided 1/12/12 • Case R08-11-005 • Decision Adopting Regulations to Reduce Fire Hazards Associated with	• Revises General Orders 95, 165 & 166 as follows: - Requires utilities to remove vegetation strain on conductors energized @ ≤ 750 volts, authorizes increases to time-of-trim vegetation clearances around bare-line	•	• Rules were adopted following series of 2007 wildfires • Resolution E-4576 was issued 5/23/13 approving advice letters (ALs) filed by utilities including PG&E, SDG&E and

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		Overhead Power Lines and Communication Facilities On reconsideration: In 6/27/13 decision, eases definition of "year" for purposes of inspection intervals for overhead lines. Says revision will enhance ability to perform inspection, enhance public safety in certain situations, and may reduce cost.	conducts per specified circumstances - Conditionally authorizes utilities to turn off power supply to property owners who block vegetation mgt. activities around overhead power lines - Requires utilities in Southern CA to prepare fire prevention plans based on specified tasks & criteria; utilities in Northern CA must conduct risk determination and prepare similar plan if need shown - Requires utilities to calculate weight loads on poles when new attachments are made • Institutes additional phase of proceeding to consider materials & practices including use of smart technologies to protect public safety & critical infrastructure, standards regarding wood structures, fire threat mapping, reporting requirements & other matters. This phase was concluded w/2/5/14 decision in this docket (entry above).		SCE. The ALs comply w/the provision to file FPPs. The FPPs, whose specific content was not approved, will be incorporated in annually submitted emergency action plans/reports of the utilities per General Order 166.
CA	Generic	• Decided 8/20/09 • Case R08-11-005 • Decision in Phase 1 – Measures to Reduce Fire Hazards in California Before the 2009 Fall Fire Season	• Directs implementation of numerous measures for electric transmission & distribution lines and related communications facilities prior to autumn 2009 fire season. - This is first phase of broad commission review of fire hazards following destructive wildfires that commission says may be linked to electric and communications lines. The orders seeks to strengthen and clarify existing rules for such facilities.	•	•
CA	Pacific Gas and Electric	• Decided 6/27/13 • Case A11-09-014 • Decision Authorizing Pacific Gas and Electric Company to Recover Costs Recorded in the Catastrophic Event Memorandum	•	• Approves settlement providing for recovery of \$26.537m of incremental disaster-related costs recorded in CEMA and incurred responding to 7 events (several wildfires, an earthquake and 2 winter storms). The approved level is closer to ratepayer advocate-recommended disallowances than PG&E's initial request of \$32.4m. - Ratepayer advocate had raised concerns about accounting & recovery methods, reasonableness & justification, existence of	•

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		Account [CEMA] Related to Certain Disasters		official disaster declarations, and other items.	
CA	Pacific Gas and Electric	• Decided 6/24/10 • Case A08-05-023 • Decision on Pacific Gas and Electric Company Request to Implement a Program to Improve Electric Distribution System Reliability	• Approves co.-proposed Cornerstone program to increase distribution system resiliency & reliability but at lower than requested funding levels; says need not shown for all proposed projects but that co. may re-propose them later; next co. rate case is in 2014 • Authorizes $357.4m in capital & $9.2m in expense for 2010-2013 for projects that: 1) address identified problems related to worst-performing circuits & substation transformer emergency capacity, and 2) implement feeder interconnectivity and rural reliability projects that are cost-effective	• Adopts ratemaking treatment under which rates to be set initially to recover forecast project costs, w/true-up to actual costs achieved via new balancing account; after 2013 program termination, project costs to be recovered via GRC • Co. has flexibility in how it spends authorized funds but must provide annual reports on work performed & forecasted work • Revenue requirements & rates covering program to be revised annually w/true-up • Underspending to result in customer refunds; overspending not authorized	
CA	• Pacific Gas and Electric • San Diego Gas & Electric • Southern California Edison • 3 other IOUs	• Decided 9/13/12 • Case E-4493 • Resolution	• Adopts contested co.-filed tariff changes under which power may be conditionally shut off to customers who do not allow access to their property for vegetation mgt. activities for fire hazard prevention		• Filings were made per 1/12/12 decision adopting regulations to reduce fire hazards associated w/overhead power lines (Case R08-11-005; see entry above)
CA	• Pacific Gas and Electric • San Diego Gas & Electric • Southern California Edison • Southern	• Decided 7/29/10 • Case E-4311 • Resolution		• Approves establishment of wildfire expense memorandum accounts (WEMAs) as interim mechanisms for recording uninsured wildfire-related costs, except for certain financing costs, incurred while PUC considers establishment of wildfire expense balancing accounts (WEBAs) in Case A09-08-020 (see entry above) - If WEBAs are approved in Case A09-08-020, WEMA balances would be transferred to WEBAs for potential base rate recovery - Categories of allowed costs for recording: 1)	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
	California Gas			payments to satisfy wildfire claims including co-insurance & deductibles expense, 2) outside legal expenses, 3) increases/decreases in wildfire insurance premiums from amounts authorized in GRCs	
CA	• San Diego Gas & Electric	• Decided 5/9/13 • Case A10-12-005 • Decision on General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company	• Requires SDG&E to implement performance incentives previously developed for co. in D08-07-046, which SDG&E had declined as then authorized. Notes that while uncertainties exist, the record shows clear link between incentives and reliability performance. Co. must include at minimum SAIDI, SAIDET & SAIFI indices, and track/record outage causes. Data to be included in next GRC filing. Fire prevention improvements cited by co. as key contributor to reliability.	• Denies co. request for treating tree/pole brushing costs in 2-way balancing account, leaves door open to revisit in next GRC. Says 1-way account encourages tree performance while containing costs, and pole brushing costs are fairly stable. • Approves funding of various smart grid capital projects but at lower than requested levels, citing financial impact on ratepayers as among the factors. Projects include SCADA controls that PUC says will reduce time it takes to locate and repair problems, to be funded at \$2.25m vs. requested \$4.699m. • Approves \$25.5m for O&M costs related to tree-trimming (400,000 potentially encroaching trees) vs. co.-requested \$27.419m and lower intervenor requests. Says activities likely to increase due to more inspections/clearances as required elsewhere and upward cost pressures from tree growth/mortality/diseases and weather. • Approves slight pole brushing increase to \$4m based on data review vs. co.-requested \$5.354m and lower intervenor requests.	
CA	• San Diego Gas & Electric • Southern California Gas	• Decided 12/20/12 • Case A09-08-020 • Decision Denying Application		• Denies recovery of uninsured expenses related to 2007 wildfires via wildfire expense balancing account (WEBA), saying companies had not met burden of showing all legal and factual issues were addressed, including whether limitless potential for ratepayers to fund 3rd party claims would open door to claims by others such as government entities, and for utility incentives to defend against 3rd-party claims and manage risk • Allows existing wildfire expense memorandum accounts, in which utilities began recording costs in July 2010, to continue. These tracking accounts	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				were authorized in Case E-4311 (below)	
CA	• Southern California Edison	• Decided 9/19/13 • Case I09-01-018 • Decision Conditionally Approving the Southern California Edison Company Settlement Agreement Regarding the Malibu Canyon Fire	• Approves settlement between co. and CPUC enforcement division involving fire caused by 3 utility poles that fell during a Santa Ana windstorm. Under the settlement, SCE: - Made certain admissions - Agreed to pay $20m to state General Fund - Agreed to provide $17m for assessment & remediation program for approx. 1,453 poles in the Malibu area • Imposes conditions, including: - Pole program to be completed w/in 18 mos. - Bi-monthly reports & comprehensive report	• Total $37m settlement amount to be funded by shareholders	
CA	• Southern California Edison	• Decided 7/11/2013 • Case A07-06-031 • Decision Granting the city of Chino Hills' Petition for Modification of Decision 09-12-044 and Requiring Undergrounding of Segment 8A of the Tehachapi Renewable Transmission Project	• Finds 10/28/11 decision effectively ignored "community values" and placed an unfair, unreasonable burden on Chino Hills residents by requiring abovegrounding Segment 8A w/massive new transmission towers set in narrow right of way. • Approves undergrounding this 3.5-mile segment, capped @$224m, saying it can be built on timely basis and at reasonable cost.		• Two commissioners dissented, saying reconsidering 4-year-old decision creates uncertainty for developers; costs more than 50x the $4m abovegrounding, which poses burden for ratepayers, esp. large energy users; and appears to send message that communities that can afford to pay attorneys will succeed in changing PUC mind.
CA	• Southern California Edison	• Decided 11/29/12 • Case A10-11-015 • Decision on Test Year 2012 General Rate Case for Southern California Edison Company	• Authorizes enhanced equipment inspections & new technology to better track condition/service record of co. assets, esp. poles and wires. Capital program includes infrastructure replacement, distribution construction & maintenance, and development of smart grid/other technologies • Orders independent assessment of system utility poles to determine whether current loads meet legal standards • Requires progress report on various initiatives to improve emergency communications & responses following Dec 2011 windstorms	• Makes numerous adjustments to rate base and forecasted expenses but overall is supportive of major infrastructure program, including significant distribution infrastructure monitoring, replacement & expansion	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			• Requires independent audit of reliability investment incentive mechanisms (RIIM), which provides incentive to spend funds authorized for reliability vs. diverting them; results must be submitted w/analysis of short-term reliability stats (SAIDI, SAIFI) tracked w/RIIM expenditures since 2003		
CT (Public Utilities Regulatory Authority)	Generic	• Decided 1/28/14 • Case 12-01-10 • Decision	• Reopens record to address motion by UI for technical hearing prior to final decision in tree trimming investigation • Will take public comment in March 2014		• Draft decision issued 11/19/13 reviews/clarifies practices, procedures and requirements for utility vegetation mgt. to comply w/governor's directives and legislative mandates
CT	Generic	• Decided 8/21/13 • Case 12-11-07 • Decision	• Makes findings from investigation into the performance of electric distribution and gas companies in restoring service following Storm Sandy. (See item below.) Finds companies performed in "a generally acceptable manner in preparing for and responding to the storm." Finds areas that can be improved. For example: - For CL&P and UI: Found significant progress in many areas such as communications since previous storms. Required further improvements in estimated time of restoration (ETR) and inclusion of analysis of ETR accuracy in future After Action Reports. Required further collaborative work with governmental agencies to identify and prioritize critical facilities. • In response to consumer advocate concerns, including effect on customers of backup generator failure, requires CL&P and UI to report on feasibility of emergency generator operational readiness management program.		
CT	Generic	• Decided 1/8/13 • Cases 12-06-12 • Decision	• Describes potential refrigerated spoilage program. Legislation would be required. Key features include:	• Potential refrigerated spoilage program would be funded by ratepayers via existing systems benefit charge	• Decision is PURA report to legislature in response to directive in S.B. 23 (see below,

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			- Residential-only - Communications package - $150 bill credit for food spoilage - Up to $200 credit for medication spoilage - Outage verification by utility - Application process w/utility		Case 12-06-09, Notes column)
CT	Generic	• Opened 11/16/12 • Case 12-11-07 • PURA Investigation into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy	• Performance to be reviewed against standards set per Act 12-148 (see entry below) • Says it may order remedies, compliance filings or issue other orders and determine whether sanctions are warranted		• PURA also is investigating cost-effective ways for CL&P to harden its system in Case 12-07-06 and ways to improve cost-effectiveness of CL&P and UI vegetation mgt. programs in Case 12-01-10
CT	Generic	• Decided 11/1/12 • Case 12-06-09 • Decision-PURA Establishment of Performance Standards for Electric and Gas Companies	• Requires electric and gas distribution companies to incorporate performance standards in Emergency Response Plans addressing: - Emergency planning, including storm preparation and communications plans - Restoration & recovery • Sets reporting requirements • Noncompliance can result in civil penalties • CL&P to initiate pilot to determine feasibility/cost-effectiveness of option-like arrangement to procure contract resources for storm response	• Determines that costs incurred to comply w/performance standards are generally recoverable in rates in future proceeding, including carrying costs calculated at co. avg. cost of capital, subject to review	• Case was opened per requirement of S.B. 23, enacted in 2012 as Public Act 12-148, An Act Enhancing Emergency Preparedness and Response, following TS Irene & Oct 2011 snowstorm. Act requires PURA to review performance of utility when more than 10% of its customers are w/o service for more than 48 consecutive hours.
CT	Connecticut Light and Power, United Illuminating	• Decided 8/1/12 • Case 11-09-09 • Decision-PURA Investigation of Public Service Companies' Response to 2011 Storms	• Establishes rebuttable presumption that CL&P ROE will be reduced in next rate case as penalty for poor mgt. performance in response to storms; CL&P will have opportunity to rebut • Both companies to track/implement recommendations from all reviews of 2011 storms (or explain why not implementing)		

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			• Both companies to implement 4-year tree trimming cycles vs. previous 5- to 7-year cycles • CL&P to file report in Case 12-06-09 (see entry above) on effectiveness of enhanced tree trimming on circuit reliability • CL&P to develop plan to establish heightened readiness for storms, including line worker resources • Both companies to discuss ways to improve mutual assistance process w/EEI & mutual assistance groups • CL&P to develop plan for real-time damage assessment & outage restoration data		
CT	• Northeast Utilities-Connecticut Light and Power	• Decided 3/12/14 • Case 13-03-23 • Decision	•	• Approves $365m storm cost reserve recovery, to be amortized over 6 yrs. w/carrying charges as of 12/1/14 when existing rate freeze expires - Amount is net of $8.3m storm reserve fund balance and $40m of costs written down per settlement agreement approved 4/2/12 in Case 12-01-07 (below) - Amounts relate to costs incurred for 5 storms in 2011-12 including Sandy - Finds most costs related to line crews and other utilities/contractors needed to repair system • Disallows $49m including amounts transferred to capital, reimbursements subsequent to filing, and those found to be already included in base rates - Recovery of capitalized amounts to be determined in next rate case	
CT	• Northeast Utilities-Connecticut Light and Power	• Decided 1/16/13 • Case 12-07-06 • Decision	• Approves co. 5-year system resiliency plan per April 2012 decision in this docket (below). Plan calls for: - Spending $300m: $258m capital, $42m expense - Short-term plan w/two phases: 1) 2013-14 increased vegetation mgt. efforts; 2) 2015-17, increased vegetation mgt. as well as structural/electrical hardening	• Approves co. proposal to recover costs through existing nonbypassable federal mandated congestion charge, subject to semi-annual reconciliation, until co.'s next rate case, at which time costs to be factored into revenue requirements	

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			- Long-term plan after 2017 to be developed based on learnings from short-term plan • Requires detailed regular status report on implementation • Prohibits commingling of storm resiliency spending w/other program spending		
CT	• Northeast Utilities-Connecticut Light and Power • NSTAR	• Decided 4/2/12 • Case 12-01-07 • Decision-Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR	• Approves settlement providing for CL&P to: - Spend $300m on additional distribution system resiliency - Develop microgrid infrastructure in collaboration w/CT Dept. of Energy & Environmental Protection - Enhance Center for Storm and Power System Resiliency at U of Conn.	• CL&P distribution rates frozen until 12/1/14; other retail rate components not affected by freeze • CL&P to file for base rate cost recovery related to TS Irene & Oct 2011 snowstorm net of insurance proceeds & storm fund but must write off $40m of such costs; approved costs may be recovered at end of rate freeze over 6 years • CL&P to submit multiyear plan & cost recovery mechanism w/in 90 days for $300m system resiliency program (see Notes column); recovery to occur via system benefits charge, federally mandated congestion charge or similar mechanism; CL&P to spend up to $100m during rate freeze period, w/revenue requirement capped @$25m, recoverable during freeze period beginning 1/1/13	• CL&P on 7/9/12 submitted an application for approval of a multiyear system resiliency plan (Case 12-07-06)
CT	United Illuminating	• Decided 8/14/13 • Case 13-01-19 • Decision Rehearing • Decided 12/16/13	• Approves $100m ETT program but requires 8-yr. implementation ($12.5m/yr.) vs. requested 4 yrs.; requires more detailed plan before 2014 work can begin	• Offsets entire $53.3m regulatory asset that co. requested to amortize over 6 yrs. through disallowances – reducing amount to $46.1m for 2009-12 – and by offsetting remaining balance via accrued earnings sharing mechanism and other accrued regulatory liabilities. Approved regulatory asset consisted of extraordinary storm expenses related to Irene, Sandy, and 2011 Nor'easter and 4 other major storm events. - Sets definition of "major storm" as having $1m expense threshold before deferral allowed • Approves reinstatement of storm reserve, funded annually @ $2m for major storm costs. (Once reserve funding is exhausted, co. may use deferred accounting.) • Allows co. to capitalize ETT (see previous column);	• On rehearing, approves $1.3m increase in storm regulatory asset and additional $5.5m in costs related to previously disallowed storms; acknowledges "mixed signals," e.g., new storm definition differed from that previously used for determining which storm costs could be recorded as regulatory asset. • Note: Co. had used storm reserve accounting until 2006, at which time PURA approved regulatory asset treatment of major storm costs out of

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				approves 5-yr. amortization of each year's costs; allows carrying charges @approved cost of capital • Approves infrastructure replacement costs of \$45m/yr. for 2013-18 vs. requested \$57.3m/yr., saying additional levels will be considered in future subject to co. providing long-term plan • Reduces rate recognition of T&D operational excellence initiative (TDOEI) consisting of products/tools for restoration work related to major storms, from requested \$98.3m to \$56.4m (total) for 2013-16; says additional funding may be considered subject to co. providing more detailed plan w/cost-benefit analysis	concern over potential overfunding of reserve.
DC (Public Service Commission)	Generic	• Released 7/1/10 • Case FC-1026 • Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia	• Consultant hired by PSC made recommendations concerning undergrounding including for: o Continued use of undergrounding when new residential developments are introduced o Selective undergrounding in specific situations where undergrounding can be bundled with infrastructure investments, such as road expansion efforts, and large scale water and sewer replacement • Does not recommend undergrounding for all existing circuits		Generic
DC	Potomac Electric Power	• Decided 10/26/12 • Case FC-1087 • Order	• N/A	• Rejects proposal to amortize over 3 years \$2.1m related to Hurricane Irene, saying Irene should not be treated differently than other storms; instead orders factoring of expenses into 3-year average storm costs • Approves increase of \$500K related to new Enhanced Integrated Vegetation Management (EIVM) program o Requires co. to file annual plan for EIVM w/quarterly targeted Milestones & quarterly reports detailing EIVM effort	• EIVM is a comprehensive program designed to address tree-related outages and increase reliability by removing hazardous trees, and trimming and removing vegetation above utility lines to prevent damage from falling limbs

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FL (Public Service Commis sion)	Generic	• Decided 5/23/07 • Case 070011-EI • Order PSC-07-0444-FOF-EI • Notice of Adoption of Rule		• Amends FL Administrative Code re use of storm reserve accounts • Establishes sub-account to cover property leased from others • In determining costs to be charged to cover storm-related damages, utility to use an Incremental Cost and Capitalization Approach methodology (ICCA) - Under ICCA, costs charged to cover storm-related damages exclude costs that normally would be charged to non-cost recovery clause operating expenses in absence of a storm • Specifies types of storm-related costs allowed to be charged to reserve under ICCA methodology • Utility may choose to expense storm recovery costs vs. crediting them to storm reserve account • Utility may petition for recovery of a debit balance in reserve account + an amount to replenish storm reserve via surcharge, securitization or other cost recovery mechanism • If utility seeks to change either target accumulated balance or annual accrual amount for storm reserve, it must file study w/PSC	• Rule 25-6.0143, F.A.C.
FL	Generic	• Decided 1/17/07 • Cases 060172-EU, 060173-EU, et al. • Order PSC-07-0043-FOF-EU • Notice of Adoption of Rules	• Amends FL Administrative Code re standards of construction, location of facilities, storm hardening & CIAC • Utilities to file by May 2007 and every three years thereafter, a detailed storm hardening plan that must: - Contain detailed description of construction standards, policies, practices & procedures used to enhance reliability of overhead & underground electrical T&D facilities in conformance w/rule provisions - Explain systematic approach utility will follow to enhance reliability & reduce restoration costs/outage times related to extreme weather events	• Establishes uniform procedure by which IOUs calculate amounts due as CIAC from customers who request new facilities or upgraded facilities in order to receive electric service • Incremental costs associated with hardening/resiliency to be recovered through base rates	

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			- Include pole attachment standards		
FL	Generic-utility storm hardening plans	• Decided 4/25/06 • Case 060198-EI • Order Requiring Storm Implementation Plans	• Requires all investor-owned utilities to file plans & estimated implementation costs for 10 storm preparedness initiatives that will be ongoing: - 3-y.r vegetation management cycle for distribution circuits - Audit of joint-use attachment agreements - 6-yr. transmission structure inspection program - Hardening existing transmission structures - Transmission & distribution GIS - Post-storm data collection/forensic analysis - Collection of detailed outage data differentiating reliability performance of overhead & underground systems - Increased utility coordination w/local governments - Collaborative research on effects of hurricane winds & storm surge - Natural disaster preparedness/recovery program		• The PSC on 5/19/08 approved FPUC's plan as part of its general rate case (Case 070300-EI); and on 12/28/07, approved plans filed by TECO (Case 070297-EI), PEF (070298), Gulf (070299) and FPL (070301). • The PSC on 10/26/10 approved plan updates filed by PEF (Case 100262-EI), TECO (100263), FPUC (100264), and Gulf (100265); and on 1/31/11 approved FPL's update (100266). Says the updates largely are continuations of the previously approved plans and notes unavailability of data to evaluate effects of plans due to lack of named storms affecting FL. • The PSC on 12/3/13 approved 2013-15 plan updates filed by Duke (Case 130129-EI), FPL (Case 130132-EI), FPUC (130131), Gulf (130139) and TECO (130138). Says the updates largely are continuations of the previously approved plans; notes unavailability of data to evaluate effects of plans due to lack of storms. Finds utilities are taking proactive steps to withstand severe weather events and reduce restoration and outage times.
FL	Generic	• Decided 2/27/06	• Requires investor-owned utilities to begin		

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		• Case 060078-EI • Order Requiring Each Investor-owned Utility to Implement Eight-year Pole Inspection Cycle and Requiring Reports	implementing 8-yr. inspection cycle of transmission & distribution wooden poles based on National Electrical Safety Code compliance • Requires annual reporting of prior year inspection results		
FL	Florida Power & Light	• Decided 1/14/13 • Case 120015-EI • Order Approving Revised Stipulation and Settlement		• Approves settlement providing for co. to implement monthly storm cost recovery surcharge, which co. proposed in lieu of seeking annual accrual to storm reserve - 60 days following a request for storm cost recovery, co. would implement on interim basis surcharge ≤ $4/1,000 kWh on residential bills based on 12-mo. recovery period - Any storm costs exceeding that level are to be recovered later as determined by PSC • If co.'s costs related to named storms exceed $800m in any one year, co. may also request increase of $4/1,000 kWh rate accordingly	
FL	Florida Power & Light	• Filed 8/15/12 • Case 120015-EI • Order pending • Joint petition to Suspend Procedural Schedule		• Co. requests approval of settlement allowing it to implement monthly storm cost recovery surcharge - 60 days following a request for storm cost recovery, co. would implement on interim basis surcharge ≤ $4/1,000 kWh on residential bills based on 12-mo. recovery period - Any storm costs exceeding that level to be recovered later as determined by PSC • If co.'s costs related to named storms exceed $800m in any one year, co. may also request increase of $4/1,000 kWh rate accordingly • Surcharge mechanism proposed in lieu of co. seeking annual accrual to storm reserve	• Settlement, including this provision, was approved by the FPSC on 12/13/12
FL	Florida Power & Light	• Decided 5/30/06 • Case 060038-EI • Order PSC-06-0464-FOF-EI		• Approves issuance of up to $708m, 12-year storm-recovery bonds backed by customer surcharge, provided initial avg. retail cents per kWh surcharge will not exceed avg. retail cents	• Similar financing orders were issued for other FL utilities • PSC on 7/2/2007 submitted report to Governor and

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		• Financing Order		per kWh for separate 2004 storm surcharge currently in effect Background: • As result of hurricanes Charley, Frances & Jeanne in 2004, FPL incurred storm-related costs of ~$890m and deficit of ~$536m in its storm reserve as of end of 2004 • PSC on 9/21/05 (Case 041291-EI) approved recovery of $442m of estimated deficit via mo. customer surcharge over 36 months • 2005 FL Legislature passed law giving utilities ability to securitize storm recovery costs - Co. subsequently filed to suspend payments to reserve account and make a new filing to recover costs in an alternative way • FPL's service territory was impacted by four storms in 2005: Dennis, Katrina, Rita & Wilma, two of which inflicted the most damage subsequent to execution of settlement on storm cost amounts, leaving FPL w/even larger reserve deficit estimated @ ~$880m net of insurance proceeds for all four storms • FPL requested financing order in this case (No. 060038) authorizing issuance of storm recovery bonds of up to $1.5b to: 1) recover remaining unrecovered balance of 2004 storm costs, 2) recover prudently incurred 2005 storm costs, less capital costs & insurance proceeds, 3) replenish storm reserve & 4) recover bond issuance costs	Legislature analyzing additional actions necessary to enhance reliability of FL utilities during extreme weather. See: http://www.psc.state.fl.us/publications/pdf/electricgas/stormhardening2007.pdf • Pursuant to Financing Order - $652 million of storm recovery bonds issued May 2007. Previously approved 2004 Storm surcharge suspended and replaced by Storm Bond recovery charge.
FL	Florida Power & Light	• Decided 9/14/05 • Case 050045-E1, et al. • Order PSC-05-0902-S-EI • Order Approving Stipulation and Settlement		• Per settlement, co. agreed to suspend current accrual (~$20m) to storm reserve as of 1/1/06 • Target level for storm reserve to be set in separate proceeding • Replenishment of storm reserve to target level to be accomplished via securitization per §366.8260, FL Statutes, or via separate surcharge that is independent of & incremental to retail base rates, as approved by PSC	
FL	Progress	• Decided 6/18/10		• Allows co. to implement on interim basis, 60 days	

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	Energy Florida	• Case 090145-EI, et al. • Order PSC-10-0398-S-EI • Order Approving Stipulation and Settlement		following a request for storm damage cost recovery, a mo. storm cost recovery surcharge of up to $4.00/1,000 kWh on residential customer bills over 12 mos. - If storm costs exceed that level, any additional costs to be recovered in subsequent year(s) as determined by PSC • Co. may also use surcharge to replenish storm damage reserve to level as of settlement implementation date	
FL	Progress Energy Florida	• Decided 7/6/09 • Case 090145-EI • Order PSC-09-0484-PAA-EI • Notice of Proposed Agency Action Order Denying Rule Waiver		• Denies co. request for waiver of rules to allow recovery via storm reserve account of projected $33m of storm hardening distribution & transmission O&M expenses and depreciation expense vs. normal operating expenses - Waiver required because rules allow only storm damage expense to be recovered via storm reserves • Finds co. had not sufficiently established that a substantial technological, economic, legal, or other type of hardship would result from its compliance w/rule	
GA (Public Service Commis sion)	Georgia Power	• Decided 12/17/13 • Case 36989 • Order Adopting Settlement Agreement		• Approves extension of amortization period, from 3 to 6 yrs., for recovery of previously incurred storm costs (Storm Damage Regulatory Asset), resulting in $6.9m adjustment. Says adjustment does not adversely affect ability to recover prudently incurred storm expenses but rather is a timing step that reduces impact of overall rate increase on ratepayers.	
IL (Comm erce Commis sion)	Ameren Illinois	• Decided 9/19/12 • Case 12-0001		• Requires 5.6% distribution rate reduction In decision on initial formula rate plan filed under Energy Infrastructure Modernization Act (see entry below) vs. co.-proposed $19.9 million reduction, as revised	• Co. has annual formula rate update pending that will result in rate adjustment in January 2013 (Case 12-0293)
IL	Commonw ealth Edison	• Decided 12/18/13 • Case 13-0318 • Order	• In 3rd formula rate plan (FRP) proceeding under 2011 legislation (SB 1652, below), approves delivery rates that reflect further statutory changes per SB 9 (2013). (See Cost	• Approves year-end (terminal) rate base, year-end capital structures for FRP rate reconciliations, and weighted cost of capital as interest rate on reconciliation amount, as required by SB 9.	

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			Recovery.)	- The changes resulted in approval of a general rate increase ($324.6m) that exceeded the original filed amount ($292m), but was lower than ComEd's revised filing submitted following S.B. 9 enactment ($336.7m.) - Revenue requirement reflects 2012 reconciliation adjustment & 2014 initial rate year revenue requirement (including projected 2013 plant additions)	
IL	Commonwealth Edison	• Decided 6/5/13 • Case 11-0662 • Order	• Grants co. waiver of liability for service interruptions that occurred 2/1/11 during major winter storm. Finds damage to distribution system was unpreventable due to severity of weather. • Declines AG request to open investigation into ComEd infrastructure and storm hardening investments, saying it found no basis.		
IL	Commonwealth Edison	• Decided 6/5/13 • Case 11-0588 • Order	• Waives liability for damages experienced by customers due to service interruptions for 5 of 6 storms in summer 2011 but for first time under 15-year-old Public Utilities Act (Section 16-125(e), said co. may be responsible for such damages related to 1 of the storms. Orders co. to notify 34,559 customers that they are eligible to file a claim for reimbursement for outages. • Rejects AG request to open investigation of ComEd system, saying it did not find any systematic failure by co.		
IL	Commonwealth Edison	• Decided 11/8/12 • Case 11-0692 • Order	• Approves undergrounding as least cost option ($121m) for 4.3-mile, 345 kV Burnham/Taylor transmission line in Chicago • Accepts co. finding that overhead options not viable because of: - insufficient space for poles - inability to secure easements on IL DOT property due to IL DOT regs - inability to cross Metra (commuter rail) ROW & meet safety standards due to		

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			obstructions - ComEd does not own or have rights to most of property needed for overhead route		
IL	Commonwealth Edison	• Decided 5/29/12 • Case 11-0721 • Reheard 10/3/12 • Order		• Approves 3-year, performance-based formula rate tariff under new law (see Notes column) - Results in rate reduction larger than co. expected • As part of formula rate plan, approves 5-year amortization of $2.2m as unusual operating expense related to Jun 2010 storm and rate-basing of unamortized storm costs of $8.9m w/deferred tax impact • On rehearing, affirms use of average rate base for calculating revenue requirement in annual FRP reconciliations vs. co. request to use year-end rate base, saying year-end method does not take into account certain depreciation or give proper weight to what actually happens in rate base prior to 12/31 of each year; that there is room for legislative interpretation; and that impact on customers should be weighed - Largely upholds approved methodology for calculating interest on reconciliation adjustments that relies on short-term debt rate vs. co.-proposed weighted avg. cost of capital - Following rehearing, co. announced it would slow pace of investment under new law	• This is first formula rate plan (FRP) proceeding under new ratemaking framework set by SB 1652, Energy Infrastructure Modernization Act, enacted 19/31/12(Public Act 97-0616). The law: - Provides for performance-based formula rate plans (FRPs) under which storm & other specified unusual operating expenses to be amortized over 5 years; any unamortized balance to be rate-based - Requires participating electric utilities to invest in T&D systems, w/cost recovery addressed in annual FRP proceedings, subject to CC review & approval - ComEd must invest $2.6b & Ameren IL $625m over 10 years - HB 3036, trailer bill enacted separately, re-directs $200m toward targeted undergrounding, tree-resistant overhead conductors & other storm hardening measures, in addition to inspection & replacement of residential underground & mainline cable programs per SB 1652 - ComEd filed investment plan

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					on 1/6/12 & Ameren filed plan on 3/3/12 for informational purposes (undocketed) - CC retains
IN (Utility Regulatory Commission)	Northern Indiana Public Service	• Decided 2/17/14 • Case 44370 • Order of the Commission	• Approves co.-proposed projects in 7-yr. plan that accompanied TDSIC proposal (below, Case 44371) - Some project approvals are subject to further definition and more specifics in plan update proceedings - Plan largely consists of replacement projects for T&D infrastructure for purposes of safety, reliability, system modernization & economic development -		• SB 560, enacted 4/30/13, authorizes URC to approve a TDSIC rider to facilitate recovery, outside of a general rate case, of costs related to infrastructure investments. A utility seeking approval of a TDSIC rider must file a 7-yr. project plan. A utility with such a tracker must file a base rate case every 7 yrs.
IN		• Decided 2/17/14 • Case 44371 • Order of the Commission		• Approves transmission, distribution, and storage system improvement charge (TDSIC) • Total projected revenue requirement related to 7-yr. plan (above, Case 44370) is approx. $262m, w/additional $139m (deferred balance over life of plan) to be recovered via base rates; rate case to be filed before end of 7-yr. plan • TDSIC: - To recover 80% of eligible/approved capital expenditures & TDSIC costs (e.g., depreciation, property taxes); remaining 20% to be deferred - Adjusted semiannually - Any related rate increase to be capped at 2% in 12-mo. period; incremental amts. to be deferred - Overall return used in rate adjustments must be calculated using regulatory capital structure that includes zero-cost capital, e.g., deferred income tax • 10.2% ROE (as approved in last rate case)	

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IN	Indiana Michigan Power	• Decided 2/13/13 • Case 44075 • Order of the Commission		• Approves $4.2m major storm damage restoration reserve based on 5-yr. average, reduced from co.-requested $6.2m based on 3-yr. average • Approves tracker for recovery of incremental variations from reserve ($4.2m) in storm O&M costs; costs to be recorded monthly as regulatory asset or liability for recovery/refund in future rate case; says this will "smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm."	
KY (Public Service Commission)	Generic	• Decided 5/30/13 • Case 2011-00450 • Order	• Requires each utility to collect/maintain all records necessary to evaluate system reliability performance in accord w/most recent IEEE Std. No. 1366 and to file reports annually w/specified information, e.g., SAIDI and SAIFI systemwide and for each circuit - Order based on finding that outage reporting requirements are not sufficient to judge adequacy of service		• Utilities filed rehearing petitions arguing that additional costs are imposed w/o guaranteeing reliability improvements. The PSC in a 7/9/13 order agreed to rehear the decision.
KY	Louisville Gas & Electric	• Decided 12/27/11 • Case 2011-00380 • Order		• Approves establishment of $8.1m regulatory asset to track O&M costs related to Aug 2011 thunderstorm w/high winds - Amt. is excess of $4.8m in storm damage expense currently embedded in base rates per 10/21/10 order (Case 2009-00549) - As total costs become known, LG&E to adjust downward if total < $8.1m & expense any actual costs exceeding $8.1m • Says in light of increasing requests for regulatory assets for severe weather events in recent years and results of previous post-storm audits, it will conduct more detailed reasonableness review than in previous cases when co. seeks recovery of deferred amounts in future rate case	• Notes similar regulatory assets were approved for LG&E and Kentucky Utilities for storm-related costs: - LG&E Case 2008-00456, et al. for storm damage from Hurricane Ike & Jan 2009 ice storm - KU Case 2008-00457, et al. for same events above - KU Case 2003-00434 for portion of 2003 ice storm expenses - LG&E Case 6220 for costs related to 1974 tornado
LA (Public Service Commission)	• Entergy Gulf States (LA)	• Decided 1/7/14 • Case U-32707-A • Order		• Approves settlement providing for withdrawal of co. request to increase storm reserve accruals in base rates. Co.'s formula rate plan (FRP) to be extended 3 yrs. - To extent Hurricane Isaac-related escrow amts.	

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				are not funded to at least $87m, inclusive of current $21.5m balance, co. may re-request accrual increase during FRP extension period	
LA	• Entergy LA	• Decided 1/7/14 • Case U-32708-A • Order		• Approves settlement providing for withdrawal of co. request to increase storm reserve accruals in base rates. Co.'s formula rate plan (FRP) to be extended 3 yrs. - To extent Hurricane Isaac-related escrow amts. are not funded to at least $187m, co. may re-request increase during FRP extension period	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 4/21/10 • Cases U-30981, U-30981-A, -B, -C • Order		• Approves "black box" settlement providing for recovery of $11.64m less than requested; approved amounts = $394m for EL & $233.9m for EGSL (including amounts already recovered via existing storm fund = $134m for EL, $85.5m for EGSL) • Approves mechanisms for companies & LA Utilities Restoration Corp. to finance – via Act 55 bond issuance – system restoration costs & replenishment of storm damage reserves up to $200m for EL & up to $90m for EGSL - Bonds to be backed by all ratepayers via mo. nonbypassable surcharge (Rider FSC II) - Separate order (Case U-30981-C) addresses calculation of offsets to FSC II Rider based on insurance proceeds, sharing of tax benefits from securitization, and other offsets - Reaffirms previous decisions that all customers/loads taking service from companies must share in cost to repair & restore service as well as cost to fund storm damage reserve, including customers taking service at transmission levels • Cost allocation was negotiated separately & included in settlement - For Entergy LA, 86.28% of costs to be classified as distribution related, 13.72% as transmission & generation related. Retail customers taking service at transmission voltages to be assigned	• Act 64 enacted in 2006 authorizes electric utilities to file for PSC approval to issue taxable bonds to securitize hurricane restoration costs • Act 55 enacted in 2007 established LA Utilities Restoration Corp., which may issue state tax-exempt bonds to finance hurricane restoration costs

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				base revenue share of 33% of costs deemed to be distribution related and 12 coincident peak share of costs deemed to be transmission & generation related - Percentages slightly differ for EGS - All approved system restoration & storm reserve costs not assigned to transmission-level retail customers to be assigned to other retail rate schedules based on each schedule's share of base revenue	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 4/16/08 • Cases U-29203-E, -F, -G • Order		• Approves settlement resolving remaining issues for recovery of storm damage costs • Accompanying financing orders authorize securitization of costs per 2007 Act 55 • Provides for additional benefits to customers over those that would have been available under previous orders (pursuant to 2006 Act 64-see entry above-Notes column) - Estimates customers will save additional $40m due to tax benefits achievable under new law that companies agreed to share w/customers, as well as other savings - Requires that any credits for insurance, government grants & certain tax benefits be credited back to customers 100%, w/o offset due to any ratemaking mechanisms - Because of potential tax savings, companies agreed to, and PSC approved, hold-harmless clause under which customers guaranteed to be at least as well off under new financing as they would have been under previously approved financing (see entry below)	• For various reasons including state of securities markets, companies were unable to issue bonds to recover costs of hurricanes Katrina & Rita per previous financing orders in this docket on terms acceptable to PSC • This case was initiated based on Act 55 enacted in 2007 allowing companies to securitize bonds at lower costs & w/additional tax benefits (see also entry above)
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 8/15/07 • Cases U-29203-B, -C, -D • Order		• Approves overall level of permanent storm damage recovery for hurricanes Rita & Katrina @$187m for EGSL & $545m for EL • Accompanying financing orders authorize securitization of costs per 2006 Act 64 (see entry above-Notes column) • Requires both companies to establish storm	

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				reserve accounts to cover costs of future storms • Requires funding of both recovery costs & establishment of storm reserve accounts via bond issuance per Act 64 • Bonds to be backed by revenue from nonbypassable customer surcharge (Securitized Storm Cost Offset Rider) - Customers cannot bypass storm charges via self-generation or co-generation; charge to be collected from all existing/future customers using transmission or distribution - Total costs to be allocated to customer classes based on their contribution to base revenues • Securitization to be performed via establishment of "Special Purpose Entities," which would be subsidiaries of companies • PSC may review proposed bond issuances	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 3/3/06 • Case U-29203-A • Order		• Grants co.-requested interim rate relief due to recovery from hurricanes Rita & Katrina • Allows EGSL to recover ≤ $6m and EL ≤ $14m for costs incurred between Mar-Sep 2006 • Recovery amounts to be recovered as extraordinary cost surcharge, to end when full amount collected • Says it will develop revenue requirement after investigation of full costs for permanent storm recovery • Requires companies to develop securitization proposal • Hires outside consultant to audit co. expenses	
LA	Entergy New Orleans	• Decided 4/2/09 • City Council Resolution R-09-136 • Resolution and Order Approving Agreement in Principal		• Approves settlement in GRC providing for formula rates for 3 years as of 1/1/10 • Formula rate plan includes recovery of non-capital storm damage costs & re-funding of storm reserves via storm reserve rider • City's auditors to review final costs of co. response to hurricanes Rita & Katrina for inclusion in rider • Capital costs to be addressed in 2010 formula rate	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				plan review	
MA (Department of Public Utilities)	Generic	• Decided 12/23/13 • Case 12-76-A • Order	• Presents straw proposal for grid modernization (GM) following Working Group report (Notes column). Plan has 2 parts: 1. Directive to each electric distribution co. to submit, w/in 6 mos. of final order, a 10-year strategic grid modernization plan (GMPs) as part of planning process. Plan must have infrastructure & performance metrics toward meeting 4 objectives including reduction of outage effects. First GMP must include comprehensive advanced metering plan. GMPs required at least every 5 years. 2. Address in separate proceedings GM topics including time-varying rates; cybersecurity, privacy and access to meter data; and electric vehicles • Notes co. methods of reducing outage effects is under review in service quality proceeding; GMPs are expected to help achieve any new reliability metrics or standards set in that proceeding (Case 12-120, below) • Seeks comment, plans hearings	• Says it will examine advanced metering functionality under targeted regulatory framework including: 1) review/preauthorization by DPU; 2) benefit-cost analysis w/in a business case; benefits must exceed costs; and 3) if justified, targeted cost recovery mechanism. If an investment is preauthorized, prudence would be evaluated in later cost recovery proceeding. - Finds capital expenditure tracking mechanism is appropriate for targeted cost recovery • Declines to adopt future test year for cost recovery model, saying it would be based on projections involving speculation and uncertainty, exposing ratepayers to unwarranted risk	• Stakeholder Working Group on 7/2/13 submitted to DPU a report containing information, principles, recommendations on wide array of GM issues
MA	Generic	• Opened 7/31/13 • Case 13-09 • Order Instituting Rulemaking	• Opens docket for purpose of implementing requirement of 2012 law, An Act Relative to Emergency Service Response of Public Utility Companies, requiring notification by transmission companies of vegetation management activities. The DPU and others must be notified at least 30 days ahead.		
MA	Generic	• Opened 12/11/12 • Docket No. 12-120 • Vote to Open Investigation	• Undertakes review of utility service quality (SQ) metrics in SQ standards to determine whether changes are needed. DPU is developing a straw proposal in a process involving discovery and hearing. • Topics include: penalties; offsets; existing and potential new metrics for reliability, safety, customer satisfaction; potential new penalty for downed wire response; potential clean		

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			energy metrics; benchmarking for metrics; potential new or deleted metrics.		
MA	Generic	• Opened 10/2/12 • Case 12-76 • Vote and Order Opening Investigation	• Opens investigation into electric grid modernization (GM) • Says GM technologies & policies are vital for maintaining/improving electric system reliability & offer opportunity to reduce frequency/duration of outages via automated remote-controlled grid devices & real-time communication to distribution companies of outages & infrastructure failures • Seeks to develop roadmap to GM over short, medium & long term; potential policies include: - Planning procedures to allow stakeholder input on GM initiatives - Requirements for EDCs to achieve specific GM goals - Performance standards for GM practices - Cost recovery treatment of GM investments - Investigation policies for consumer protection • GM Stakeholder Working Group (WG) established with series of meetings scheduled - Initial WG report is due Jun 2013		
MA	National Grid	• Decided 5/3/13 • Case 13-59 • Order	•	• Allows co. to replenish storm fund outside base rate case band before prudence review by $40m annually over next 3 yrs. for total $120m - Says replenishment will save ratepayers $41m in interest as compared to alternative deferral scenario - Says co. not entitled to replenishment until prudence review completed in separate proceeding for costs incurred related to 14 extraordinary storms in previous 3 yrs; any overcollection to be returned to ratepayers w/interest	
MA	National Grid	• Decided 8/3/12 • Case 11-129	• Approves 2-year voluntary smart grid pilot, citing among potential benefits reduced	• Approves 5-year depreciation for all smart grid technology related to pilot	

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		• Order	customer outage time & increased operational efficiency of grid - Pilot includes testing of remote power outage sensors that enable crews to be dispatched directly to source of problem & restore power more quickly. It also will include systems to help identify affected customers during storms, thereby improving restoration times.	• Allows use of co. tax-adjusted weighted avg. cost of capital as carrying charge for all pilot investments • Approves allocation of grid-facing costs to distribution customers and allocation of customer-facing costs to basic service customers; approves co.-proposed method for allocating shared capital expenses to both components • Co. to file request for cost recovery in year after costs incurred	
MA	National Grid	• Decided 9/22/11 • Case 11-03 • Order on Amended Settlement	• Approves settlement providing for: - Voluntary $1.2m penalty - Implementation of automated system to identify affected life support customers, make required notifications & related actions - Improved wires down dispatch & related service quality metric for response times - Co.-funded study at MA university on correlation between wind speed, direction, geography, weather conditions & outages, @$50K to $100K cost. - Co. contribution of $50K for firefighting training at MA academy & additional $50K each to United Way of MA and American Red Cross		
MA	National Grid	• Decided 11/30/09 • Case 09-39 • Order	• N/A • N/A	• Permits continued operation of storm fund after 12/31/09 expiration set in previously approved settlement (Case 99-47 (1999)); cites levelizing effect on rates - Allows annual collection of ~$4m in base rates for fund - Allows fund to be used to recover non-capital storm costs in excess of $1.25m - Fund balance accrues interest @co. weighted avg. cost of capital - Fund capped @$20m (symmetrical); any excess returned to ratepayers via reconcilable surcharge w/interest; for deficits co. may	

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				propose recovery method • Allows recovery of ~$30m storm fund deficit balance resulting from 2008 winter storm via 5-year surcharge + interest, subject to prudence review; cites "excellent preparedness" by co.	
MA	• Northeast Utilities-Western Massachusetts Electric • NSTAR	• Decided 4/4/12 • Case 10-170-B • Order		• Approves NU-NSTAR merger settlement providing that storm costs incurred by NSTAR for TS Irene & Oct 2011 snowstorm will be excluded from storm fund calculation & deferred, w/carrying costs calculated @prime rate, to be recovered via surcharge outside of base rates over 5 years, subject to prudence review • WMECO recovery of Oct 2011 storm costs to be deferred until final decision in Case 11-119-C • Says settlement does not shield merging companies from penalties if ongoing storm investigations find violations of regulatory standards set in CMR §19.03	
MA	NSTAR	• Decided 12/30/13 • Case 13-52 • Order		• Disallows $3.5m of requested $38m in costs related to T.S. Irene & Oct 2011 snowstorm; finds remaining costs were incremental, storm-related, and reasonably & prudently incurred - Finds co. imprudent in not seeking reimbursement from Verizon for vegetation mgt. of jointly owned poles; disallows 50% of requested $6.2m + carrying charges - Disallows some incremental telephone & fuel costs, citing lack of record support • Requires utilities in future storm cost recovery filings to provide "complete, reviewable, and cohesive documentation," including specified work order information; cites difficulty in reviewing storm-related costs in this proceeding	
MA	Western Massachusetts Electric	• Decided 1/31/11 • Case 10-70 • Order		• Permits continued operation of storm fund previously set per 2006 settlement (Case 06-55) - Increases annual revenue to existing storm fund from $300K to $575K to better reflect incremental expenses - Caps storm fund @$3m (symmetrical)	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				- Allows fund to be used to recover storm costs in excess of $300K • Allows ~$15m in non-capital costs from 2008 ice storm to be recovered outside of base rates & outside of storm fund via reconcilable storm surcharge over 5 years, w/carrying costs calculated @customer deposit rate • Allows co. to propose cost recovery mechanism if storm fund deficit exceeds $3m • Will conduct separate prudence inquiry on actual costs to be applied against fund	
MD (Public Service Commis sion)	Generic	• Decided 9/3/13 • Rulemaking (RM) 43 • Order	• Accepts 1st annual reports by utilities under RM43 (below) for partial year 2012 as well as corrective action plans where warranted, and w/certain modifications • Finds utilities substantially complied w/systemwide reliability standards		
MD	Generic	• Decided 2/27/13 • Case 9298 • Order	• Following investigation of utility response to 2012 derecho, finds no cause for civil penalties or further action • Finds "disconnect" between public expectations for distribution reliability and ability of systems to meet those expectations • Directs utilities to file shorter-term (5 yr.) plans to improve reliability • For longer term, directs utilities to submit studies on infrastructure or operational investments needed to reduce outages • Directs staff to draft proposed changes to reliability regs to include major outage event data and strengthen poorest performing feeder standard • Directs staff to study performance-based ratemaking to better align rates w/reliability, including provision for penalties • Directs other utility steps, including reports on staffing and communications, and participation in work group w/staff		
	Generic	• Decided 10/26/12	• N/A	• Affirms & expands 1/25/12 order in this docket	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		• Cases 9257, 9258, 9260 • Order		(see entry below) to prevent imposition on customers of decoupling surcharge for revenue losses even during first 24 hours of the onset of a major storm	
MD	Generic	• Executive Order .01.01.2012.15 • Issued 9/24/12	• In late July 2012, following 6/29 Derecho, Gov. O'Malley issued Executive Order creating task force to issue report about options for improving resiliency of electric distribution system in MD as well as options for financing and cost recovery of such options • Task Force made 11 recommendations: - Improve RM 43's reliability and reporting requirements (see below for RM 43 details) - Accelerate RM 43's march toward reliability - Allow tracker cost recovery mechanism for accelerated and incremental investments - Implement a ratemaking structure that aligns customer and utility incentives by rewarding reliability that exceeds metrics and penalizes reliability that doesn't - Perform joint exercises between state and utilities - Facilitate information sharing among utilities, state agencies and emergency management agencies - Increase citizen participation in "special needs" customer lists and share information with emergency management agencies - Evaluate state-wide vegetation management regulations and practices - Determine cost-effective levels of investment in resiliency - Study staffing pressures due to graying of workforce - Task Energy Future Coalition with developing a pilot proposal	• See task force recommendations	
MD	Generic	• Effective 5/28/2012 • Rulemaking (RM) 43	• Rulemaking to address reliability and service quality standards initiated as result of legislation passed by MD General Assembly	• Legislation increased potential penalties for non-compliance with regulations	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			• Requires utilities to achieve standards of reliability performance and report certain data re service quality (SQ) and reliability • Among other things, the regulations: - Establish specific SAIFI and SAIDI metrics for each utility from 2012 to 2015 - Require that remediation action be taken for poorest performing 3% of feeders and protective devices activities 5 times or more during a 12 month period - Require at least 92% of sustained outages during normal events be restored w/in 8 hrs. - Require at least 95% of sustained outages during "Major Events" of < 400,000 or 40% of customers be restored w/in 50 hrs. - Require response to a government emergency responder-guarded downed wire w/in 4 hrs. after notification by a fire or police department, or 911 emergency dispatcher at least 90% of the time - Set min. vegetation management standards		
MD	Generic	• Decided 1/25/12 • Case 9257, et al. • Order		• Finds decoupling mechanisms for utilities as currently designed do not appropriately align company financial incentives w/reliability goals • Prevents imposition on customers of decoupling surcharge for revenue losses beginning 24 hours after commencement of a major storm and continuing until all major storm-related sustained interruptions are restored	• PSC established these non-consolidated dockets to investigate whether decoupling mechanisms previously approved for MD electric utilities inadvertently eliminated incentive for utilities to quickly restore lost service to customers by authorizing the recovery of revenues foregone during extended outages, and if so, whether the decoupling mechanisms should be modified to prevent that outcome
MD	Baltimore Gas and Electric	• Decided 12/13/13 • Case 9326	• Conditionally approves 5-yr., $72.6m Electric Reliability Investment (ERI) program consisting	• Approves recovery of costs related to 5 approved ERI programs via annually trued up surcharge,	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		• Order	of 5 of 8 co.-proposed programs: 1) Expansion of poorest performing feeders, 2 & 3) expanded recloser deployment (13 kV distribution feeders & 34 kV lines), 4) diverse routing of 34 kV supply circuits, and 5) half of selective undergrounding initiative. Revenue requirement increases from $2.3m in 2014 to $9.5m in 2018; cites cost in approving only half of this program. - Conditions including enhanced reporting requirements. - Approval criteria: cost-effectiveness; provision of accelerated & incremental benefits to increase reliability & resiliency; appropriateness for surcharge cost recovery. - Prudence of actual expenditures to be reviewed later. • Reasons for rejecting 3 of 8 proposed ERI programs: 1) expansion of vegetation mgt.; says fuller understanding of impact needed; 2) CIADI improvement; cites uncertainty over cost-effectiveness; and 3) substation reliability performance improvement; cites minimal estimated benefits to ratepayers.	called grid resiliency charge, to sunset in 5 years. • Rejects consumer advocate proposed basis point reduction in overall ROE as result of surcharge, saying this can be addressed later in rate case • As in other cases (e.g., Case 9299 below), accepts 2 rate base adjustments: - Terminal test year treatment of non-revenue producing investments to improve safety & reliability; increases electric rate base by $58.4m - Actual post-test year safety & reliability investments thru Oct 2013; increases electric rate base by $20.4m • As in Case 9299 (below), rejects post-test year projected investment because "not known and measureable" • Rejects co. proposal to recover storm restoration expense over 3 yrs. vs. existing 5 yrs., citing lack of "demonstrable scientific evidence" that extreme weather would continue to occur on any predictable basis and that 5 yrs. is insufficient. • Approves annualized vegetation management expense, saying RM43 compliance will marginally increase such expenses & require time before they normalize	
MD	Baltimore Gas and Electric	• Decided 9/9/13 • Case 9291-Phase 1 • Order	• Based on staff investigation of 14 feeders, finds BGE did not violate state law or regulation but also finds some feeders in Howard Co. have significant reliability issues • Directs co. to continue work on its Reliability Enhancement Work Plan and report on results • Directs co. to annually survey customers on these feeders on satisfaction w/work plan		• Proceeding was initiated by apparently first of its kind petition whereby a PSC investigation is triggered when at least 100 customers join to file a complaint • Phase 2 will involve staff investigation of 33 additional feeders in Howard Co. identified by complaint
MD	Baltimore Gas and Electric	• Decided 2/22/13 • Case 9299 • Order		• Approves adjustments to historical test year treatment as follows: - Terminal test year treatment of non-revenue producing investments to improve safety &	

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				reliability and comply w/RM43 (generic item above 5/28/12); says this increases electric rate base by approx. $41.5m total (w/ corresponding operating income adjustments). Says approval based on co. demonstration of commitment to safety & reliability - Actual post-test year safety & reliability and RM43 investments for Oct-Nov 2012 • Rejects inclusion of planned post-test year safety & reliability and RM43 investments for Dec 2012-Dec 2013, finding the adjustment fails to meet "known and measurable" standard because it is based on estimate that is based on limited experience to date	
MD	Baltimore Gas and Electric	• Decided 3/9/11 • Case 9230 • Order		• Approves creation of regulatory asset allowing deferral of non-capital storm restoration costs for Dec 2009 & Feb 2010 snowstorms, which were not "major storms" per PSC) • Continued historical practice of 5 year normalization of major storm costs • Declines co. proposal to utilize terminal test year rate base instead of 13-month avg. test year rate base for reliability investments, saying co. did not show that its proposed adjustments were required to address existing or ongoing reliability shortfalls	
MD	Delmarva Power and Light	• Decided 9/3/13 • Case 9317 • Public Utility Law Judge Division-Letter to Parties Finalizing the Proposed Order		• Adopts settlement providing for 3-yr., reconcilable grid resiliency charge (GRC) w/2014 revenue requirement of $0.1m; future amounts to be decided in annual true-up proceedings - GRC to recognize investments in accelerated feeder-line replacement - Same conditions apply as those included in Pepco GRC (Case 9311 below)	
	Delmarva Power and Light	• Decided 7/20/12 • Case 9285 • Order		• Allows use of terminal test year basis for reliability investments (instead of avg. test year basis) and inclusion of post-test year reliability investments (that don't produce add'l revenue) in rate base • Approves amortization over 5 years of capital	

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				costs incurred during Hurricane Irene • Negatively adjusts recoverable amount of Irene capital costs by 7.66%, citing inadequate tree trimming practices that it says resulted in excessive expenses in restoration efforts • Denies cost recovery related to Service Quality and Reliability Standards (RM43) that defined reliability & service quality performance standards for distribution systems on grounds that costs are not known or measurable as the regulations had just recently become effective • Rejects proposal for Reliability Investment Recovery Mechanism (RIM) to remain consistent in denying all such requests for infrastructure surcharges and saying reliability surcharge will not enhance reliability	
MD	Delmarva Power and Light	• Decide 12/30/09 • Case 9192 • Order		• Allows in rate base post-test year reliability investments that will not generate additional revenue	
MD	Potomac Electric Power	• Decided 7/12/13 • Case 9311 • Order	• Disallows $23.4m related to AMI meters, saying co. has not yet demonstrated cost-effectiveness; declines to follow previous order (No. 85028 in Case 9286) where rate recovery was allowed for AMI meters on basis of being "used and useful."	• Conditionally approves 3-yr. reconcilable grid resiliency charge (GRC), including return on investment, for 1 co.-proposed project: $24m accelerated priority feeder replacement project - Co. must meet new reporting requirements including detailed project description, performance objectives, incremental milestones and projected costs - Declines to adopt related co.-proposed performance-based incentive mechanism, citing limited scope of GRC • Rejects GRC for 2 other co.-proposed projects: 1) accelerated vegetation mgt.; says one-time benefit does not justify GRC treatment; and 2) selective undergrounding; says approval premature and directs further study. • Approves terminal test year treatment of reliability projects completed through 2012 test year, increasing rate base by $12.5m • Approves post-test year additions of reliability	• Commissioner Williams filed partial dissent on GRC, saying he would have preferred a deferred 2-yr. regulatory asset • Commissioner Brenner issued concurrence, citing concerns over GRC and saying he would have preferred a deferred regulatory asset

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				projects completed in 1Q 2013, increasing rate base by $45m • Rejects post-test year projected investment beyond 1Q 2013 because "not known and measureable"; reflects $123.5m of investment not included • Approves 5-year amortizations of O&M costs related to 2012 Derecho and Sandy and inclusion of unamortized balances in rate base, finding co. testimony "credible but unverified"; requires audit on which to base any future adjustments to these items • Approves expenses for compliance w/RM 43 (below) reliability regulations.	
MD	Potomac Electric Power	• Decided 7/20/12 • Case 9286 • Order		• Allows use of terminal test year basis for reliability investments (instead of average test year basis) and inclusion of post test year reliability investments (that don't produce add'l revenue) in rate base • Approves amortization over 5 years of capital costs incurred during Jan 2011 snowstorm & Hurricane Irene • Negatively adjusts recoverable amount of Hurricane Irene costs by 1.5% and Jan 2011 storm by 6.2%, citing inadequate tree trimming practices that it says resulted in excessive expenses in storm restoration efforts • Denies cost recovery related to Service Quality and Reliability Standards (RM43) that defined reliability & service quality performance standards for distribution systems on grounds that costs are not known or measurable as the regulations had just recently become effective • Disallows recovery for vegetation mgt. program, citing significant amount of under-spending in past years and saying the non-industry standard 2-year trim cycle maintained by co. has resulted in continued catch-up spending due to imprudence • Rejects co. proposal for Reliability Investment	• Co. filed for recovery of costs related to annual vegetation mgt. costs @$23.5m, including $15m for forecasted tree trimming • Dissenting opinion would allow immediate full recovery of storm costs due to their 'minor storm' status

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				Recovery Mechanism (RIM) to remain consistent in denying all such requests for infrastructure surcharges and saying reliability surcharge will not enhance reliability	
MD	Potomac Electric Power	• Decided 8/6/10 • Case 9217 • Order	• Approves establishment of new Enhanced Integrated Vegetation Management (EIVM) initiative that includes: hazard tree removal; removal of over-hanging limbs; removal of undergrowth and aggressive clearance pruning	• Approves 10-year amortization of ~$7.5m in non-capital costs related to Feb 2010 snowstorm • Approves increase in net annual O&M expenses related to new EIVM initiative • Defers decision to approve $1.6m of AMI expenses because it had not yet approved co.'s AMI program in a separate preceding • Rejected co. proposal to use terminal test year basis for reliability investments (instead of average test year basis) and to include post test year reliability investments in rate base	
MI (Public Service Commis sion)	Generic	• Opened 1/8/14 • Case U-17542 • Order Commencing Investigation	• Opens investigation related to ice storm that hit Lower Peninsula 2/21-22/13. Issues: - Impact on utility distribution systems - Utility response before/during storm - Whether changes needed to reduce outage potential - Whether utilities failed to properly maintain distribution systems - Customer reporting of outages - Safety concerns related to downed lines • Sets timetable for reports and comments • Remedial action possible		
MO (Public Service Commis sion)	Generic	• Opened 3/20/13 • Case EW-2013-0425 • Order Opening an Investigation to Address Legislative Concerns Regarding Proposals to Modify Ratemaking Procedures for Electric Utilities and Establishing a Procedural Schedule		• Opens docket to gather comments in response to request by legislator on pending bills, HB 398 and SB 207. Bills would authorize utility implementation of infrastructure system replacement surcharge (ISRS) and expense tracker for tracking/recovery, outside of general rate cases, of costs related to reliability and other infrastructure investments. Gas utilities in the state use ISRS mechanisms.	• Comments were gathered by the PSC. However, the bills failed.

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MO	Generic	• Effective 6/1/08 • Rule 4 240-23.020- Electrical Corporation Infrastructure Standards • Rule 4 CSR 240-23.030- Electrical Corporation Vegetation Management Standards and Reporting Requirements	• Establishes standards requiring electric utilities to inspect/replace old & damaged T&D infrastructure • Requires utilities to more aggressively trim trees/other vegetation: 4-year cycle for urban infrastructure & 6-year cycle for rural	• Both rules include provisions allowing utility to seek recovery of extra costs incurred to comply.	• Rules were implemented following extensive storm-related outages in 2006
MO	Ameren-Union Electric	• Decided 7/13/11 • Case ER-2011-0028 • Report and Order	• Finds co. reliability has improved since two new rules took effect on 6/30/08: Rule 4 CSR 240-23.020) & (Rule 4 CSR 240-23.030 (see entry above) • Encourages co. to continue spending money to improve reliability • Requires co. to spend ~$1.3m/year on heavy underground apprentice program under which staff to be trained on industrial type routing of underground electric lines in urban areas; adds ~$1.3m to revenue requirement	• Approves continuation of vegetation mgt. & infrastructure inspection tracker (see entry below) • Sets tracker base levels @$52.2m for vegetation mgt.; $7.7m for infrastructure • Accepts contested 47-mo. normalization for calculating avg. annual non-labor storm costs; allows recovery via base rates of co.-requested $7.1m test year storm costs	• Says storm costs vary greatly from year to year, citing as examples: - Co. incurred $6m in non-labor storm restoration costs in 9 mos. ending 12/31/07 - $4.8m in 2008 - $9m in 2009 - $38K in 2010 - $8.1m in Feb 2011
MO	Ameren-Union Electric	• Decided 5/28/10 • Case ER-2010-0036 • Report and Order		• Approves continuation of vegetation mgt. & infrastructure inspection tracker (see entry below) • Sets tracker base levels @$50.4m for vegetation mgt.; $7.6m for infrastructure, based on spending in 12 mos. thru 1/31/10 • Orders refund to customers of $3.4m overcollection, amortized over 3 years • Denies co.-requested tracker for storm restoration costs, citing unwillingness to expand use of trackers; finds existing accounting authority order (AAO) approach adequate under which co. allowed to accumulate/defer extraordinary storm non-labor O&M costs, to be considered for recovery – typically over 5 years – in next GRC.	

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				• Allows base rate recovery of $6.4m in test year storm costs; remaining $4m in extraordinary storm expense to be amortized/recovered over 5 years	
MO	Ameren-Union Electric	• Decided 1/27/09 • Case ER-2008-0318 • Report and Order		• Citing uncertainty re cost of complying w/2 new rules (per entry above), establishes two-way tracker under which co. to track actual expenditures around base levels. Co. to create regulatory asset/liability for possible future recovery/refund. • Spending above base level capped @$10%. Co. may request accounting order for amounts exceeding cap. Assets & liabilities to be netted against each other & considered in next GRC • Sets tracker base levels @$54.1m for vegetation mgt.; $10.7m for infrastructure inspection	
MO	Empire District Electric	• Decided 2/27/13 • Case ER-2012-0345 • Order Approving Stipulation and Agreement		• Approves settlement providing for continuation of vegetation mgt. tracker mechanism, w/expense base level of $12m • In 10/31/12 decision in this docket, denied co.-requested interim increase, citing order in Case EU-2011-0387 (below) and other factors that it says make co. adequately protected until final rate decision	• Generate rate increase request had as key drivers restoration costs related to May 2011 tornado and loss of customers related to tornado
MO	Empire District Electric	• Decided 11/30/11 • Case EU-2011-0387 • Order Approving and Incorporating Unanimous Stipulation and Agreement		• Allows co. to defer & capitalize expenses related to May 2011 tornado for possible future recovery in next GRC - Co. to defer actual incremental O&M costs related to restoration following tornado as well as depreciation & carrying charges = ongoing AFUDC rates related to tornado capex	
MO	Empire District Electric	• Decided 7/30/08 • Case ER-2008-0093 • Report and Order		• Allows co. to implement 2-way tracker to track costs related to vegetation mgt. & infrastructure inspection around base level and defer for future recovery/refund • Sets tracker base level @total $8.6m	• Tracker is similar to one approved for AmerenUE; see entry above for further detail • PSC on2/27/13 approved settlement providing for continuation of vegetation mgt. tracker & $12m base level (Case ER-2012-0345)

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MS (Public Service Commis sion)	Entergy MS	• Decided 10/7/11 • Case 2010-UN-436, et al. • Order Adopting Joint Stipulation		• Approves change in existing storm damage rider to reflect increase in frequency/severity of storms - Increases rider collections to allow co. to recover deficit in storm damage reserves that occurred due to hurricanes Gustav & Ike in 2010, and additional storms of 4/4/08 • Increases cap of storm reserve fund from $15m to $25m	
MS	Entergy MS	• Decided 5/22/07 • Case 2006-UA-350 • System Restoration Charge Order		• Approves Rider Schedule SRC as mechanism to recover securitized & other funds authorized by PSC - Rider is to be applied as non-bypassable surcharge to all customers - Includes formula-based mechanism to allow expeditious adjustments intended to correct over-/under-recovery of costs - Estimated to initially increase customer bills by 1.5%	
MS	Entergy MS MS Power	• Decided 6/28/06 • Case 2006-UA-82 • Order • Decided 6/28/06 • Case 2005-UA-0555 • Order	• Orders both companies to harden their locations to withstand hurricane force winds ~10 miles inland from potential flooding • Grants MS Power funds for new storm operations center & facility annex	• Approves recovery of $89.2m for Entergy and $303.4m for MS Power for recovery of costs from Hurricane Katrina • Requires companies to mitigate customer impacts by securitizing these costs pursuant to "Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act of 2006" • Authorizes State Bond Commission (established by legislation) to issue bonds to finance recovery costs • Bond debt service is repaid via system restoration charges reset by companies annually to recover 110% of required annual debt service • System restoration charge is a bill surcharge paid by all customers	• Approved recovery to be reduced by any funds received via Community Development Block Grants or other sources • ~$350m of CDBG funds were ultimately made available to MS utility customers
NC (Utilitie s Commis sion)	Generic	• Issued 11/21/03 • Undocketed • Report of the Public Staff to the North Carolina Natural Disaster	• Reflects results of feasibility investigation conducted in conjunction w/investigation of utility response to Dec 2002 ice storm (see entry below) • Staff focuses on undergrounding distribution, saying most damage sustained in severe		

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		Preparedness Task Force. "The Feasibility of Placing Electric Distribution Facilities Underground," Nov 2003	weather events usually involves distribution vs. transmission lines • Staff concludes that replacing overhead lines w/underground would be prohibitively expensive (~ 6X current value of utility distribution assets) and would also result in higher O&M costs • Staff recommends that companies identify overhead facilities that repeatedly experience reliability problems, determine whether conversion to underground is cost-effective option and, if so, develop plan for undergrounding those facilities • In interim, Staff recommends companies continue current practices of: 1) placing new facilities underground when additional revenues cover costs or cost differential is recovered via CIAC, 2) replacing existing overhead facilities w/underground when requesting party pays conversion costs, and 3) replacing overhead facilities w/underground in urban areas where factors such as load density & physical congestion make overhead service impractical		
NC	Generic	• Issued 8/29/03 • Undocketed • Report of the North Carolina Public Utilities Commission and the Public Staff to the North Carolina Disaster Preparedness Task Force. "Response of Electric Utilities to the December 2002 ice Storm," Sep 2003	• Finds ice storm was unprecedented in NC history in terms of customer outages for Duke Energy and almost unprecedented for Progress Energy • Finds some government officials faulted companies for communications during storm and improvements have since been made • Finds utilities have in place proper procedures for advance planning & obtaining aid from other utilities that were disrupted to some extent by circumstances of this storm • Finds that all utilities should examine tree trimming practices to determine whether improvements are possible	• Notes costs of storm are being recovered in current rates, making rate increase unnecessary	
NC	Duke	• Decided 3/5/14	• Asserts exclusive jurisdiction over utility		• The case arose out of

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
	Energy Carolinas	• Case E-7, Sub 1038 • Order on Jurisdiction and Dismissal of Complaint	implementation of vegetation management practices, dismisses city complaint - Determines that 4 proposed areas of utility regulation by the City of Greensboro via a Utility Vegetation Management Ordinance are preempted by state law - The 4 areas are: 1) trimming standards, 2) trimming cycle, 3) appeals process, 4) large debris removal		Greensboro resident complaints over tree trimming activities by Duke pursuant to its vegetation management plan and policies (VMPP) filed with the commission in May 2012 in Case E-7, Sub 1014 (below)
NC	Duke Energy Carolinas	• Decided 6/3/13 • Case E-7, Sub 1014 • Order Accepting Compliance Filings and Requiring Filing of Reliability Data	• Reviews co. filing of vegetation management policy & practices as required in Case E-7, Sub 989 (below) as well as co. response to customer concerns. • Finds co. implemented policies in reasonable manner but imposed additional reporting requirements		
NC	Duke Energy Carolinas	• 1/27/12 • Case E-7, Sub 989 • Order Granting General Increase in the Matter of Application of Duke Energy Carolinas , LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	• Approves GRC settlement providing for co. to review vegetation mgt. policies/ procedures & develop clear, comprehensive, consistent & publicly available policy description, to be filed for review in separate docket w/in 90 days - Provision arose out of Public Staff testimony re public complaints on vegetation mgt. practices - Complaints generally concerned removal of trees that customers did not want removed, failure to remove tress that are interfering w/power lines & tree cutting debris being left on customer premises • Staff said co. practices/procedures were not well-defined or publicly available		• Similar recent finding made for Progress Energy Carolinas • Following several extensions, co. filed vegetation mgt. policies/procedures on 5/21/12 (Case E-7, Sub 1014; Status = open)
ND (Public Service Commis sion)	Xcel-Northern States Power	• Decided 2/29/12 • Case PU-10-657, et al. • Order on Settlement	• Approves settlement providing for co. to file PBR plan w/metrics to measure/evaluate system reliability, including rate of return incentives & penalties - Plan to include focus on localized reliability performance • Approves increased funding for reliability improvements including additional engineer		

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			• Sets additional reporting requirements • Approves new funding for additional veg. mgt. crew ($212,000 in 2012) • Approves recovery of capital investments related to Minot flood restoration effort		
NH (Public Utilities Commis sion)	Public Service Co. of New Hampshire	• Decided 6/27/13 • Case DE 13-127 • Order Following Hearing		• Approves co. request to increase annual revenue amt. to be deposited in major storm reserve fund from $7m to $12m, citing frequency/severity of recent storms & related repair/restoration costs • Approves co. request to recover pre-staging costs for qualifying storms; PUC encouraged pre-staging as part of review of Dec 2008 & Oct 2011 storms • Affirms co. capital cost treatment of hazard tree removal that was formerly O&M expense, saying there is no evidence that capitalization is inconsistent w/FERC chart of accounts, and it is subject to audit	
NH	Public Service Co. of New Hampshire	• Decided 6/28/10 • Case DE 09-035 • Order Approving Settlement Agreement on Permanent Rates	• Approves continuation of, and base rate increases for, reliability enhancement program (REP) (previously approved 5/25/07, Case DE 06-028): - Co. to continue spending $8.2m/year for O&M for existing - Co. to invest $12.8m/year in capital projects for expanded program (REP II) - Co. to spend additional $2.4m in O&M thru 6/30/12, followed by additional increases for O&M, for REP II - Co. to file annual reports • Approves high level design for geographic information system including GIS-based outage mgt. system	• Approves $3.5m/year base rate funding for existing major storm cost reserve (Note: This amount was doubled to $7m/year in order issued 6/27/12, Case DE-12-110, approving step increase per settlement) • Approves amortization of ~$44m of costs related to 2008 ice storm on straight-line basis over 7 years; any unamortized balance to accrue interest @4.5%/year	
NH	Unitil Energy Systems	• Decided 4/26/11 • Case DE 10-055 • Order Approving Settlement Agreement	• Approves expanded reliability enhancement program (REP) & vegetation mgt. program (VMP): - Co. to spend $1.75m/year in REP capex during 5-year settlement term & increase annual REP O&M expense by $300K as of 5/1/12. Additional amts. to be included in	• Approves storm cost reserve w/annual $0.4m funding to enable cost recovery for major storms as of 7/1/10 thru 5-year settlement term • Allows levelized recovery of previously deferred $7.7m + interest related to 2008 ice storm & 2010 wind storm via reconcilable storm recovery adjustment factor surcharge; any unamortized	• This action came with approval of 5-year rate plan w/4 step adjustments; specific amounts for future increases are not yet approved • PUC on 6/29/10 approved interim base rate increase

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			future step increases - VMP to incorporate 5-year trim cycle on multi-/single- phase distribution systems; augmented spending includes $1.25m step increase as of 5/1/11 & additional amt. in future step increase, subject to review • Co. to file annual reports for REP, VMP & complete fuse and re-closer studies	balance to accrue interest • Funding for REP, VMP capital and O&M expenses to be included in base rate step increases as follows: - REP revenue requirements to be based on actual capex, capped @$2m in 2012, 2013 & 2014 - VMP increases in step adjustments are ~$1.3m in 2011 & ~$1m in 2012	including recovery of $0.5m of costs related to Dec 2008 ice storm and $0.5m of incremental costs related to vegetation mgt.
NJ (Board of Public Utilities)	Generic	• Decided 5/29/13 • Case EO12111050 • Order Requiring Electric Utilities to Implement Recommendations	• Imposes new requirements aimed at improving communications among utilities, municipal officials, customers and the Board during extreme weather events/outages		
NJ	Generic	• Decided 3/20/13 • Case AX13030196, EO13020155, et al. • Establishment of a Generic Proceeding	• Opens investigation of the prudence of costs related to 2011 & 2012 major storms for which electric distribution companies (EDCs) are seeking rate recovery. - For each pending or future base rate case, EDCs must file detailed report by 7/1/13		• See 3/19/14 entry below for JCP&L
NJ	Generic	• Decided 3/20/13 • Case AX13030197, EO13020155, et al. • Establishment of a Proceeding	• Opens generic docket, "Storm Mitigation Proceeding," to investigate ways to support/protect utility infrastructure in relation to major storms – for all regulated utilities, not only electric distribution companies (investor owned). • Invites all regulated utilities to submit detailed proposals for infrastructure upgrades, per parameters set by 1/23/13 order (below) • Directs staff to evaluate PSEG's proposed Energy Strong measures		
NJ	Generic	• Decided 2/20/13 • Case EO12070650 • Order	• Imposes new reporting requirements on power outages, circuit performance, hazard trees in the aftermath of Sandy - The information will be used to identify areas or equipment that may warrant further investigation		
NJ	Generic	• Decided 1/23/13	• Accepts consultant report released 8/9/12		• Hurricane Sandy is not

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		• Case EO11090543 • Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations	(below) and requires actions by utilities in specified timeframes in 5 categories of potential improvements: - Preparedness: Conduct 1st annual training exercise simulating response to outage affecting 75% of customers - Communications: Provide pre-/post-event information thru various methods to assist customers, govt. & emergency mgt. officials, and mutual aid crews in preparing for & dealing w/aftermath of major events - Restoration & response: Establish better process for obtaining mutual assistance, esp. when large-scale events affecting multiple utilities occurs, and better track/support crews - Post event: Track and use "lessons learned" from each major event to make improvements and seek stakeholder input - Underlying infrastructure issues: Provide cost-benefit analyses related to various upgrades; examine infrastructure and use available data to determine how to better protect substations from flooding, how vegetation mgt. is impacting electric systems, and how distribution automation can be incorporated to improve reliability		addressed in order and is the subject of a separate investigation.
NJ	Generic	• Report released 8/9/2012 • Performance Review of EDCs in 2011 Major Storms	• Recommendations for EDCs include: - more detailed development of vegetation management program - development of Incident Command System - using company websites & social media to provide more granular outage details & estimated time of restoration - conducting annual training/exercise drills - require practice of benchmarking & external analysis of each company's restoration experiences		• Report prepared for BPU by Emergency Preparedness Partnership in response to 12/14/11 Order (Case EO11090543)
NJ	Generic	• Decided 12/14/11 • Case EO11090543	• BPU orders EDCs to take several actions including:		• In addition to preliminary order, BPU ordered the hiring

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		• Investigation of New Jersey's Utilities' Response to Hurricane Irene	- Improved coordination of resources/staff w/government officials - Improved outage websites & use of social media for restoration updates - Development of process for more accurate, timely & more geographically targeted estimated time of restoration - Review/revision of customer call back scripts to better convey messaging - Reevaluate provision of restoration information to specific customer classes including special needs customers & well-water dependent customers - Coordinate more closely w/state & local crews working to clear roads and remove storm debris • For one EDC, directs full implementation of its Preliminary Communications Plan for any subsequent severe weather events		of a consultant to further investigate the Storms of 2011 in more detail with emphasis on substations, vegetation management, and customer communications
NJ	Atlantic City Electric	• Decided 6/21/13 • Case ER12121071 • Order Approving Stipulations		• Approves settlement adopting co. proposal to fully recover $70m of incremental storm restoration costs related to 2012 derecho wind storm and Sandy. Of the total, $44.2m in capital costs will be included in rate base and $25.8m in O&M costs will be recovered in base rates via 3-yr. amortization, with no rate base treatment of unamortized balance. ACE agreed not to seek further rate increases associated w/the 2 storms.	• The storm-related settlement amount was based on a finding of prudence in a generic proceeding (Case AX13030196, above).
NJ	Jersey Central Power & Light	• Decided 3/19/14 (written order pending) • Case AX13030196		• Approves settlement providing for recovery of $736m of requested $744m of costs related to 2011-12 storms including Sandy - Of total, $163m of costs related to Irene and an Oct 2011 snowstorm will be reflected in a separate, pending distribution rate case (Case ER-12111052); recovery mechanism for remainder of settlement costs is uncertain	• The decision for JCP&L came in a generic investigation of the prudence of utility storm costs (above)
NJ	Public Service Electric and	• Decided 6/21/13 • Case EO13020155, et al.	• Directs PSEG to implement staff recommendations to: - Begin work on Energy Strong Station Flood		

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	Gas	• Order – Request for Specific Action and Additional Information	and Storm Surge Mitigation subprogram w/investigations & planning - Provide detailed cost estimates		
NM (Public Regulation Commission)	Generic	• Decided 11/27/12 • Case 12-00089-UT • Final Order and Final Amended Rules	• Promulgates final rules based on 12/21/11 staff report, "Severe Weather Event of February, 2011 and its Cascading Impact on NM Utility Service." Rules require electric & gas utilities to: - Explicitly consider fuel diversity, alternative or redundant fuel delivery systems, and backup fuel capability in planning processes - Recognize electricity- and gas-dependent facilities that serve retail load as critical load - Modify/standardize outage reporting - Implement emergency plans including specified components		
NV (Public Utilities Commission)	Generic	• Decided 10/4/05 • Case 05-5014 • Order		• Requires utilities to develop analysis of incremental undergrounding costs in cases where localities mandate such undergrounding and to maintain in records until cost recovery determined in general rate proceeding - Points to New Mexico Public Service undergrounding special services tariff as reasonable starting point for such analysis	
NV	Sierra Pacific Power	• Decided 12/23/10 • Case 10-06001, et al. • Order	• Approves ~$25m related to Phase II Tracy-Silver Lake transmission line w/some undergrounding; incremental ~$15m undergrounding costs estimated generally @4x cost of overhead option; co. to file actual costs in compliance filing • Approves ~$1.7m for Fairview 900 AM distribution feeder facilities including ~$1.5m for undergrounding costs, of which $961,624 was incremental (higher than would have been paid for aboveground option) • Approves ~$1.9m for Radio Channel Project to upgrade radio communications as result of lessons learned in 2005 fire in Carson City	• Allocates incremental T&D undergrounding costs to ratepayers of two localities that mandated underground portions as conditions of permits; cites cost causation principles; direct costs + interest to be amortized over 3 years or until paid, to be recovered via surcharge @levelized per kWh rate • Radio channel upgrade costs to be recovered via base rates	• Phase 1 approvals given in 2007 GRC, Case 07-12001

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NV	Sierra Pacific Power	• Decided 6/27/08 • Case 07-12001 • Order	• Approves ~$10m related to 16-mi., 120 kV Tracy to Sugarloaf transmission line, including $5.9m for undergrounding 3.36 mi.	• Assigns incremental undergrounding costs to ratepayers of locality that mandated undergrounding as condition of permits; cites cost causation principles; direct costs + interest to be amortized over 3 years and recovered via surcharge; costs treated as non-standard installation where customers provide CIAC	
NY (Public Service Commis sion)	Generic	• Decided 12/26/13 • Case 07-M-0548 • Order Approving EEPS [Energy Efficiency Portfolio Standard] Program Changes	• Directs staff to recommend in 1Q 2014 a process for decisions to change regulatory model, including performance- and outcome-based incentives, that will be required to achieve policy objectives. - Policy outcomes include assurance of system reliability & resiliency. Says customer-based resources should be deployed and used to support economically efficient system resiliency • Directs staff, NYSERDA and utility program administrators (EEPS) to convene "E^2 working group" to develop action plan • Makes specified changes to EEPS for 2014-15		• The order was issued in keeping with the Moreland Commission Final Report issued 6/22/13), which recommended, among other things, redirecting public benefit and energy efficiency funds to use to better protect the grid
NY	Generic	• Decided 12/23/13 • Case 13-E-0140 • Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages	• Adopts quantitative tool, or "scorecard," for use by utilities and PSC to assess utility storm restoration performance; says it is intended as guide in assessing utility performance and in setting utility expectations of what PSC wants. - Assigns metrics & points into 3 categories: Preparation (150 pts.), operational response (550 pts.) and communications (300 pts.) - Utilities must submit specified data on per-event basis w/in 30 days of restoration for use by staff to score each outage for each utility		
NY	Generic	• Decided 11/19/13 • Case 13-M-0047 • Order Instituting a Process for the Sharing of Critical Equipment	• Directs utilities to finalize protocols, procedures & plans for sustaining shared equipment & supplies stockpile, to be filed by 12/16/13 - Program to build on existing utility equipment storage & delivery system		• Proceeding was initiated by 2/13/13 order to address recommendations by Gov. Cuomo to establish inventory of long-term capital assets and critical equipment for mutual

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			• Urges utilities to work toward standardizing their most common materials • Urges uniform accounting practices for sale of utility shared critical equipment & supplies • Grants pre-approval of equipment transfers, subject to conditions, e.g., annual reporting • For security purposes, urges utilities to request trade secret protection for storeroom location and inventory information • Directs utilities to form Material Sharing Group to formulate detailed procedures and protocols for sharing equipment & supplies		use of utilities during emergency events
NY	Consolidated Edison Co. of New York	• Decided 2/21/14 • Case 13-E-0030, et al. • Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal	• Approves settlement providing for minimum $1b investment over 4 years in capital projects & programs to address reliability, storm hardening & resiliency, and related areas • Provides for ConEd to develop plan to address load growth in section of Brooklyn that offers DG as alternative to traditional infrastructure, facilitates DG installation, and other measures • Approves development of implementation plan for microgrid project • Approves changes to reliability performance and customer service metrics to provide incentives for higher performance levels • Approves expanded business incentive rate program to help small businesses recovering from Superstorm Sandy • Approves second phase of Resiliency Collab orative, which will focus on completion of co.'s voluntary 2014 climate change vulnerability study, review of 2015-16 storm hardening initiatives, ID of potential alternative resilience strategies such as microgrids and DG, and other areas (See Notes column)	• Approves recovery of $247m of Sandy costs and $78m in costs related to other storms, to be amortized over 3 yrs. subject to refund following staff review - Finds $124m in incremental storm costs reflected in above amounts (relative to current rates) to be appropriate in light of increased frequency of storms w/higher restoration costs • Approves increase in storm reserve fund from $5.6m/yr. to $21.4m/yr. - Approves new rules relating to costs charged to reserve to avoid potential double recovery and ensure efficient use of resources -	• The ALJ for the proceeding led a collaborative track of the proceeding regarding storm hardening & resiliency issues. The collaborative resulted in a stipulation on flood maps and a report filed by ConEd on 12/5/13. The collaborative parties agreed on an interim design standard to protect critical utility infrastructure from flooding in the future. Four working groups address: 1) storm hardening design standards, 2) alternative resiliency strategies, 3) natural gas system resiliency , and 4) risk assessment/cost benefit analysis.
NY	Consolidated Edison Co. of New	• Decided 3/26/10 • Case 09-E-0428 • Order	• Reaffirms outage notification system & incentive mechanism detailed in Case 00-M-0095 (decided 4/23/02) whereby failure to	• Co. agrees as part of settlement to defer costs in excess of storm reserves of $16.8m for future recovery	

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	York		meet applicable performance thresholds will result in revenue adjustment		
NY	National Grid-Niagara Mohawk Power	• Decided 3/15/13 • Case 12-E-0201, et al. • Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal	• Adopts 3-yr. rate plan as outlined by major parties in Joint Proposal (JP), which allows for new PSC storm preparedness initiatives during rate period • Reliability performance incentives are linked to SAIFI and CAIDI but do not apply to major storms; however, JP specifies that staff makes/submits findings after major storms • JP provides for system hardening activities, e.g., equipment inspections, periodic tree-trimming, targeted feeder work, flood mitigation and new transformer banks	• Per JP, approves $29m for major storm recovery, reflecting 10-yr. avg. and $6m increase from last rate case (10-E-0050) - Amount is reconcilable; costs exceeding $29m to be deferred via simplified mechanism • NiMo can change capital projects (previous column), accommodated w/in overall capital funding levels; if cost of change exceeds $8.8m annual threshold, co. can defer added costs	
NY	National Grid-Niagara Mohawk Power	• Decided 9/23/11 • Case 10-E-0050 • Order Approving Emergency Economic Development Programs with Modifications	• Approves w/changes co.-proposed 4 emergency economic development programs for qualifying non-residential customers affected by Hurricane Irene and TS Lee. - Co. to provide grants up of to $100K per community to customers and communities for activities such as capital investment. - Imposes reporting requirements - Requires outreach/communication plan	• Approves deferral of up to $6m for potential future recovery	• Approves on 7/19/13 similar program for nonresidential customers affected by flooding from rains in Jun 2013; capped @$2m total. Deferral not allowed but co. may petition later. Case 12-E-0201, et al. This emergency rule was made permanent in order issued 10/15/13.
NY	National Grid-Niagara Mohawk Power	• Decided 1/24/11 • Case 10-E-0050 • Order		• Approves $23m base rate allowance for major storm expenses • Denies co. proposal to establish $30m storm reserve account, citing inability to accurately estimate storm costs • Approves establishment of deferral account for major storms w/ $2.205m per storm deductible for use in severe weather events where costs exceed annual budgeted amount	
NY	Orange & Rockland Utilities	• Decided 6/14/12 • Case 11-E-0408 • Order		• Approves continued use of storm reserves for major storm events • Approves amortization of costs of Hurricane Irene & Oct 2011 snowstorm = $2.08m annual rate expense; recovery to begin in Rate Year 2 of multiyear rate plan	

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NY	Orange & Rockland Utilities	• Decided 6/16/11 • Case 10-E-0362 • Order		• Approves continued use of storm reserve accounting for storm restoration • Adopts 5-year amortization schedule for deficit between actual expenditures & storm reserves	
OH (Public Utilities Commission)	AEP-Ohio Power	• Decided 3/20/13 • Case 12-1969-EL-ATS • Financing Order		• Approves securitization of approx. $298m of previously approved deferred costs, including storm costs related to Hurricane Ike windstorm in Sep 2008 - Storm cost deferral was approved 12/19/08 in Case 08-1301-EL-AAM - Deferred asset recovery rider (DARR) was approved 12/4/11 to collect costs related to storm cost deferral and other approved regulatory assets. DARR to be withdrawn under securitization order. • Bonds to be backed by new phase-in rider, to be trued up annually • Bond proceeds to be used to redeem, retire or repay portion of existing debt, resulting in estimated savings to customers of $22m (nominal) or $28.8m (net present value). Savings result from lower effective interest rate as compared to currently authorized carrying charge on deferred assets	• Approval is made under recent law, H.B. 364, enacted 12/21/11. Law allows electric distribution companies to securitize previously deferred assets via issuance of phase-in-recovery (PIR) bonds. Deferred assets may consist of fuel costs, infrastructure costs, environmental cleanup and other costs. This case represents one of first times PUC has issued a decision under the law.
OH	AEP-Ohio Power	• Decided 8/8/12 • Case 11-346-EL-SSO, et al. • Opinion and Order		• Approves distribution investment rider (DIR) to accelerate recovery of prudently incurred capital costs, including carrying costs, for incremental infrastructure to maintain/improve reliability - Finds DIR will facilitate better service reliability & align co./customer expectations - DIR includes 10.2% ROE - DIR to be capped @$86m in 2012, $104m in 2013, $124m in 2014 & $51.7m after that thru 5/31/15, when electric security plan (ESP) expires, for total $365.7m. Overages/under-recoveries to be applied to increase or decrease next-year cap - DIR to be adjusted quarterly to reflect in-service net capital additions; to be reviewed annually	• Actions are part of case involving continued transition to competitive market via electric security plan, which has as major goal improvement of service reliability • Enhanced vegetation mgt. program was first approved 3/18/09; co. is moving from performance-based to 4-year, cycle-based program (Case 08-917-EL-SSO)

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				- DIR to be collected as % of base distribution revenues; co. agrees not to seek base rate change before 6/1/15 - Directs co. to work w/staff to develop distribution maintenance/replacement plan • Approves deferral of incremental storm costs above or below $5m/year for possible future recovery, pending outcomes of prudence reviews; if costs are incurred due to unexpected large storms, co. to file separate application each year throughout 3-year term of ESP • Approves continuation of enhanced vegetation mgt. program via previously approved Enhanced Service Reliability Rider (ESRR) - Approves merger of ESRR zonal rates into 1 rate - Directs co. to file revised vegetation mgt. program by 12/31/12 • Approves continuation of previously approved gridSMART rider, subject to annual true-up/reconciliation, w/certain changes; gridSMART investment not included in DIR rider (see above)	
OH	AEP-Columbus Southern Power	• Decided 4/5/11 • Case 08-846-EL-CSS • Opinion and Order	• Denies allegation by city of Reynoldsburg that co. Tariff 17 providing that munis must pay for cost of undergrounding to extent cost exceeds that of standard overhead lines is unjust, unreasonable or unlawful • Finds it does not have authority to resolve questions whether local ordinance supersedes tariff or whether tariff violates state Constitution; says those are matters for court to resolve - Reynoldsburg ordinance authorizes city to require a utility to relocate its facilities underground at its own cost - City sought to recover $1.2m it spent in relocation costs • Finds AEP appropriately applied tariff and charged city for relocation costs		• OH Supreme Court found tariff supersedes ordinance, saying ordinance was exercise of police power to promote public health/safety and did not overcome "general law" of the state attached to the tariff (Slip Opinion 2012-Ohio-5720; Case 2011-1274, decided 11/15/12) • Tariff 17, "Temporary and Special Service," was approved 5/12/92 (Case 91-418-EL-AIR) • Reynoldsburg Ordinance (City Code Chapter 907) was passed 5/9/05
OH	Dayton	• Decided 12/19/12		• Allows deferral of incremental O&M expenses	• DP&L is seeking to recover

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	Power and Light	• Case 12-2281-EL-AAM • Finding and Order		related to June 2012 wind storm but reduces requested amt. by 3-yr. avg. of O&M expenses related to major storms - Carrying cost is most recent approved cost of long-term debt = 5.86%	O&M expenses related to major storms in 2011 & 2012 and certain 2008 expenses, and requested approval of a storm cost recovery rider for expenses going forward, in Case 12-3062-EL-RDR
OH	Duke Energy Ohio	• Decided 5/1/13 • Case 12-1682-EL-AIR, et al. • Opinion and Order		• Adopts settlement providing for: - $11 increase for vegetation mgt. to maintain 4-yr. trim cycle - Withdrawal of co. request for storm deferral/tracking mechanism and incremental recovery of 2012 storm costs	
OH	Duke Energy Ohio	• Decided 1/11/11 • Case 09-1946-EL-RDR • Opinion and Order		• Approves recovery of ~ $14m of incremental O&M costs related to 2008 Hurricane Ike wind storm, lowering by about half co.'s $28.5m request • Says co. did not meet burden of proof in showing disallowed costs were prudently incurred, e.g., discretionary supplemental expenses for salaried employees and certain contractor costs billed to OH rather than IN & KY • Costs to be recovered via previously approved Distribution Reliability Rider (DR-IKE) over 3 years; carrying charges included @most recently approved long-term debt rate of 6.45% • Costs to be allocated to distribution customers; demand-billed customers to be charged on per-kW basis & all other classes to be billed class-specific mo. customer charge	• OH Supreme Court on 4/5/12 upheld PUC decision against Duke challenge (Slip Opinion 2012-Ohio-1509, Case 2011-0767, Decided 4/5/12) • Related PUC actions: - Approved on 7/8/09 Duke's Distribution Reliability Rider, set at zero, for 2008 Ike storm costs as part of GRC settlement; authorized co. to file for initial rider level later (Case 08-709-EL-AIR) - Approved on 1/14/08 Duke deferral of $31mof incremental O&M expenses related to 2008 Ike storm w/carrying costs for possible future recovery (Case 08-709-EL-AIR) - Approved on 1/14/08 similar deferra7 for Dayton Power & Light @unspecified amount (Case 08-1332-EL-AAM)
OK	Oklahoma	• Decided 7/9/12	• Approves funding for increased vegetation	• Adjusts smart grid rider	Cites to: Order No. 558445 in

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
(Corporation Commission)	Gas and Electric	• Case PUD 201100087 • Final Order Approving Joint Stipulation and Settlement Agreement	mgt. • Report required on results of smart grid deployment	• Extends storm cost recovery rider • Modifies system hardening program rider	Cause Nos. PUD 200800215 and PUD 200700447; Cause PUD 200800398; Arkansas Docket 10-109-U, Order No. 8)
OK	Public Service Co. of Oklahoma	• Decided 1/5/11 • Case PUD 201000050 • Final Order Approving Joint Stipulation and Settlement Agreement			
OK	Public Service Co. of Oklahoma	• Decided 12/18/09 • Case PUD 200900181 • Final Order Approving Joint Stipulation and Settlement Agreement		• Approves capital investment rider under which co. to annually recover ~$30m, reflecting return of/on costs related to certain incremental generation and T&D investments (including vegetation mgt.) not yet reflected in existing rates • Rider amts. subject to refund pending review in next GRC	
PA (Public Utility Commission)	• Generic	• Decided 3/6/14 • Case M-2013-2382943 • Policy Statement	• Finalizes proposed policy statement that revises existing response, recovery & public notification guidelines - Adds storm preparation and response best practices developed following hurricanes Irene & Sandy - Focus is on coordination, communications, event forecasting, and holding exercises to better respond to major storms • Establishes Critical Infrastructure Interdependency Working Group, which will identify mission critical facilities and discuss interdependencies & best practices of different types of utilities and other entities involved in restoration of critical infrastructure		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
PA	• Generic	• Issued 5/7/13 • Undocketed • Summary Report of Outage Information Submitted by Electric Distribution Companies Affected by Hurricane Sandy October 29-31, 2012	• Releases report on Hurricane Sandy prepared by PUC Bureau of Technical Utility Services • Report finds utility response reflected many lessons learned from 2011 storms, especially regarding communicating w/customers, elected officials & local emergency mgt. • Recommendations to utilities include: - Continued use/enhancement of social media & other communication methods - Collaboration on best practices for managing estimated restoration times - Continued work on messaging - Continued cooperation/communication w/local emergency mgt. - Continued work on peak call volume issues - Continued offering of regional concalls before a storm and during restoration • Report provides that staff will continue to work w/utilities to reduce duration/number of outages due to worst performing 5% of circuits and to ensure circuits help are not on 5% list for more than 4 consecutive quarters		
PA	• Generic	• Decided 8/2/12 • Case M-2012-2293611 • Final Implementation Order	• As precondition for DSIC approval, a utility must submit 5- to 10-year long-term infrastructure improvement plan (LTIIP) & asset optimization (AAO) plan (see Cost Recovery column) • LTIIPs must reflect/maintain acceleration of infrastructure replacement over historic levels • AAO Plans must describe eligible property repaired/replaced/improved in previous 12 mos. and those to be improved in upcoming 12 mos. • PUC must review plans at least once every five years • Will initiate separate rulemaking proceeding regarding periodic review of LTIIPs	• Authorizes electric/other utilities to apply for cost recovery between GRCs for distribution infrastructure repair, replacement & improvement via distribution system improvement charge (DSIC), a voluntary project-specific mechanism formerly available only to water utilities - DSIC subject to audit - Cost of equity = ROE approved in utility's most recent fully litigated base rate case, including ROE set via settlement, w/in previous 2 years - If last GRC was > 2 years ago, ROE set by other means; will form working group to address related issues - Caps DSIC-related rate increases between GRCs @5% of distribution rates billed; PUC says waivers are allowed but it is not likely to waive	• HB 1294 (Act 11) enacted on 2/14/12, amending Title 66 of PA Consolidated Statutes, to reduce regulatory lag & provide more ratemaking flexibility for time recovery of prudently incurred infrastructure costs so as to improve access to capital at lower rates and accelerate infrastructure improvement & replacement • PUC Commissioner Gardner dissented on the final rule's acceptance of use of a stipulated ROE for the DSIC vs. fully litigated, non-settled ROE

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				cap absent experience w/actual operation of DSIC - DSIC is rest to zero if new base rates are set or if showing is made that utility will earn ROR used to calculate fixed costs beyond authorized level • Sets procedures for use of fully projected test year in base rate cases; will initiate separate rulemaking to further address related issues	
PA	PPL Electric	• Decided 10/31/13 • Case M-2013-2275471 • Opinion and Order	• Approves settlement providing for co. to add provision to storm restoration procedures instructing personnel not to deviate from co. guidelines when assigning restoration crews • Per settlement, co. to pay $60K civil penalty • Finds underlying incident, which involved alleged reassignment of crew from higher priority to lower priority job related to Oct 2011 snowstorm, appears to be of a singular, non-recurring nature		
PA	PPL Electric	• Decided 5/23/13 • Case P-2012-2325034 • Opinion and Order		• Approves distribution system improvement charge (DSIC) mechanism for projected included I previously approved long-term infrastructure improvement plan (LTIIP). Projects include repairs, replacement or upgrade of poles & towers, overhead/underground conductors, transformers & distribution substation equipment, and other capital projects. Features include: - 5% cap on total revenue collected - Annual reconciliations - PUC audits - Customer notification of changes in DSIC - Reset to zero when eligible plant is included in rate base - Reset to zero when PPL is determined to have overearned • Directs some issues to ALJ for hearing and recommended decision, e.g., whether revenues associated with other riders are properly included as distribution revenue	• PPL's DSIC is first such mechanism approved for electric utility under Act 11 (See entry above for Case M-2012-2293611.)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				- DSIC rates are subject to refund pending final resolution of ALJ issues	
PA	PPL Electric	• Decided 12/15/11 • Case P-2011-2270396		• Allows deferral of unanticipated O&M expenses, possibly $15m to $20m but unknown at this time, related to Hurricane Irene in Aug 2011 for potential recovery in future rate case - Says it is not ruling on reasonableness of costs and future recovery is not guaranteed - Does not specify amortization schedule but says PPL should expense deferred amounts on "reasonable" schedule	• Notes approved deferral is similar to deferrals approved in the past for accounting purposes
TX (Public Utility Commission)	Generic	• Decided 9/22/11 • Case 39465 • Order Adopting New §25.243 as Approved at the September 25, 2011 Open Meeting		• Approves distribution cost recovery factor (DCRF) mechanism similar to existing interim transmission cost recovery mechanism • Enables utilities to more efficiently/timely recovery & earn return on distribution-related investment including storm hardening & smart grid investment if included in eligible FERC accounts as follows: • Distribution plant-FERC 352, 353, 360-374, 391 • Distribution-related intangible plant-FERC 303 • Distribution-related communication & networks-FERC 397 • Prudence review/reconciliation occurs in next general base rate case • DCRF may be considered in setting rate of return in GRC	• No utility DCRF application had been made as of 11/19/12 • Rule implements SB 1693, enacted 5/28/11; provides for streamlined proceedings to authorize recovery of/on new distribution investment + related taxes; does not provide for recovery of expenses; applies to both restructured & vertically integrated utilities; allows annual rate updates, capped @four increases between full rate cases; new DCRF rates should reflect increases in base rate revenue resulting from load growth; requires PUC rule under which utilities to file earnings reports; law sunsets 8/31/17
TX	Generic	• Decided 6/24/10 • Case 37475 • Order Adopting New §25.95 as Approved at the June 11, 2010 Open Meeting	• Adopts rule requiring utilities to develop infrastructure storm hardening plan providing for cost-effective strategies to increase ability of T&D facilities to withstand extreme weather conditions • Requires each utility to submit forward-		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			looking plans over 5-year period as of 1/1/11, updated every 5 years		
TX	Generic	• Decided 12/14/09 • Case 37472 • Order Adopting New §25.94 as Approved at the December 2, 2009 Open Meeting	• Requires each utility to submit annual report describing efforts to identify areas w/in service territory that are esp. susceptible to damage during severe weather and to harden T&D facilities in those areas		• Rule implements HB 1831 enacted in 2009 - Makes various changes to existing law regarding disaster preparedness, emergency management and vehicles used in emergencies - Emphasizes importance of T&D infrastructure risk mgt. & maintenance
TX	CenterPoint Energy Houston Electric	• Decided 8/26/09 • Case 3720 • Financing Order		• Approves securitization, authorizes issuance of 13-year transition bonds backed by nonbypassable system restoration surcharge imposed on retail electric providers to finance $662.8m of system restoration costs related to hurricanes Ike & Gustav + carrying costs - Amount reached via settlement approved 4/17/09 (Case 36918) - Says transaction will save ratepayers $417m (nominal) over bond term & $326m on present-value basis	
TX	Entergy Gulf States	• Decided 1/17/06 • Case 31710 • Order		• Grants waiver to allow recovery via existing fuel adjustment clause (FAC) of surplus capacity/energy costs of purchasing surplus power from affiliate Entergy New Orleans (ENO), which lost significant for unknown period as result of Hurricane Katrina - Only energy cost recovery allowed in absence of waiver - Cites special circumstances and co. position that low-priced, short-term arrangement helps mitigate ENO financial burden resulting from hurricane, allows time for Entergy system restoration efforts, and saves fuel costs for EGS customers - Limits recovery to actual all-in contract or cost	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				that would have been incurred/recovered via FAC but for those purchases, the latter based on reported prices for on-/off-peak energy	
TX	Entergy TX	• Decided 9/14/12 • Case 39896 • Order		• Reduces regulatory asset balance for deferred Hurricane Rita costs from $22.2m to $15.2m, saying calculation begins w/co.-claimed amt. in previous rate case (Case 37744-black box settlement of Rita costs approved), less amortization accruals (over 5 years) to end of test year in present case, less additional insurance proceeds received since previous rate case - Says accrual of carrying charges on asset should have ceased when Case 37744 concluded because the asset would have then begun earning return as part of rate base • Says co. should continue recording annual storm reserve accrual until modified by PUC order. - Finds appropriate total annual self-insurance storm reserve expense is ~$8.3m, consisting of annual $4.4m accrual for avg. annual expected storm losses + annual $3.9m accrual for 20 years to restore reserve from current deficit - Says target self-insurance reserve is ~$17.6m	
TX	Entergy TX	• Decided 9/11/09 • Case 37247 • Financing Order		• Approves securitization, authorizes issuance of 14-year transition bonds backed by nonbypassable customer transition surcharge to finance $539.8m of system restoration costs related to Hurricane Ike + estimated upfront qualified costs & carrying costs - Amount reached via settlement approved 8/18/09 (Case 36931) - Says transaction will save ratepayers $322m (nominal) over bond term & $240m on present-value basis	• SB 769 enacted in 2009 authorizes securitization to obtain timely recovery of system restoration costs
TX	Xcel Energy-Southwestern Public Service	• Decided 6/19/13 • Case 40824 • Order		• Approves settlement under which SPS agrees to refrain for filing for distribution cost recovery factor in 2013	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
VA (State Corporation Commission)	Dominion Virginia Power	• Decided 7/15/05 • Case PUE-2004-00062	• Approves construction of $13.1m, 8-mile, 500 kV transmission line on company-preferred route in Fauquier Co. to meet reliability needs - Rejects intervenor-proposed underground alternative, saying co. showed higher cost, reliability risk (e.g., effects on power flows per co. testimony) outweigh ratepayer benefits		• Co. testimony cited other cases (e.g., PUE-2002-00702, Decided 10/8/04) where SCC has declined to require or commented unfavorably on undergrounding when feasible overhead options exist
WV (Public Service Commission)	Generic	• Decided 1/23/13 • Case 12-0993-E-T-W-GI • Commission Order	• Following investigation of effects of derecho and Hurricane Sandy in 2012, finds increased right of way (ROW) maintenance will lessen future storm impacts. Requires utilities to: - File petitions for approval of comprehensive, time cycle-based ROW vegetation mgt. programs w/spot trimming as necessary - File status reports on progress toward planned improvements to storm response procedures as stated in derecho storm reports filed in this proceeding	• Required petitions for ROW programs (previous column) must propose cost recovery mechanism for any rate increase - Proposals for surcharges or other adjustment mechanisms must contain specified information, e.g., calculation methodology and true-up procedure	• Says it might be appropriate for utilities to seek legislation authorizing trimming outside of existing ROWs if trees pose significant risk to utility service
WV	Generic	• Decided 11/7/12 • Case 12-0014-E-PC, et al. • Commission Order	• Adopts settlements under which utilities agree to meet reliability targets recommended by staff. The SAIDI, CAIDI and SAIFI targets will be effective 2014-18.		• Following a severe snowstorm and outages in 2009-10, the commission adopted reliability rules in July 2011. Rules for the Government of Electric Utilities, 150 C.S.R. 3. The rules required utilities to file reliability targets, which they did in this proceeding, resulting in the approved settlements.
WV	AEP-Appalachian Power, Wheeling Power	• Decided 3/18/14 • Case 13-0557-E-P • Commission Order	• Approves co.-proposed 4-yr., end-to-end, cycle-based vegetation management program (VMP), which is significant expansion of existing program. - Finds it is in the public interest to institute an "aggressive" program in light of increasingly severe storms since 2009. "The enhanced VMP will cost money, but doing	• States that it will develop a cost recovery mechanism in co.'s upcoming base rate case - VMP costs incurred before end of rate case to be deferred @4% interest - Mechanism will recover actual & projected costs, w/periodic review - Mechanism may include surcharge, base rate increment, or combination	• AEP filed in response to 1/23/13 order requiring utilities to make filings for expanded vegetation management plans (See case entry above)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			nothing, in our opinion, costs even more."		

Note: Public utility commission cases are listed first by any generic orders, then alphabetically by company and chronologically for each company, starting with the most recent
Sources: Published material from state utility commissions, state legislatures, courts and companies; SNL Financial Inc.
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Acronyms & Abbreviations

AAO – accounting authority order
AFUDC – allowance for funds used during construction
AMI – advanced metering infrastructure
BPU – Board of Public Utilities
CAIDI – customer average interruption frequency index
CC – Commerce Commission or Corporation Commission
CIAC – contributions in aid of construction
CIS – customer information system
DCRF – distribution cost recovery factor
DOT – department of transportation
DPU – Department of Public Utilities
DSIC – distribution system improvement charge
EDC – electric distribution company
EIVM – enhanced integrated vegetation management
Generic – applies to more than one utility
GM – grid modernization
GRC – general rate case
IOUs – investor-owned utilities
MOU – memorandum of understanding
N/A – not applicable or not addressed
O&M – operation and maintenance
PBR – performance-based regulation
PSC – Public Service Commission
PUC – Public Utility Commission or Public Utilities Commission
PURA – Public Utilities Regulatory Authority
ROE – return on equity
ROW – right of way
SAIDI – system average interruption frequency index
SB – Senate bill
SG – smart grid
T&D – transmission and distribution
TBD – to be determined
TS – tropical storm
UC – Utilities Commission

Edison Electric Institute
Power by Association

APPENDIX B

EEI Cross-Section of State Legislative Proposals on Storm Hardening & Resiliency

March 2014

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CA	• Approved 9/23/12 • A.B. 1650 • Portantino. Public utilities: emergency and disaster preparedness	• Requires the commission to establish standards for disaster and emergency preparedness plans within an existing proceeding, as specified. Requires an electrical corporation to develop, adopt, and update an emergency and disaster preparedness plan, as specified. Authorizes every city, county, or city and county within the electrical corporation's service area to designate a point of contact for the electrical corporation to consult with on emergency and disaster preparedness plans.	• N/A	Enacted 9/23/12 Adds Section 768.6 to the Public Utilities Code
	• Approved 9/7/12 • A.B. 2584 • Bradford. Electrical corporations: investigations.	• Requires every electrical corporation and gas corporation that has an unplanned service outage resulting from an accident, natural event, or caused by the unplanned act of a utility employee, to preserve and not dispose of any materials that evidence the cause of the unplanned outage for 5 business days following the unplanned outage.	• N/A	Signed by the Governor 9/7/12 Adds Section 316 to the Public Utilities Code

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CT	• Approved 6/15/12 • S.B. 23 • An Act Enhancing Emergency Preparedness and Response – Public Act No. 12-148	• The Public Utilities Regulatory Authority shall initiate a docket to establish industry specific standards for acceptable performance by each utility in an emergency to protect public health and safety, to ensure the reliability of such utility's services to prevent and minimize the number of service outages or disruptions and to reduce the duration of such outages and disruptions, to facilitate restoration of such services after such outages or disruptions, and to identify the most cost-effective level of tree trimming and system hardening, including undergrounding, necessary to achieve the maximum reliability of the system and to minimize service outages.	• The authority shall allow, in a future rate proceeding, each utility to recover the reasonable costs incurred by such utility to maintain or improve the resiliency of such utility's infrastructure necessary to meet the standards established pursuant to this section pursuant to a plan first approved by the authority.	Signed by the Governor 6/15/12 Replaces subsection (b) of section 28-5 of the 2012 supplement to the general statutes
	• Introduced 3/21/12 • H.B. 5551 • An Act Concerning the Protection of Power and Telephone Lines	• To (1) allow companies that provide electric or telephone services to acquire by eminent domain a tree or shrub that is on or adjacent to an existing right-of-way or easement held by the company if the company determines that such tree or shrub would cause an interruption in the delivery of such service due to the condition of the tree or in the event of a storm accompanied by winds of hurricane force, snow or ice, and (2) make technical changes.	• N/A	Introduced by the Judiciary Committee 3/21/12 Public hearing 3/29/12

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CT	• Introduced 3/12/12 • H.B. 5544 • An Act Concerning Storm Preparation and Emergency Response	• To review the emergency response and service restoration efforts of certain public service companies and to establish emergency response and service restoration performance standards for such companies; to require back-up generators for telecommunications towers; to encourage the placement of certain utility infrastructure underground; to enable increased tree trimming; and to establish a micro-grid grant and loan pilot program.	• N/A	Introduced by the Energy and Technology Committee 3/12/12 Public hearing 3/20/12
	• Introduced 3/2/12 • H.B. 5407 • An Act Concerning Performance Standards for Public Utilities	• Requires the Commissioner of Energy and Environmental Protection to recommend performance standards for utility companies with the objective of enhancing communication during emergencies.	• N/A	Introduced by the Planning and Development Committee on 3/2/12 Public hearing 3/9/12
DC	• Approved 3/3/14 • B. 20-387 • Electric Company Infrastructure Improvement Financing Act of 2013	• Provides for the filing of a triennial Underground Infrastructure Improvement Projects Plan to identify problem feeders and recommendations for undergrounding the worst performing overhead feeders	• Authorizes and provides for the issuance of revenue Bonds in an aggregate principal amount not to exceed $375 M to finance the construction by the District Department of Transportation of underground facilities to be used by the Potomac Electric Power Company in connection with the undergrounding of certain electric power lines and their ancillary facilities.	Signed by Mayor Vincent Gray 3/3/14
HI	• Introduced 1/22/14 • H.B. 2384 • Relating to Natural Disasters	• Establishes the natural disaster working group to develop procedures for expediting recovery from natural disasters that are not declared "state disasters" by the governor.	• N/A	Introduced by Representative Cindy Evans (D) Referred to House Committee on Public Safety 1/27/14 Referred to House Committee on Finance 1/27/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
IL	• Approved 12/30/11 • H.B. 3036 • Public Utilities – Net Metering – Upgrade Investments – Public Act No. 97-0646	• provides for an infrastructure investment program for improvements designed to reduce outages due to storms	• A participating utility shall recover the expenditures made under the infrastructure investment program through the ratemaking process, including, but not limited to, the performance-based formula rate process	Signed by the Governor 12/30/11 Adds 16-108.5 (b)
	• Introduced 11/21/11 • H.B. 3884 • Overhead Utility Facilities Damage Prevention Act	• Provides that it shall be unlawful for any person to plant restricted vegetation within 20 feet of an electric utility pole or overhead electrical conductor located within the State. Provides that any restricted vegetation planted, whether by a person or by natural means, within 20 feet of an electric utility pole or overhead electrical conductor located within the State shall be subject to removal.	• N/A	Introduced by Representative Jack Franks (D) 11/21/11 House Session Sine Die 1/8/13
	• Introduced 10/24/11 • S.B. 2507 • Electric Utility Outages	• Amends the Public Utilities Act. Creates a new Article concerning electrical outages and emergency preparedness for electric utilities. Defines "area outage emergency". Provides that an electric utility must establish an Emergency Operations Center capable of receiving communications from municipalities and counties regarding down power lines or other damage during an area outage emergency.	• N/A	Introduced by Senator Sue Garrett 10/24/11 Senate Session Sine Die 1/8/13
MA	• Introduced 7/3/13 • H.D. 3750 • An Act relative to public utility company vegetation management.	• **[Bill text not yet available]**	• N/A	Introduced by Representative Josh Cutler (D)

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MA	• Introduced 1/15/13 • H.B. 2929 • An Act promoting storm resistant utility infrastructure upgrades	• Modifies existing law related to emergency response plans to require the identification of necessary upgrades to transmission and distribution infrastructure to ensure reliable service to customers, including, but not limited to, the replacement of damaged wires, transformers, conduits or substations with storm-resistant, modernized technologies and other upgrades to prevent service disruption during emergencies. Establishes that each investor-owned electric distribution, transmission or natural gas distribution company, when implementing an emergency response plan, shall replace damaged or destroyed distribution or transmission infrastructure with upgraded, storm-resistant or other modernized infrastructure to prevent future service disruptions, as determined in advance by the department. The department shall consider and approve of such necessary upgrades annually in each emergency response plan.	• N/A	Introduced by Representative Stephen DiNatale (D) Referred to Joint Committee on Telecommunications, Utilities and Energy 1/22/2013 Hearing scheduled 9/10/13

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MA	• Introduced 1/17/13 • H.B. 2989 • An Act relative to underground infrastructure	• Directs the Department of Public Utilities to promulgate rules and regulations relating to the construction of utility infrastructure designed to shield the utility infrastructure from damage sue to storms, vandalism, security issues, maintenance issues and overload issues. Directs the Department of Public Utilities to prioritize and incentivize the creation of underground utilities wherever feasible.	• N/A	Introduced by Representative Chris Walsh (D) Referred to Joint Committee on Telecommunications, Utilities and Energy 1/22/2013 Hearing held 9/10/2013 – a vote was not taken on the measure
	• Approved 8/6/12 • S.B. 2143 • An Act relative to the emergency service response of public utility companies	• Provides for filing of emergency preparedness plans, sharing of information and designation of emergency staff	• Establishes Department of Public Utilities Storm Trust Fund to reimburse department of public utilities for investigations into the preparation for and responses to storm and other emergency events by the electric companies • funding is provided through an assessment against each electric company based upon the intrastate operating revenues derived from sales within the commonwealth of electric service • specifies that any penalty levied by the department against an investor-owned electric distribution, transmission or natural gas distribution company for any violation of the department's standards of acceptable performance for emergency preparation and restoration shall be credited by the company to the affected customers of the penalized company	Signed by the Governor on 8/6/12 Adds sections to General Law Chapters 25 and 164

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MD	• Introduced 8/9/12 • S.B. 9 • Electric Companies - Rate Adjustment to Recover Profits Lost During Service Disruption - Prohibition	• N/A	• Prohibits the Public Service Commission from authorizing an electric company to adjust the electric company's rates to recover profits lost during a disruption in electrical service; and making the Act an emergency measure.	Introduced by Senator Frosh 8/9/12 First reading in Senate Rules
MS	• Approved 3/6/06 • H.B. 1498 • The Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act	• N/A	• Authorizes state general obligation bonds to be issued to pay for damage to electric utilities caused by Hurricane Katrina	Signed by the Governor 3/6/06
NJ	• Introduced 1/14/14 • A.B. 248	• Directs Board of Public Utilities (BPU) to adopt best practices and standards concerning electric, gas and water public utility infrastructure design and response to service interruptions resulting from a major catastrophic event which is defined to mean a natural or humanly caused occurrence arising from conditions beyond the control of the public utility, including, but not limited to, a thunderstorm, tornado, hurricane, flood, heat wave, snowstorm, ice storm or an earthquake, which results in a sustained interruption of utility service to at least 10% of the customers in an operating area or 10% of the customers of a municipality or county located in an operating area or the declaration of a state of emergency or disaster by the State or by the federal government.	• N/A	Introduced by Assembly member Sean Kean (R) and Assembly member David Rible (R) Referred to Assembly Telecommunications and Utilities Committee Identical bills from last session: A.B. 3532, S.B. 2439

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/14/14 • A.B. 274	• Requires public utilities to meet with county emergency management coordinators on a daily basis for the duration a major catastrophic event. Provides that, no later than 24 hours following a major catastrophic event, a public utility representative is required to be available to meet with the county emergency management coordinator at a location in the county experiencing the major catastrophic event.	• N/A	Introduced by Assembly member Donna Simon (R) Referred to Assembly Homeland and Security and State Preparedness Committee
	• Introduced 1/14/14 • A.B. 1014	• Requires certain electric public utilities to file emergency response plan with BPU.	• N/A	Introduced by Assembly member Daniel Benson (D) Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 1/14/14 • A.B. 1032 • The Reliability, Preparedness, and Storm Response Act	• Requires public utilities to file certain information concerning emergency preparedness with BPU and increases penalties.	• N/A	Introduced by Assembly member Daniel Benson (D) Referred to Assembly Telecommunications and Utilities Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/14/14 • A.B. 1412 • An Act establishing uniform Statewide reliability standards for electric and gas public utilities	• Requires the BPU to establish uniform statewide standards of acceptable performance for service reliability and restoration of service after a service interruption that every investor-owned electric and gas public utility in the State must follow and requires electric public utilities to submit to the board a review of strategies to mitigate flooding of substations within flood zones. • Requires all electric and gas public utilities to file a service reliability plan and an emergency communications strategic plan for review and approval by the board; Allows the board to impose civil penalties if it finds that the length of the service interruptions were materially longer than they would have been but for the utility's failure.	• amendment authorizes BPU to authorize the recovery of all reasonable and prudent costs incurred by an electric or gas public utility in repairing, improving, and replacing its equipment and property reasonably associated with the improvement of utility service reliability consistent with the provisions of the bill. For the purpose of determining rates, such costs may include placing them in the respective public utility's rate base through an annual adjustment or recovering the costs through another ratemaking methodology approved by the board. All costs associated with repairing, improving, and replacing utility equipment and property reasonably associated with the improvement of utility service reliability may be eligible for rate treatment that is approved by the board, including a full return on the public utility's invested capital.	Introduced by Assembly member Upendra Chivukula (D) Referred to Assembly Telecommunications and Utilities Committee Hearing held; amended; passed 2/6/14 Identical bill from previous session: A.B. 2760
	• Introduced 1/14/14 • S.B. 166 • The Reliability, Preparedness, and Storm Response Act	• Requires public utilities to file certain information concerning emergency preparedness with BPU and increases certain penalties	• N/A	Introduced by Senator Jim Whelan (D) and Senator Shirley Turner (D) Referred to Senate Economic Growth Committee Identical bills from previous session: S.B. 26, A.B. 3671

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/8/13 • S.B. 2429 • Public Utility Reliability Investment Act	• Requires public utilities to file infrastructure improvement plans to increase service reliability with the Board of Public Utilities	• N/A	Introduced by Senator Raymond Lesniak (D) 1/8/13 Identical bill: A.B. 3816 Introduced 2/11/13 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/17/12 • S.B. 2414	• Directs the BPU to study, prepare and submit, within six months of the effective date of the bill, to the Governor and to the Legislature, a written report which shall make findings which shall include the BPU's determination of whether the state's electric distribution system is maintained and operated by the electric public utilities in a manner that meets BPU standard and an assessment of the reliability of the state's electric distribution system through an application of other applicable standards. Directs the BPU to provide recommendations to improve reliability. •	• N/A	Introduced by Senator James Holzaphel (R) 12/17/12 Referred to Senate Economic Growth Committee Identical bill: A.B. 3616 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/13/12 • A.B. 3621	• Establishes requirements for newly installed and replacement electric utility poles and transmission towers. •	• N/A	Introduced by Assembly member John McKeon (D) 12/13/12 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/13/12 • A.B. 3622	• Directs the BPU to study the feasibility of adopting certain requirements for the installation of new and replacement electric distribution utility poles and transmission towers. •	• N/A	Introduced by Assembly member John McKeon (D) 12/13/12 Referred to Assembly Telecommunications and Utilities Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 12/6/12 • A.B. 3589	• Requires new electric distribution lines to be located underground wherever practicable	• N/A	Introduced by Assembly member Michael Carroll (R) Referred to Assembly Telecommunications and Utilities Committee 12/10/12
	• Introduced 12/3/12 • A.B. 3535	• Establishes Energy Infrastructure Study Commission. • Tasks the commission with making recommendations for improving the State's electric utility infrastructure	• N/A	Introduced by Assembly member Wayne DeAngelo (D) Passed by Assembly 5/20/13 Referred to Senate Economic Growth Committee 5/20/13
	• Introduced 11/19/12 • A.B. 3488	• Requires the BPU to adopt standards providing that, in operating areas that have been affected by a major catastrophic event, every electric distribution line of an electric public utility installed after the effective date of the bill, or installed, reinstalled, or repaired in response to damage resulting from a major catastrophic event, shall be located underground, wherever feasible, as determined by the BPU	• N/A	Introduced by Senator James Holzaphel (R) Referred to Telecommunications and Utilities Committee 12/3/2012 Identical bill: S.B. 2358 Referred to Senate Economic Growth Committee
	• Introduced 11/19/12 • A.B. 3482	• Requires the State's electric public utilities having ownership or control of utility plant infrastructure located in a flood hazard area to establish a plan to move the utility plant infrastructure out of the flood hazard area or to submit information showing that any plan to move utility plant infrastructure would not be feasible	• N/A	Introduced by Assembly member Jack Ciattarelli (R) Referred to Telecommunications and Utilities Committee 12/3/2012

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 11/19/12 • A.B. 3483	• Establishes in the Department of Community Affairs, the "New Jersey Task Force on Underground Utility Lines" (task force). Specifies that the purpose of the task force is to study and evaluate the extent to which underground utility lines have been installed in the state, and to develop recommendations relating to the feasibility of expanding the number of underground utility line installations, the various options for the financing of such expansion, and the consequences of expanding installation of underground utility lines in this State	• N/A	Introduced by Assembly member Amy Handlin (R) Referred to Telecommunications and Utilities Committee 12/3/2012
	• Introduced 9/27/12 • A.B. 3255 • The Reliability, Preparedness, and Storm Response Act of 2012	• Requires the BPU to develop and enforce performance benchmarks for service reliability and communications for electric public utilities and requires electric public utilities to submit to the BPU a review of strategies to mitigate flooding of substations within flood zones. In addition, the bill requires all public utilities conducting business in the State to file a service reliability plan and an emergency communications strategic plan for review and approval by the BPU. After review of a public utility's service reliability plan and communications plan, in either or both, the BPU may order the public utility to make such modifications as it deems reasonably necessary to remedy any deficiency • Gives BPU authority to increase certain penalties	• N/A	Introduced by Assembly member Gregory McGuckin (R) 9/27/12 Referred to Assembly Homeland Security and State Preparedness Committee Identical bill: S.B. 2206 Referred to Senate Economic Growth Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 1/9/14 • A.B. 8387	• Requires every city in the state, who has a population of 95,000 or more, to conduct a study of preparedness and readiness in the case of a disaster, natural or man-made, that would affect the state's power grid in such city. Requires each city to study their ability to maintain vital services, backup generating systems, law enforcement, hospitals, the integrity of computer systems operated by institutions within the city, first responders for immediate deployment and any further analyses that the Commissioner of Homeland Security and Emergency Services or Director of the Office of Emergency Management deems necessary. States that the purpose of these studies is for the cities to identify those areas of concern.	• N/A	Introduced by Assembly member Felix Ortiz (D) Referred to Assembly Committee on Cities
	• Introduced 4/4/13 • A.B. 6502 • Utility Preparedness Act of 2014	• Creates a utility preparedness program, which will impose new standards for preparedness and power restoration to address forthcoming major utility outages, like that experienced during Hurricane Sandy. • States that the public service commission adopt and enforce rules, performance incentives and standards for each transmission and distribution company during power outages in which more than ten percent of a transmission and distribution company's customers are without power for more than forty eight-consecutive hours.	• N/A	Introduced by Assembly member Shelley Mayer (D) Referred to Assembly Corporations Authorities Commissions Committee Amended 1/28/14 Identical bill: S.B. 4502 Referred to Senate Energy and Telecommunications Committee Re-referred to Senate Energy and Telecommunications Committee 1/8/14 Amended 1/24/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 2/14/13 • S.B. 3761 • Natural Disaster Preparedness and Mitigation Act	• Enacts the "natural disaster preparedness and mitigation act" providing for enhanced disaster preparedness and recovery from disasters.	• The disaster preparedness Commission shall utilize, in rate setting proceedings, to recover the reasonable costs incurred to maintain or improve the resiliency of the utility's infrastructure necessary to comply with the established standards	Introduced by Senator Malcolm Smith (D) Referred to Senate Veterans, Homeland Security & Military Affairs Committee Re-referred to Senate Veterans, Homeland Security & Military Affairs Committee 1/8/14 Amended 1/28/14
	• Introduced 1/29/13 • A.B. 3822	• Requires electric corporations to submit electric utility emergency plans to the public service commission for review and approval; provides such plans shall set forth training and planning for power outages, procedures to determine the extent of outages, procedures to determine the length of time the outages will continue, load relief policies, decision making plans, and any other information such commission requires; annually requires electric corporations file emergency plans and verification of the ability to implement such plan; requires electric corporations to report to the public service commission within 60 days of an outage which lasts more than 48 hours.	• N/A	Introduced by Assembly member Francisco Moya (D) Referred to Assembly Energy Committee 1/29/13 Re-referred to Assembly Environmental Energy 1/8/14 Identical bill: S.B. 2773 Referred to Senate Energy and Telecommunications Committee 1/23/13 Re-referred to Senate Energy and Telecommunications Committee 1/8/14
	• Introduced 1/14/13 • A.B. 2300	• Regulates the cutting, topping and removal of trees upon rights of way by providers of electric service. Requires the planting of replacement trees in certain cases.	• N/A	Introduced by Assembly member Thomas Abinanti (D) Referred to Assembly Energy Committee 1/14/13 Re-referred to Assembly Environmental Energy 1/8/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 1/9/13 • S.B. 710	• Requires the public service commission to establish standards of acceptable performance for electric corporations.	• N/A.	Introduced by Senator Kevin Parker (D) Referred to Energy and Telecommunications Re-referred to Energy and Telecommunications 1/8/14
	• Introduced 1/9/13 • S.B. 1345	• Requires that the Public Service Commission ensure equitable treatment of all retail customers of electric corporations and municipal electric utilities by requiring investor owned utilities include them in any filed storm preparation and response plans.	• N/A	Introduced by Senator George Maziarz (R) Referred to Energy and Telecommunications Re-referred to Energy and Telecommunications 1/8/14 Recommit, enacting clause stricken 1/22/14
	• Introduced 1/4/12 • S.B. 6094	• Amend the public service law, in relation to requiring the PSC to establish standards of acceptable performance for electric corporations in the event of a power outage and subsequent power restoration	• N/A	Introduced by Senator Kevin Parker (D) 1/4/12 Referred to Energy and Telecommunications
	• Introduced 1/27/11 • S.B. 1777 • Safety and Reliability Inspection	• Requires a safety and reliability inspection of all utility poles used by electric corporations providing electric service to over 300,000 customers and the replacement or removal of deficient poles	• N/A	Introduced by Senator Bill Perkins (D) 1/27/11 Referred to Codes 6/14/11 Referred to Ways and Means 6/17/11 Enacting Clause stricken 7/11/11 Identical bill A.B. 6181; Amended 6/8/11 Referred to Energy and Telecommunications 1/4/12 Amended and recommitted to Energy and Telecommunications 6/8/11 Referred to Energy and Telecommunications 1/4/12

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
PA	• Introduced 2/6/13 • S.B. 35	• Authorizes and provides for the coordination of activities relating to disaster preparedness and emergency management activities by agencies and officers of the Commonwealth, and similar Federal-State and State-Local activities in which the Commonwealth, and its political subdivisions, intergovernmental cooperative entities, regional task forces, councils of governments, school districts and other appropriate public and private entities participate.	• N/A	Introduced by Senator Lisa Baker (R) Referred to Veterans Affairs and Emergency Preparedness Committee
TX	• Approved 6/17/11 • S.B. 937	• Requires the Public Utility Commission of Texas by rule to require an electric utility, municipally owned utility, electric cooperative, qualifying facility, power generation company, exempt wholesale generator, or power marketer to give to a nursing facility, an assisted living facility, and a facility that provides hospice services the same priority that it gives to a hospital in its emergency operations plan for restoring power after an extended power outage.	• N/A	Signed by the Governor 6/17/11 Subchapter D, Chapter 38, Utilities Code, is amended by adding Section 38.072
	• Approved 4/16/09 • S.B. 769	• N/A	• Provides for securitization methods for the recovery of system restoration costs incurred by electric utilities following hurricanes, tropical storms, ice or snow storms, floods, and other weather-related events and natural disasters.	Signed by the Governor 4/16/09 Amends Chapter 36, Utilities Code, by adding Subchapter I

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
VT	• Approved 4/4/13 • Executive Order 04-13 • Governor's Emergency Preparedness Advisory Council	• The order states that the mission of the Governor's Emergency Preparedness Advisory Council shall be to assess the state's overall homeland security preparedness, policies, communications and to advise on strategies to improve the system already in effect. • The order also states that the Council shall carefully consider the interdependencies between federal, state, local governments, Vermont National Guard, first responders, law enforcement, emergency managers, public health officials and private community organizations. The Council is also urged to take into consideration the available financial resources.	• N/A	Signed by Governor Peter Shumlin (D) 4/4/13 Expires 7/15/19

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
WI	• Approved 12/13/13 • S.B. 119	• Ratifies a compact between several states and provinces of Canada that would provide for the possibility of mutual assistance in managing an emergency or disaster. • Allows for the temporary suspension, to the extent authorized by law, of statutes or ordinances that impede the response to an emergency or disaster. Requires members to agree to respond to the request for assistance as soon as possible, but the compact allows a member to withhold or withdraw resources to protect its own jurisdiction. • Provides that the states currently considering ratifying the compact as Illinois, Indiana, Ohio, Michigan, Minnesota, Montana, North Dakota, Pennsylvania, New York and Wisconsin and the Canadian provinces of Alberta, Manitoba, Ontario and Saskatchewan. Allows other states and provinces to ratify the compact.	• N/A	Approved by Governor Scott Walker (R) 12/13/13 2013 Wisconsin Act 97 Identical bill: A.B. 136

APPENDIX C
National Response Event

In 2013, EEI and its members ratified a new mutual assistance framework for events that require a national, industry-wide response. Going forward, when an event requires a national response, the industry will declare a "national response event" (NRE). An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). When an NRE is declared, the industry's mutual assistance efforts will be scaled to the national level and coordinated so industry restoration resources are allocated in a singular and seamless fashion. All available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, transparent, and equitable manner. The NRE framework is designed to help increase public safety, accelerate the industry's response during national events, and minimize economic consequences for consumers and the nation.

- In the case of an industry-wide NRE, the industry's mutual assistance process will be coordinated at the national level in order to ensure industry resources are seamlessly allocated in the most efficient manner possible. For regional or local outages, mutual assistance resources will continue to be managed through the RMAG process.
- A new National Response Executive Committee (NREC), comprised of senior-level utility executives from all regions of the country, will govern the NRE allocation process. Upon request of an affected utility CEO, the NREC will declare an NRE and will activate the National Mutual Assistance Resource Team (NMART).
- The NMART evaluates mutual assistance requests and assigns available resources to affected utilities in coordination with the RMAGs. When an NRE is declared, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to best meet restoration needs in a catastrophic event.
- During an NRE, mutual assistance is provided in a coordinated, transparent, and equitable manner to restore power as efficiently and safely as possible for all customers and communities.
- An NRE designation is reserved for only the most significant events, such as a major hurricane, earthquake, an act of war, or other occurrence that results in widespread power outages.

The electric power industry is prepared for significant outage events and continues to improve its coordination and response and recovery efforts. Customers have increasing expectations and electricity dependence, and the industry is committed to making the mutual assistance process efficient, transparent, and equitable regardless of the size and scope of the event.

Electric Power Industry-Government Partnerships

Improving Communication and Coordination

In order to facilitate and improve information sharing, communication, and coordination during major outages, senior electric power industry officials will be embedded with government response teams at the U.S. Department of Energy and will coordinate with the Federal Emergency Management Agency. This allows a direct, two-way flow of information between industry responders and government emergency managers.

Streamlining Transportation

The industry is partnering with the U.S. Department of Transportation and state transportation agencies to expedite the movement of electric utility resources in support of mutual assistance and power restoration. EEI, with the support of federal and state governments, is developing information resources and tools to address the specific needs of utilities to move fleets and resources across state lines during a significant outage event.

The industry also has negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.

Enhancing Logistical Support, Security, and Road Access

During Sandy, the U.S. Department of Defense (DOD) assisted the industry by providing airlift for crews and equipment. The industry is currently engaged in an ongoing dialogue with the DOD to build upon the unique capabilities that the military can provide during an emergency.

This effort includes working to expand logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.

The result of these partnerships is a higher level of collaboration between the electric power industry and government to ensure we are all better prepared for the next major outage event.

For more information on the National Response Event framework, please see http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/RestorationResources/Pages/default.aspx

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers.

With more than $85 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

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Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018

July 2018

State of Florida
Florida Public Service Commission

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Terms and Acronyms

APPA	American Public Power Association
CIAC	Contributions-in-Aid-of-Construction
Cooperative	Rural Electric Cooperative Utility
DEF	Duke Energy Florida, LLC
DEM	Florida Department of Emergency Management
EEI	Edison Electric Group
EOC	Emergency Operation Center
ESF-12	Emergency Support Function 12
F.A.C.	Florida Administrative Code
FECA	Florida Electric Cooperatives Association, Inc.
FEMA	Federal Emergency Management Agency
FIPUG	Florida Industrial Power Users Group
FMEA	Florida Municipal Electric Association
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
FRF	Florida Retail Federation
F.S.	Florida Statutes
GIS	Geographic information system
GPC	Gulf Power Company
IOUs	The five investor-owned electric utilities: DEF, FPL, TECO, GPC, and FPUC
Municipal	Municipal Electric Utility
NRECA	National Rural Electric Cooperatives Association
OPC	Office of Public Counsel
PURC	Public Utility Research Center – University of Florida
RMAG	Regional Mutual Assistance Groups
TECO	Tampa Electric Company

Executive Summary

The Florida Public Service Commission (PSC or Commission) has broad authority over the adequacy and reliability of the state's electric transmission and distribution grids. In addition, the Commission's jurisdiction extends to rate setting and all cost-recovery matters for investor-owned electric utilities (IOUs).

To promote strengthening of Florida's electric infrastructure and to reduce the frequency and length of outages following the intense 2004 and 2005 hurricane seasons, the Commission adopted extensive storm hardening initiatives, such as wooden pole inspection and replacement. The Commission ordered IOUs to file updated storm hardening plans for Commission review every three years. Those initiatives and the utilities' hardening plans have been the roadmap for aggressively improving resilience during the past 12 years. There were no major storm landfalls in Florida until the four hurricanes of 2016-2017, making the last two storm seasons the first opportunity to gather performance data.

On October 3, 2017, the Commission opened Docket No. 20170215-EU to review electric utility storm preparedness and restoration actions, and to identify potential areas where infrastructure damage, outages, and recovery time for customers could be minimized in the future. Commission staff issued several data requests to all utilities and sought input from non-utility stakeholders and customers, including a customer comments portal on the PSC website.

On May 2-3, 2018, the Commission held a workshop during which information was presented by utilities, customers and their representatives, and local governments. All of the IOUs provided data at the workshop that showed hardened facilities performed better than non-hardened facilities. There were clearly fewer outages for underground than overhead circuits.

The utilities suggested improvements such as targeted undergrounding projects for certain lateral circuits, possible legislation to require inspections and hardening of non-electric utility poles, and additional coordination and communication regarding vegetation outside of the utilities' rights of way. Non-utility stakeholders, including local governments, suggested increased coordination and more utility staffing at local Emergency Operations Centers (EOCs).

Key Findings

- Florida's aggressive storm hardening programs are working. (Section V)
- The length of outages was reduced markedly from the 2004-2005 storm season. (Section IV)
- Hardened overhead distribution facilities performed better than non-hardened facilities. (Section V)
- Very few transmission structure failures were reported. (Section V)

- Underground facilities performed much better compared to overhead facilities. (Section V)

- Despite substantial, documented improvement, some customers were dissatisfied with the extent of Hurricane Irma outages and restoration times. (Section VI)

- Rising customer expectations are that resilience and restoration will have to continually improve. (Section VI)

- The primary causes of power outages came from outside the utilities' rights of way including falling trees, displaced vegetation, and other debris. (Section IV)

- Vegetation management outside the utilities' rights of way is typically not performed by utilities due to lack of legal access. (Section IV)

- In some instances, following Hurricane Irma, estimates of restoration time proved inaccurate, and consumer communication systems were overwhelmed. (Section VI)

- Some local governments see a need for better coordination and communication with utilities during and after storms. (Section VI)

Commission Actions

At the July 10, 2018 Internal Affairs meeting, the Commission directed its staff to initiate the following:

- Open storm hardening plan review dockets earlier than previously scheduled, for all five IOUs and begin collecting additional details related to:

    - Meetings with local governments regarding vegetation management and the identification of critical facilities.

    - Utility staffing practices at local emergency operations centers.

    - Planned responses to roadway congestion, motor fuel availability, and lodging accommodation issues.

    - Alternatives considered before selecting a particular storm hardening project.

    - The collection of more uniform performance data for hardened vs. non-hardened and underground facilities, including sampling data where appropriate.

    - The impact of non-electric utility poles on storm recovery.

- Begin collecting data related to the targeted undergrounding projects of Florida Power & Light Company (FPL) and Duke Energy Florida, LLC (DEF) as part of the staff's annual distribution reliability review.

- Initiate a management audit to examine the procedures and processes used by the IOUs to estimate and disseminate outage restoration times following a major storm.

- Initiate a management audit to examine the procedures and processes used by the IOUs to inspect and schedule maintenance on transmission structures.

Legislative Considerations

The Commission also identified several issues outside its jurisdiction that the Legislature may consider:

- Revision of vegetation management policies to improve the ability of electric utilities to conduct vegetation management outside of rights of way to reduce outages and restoration costs.

- Possible legislation to require inspection and hardening of non-electric utility poles.

- Enhanced statewide public education regarding tree trimming and problem tree placement and removal on private property. This program could be similar to a Right Tree, Right Place initiative already used by several utilities.

- Implementation of emergency procedures regarding roadway congestion, motor fuel availability, and lodging accommodations for mutual aid personnel.

Section I: Background

In response to the intense impact that the 2004 and 2005 hurricanes had on the state, the 2006 Florida Legislature directed the Commission to ". . . conduct a review to determine what should be done to enhance the reliability of Florida's transmission and distribution grids during extreme weather events, including the strengthening of distribution and transmission facilities." Based on its review of the 2004 and 2005 hurricane seasons, the Commission provided three recommendations in a 2007 report to the Legislature:[1] (1) maintain a high level of storm preparation; (2) strengthen the electric infrastructure to withstand severe weather events with the use of hardening activities; and (3) establish additional planning tools to identify and implement instances where undergrounding is appropriate as a means of storm hardening. As discussed in the 2007 report to the Florida Legislature, ". . . the Commission has been careful to balance the need to strengthen the state's electric infrastructure to minimize storm damage, reduce outages, and reduce restoration time while mitigating excessive cost increases to electric customers."

The 2006 Order

In 2006, after considering recommendations from the utilities, the Commission ordered IOUs to inspect wooden poles every eight years to assure weakened ones are replaced, and to implement 10 storm preparedness initiatives:

- Three-year Vegetation Management Cycle for Distribution Circuits
- Audit of Joint-Use Attachment Agreements (shared use of poles with telecom)
- Six-year Transmission Structure Inspection Program
- Hardening of Existing Transmission Structures
- Development of Transmission and Distribution Geographic Information System
- Collection of Post-Storm Data and Forensic Analysis
- Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems
- Increased Utility Coordination with Local Governments
- Collaborative Research on Effects of Hurricane Winds and Storm Surge
- Development of Natural Disaster Preparedness and Recovery Program Plans

The Commission also ordered electric utilities to file updated storm hardening plans every three years, and began annual Hurricane Season Preparation Workshops, which allow the IOUs, Municipals, and Cooperatives to share individual hurricane season preparation activities. These practices continue today.

[1] Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather, July 2007, http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/EnergyInfrastructure/UtilityFilings/docs/stormhardening2007.pdf.

The Commission requires all IOUs to file an Annual Distribution Reliability Report with the PSC. This report includes updates of utilities' hardening efforts to allow the Commission to monitor progress. Additionally, each IOU updates its tariff as necessary to reflect the Commission requirement that the cost of conversion from overhead to underground, as well as the benefits of storm hardening, be incorporated into the Contributions-in-Aid-of-Construction (CIAC) calculation as outlined in Rules 25-6.0342 and 25-6.064, Florida Administrative Code (F.A.C.).

Also in 2006, the Commission required Florida's local exchange telecommunications companies to implement inspections of their wooden poles.[2] The Commission's authority to impose that requirement was subsequently repealed in 2011 as part of a number of deregulatory changes made to Chapter 364, Florida Statutes.

2016-2017 Hurricanes

During 2016, Florida was impacted by two hurricanes: Hermine and Matthew and in 2017, Hurricanes Irma and Nate impacted Florida. The largest storm, Hurricane Irma, made landfall in Florida on September 10, 2017, as a Category 4 hurricane in Monroe County; then made a second landfall as a Category 3 hurricane in Collier County, providing the first major test to the system since 2005.

On October 3, 2017, the PSC opened Docket No. 20170215-EU to identify potential areas where infrastructure damage, outages, and recovery time for customers could be minimized in the future. In order to identify these areas, Commission staff issued several data requests to all utilities in the areas of preparation, restoration practices, customer communication, outage causes, facility performance, meteorological data, and suggested improvements.

Commission staff also sought comments from non-utility stakeholders and customers. A summary of the non-utility stakeholders' comments are provided in Appendix A. On October 9, 2017, a customer portal was opened on the Commission's website, allowing customers to submit comments regarding their reaction to utility restoration/communication efforts. The portal was closed on May 1, 2018, with 701 customer comments and 14 non-utility stakeholder comments received.

On May 2-3, 2018, the Commission held a workshop. Leading up to the workshop, staff provided topics for utilities to address, which included preparation and restoration processes, hardened vs. non-hardened facility performance, underground vs. overhead performance, impediments to restoration, customer/stakeholder communication, and suggested improvements based on lessons learned.

[2] Order No. PSC-06-0168-PAA-TL, issued March 1, 2006, in Docket No. 20060077-TL, *In re: Proposal to require local exchange telecommunications companies to implement ten-year wood pole inspection program.*

At the workshop, the following provided input:

- FPL
- DEF
- Tampa Electric Company (TECO)
- Gulf Power Company (GPC)
- Florida Public Utilities Company (FPUC)
- Florida Electric Cooperatives Association, Inc. (FECA)
- Florida Municipal Electric Association (FMEA)
- Office of Public Counsel (OPC)
- Florida Industrial Power Users Group (FIPUG)
- Florida Retail Federation (FRF)
- City of Dunedin
- St. Johns County
- City of Monticello

The IOUs provided data at the workshop that showed hardened facilities performed better than non-hardened facilities. There were clearly fewer outages for underground than overhead circuits.

The utilities suggested improvements such as targeted undergrounding projects for certain lateral circuits, possible legislation to require inspections and hardening of non-electric utility poles, and additional coordination and communication regarding vegetation outside of the utilities' rights of way. Non-utility stakeholders, including local governments, suggested increased coordination and more utility staffing at local EOCs.

Section II: Hurricane Preparedness Practices

Commission Role

No amount of preparation can eliminate outages in extreme weather events, so utility regulators work to reduce and shorten outages. In support of sharing individual hurricane preparation activities among IOUs, Municipals, and Cooperatives, the Commission has held annual Hurricane Season Preparation Workshops since 2006. These workshops provide an opportunity for electric utilities to discuss their storm preparation and restoration processes, coordination with local governments, and public outreach.

The Commission's Division of Engineering is responsible for staffing the Emergency Support Function 12 (ESF-12) in the State's Emergency Operations Center. ESF-12 coordinates with the electric and natural gas utilities operating in Florida to ensure the integrity of their energy supply systems are maintained during emergency situations. In this role, Commission staff also participates in an annual hurricane preparedness drill and other EOC related exercises.

The Commission provides information to consumers regarding storm preparedness, such as hurricane survival kits, portable generator safety, and ways to prepare your home before a storm. In the event of a storm, links to current Florida Division of Emergency Management (DEM) information are highlighted on the PSC website (www.floridapsc.com), as well as links to the Federal Emergency Management Agency (FEMA) and the National Hurricane Center. The PSC issues statewide news releases at the beginning of each storm season regarding hurricane workshops, or Commission decisions on utility storm preparedness plans. All of this information is distributed via the PSC's Twitter account (https://twitter.com/floridapsc) at appropriate times throughout the year.

Utility Preparedness and Storm Hardening Activities

Throughout the year, utilities participate in hurricane exercises and drills in order to better prepare for a storm event. Prior to hurricane season, utilities ensure that they have the required internal materials on hand, as well as commitments for external resources which may be needed following a storm. Utilities also partake in hurricane preparedness exercises and meetings with local governments and the state Emergency Operations Center, and they ensure that the proper critical facilities (i.e., hospitals, water and wastewater treatment plants, and fire stations) are identified.

The activities outlined in each IOUs' storm hardening plan vary to a degree; however, all are grounded in substantive strengthening and protection of the utility's electric facilities. Programs include tree trimming, pole inspections, hardening of feeders and laterals, and undergrounding.

Utilities typically focus hardening efforts on transmission infrastructure, as these can impact large numbers of customers. Hardening efforts are also prioritized for infrastructure that serves critical facilities, which are generally restored first following a storm event.

IOUs complete tree trimming of their distribution circuits, composed of laterals and feeders, in three- to six-year cycles. Feeders run outward from substations and have the capability of serving thousands of customers. Laterals branch from the feeder circuits and are the final portion of the electric delivery system, serving a smaller portion of customers, and are typically associated with residential areas.

Each year, IOUs trim a certain percentage of their total lateral and feeder miles as part of their hardening plans; however, the trees trimmed only include those that are in the utilities' rights of way. Most IOUs trim overhead feeder circuits over a three-year trim cycle, excluding TECO which is currently on a four-year trim cycle.[3] For overhead laterals, IOUs must complete all trimming during a maximum six-year cycle.[4]

Table 2-1 lists the number of miles of vegetation cleared or trimmed that each IOU has completed for its feeder and lateral circuits since 2006. The number of miles provided includes planned tree trimming and may not include hot-spot or mid-cycle trimming. Hot-spot tree trimming occurs when crews are sent to specific areas that require unscheduled trimming due to rapid growth.

Table 2-1
Vegetation Clearing from Feeder and Lateral Circuits (in Miles)

	DEF		FPL		FPUC		GPC		TECO	
	Feeders	**Laterals**	**Feeders**	**Laterals**	**Feeders**	**Laterals**	**Feeders**	**Laterals**	**Feeders**	**Laterals**
2006	723	2,703	10,094	825	-	-	-	-	268	840
2007	2,112	2,203	4,454	2,215	-	-	1,878	675	363	945
2008	708	2,544	4,262	2,078	59	86	274	821	374	806
2009	467	3,178	4,151	2,768	63	96	274	821	374	806
2010	787	4,139	5,222	2,741	65	84	281	1,060	617	1,634
2011	2,370	1,132	4,337	3,367	68	205	259	1,530	606	1,514
2012	196	3,228	4,045	3,703	52	123	240	857	435	1,282
2013	476	3,810	4,637	4,124	67	129	240	1,293	374	1,098
2014	3,297	2,782	4,249	3,685	52	145	241	1,294	465	1,161
2015	1,024	3,579	4,209	3,817	51	134	241	913	454	1,146
2016	1,016	2,173	4,418	3,745	62	188	241	331	386	926
2017	2,106	1,909	4,381	3,560	29	86	241	446	199	627

Source: IOUs' 2006-2017 distribution reliability reports.

[3] Order No. PSC-12-0303-PAA-EI, issued June 12, 2012, in Docket No. 20120038-EI, *In re: Petition to modify vegetation management plan by Tampa Electric Company*.
[4] Order No. PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 20060198-EI, *In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates*.

As part of each IOUs' storm hardening plan, the Wooden Pole Inspection Program requires each utility to inspect and assess the strength of all of its installed wooden poles over an eight-year period. IOUs also have wooden pole replacement programs in place where a select number of existing poles are replaced with hardened poles. The National Electrical Safety Code Extreme Wind Loading standards are used in designing replacement poles. Table 2-2 shows the number of transmission and distribution wooden poles replaced from 2006 through 2017.

Table 2-2
Wooden Pole Replacement

	DEF		FPL		FPUC		GPC	TECO	
	Trans.	**Distr.**	**Trans.**	**Distr.**	**Trans.**	**Distr.**	**Distr.**	**Trans.**	**Distr.**
2006	-	-	307	2,334	-		-	-	-
2007	956	1,130	1,471	8,164	-		185	494	1,536
2008	866	1,903	1,966	7,533	47		736	781	2,056
2009	704	3,018	3,206	7,342	34		969	713	1,640
2010	-	-	1,409	10,639	215		418	900	2,815
2011	635	2,887	1,559	9,942	215		1,060	1,060	3,328
2012	803	4,670	816	10,454	242		1,032	683	4,957
2013	1,347	5,722	1,106	13,639	135		380	866	6,572
2014	2,028	5,597	2,070	12,777	536		790	720	6,038
2015	1,738	8,420	1,888	15,089	382		676	649	5,392
2016	698	4,429	1,737	12,067	254		693	940	6,701
2017	530	2,654	1,934	8,486	-		746		
Total	10,305	40,430	19,469	118,466	2,060		6,939	7,806	41,035

Source: Document Nos. 01516-2018, 01517-2018, 01518-2018, 01519-2018, 01520-2018, DEF's 2006-2017 distribution reliability reports.

Underground Facilities

The Commission's 2006 storm hardening initiatives included collaborative research efforts involving the electric utilities and the Public Utility Research Center (PURC), Warrington College of Business at the University of Florida. Specifically, the research provided three reports addressing material relevant to the modeling and assessment of the costs and benefits of relocating existing overhead electric distribution systems to underground. The effort reflects the state of facts that existed at that time and the results of this research remain available to the general public and local communities that are interested in relocating existing overhead electric distribution facilities.

In response to staff's data requests, the three largest IOUs stated that approximately 40 percent of all distribution lines are underground and that the majority of recent underground projects were for new construction, rather than the conversion of overhead to underground. Since 2006, the installed underground facilities have increased by approximately 5,300 miles for the IOUs. The total amount of installed underground facilities during the past five years was approximately 2,200 miles for an average rate of 440 miles/year.

The construction of underground electrical distribution systems, when compared with overhead systems, is more expensive. For construction of underground, the customer is responsible for the difference in the costs between underground and overhead, which often results in an installation barrier. Pursuant to Rules 25-6.0342 and 25-6.064, F.A.C., the costs and benefits of storm hardening are factored into the cost difference calculation for new construction or conversion to underground facilities, as reflected on each IOUs' tariff.

In an effort to further the deployment of underground facilities, DEF and FPL have initiated targeted undergrounding programs over the next few years. Both programs are scheduled to begin in 2018, focus on historically poor performing lateral circuits to replace several hundred miles of overhead lines, and are being funded through current base rates including any previously approved step increases. DEF's program is scheduled over a period of ten years and FPL's pilot program is currently scheduled for three years. The goal for each program is to test different construction techniques and identify impediments to converting these targeted overhead facilities to underground.

Storm Hardening Cost Recovery

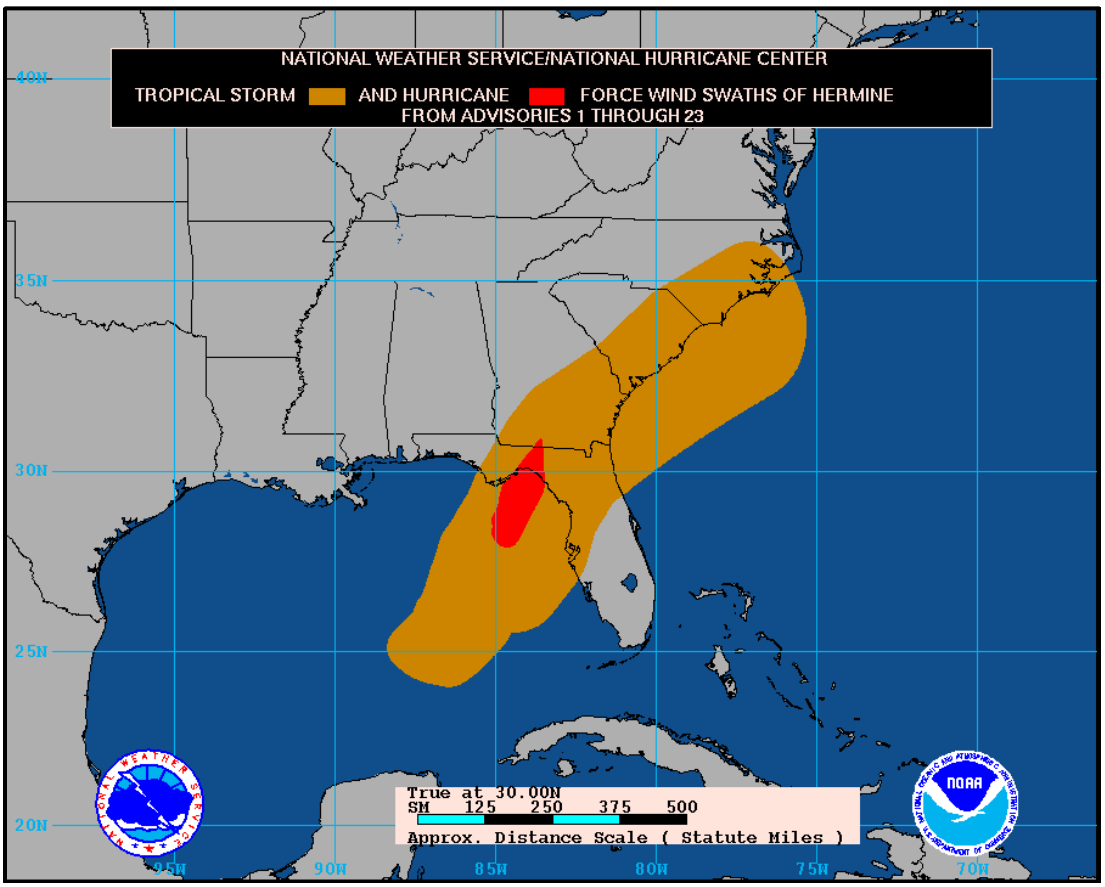
While an IOU's storm hardening plan must be approved by the Commission, this does not guarantee an IOU the recovery of all incurred costs for the implementation of the plan. Storm hardening costs are addressed during an IOU's general rate case proceeding, and those costs are covered in base rates since they are considered a part of providing electric service in Florida. During a general rate case, the costs for storm hardening are taken into consideration and the Commission makes a ruling on whether the costs were prudently incurred.

Section III: Summary of 2016 and 2017 Storms

Hurricane Hermine

Hurricane Hermine made landfall on September 2, 2016, near Wakulla and Jefferson counties. Hurricane Hermine was a Category 1 hurricane when it made landfall, primarily affecting the Big Bend area. Figure 3-1 illustrates the path of Hurricane Hermine, and the areas that experienced tropical storm and hurricane force winds. The National Hurricane Center defines tropical storm force winds as winds between 39 miles per hour (mph) to 73 mph. Winds that are equal to or exceeding 74 mph are defined as hurricane force winds.

Figure 3-1
Hurricane Hermine – Tropical Storm and Hurricane Force Winds



Source: NOAA's National Hurricane Center

Wind, rainfall, and storm surge data was requested from IOUs, Municipals, and Cooperatives for each hurricane. A total of 36 utilities provided data and the maximum reported sustained winds, wind gusts, rainfall, and storm surge for Hurricane Hermine, summarized in Appendix C. The three counties that experienced some of the highest sustained winds and wind gusts from Hermine were Jefferson, Madison, and Taylor. These counties also received high levels of rainfall; however, the two counties with the largest amounts of rainfall were Manatee and Sarasota. These two counties did not rank highest for any other category, and appear to be outliers in the reported weather data. The reason for the large amount of rain experienced in Manatee and Sarasota counties may have been due to strong storm bands that hit that part of the state. The three counties that had the largest storm surges were Dixie, Taylor, and Wakulla. All of these counties, with the exception of Manatee and Sarasota, were located in the area where Hurricane Hermine made landfall.

Table 3-1 provides the five counties with the highest number of outages for Hurricane Hermine. This outage data was reported to the state EOC by IOUs, Municipals, and Cooperatives at set intervals of reporting times. The percentages of accounts without power were calculated based on the peak number of customer accounts without power divided by the total number of customer accounts for that county, which includes IOUs, Municipals, and Cooperatives' customers. The total peak percentage of accounts in the state without power was approximately 3 percent for Hurricane Hermine. Appendix B provides a comprehensive list of the peak number of customer accounts by county that were without power for each hurricane.

Table 3-1
Hurricane Hermine – Five Counties with Highest Maximum Outages

	Max. Account Outages	Max. Percent of Account Outages
Hamilton	5,864	87.9%
Jefferson	5,762	71.5%
Lafayette	2,965	71.5%
Madison	7,278	69.0%
Wakulla	14,009	93.0%

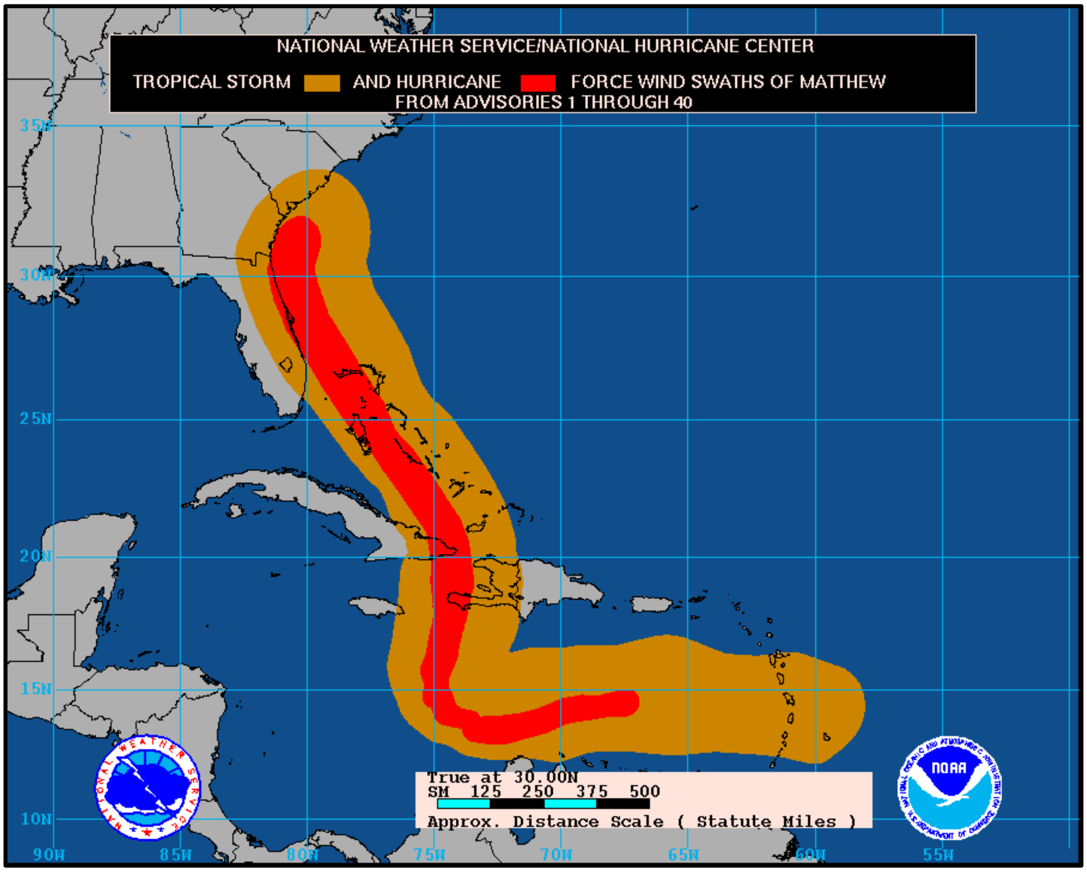
Source: State EOC power outage reports.

The outages for Jefferson, Madison, and Wakulla counties correlate to the reported weather data as they were among the counties that experienced the highest winds, rainfall, and storm surges. Wind data was not reported for Hamilton and Lafayette counties, though they both received large amounts of rainfall.

Hurricane Matthew

While Hurricane Matthew never made landfall in Florida, it passed along Florida's east coast shoreline, where some areas experienced sustained hurricane force winds. Hurricane Matthew began as a Category 4 hurricane on October 7, 2016, but weakened and later became a Category 2 hurricane northeast of Jacksonville Beach on October 8, 2016. Figure 3-2 illustrates the path of Hurricane Matthew, and the areas that experienced tropical storm and hurricane force winds.

Figure 3-2
Hurricane Matthew – Tropical Storm and Hurricane Force Winds



Source: NOAA's National Hurricane Center

Wind speed, rainfall, and storm surge data for Hurricane Matthew is contained in Appendix D. The three counties that experienced some of the highest sustained winds and wind gusts for Hurricane Matthew were Brevard, St. Johns, and Volusia. From the reported rainfall data, the counties with the three highest amounts of rainfall were Brevard, Indian River, and St. Lucie. The three counties that had the largest storm surges were Flagler, Nassau, and St. Johns. All of these counties are located on Florida's east coast and correspond to the path of the storm. Table 3-2 provides the five counties with the highest number of outages for Hurricane Matthew. The total peak percentage of customer accounts in the state without power was 11 percent.

Table 3-2
Hurricane Matthew – Five Counties with Highest Maximum Outages

	Max. Account Outages	Max. Percent of Account Outages
Flagler	57,016	100.0%
Indian River	59,244	67.2%
Putnam	27,393	66.8%
St. Johns	78,610	89.6%
Volusia	257,718	92.0%

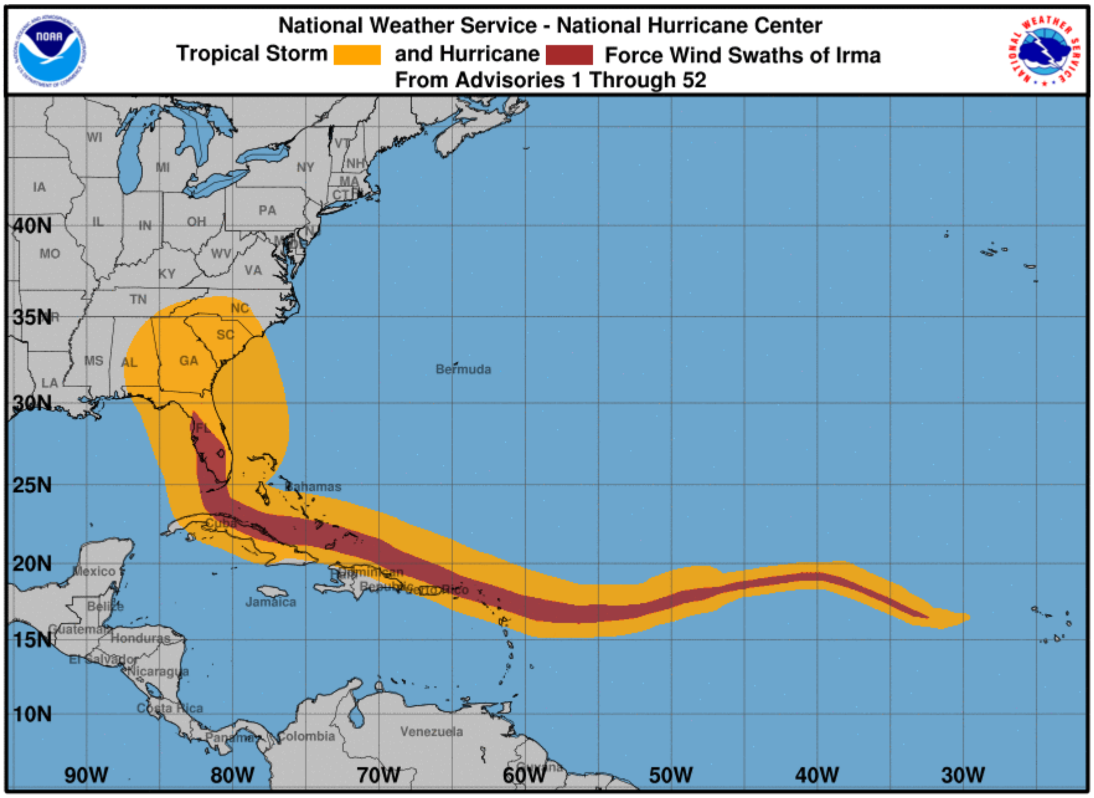
Source: State EOC power outage reports.

The outages for Flagler, Indian, St. Johns, and Volusia counties correlate to the reported weather data as they were among the counties that experienced the highest winds, rainfall, and storm surges. Rainfall data was not reported for Putnam County; however, it is located next to St. Johns County, which experienced severe weather conditions.

Hurricane Irma

Hurricane Irma was the first major hurricane to make landfall in Florida since the 2004 and 2005 hurricane seasons. On September 10, 2017, Hurricane Irma made landfall in the Florida Keys as a Category 4 hurricane and weakened to a Category 3 hurricane as it made a second landfall near Marco Island, Florida on the same day. The storm continued to weaken as it moved over Florida, affecting all 67 counties in the state and resulting in widespread power outages. Figure 3-3 illustrates the path of Hurricane Irma, and the areas that experienced tropical storm and hurricane force winds.

Figure 3-3
Hurricane Irma – Tropical Storm and Hurricane Force Winds



Source: NOAA's National Hurricane Center

Wind speed, rainfall, and storm surge data for Hurricane Irma is contained in Appendix E. The three counties that experienced the highest maximum sustained winds for Hurricane Irma were Collier, Monroe, and Polk. The largest amount of rainfall was reported for Bradford, Hillsborough, and St. Lucie counties. The three counties that had the largest maximum storm surge were Collier, Monroe, and Nassau. Due to the path of Hurricane Irma, many of the southernmost counties, such as Monroe and Collier, experienced high winds and storm surges, while parts of central Florida had large amounts of rain. Additionally, parts of northeast Florida, such as Nassau County, experienced high winds and storm surges due to the outer bands and the path of the storm.

Table 3-3 provides the five counties with the highest number of outages for Hurricane Irma. The total peak percentage of customer accounts in the state without power was 62 percent.

Table 3-3
Hurricane Irma – Five Counties with Highest Maximum Outages

	Max. Account Outages	Max. Percent of Account Outages
Hardee	11,976	97.4%
Hendry	18,750	100.0%
Highlands	62,010	99.3%
Nassau	43,740	97.6%
Okeechobee	21,990	96.5%

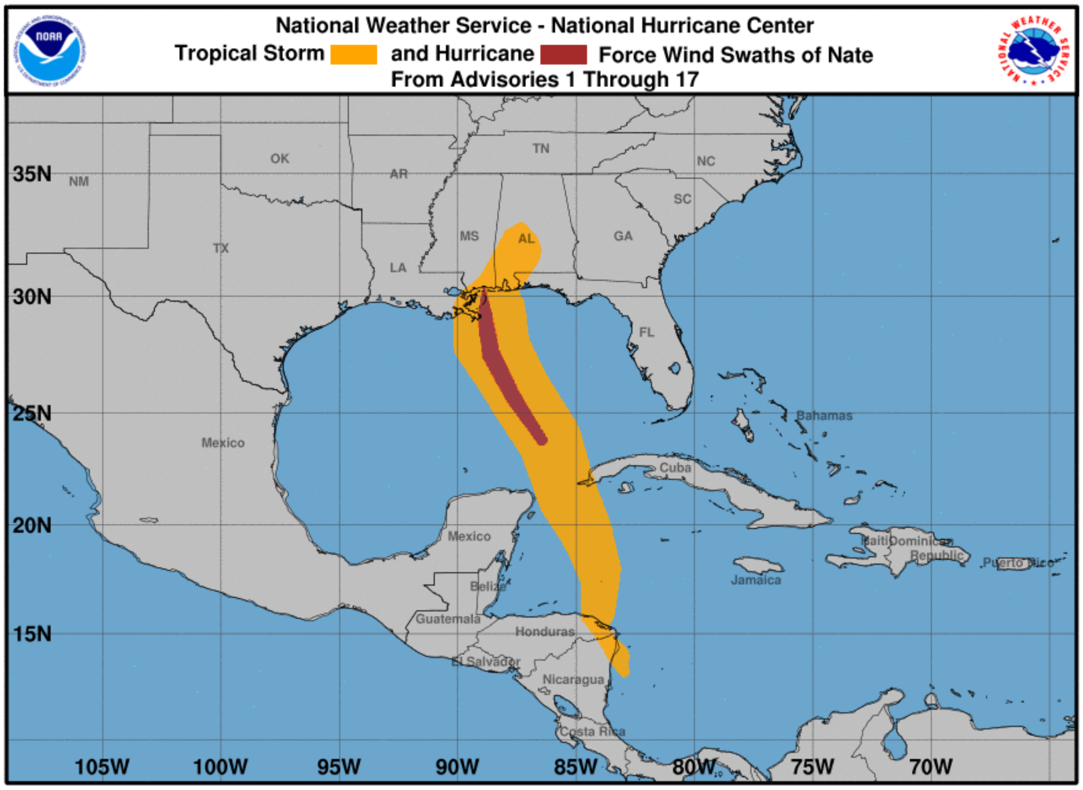
Source: State EOC power outage reports.

The outages for Nassau County correlate to the reported weather data as it was among the counties that experienced high storm surges. Okeechobee, Hardee, Henry, and Highlands counties are in close proximity to one another and are located in south Florida, near Hurricane Irma's landfall. All of these counties experienced wind gusts over 100 mph and all but Okeechobee recorded over 10 inches of rainfall.

Hurricane Nate

On October 7, 2017, Florida was impacted by a second storm, Hurricane Nate, which made its first landfall at the mouth of the Mississippi River as a Category 1 hurricane, followed by a second landfall near Biloxi, Mississippi on the same day. While Hurricane Nate did not make landfall in Florida, parts of the panhandle were impacted by the hurricane. Figure 3-4 illustrates the path of Hurricane Nate, and the areas that experienced tropical storm and hurricane force winds.

Figure 3-4
Hurricane Nate – Tropical Storm and Hurricane Force Winds



Source: NOAA's National Hurricane Center

Wind speed, rainfall, and storm surge data for Hurricane Nate is contained in Appendix F. The impact of Hurricane Nate was much smaller in scope compared to the previous three hurricanes. The three counties that experienced the highest sustained winds, wind gusts, and rainfall were Escambia, Okaloosa, and Santa Rosa. The three counties that had the highest storm surges were Escambia, Franklin, and Santa Rosa. All of these counties are located in Florida's panhandle, close to where Hurricane Nate made landfall. Table 3-4 provides the five counties with the highest number of outages for Hurricane Nate. The total peak percentage of accounts in the state without power was 0.1 percent.

Table 3-4
Hurricane Nate – Five Counties with Highest Maximum Outages

	Max. Account Outages	Max. Percent of Account Outages
Escambia	5,384	3.4%
Holmes	77	0.7%
Okaloosa	6,382	5.9%
Santa Rosa	1,712	2.2%
Walton	613	1.0%

Source: State EOC power outage reports.

The outages for Escambia, Okaloosa, and Santa Rosa counties correlate to the reported weather data as they were among the counties that experienced some of the highest winds, rainfall, and storm surges. While Walton County did not have the highest reported winds and rainfall, it experienced high winds comparable to Okaloosa County, as well as receiving several inches of rain. Wind data was not reported for Holmes County; however, it is located in the panhandle area near Okaloosa and Walton counties.

Section IV: Review of Outage Restoration Activities

Restoration Process

The restoration process is a year-round activity. Many utilities across the state engage in exercises that simulate storms in order to better prepare for an actual hurricane or other significant weather event.

In an actual hurricane, utilities may initiate pre-staging meetings and activities as early as 240 hours before landfall, which may include requests for mutual aid. IOUs communicate with county EOCs to identify critical facilities (i.e., hospitals, water and wastewater treatment plants, and fire stations) and coordinate on other restoration activities.

Before a storm makes landfall, an assessment of potential damage is completed by utilities based on the forecasted path of the storm. This information can be used to determine if mutual aid and additional material resources should be requested.

As the storm approaches, repair activities will continue until winds reach 35-40 miles per hour, at which time crews will be called back for a stand-down period. Once winds drop below 35-40 miles per hour and weather conditions are considered to be safe following a storm, utility crews are re-deployed to continue the restoration process.

Once the storm has passed, a post-storm damage assessment is completed, where utilities can establish what facilities have been damaged, refine restoration time estimates, manage workloads, and allocate resources to where they are needed. Restoration begins with repairs to generation plants and transmission facilities that sustained damage, followed by repairs to substations and feeders. Substations and feeders that power critical infrastructure are prioritized first in order to get those necessary facilities back in service.

Feeders that serve the largest number of customers are restored next, and finally laterals that serve neighborhoods with fewer customers are repaired and restored. Overall, utilities strive to restore as many customers as possible in the shortest amount of time.

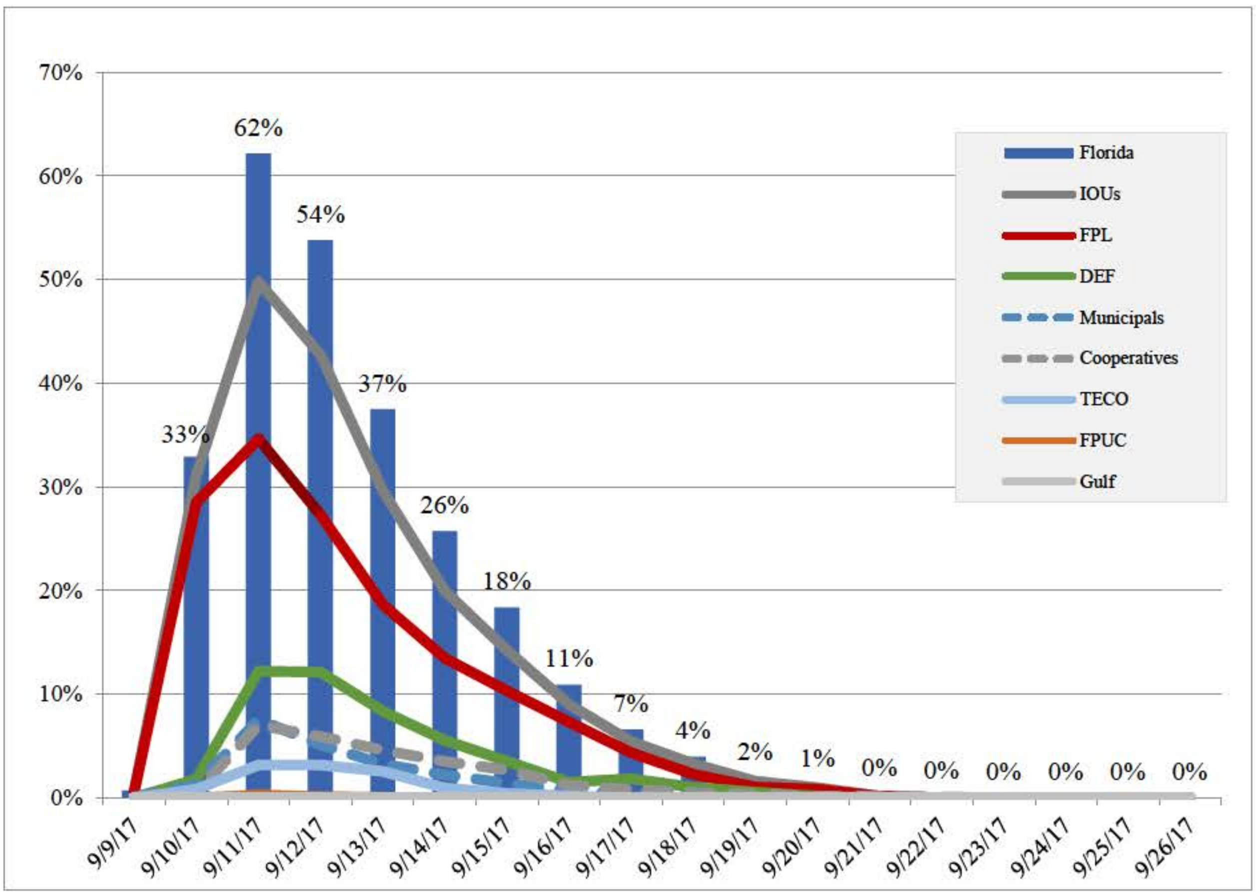
Based on a review of the utility presented data for each hurricane, the utilities performed consistently in restoring service. Hurricane Irma affected the entire state and was the first significant test of Florida’s electric infrastructure since the 2004 and 2005 hurricane season. For simplification purposes, and due to the size and scope of the storm, the following subsections on restoration, outage causes, mutual aid, and impediments are specific to Hurricane Irma only. Data from other storms was used for comparison purposes to determine if there were any anomalies or unique circumstances.

Hurricane Irma Restoration

Florida's utilities managed more than 27,000 crews in the aftermath of Hurricane Irma. The rate of restoration was fairly rapid with comparable results for all utilities.

Using outage data reported to DEM, Figure 4-1 provides the number of customer accounts without power in proportion to the total number of customers in the state. The peak outages occurred on September 11, 2017, when more than 6.5 million customers (62 percent of the state's approximately 10.5 million customers) were without power. Five days following this peak, the number of outages dropped to approximately 11 percent. On September 20, 2017, ten days following the outage peak, the percent of customer accounts without power dropped below 1 percent.

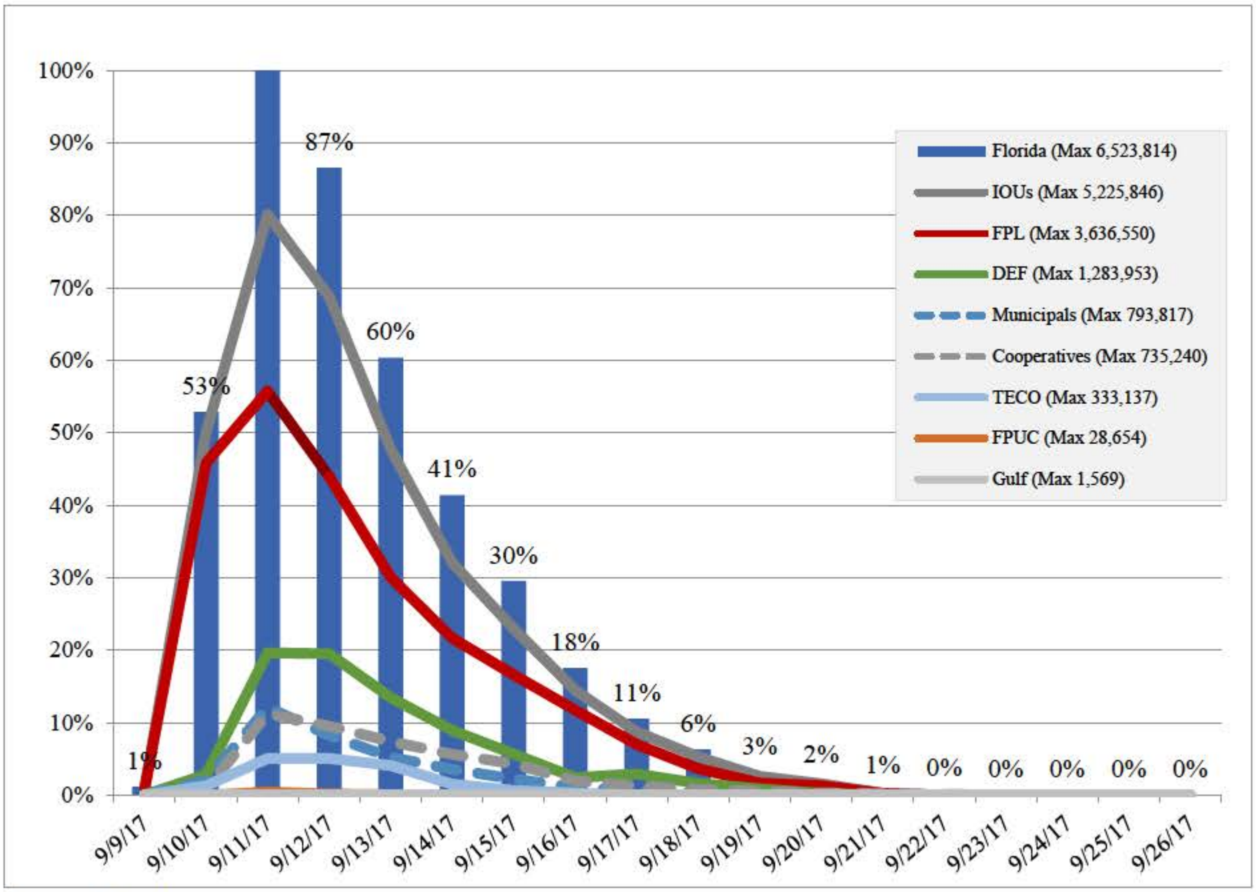
Figure 4-1
Hurricane Irma – Percent of Florida's Total Customers without Power



Source: State EOC power outage reports.
Note: Individual utility outage maximums occurred at different times and do not add to the total.

As previously stated, the peak number of outages occurred on September 11, 2017. Figure 4-2 provides the daily percentages of customers without power based on the peak outages. Following September 11, 2017, the proportion of affected customers that were still without power was below 50 percent three days later on September 14, 2017. Additionally, by September 20, 2017, the number of customers that were without power dropped to 2 percent. For several utilities, once the number of customers without power dropped to 2 percent or less, the utility stopped reporting outages to the DEM as these outages could be unrelated to the storm event.

Figure 4-2
Hurricane Irma – Percent of Affected Customers without Power



Source: State EOC power outage reports.
Note: Individual utility outage maximums occurred at different times and do not add to the total.

Overall, Figures 4-1 and 4-2 illustrate that the graphs for IOUs are similar in shape to the Municipals and Cooperatives, demonstrating comparable power restoration achievements for the different utility groups. No irregularities were observed in the data.

During the May 2018 workshop, FPL provided a comparison of outage data and restoration times for Hurricane Wilma (2005) and Hurricane Irma. As seen in Table 4-1, it took one day to restore power to 50 percent of FPL's customers for Hurricane Irma, while FPL reported it took five days for Hurricane Wilma. Restoring all customers took 10 days after Hurricane Irma, and it took 18 days after Hurricane Wilma.

Table 4-1
FPL – Outage and Restoration Data for Hurricanes Wilma and Irma

	Wilma	Irma
Customer outages	3.2M	4.4M
Staging sites	20	29
% Restored / days	50% / 5	50% / 1
All restored (days)	18	10
Avg. days to restore	5.4	2.1

Source: FPL's presentation at the May 2, 2018, Commission Workshop.

Also at the May 2018 workshop, TECO provided a comparison of time to complete restoration after Hurricane Irma (7 days) and in 2004 Hurricane Jeanne (11 days). No other utility provided a similar comparison. While each storm is different and presents its own set of difficulties, the data show restoration times have decreased markedly compared to previous storms.

Outage Causes

Data collected from 39 utilities identified that the biggest source of outages was vegetation issues. Many utilities described that these issues were from fallen trees or branches that were outside of the utilities' rights of way where utilities typically do not have a legal access to perform vegetation management. Additional trimming by the utilities within their rights of way would not eliminate these vegetation related outages. It should also be noted that typical hardening projects are designed and constructed to withstand extreme wind loads, not fallen trees. The second most prevalent outage cause was from embedded severe weather events, such as tornadoes, microbursts, and flooding.

Proactive tree trimming has been a key initiative of the Commission, and the results of the review indicate that vegetation continues to be a primary cause of damage and outages. Entities with authority over tree trimming policies should carefully consider options that would enhance the ability of electric utilities to conduct vegetation management in order to further reduce outages and restoration costs. Enhanced statewide public education regarding tree trimming and problem tree placement and removal on private property could provide additional benefits.

Mutual Aid

Many mutual aid agreements among IOUs throughout the country are managed by seven Regional Mutual Assistance Groups (RMAGs). Florida's IOUs are members of the Southeastern Electric Exchange RMAG. RMAGs facilitate the process of identifying available restoration workers and help coordinate the logistics to help with restoration efforts.

IOUs that are in RMAGs follow guidelines established by the Edison Electric Institute (EEI), and also establish additional guidelines that aid in the communication process and rapid mobilization and response efforts. EEI also communicates regularly with the associations that serve Municipals and Cooperatives during major outage incidents, providing a process for electric companies to request support from other electric companies that have not been affected by major outage events.[5]

The American Public Power Association (APPA), together with state and regional public power utilities and organizations, coordinate the mutual aid network for the nation's public power utilities. These utilities have local, state, and regional contracts and agreements for mutual aid, and there is a national mutual aid agreement with over 2,000 public power and rural electric cooperatives so they are able to assist one another when needed. Florida's electric cooperatives sign mutual aid agreements through the National Rural Electric Cooperatives Association (NRECA). These mutual aid agreements include more than 800 cooperatives in Florida, the Southeast, and across America.

Section 252.40, Florida Statutes, Mutual Aid Arrangements, authorizes the governing body of each political subdivision of the state, "to develop and enter into mutual aid agreements within the state for reciprocal emergency aid and assistance in case of emergencies too extensive to be dealt with unassisted." It also provides that, "[s]uch agreements shall be consistent with the state comprehensive emergency management plan and program, and in time of emergency it shall be the duty of each local emergency management agency to render assistance in accordance with the provisions of such mutual aid agreements to the fullest possible extent."

Mutual aid played a key role in restoring the power quickly after Hurricane Irma.[6] At the May 2018 workshop, all utilities stated that they received all assistance that was requested.

Prior to Hurricane Irma making landfall, many utilities made requests for mutual aid. Based on information from the state EOC, a total of 49 utilities received mutual aid. Information on the number of crew managers and crews managed, which includes both utility and mutual aid crews, was requested from utilities.

Table 4-2 illustrates the large number of crews that were managed by a limited number of experienced managers. From the 47 utilities that responded to staff's data request, the average experience level of the crew managers was 25 years. This demonstrates the level of expertise that is required to coordinate large recovery efforts, particularly in regard to mutual aid crews that are unfamiliar with local terrain, the transmission and distribution systems, and procedures specific to each utility.

Considering the large number of mutual aid crews that were brought in to assist with power restoration, the number of injuries was low and there were no fatalities. Of the total 103 injuries, 38 were reported for utility personnel and 65 were reported for mutual aid personnel.

[5] Edison Electric Institute, *Understanding the Electric Power Industry's Response and Restoration Process* (October 2016).
[6] APPA letter to U.S. House Energy & Commerce Committee, Subcommittee on Energy (November 1, 2017).

Table 4-2
Hurricane Irma – Utility Coordination, Injuries, and Fatalities

	Managers	Crews Managed	Meals	Injuries	Fatalities
IOU	48	22,398	1,409,352	76	0
Municipals	96	1,935	109,266	13	0
Cooperatives	104	3,295	171,803	14	0
Total	248	27,628	1,690,421	103	0

Impediments to Restoration

Data was collected from 39 utilities on the primary impediments that were identified for Hurricane Irma. Consistent with prior hurricanes, the biggest impediment to restoration was clearing vegetation, much of which was debris from fallen trees or branches that were outside of the utilities' rights of way.

Other impediments to restoration unique to Hurricane Irma were roadway congestion and lack of motor fuel availability due to the size and scale of evacuations. Therefore, utility crews that were tasked to aid in power restoration for various areas were delayed by some fuel shortages and traffic congestion on the roadways.

Storm Restoration Cost Recovery

Storm hardening costs (Section II), incurred to make the system less vulnerable, are covered by the base rates the utility is authorized to charge. Storm restoration costs, incurred in response to a specific storm, are addressed differently and are not covered by base rates.

Following Hurricane Andrew in 1992, which radically changed the availability and cost of commercial insurance, IOUs requested that the Commission allow for alternative risk mitigation for storm damage. The Commission considered various forms of storm cost risk mitigation for the IOUs and settled on a three part approach:

- A storm damage reserve.
- An annual storm accrual.
- A provision to seek recovery of costs that exceed the storm damage reserve balance.

Under the three-part system, cost recovery of storm related damage is typically addressed through a storm damage reserve, a surcharge, or a combination of the two.

A storm damage reserve can address the costs associated with less severe storm damage. The annual accrual spreads cost over a long period to build a reserve dedicated to storm expenses. Once the storm reserve reaches a target value, the accrual can be suspended. The reserve alleviates consumer rate shock, either by entirely absorbing the cost of lesser storm damage, or at least diminishing the cost impact of major storms that may exceed the reserve balance. When the reserve is depleted, typically it is replenished through a small amount added to customer's monthly bills.

In order to define what type of costs can be recovered, the Commission adopted Rule 25-6.0143, F.A.C., which specifies that only incremental costs – those above the normal costs that are covered by rates – can be charged to the storm reserve or recovered in a storm cost recovery proceeding. The largest incremental storm cost categories typically include repair materials, added payroll/overtime, contracted crews, travel, housing, and food.

In the event that the storm reserve is depleted from a major storm or multiple storms, or if a utility does not have a storm reserve, an IOU can request an interim storm surcharge added to customer rates for a specific period based on an estimate, pending a thorough accounting. Upon determination by the IOU, the Commission dockets the matter for a formal process to determine actual eligible costs when they are available.

Revenues collected with the interim storm charge are compared to the total actual amount of storm restoration costs determined to be eligible. Expenses that exceed what the interim charge generated are recovered in rates, or excess interim charge revenues are flowed back to customers.

Section V: Storm Hardening Performance

Analyzing infrastructure performance is inherently problematic because conditions vary widely among storms, and among different times and locations within the same storm. However, Hurricane Irma's very large footprint, which spread extreme weather conditions across multiple IOUs' service territories throughout the Florida peninsula, provided a sample that tends to offset those variables. This section focuses on Hurricane Irma outcomes.

Although the sample was large, data collection was limited due to urgency and tumultuous conditions during storm restoration. With a decade having passed since the Commission's 2006 storm order, the IOUs report they were focused on restoring service as rapidly as possible and making it infeasible to collect data during restoration. In part, the performance data had to be reconstructed after the fact, not all the contemplated data is available, and much of it is based on differing methodologies, making comparisons among utilities difficult.

The 2016-2017 experience suggests the next step is more complete and standardized data collection in future storms, which will allow a deeper analysis of the circumstances under which hardening and undergrounding are most beneficial. However, the Hurricane Irma data provides a broad performance comparison of non-hardened overhead, hardened overhead, and underground facilities.

FPL, the state's largest utility, was able to report outage rates of Irma-impacted facilities broken out by non-hardened, hardened, and underground facilities.

Table 5-1
FPL Outage Rates for Facilities Impacted by Hurricane Irma

	Transmissions	Distribution feeders	Distribution Laterals
Overhead, Non-hardened	20%	82%	24%
Overhead, Hardened	16%	69%	N/A
Underground	--- [7]	18%	4%

In addition to the reduction in number of outages shown in Table 5-1, hardening reduced the length of outages: the construction man hours to restore hardened feeders was 50 percent less than non-hardened feeders, primarily due to hardened feeders experiencing less damage than non-hardened feeders.[8]

[7] No underground section was damaged or failed causing an outage; however, the sections were out due to line termination equipment in substations.
[8] Document No. 04232-2018, FPL's Third Supplemental Amended Response to Staff's First Data Request No. 29

Supporting data for Table 5-1 is contained in Appendix G. The results showed, across FPL's system, that hardening overhead lines resulted in fewer outages and underground lines suffered minimal outages.

Hardening overhead facilities also resulted in lower rates of pole failure, and failure rates of underground facilities were even lower, across all three of Florida's largest IOUs. (Gulf Power Company's territory was not materially affected by Hurricane Irma, and FPUC's territory would provide a very small data sample.) Very few transmission structures failed as a majority of damaged facilities were related to the utilities' distribution systems. The data reflecting infrastructure performance is contained in Appendix H.

It should be noted that while underground facilities fared particularly well during Hurricane Irma, they also can be susceptible to damage caused by uprooted trees and flooding. Repairs to such facilities typically take longer to complete.

Forensic Analysis

As part of their storm hardening plans, as required by the 2006 order, IOUs conduct post-storm forensic analyses which review storm-related data and assess damaged facilities that did not perform as designed. Following a review of the storm damage data, which typically takes several months, a report is issued outlining the findings of the review.

For Hurricane Irma, FPL, DEF, and TECO completed a forensic analysis to evaluate the performance of their facilities during the storm.[9] GPC and FPUC indicated that forensic analyses were not completed due to a lack of significant damage or determined that all damage was caused by vegetation.

DEF provided five forensic analysis reports related to failures of wooden distribution poles, wooden transmission poles, and a transmission tower. In the forensic report on the steel transmission tower that fell during Hurricane Irma, the failure was identified as corrosion at the base of the tower. DEF's forensic reports also identified 27 wooden transmission pole failures due to high winds, with wood rot contributing to some of the failures. FPL provided a post-storm forensic review for Hurricane Irma, which identified five wooden transmission pole failures. TECO's forensic analysis identified three leaning structures following Hurricane Irma, and at the May 2018 workshop, TECO reported that it had ten transmission structure failures.

[9] Forensic analysis reports for FPL see Document No.03152-2018; for DEF see Document No. 00416-2018; for TECO see Document No. 01051-2018.

Section VI: Customer Communication

Public preparedness is critical during natural disasters. The utilities and the Commission provide information to consumers regarding storm preparedness, such as hurricane survival kits, portable generator safety, and ways to prepare a home before a storm.

Following a storm, customers are provided various methods to communicate with utilities. Customers can report a power outage to the utility through various means such as interactive voice response systems, customer call centers, the utility's website, mobile applications, and the PSC.

Communication issues were a notable source of customer dissatisfaction during Hurricane Irma. Customers particularly complained of inaccurate restoration projections and unavailability of overwhelmed utility websites and apps.

A total of 41 utilities provided data on the number of customer representatives that were utilized during Hurricanes Hermine, Matthew, Irma, and Nate. This information is summarized in Table 6-1, which includes third-party representatives.

Table 6-1
Total Number of Utility and Third-Party Customer Contact Representatives

	Hermine	Matthew	Irma	Nate
IOUs	948	1,825	2,418	106
Municipals	300	571	1,059	48
Cooperatives	163	84	297	6
Total	1,411	2,480	3,774	160

Source: Utilities' responses to staff's first data request, No. 14.

Table 6-2 provides the number of customer contacts for Hurricanes Hermine, Matthew, Irma, and Nate. Customer contacts may include various forms of communication, including phone, email, mobile application, utility website, and social media.

Table 6-2
Total Customer Contacts

	Hermine	Matthew	Irma	Nate
IOUs	395,358	3,605,174	11,424,246	30,545
Municipals	71,302	414,202	1,634,438	0
Cooperatives	53,804	12,053	207,488	343
Total	520,464	4,031,429	13,266,172	30,888

Source: Utilities' responses to staff's first data request, No. 15.

Table 6-3 provides the average number of customer contacts that were handled by each utility and third-party customer contact representatives. For Hurricane Irma, an average number of 2,513 customer contacts per representative, which demonstrates the large scale of communication that occurred between customers and the electric utilities.

Table 6-3
Average Number of Customer Contacts per Utility Representative[10]

	Hermine	Matthew	Irma	Nate
IOUs	628	1,776	2,513	332
Municipals	138	774	1,061	0
Cooperatives	439	84	796	57

Source: Utilities' responses to staff's first data request, Nos. 14 and 15.

Public Comments to the PSC

Following the establishment of Docket No. 20170215-EU, a customer portal was opened on the Commission's website on October 9, 2017, allowing customers to submit comments regarding their reaction to utility restoration/communication efforts.

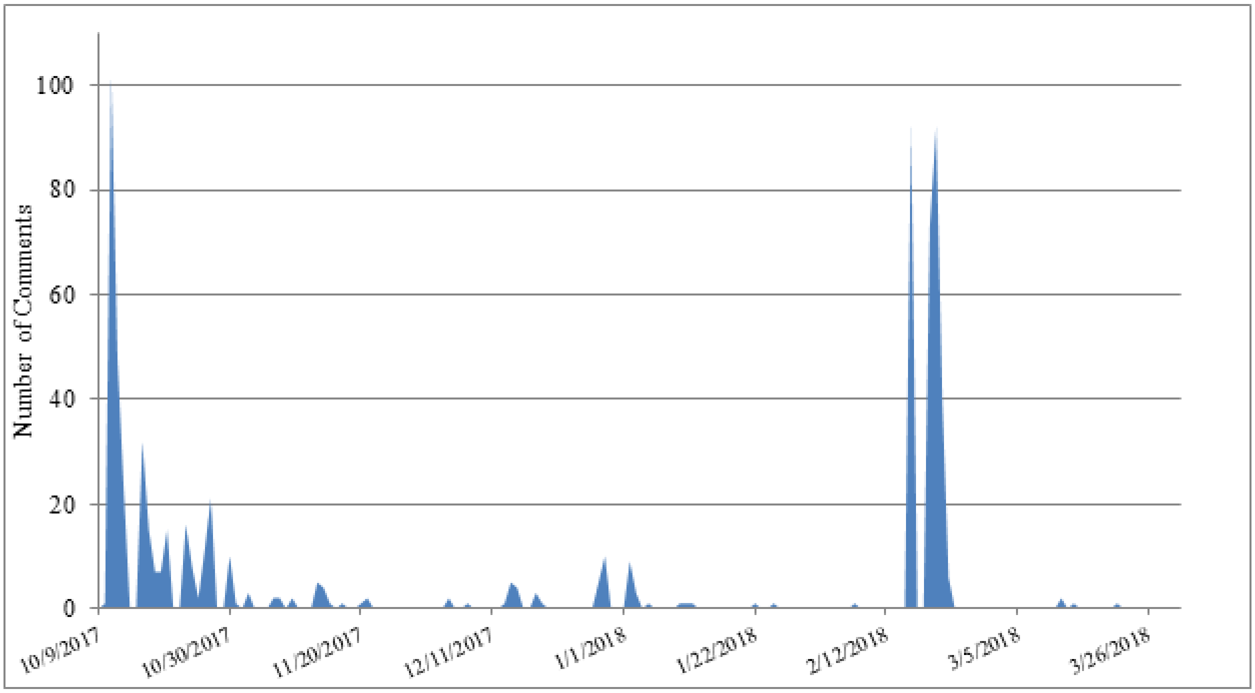
The portal provided consumers four categories to select from, as well as the option to submit written comments, where consumers could address any specific concerns. The four categories that consumers could select from were:

- Power restoration time.
- Information provided by electric utility provider prior to the storm.
- Information provided by electric utility provider after the storm.
- Other.

[10] It should be noted that this average includes only utilities that were affected by a storm.

Figure 6-1 provides a timeline of the number of comments received through the PSC Consumer Comment Portal.

Figure 6-1
PSC Portal – Timeline of Consumer Comments Received



Source: PSC Consumer Comment Portal

For the month of October the PSC received 319 comments, which mostly related to consumers' experiences and feedback during Hurricane Irma. Comments focused on frustration with timely communication, inaccurate estimated restoration times, and tree trimming.

Comments decreased after October 2017, but there was a small swell of comments from December 28, 2017, to January 12, 2018. Comments during this period expressed concerns about the potential addition of a surcharge to customer bills as a result of the hurricane.

From February 16 to February 22, 2018, a total of 303 comments were received, which were predominantly focused on supporting and encouraging the use of distributed solar generation. The portal was closed on May 1, 2018, with a total of 701 public comments received.

Staff collected and sorted the comments by category and divided them into subcategories based on whether the comment was negative, positive, or neutral. Table 6-4 provides a summary of the comments that were received.

Table 6-4
PSC Portal – Customer Comments

Category	Comments
Power Restoration Time	345
Information Provided Prior to the Storm	14
Information Provided After the Storm	69
Other	273
Total	701
Positive vs. Negative Comments	
Negative Comments on Electric Utility	346
Positive Comments on Electric Utility	74
Not Expressed	281
Total	701

Source: PSC Consumer Comments Portal

Table 6-5 provides the number of comments received for IOUs, Municipals and Cooperatives. Two of the customer comments did not provide the names of their electric utilities.

Table 6-5
PSC Portal – Customer Comments by Utility Type

Utility Type	Comments
Investor Owned Electric Utility	616
Municipal Electric Utility	48
Cooperative Electric Utility	35
Not Specified	2
Total	701

Source: PSC Consumer Comments Portal

The most prevalent topics were related to supporting and encouraging the use of roof-top or distributed solar generation, cost responsibility for restoration, frustration with communication, tree trimming, and effectiveness of storm hardening.

Table 6-6 provides the number of comments that were received for each of these topics.

Table 6-6
PSC Portal – Most Prevalent Topics Discussed in Customer Comments

Subcategory	Comments	Percent of Total
Support and encouragement of solar	258	37%
Cost responsibility for restoration	105	15%
Frustration with timely communications	84	12%
Tree trimming	73	10%
Effectiveness of hardening	60	9%

Stakeholder Comments to the PSC

In addition to comments from utilities and customers, staff also solicited comments from non-utility stakeholders, which included Associated Industries of Florida, the Florida Chamber of Commerce, Florida Association of Counties, and Florida League of Cities. Appendix A provides a summary of the stakeholder comments that the Commission received. A total of 14 stakeholders provided comments on the topics of vegetation management, undergrounding, and coordination and communications. Aside from the suggested areas of improvement mentioned below, the overall comments that stakeholders provided were positive.

Regarding vegetation management, the comments mainly focused on improving communication between stakeholders and utilities on where and when tree trimming occurs, as well as better educating the public on tree trimming. While the comments on undergrounding varied, many voiced a positive position on undergrounding, though stakeholders expressed differences in opinion on cost responsibility. Last, the comments on coordination and communication largely concentrated on more involvement from utilities at local EOCs, in addition to improving post-event information and power restoration time estimates.

Section VII: Commission Actions

Preparedness and Restoration

No amount of preparation can eliminate outages in extreme weather events. Throughout the year, utilities participate in hurricane exercises and drills in order to better prepare for a storm event. Prior to hurricane season, utilities ensure that they have the required internal materials on hand, as well as commitments for external resources which may be needed following a storm. Utilities also partake in hurricane preparedness exercises. Preparedness and restoration efforts appear consistent across the different utility entities. All utilities have similar staging, damage assessment, and workload management processes. Data collected after the storms show the causes of outages were consistent across utilities.

Utilities reported that they have regular meetings with local governments regarding vegetation management and identification of critical facilities (i.e., hospitals, water and wastewater treatment plants, and fire stations). However, the utilities, local government representatives, and the Office of Public Counsel agreed that communication among all affected parties could be improved. Counties should continue to take the lead in identifying critical facilities for priority restoration and utilities should work with the counties to provide information and expertise. Restoration priority lists should be based on community priorities balanced with the practical realities of restoration. During the May 2018 workshop, some local government representatives expressed a desire for additional utility staffing at local emergency operations centers.

Action: Commission staff should collect additional details regarding meetings with local governments regarding vegetation management, identification of critical facilities, and utility staffing practices at local EOCs as part of the Commission's review of utility storm hardening plans.

The Commission has been careful to balance the need to strengthen the state's electric infrastructure to minimize storm damage, reduce outages, and reduce restoration time while mitigating excessive cost increases to electric customers. Approval of an IOUs storm hardening plan does not equate to approval for cost recovery. During a general rate case, the costs for storm hardening are taken into consideration and the utility has the burden of proof to show that the costs are prudent for cost recovery. In order to enhance the review process related to storm hardening activities, a comparison of all viable alternatives considered by the IOUs before selecting proposed hardening projects would ensure that storm hardening is being pursued in a cost-efficient manner. For example, a utility should be able to explain why a proposed underground project is preferable to a hardened overhead project or additional smart grid investment, etc.

Action: Commission staff should collect information on all viable alternatives considered before selecting a particular storm hardening project as part of the Commission's review of utility storm hardening plans.

Distribution Infrastructure

While granular data appeared to be somewhat lacking due to a focus on restoration, Florida's aggressive hardening programs are working, as fewer poles were replaced and the length of outages was reduced markedly compared to the 2004-2005 storm seasons. The IOUs affirmed that the hardened facilities, including poles, performed better than non-hardened facilities. The Commission's required eight-year wooden pole inspection program resulted in proactive replacement of poles before outages occurred. Based on the wooden pole replacement data provided by the IOUs, as well as the post-storm review, there were fewer broken poles due to non-vegetation causes than with prior storms.

Action: Commission staff should explore the collection of more uniform performance data for hardened vs. non-hardened and underground facilities, including sampling data where appropriate, as part of the Commission's review of utility storm hardening plans.

Some IOUs suggested legislation to require inspections and hardening of non-electric utility distribution poles, which includes poles owned and maintained by telecommunications providers. In 2006, the Commission required Florida's local exchange telecommunications companies to implement an eight-year inspection cycle of their wooden poles. The Commission's authority to impose that requirement was pursuant to Section 364.15, F.S., which was subsequently repealed in 2011. Thus, the Commission no longer has the authority to require inspections of poles owned by telecommunications companies.

Action: Commission staff should seek additional information on the impact of non-electric utility poles on storm recovery as part of the Commission's review of utility storm hardening plans.

Legislative Consideration: The Legislature may consider possible legislation to require inspection and hardening of non-electric utility poles.

Undergrounding

The data collected showed that underground lines suffered minimal outages during storms. It should be noted that while underground facilities fared particularly well during Hurricane Irma, they also are susceptible to damage, causing outages. The damage to underground lines may be caused by uprooted trees and flooding, and the repairs to such facilities typically take longer to complete. Under current pricing policies, approximately 40 percent of all distribution lines are underground and the majority of recent underground projects were for new construction, rather than the conversion of overhead to underground. In an effort to further the deployment of underground facilities, DEF and FPL have initiated targeted undergrounding programs over the next few years. Both programs are scheduled to begin in 2018, focus on historically poor performing lateral circuits to replace several hundred miles of overhead lines, and are being funded through current base rates including any previously approved step increases. The goal for each program is to test different construction techniques and identify different impediments to converting these targeted overhead facilities to underground.

Action: Commission staff should collect data and monitor the progress of targeted undergrounding programs as part of the annual distribution reliability review.

Transmission Infrastructure

The transmission infrastructure appears to have generally performed as designed. As part of their storm hardening plans, IOUs conduct post-storm forensic analyses which include a review of storm-related data and an assessment of damaged facilities that did not perform as designed.

Despite regular inspection requirements, post-storm forensic reports identified corrosion and/or wood rot as a contributing factor to the failure of some DEF transmission towers. Post-storm analyses provided by FPL reported five wooden transmission pole failures and TECO reported ten wooden transmission pole failures. A more thorough examination of the procedures and processes used by the IOUs for the inspection and maintenance of transmission structures may identify areas of improvement in the future.

Action: Commission staff should initiate a management audit to examine the procedures and processes used by the IOUs to inspect and maintain transmission structures.

Impediments to Restoration

In addition to the usual impediment of vegetation clearing, the majority of the utilities identified roadway congestion and procurement of fuel to be impediments to restoration during Hurricane Irma. Due to the large number of evacuations, major roadways experienced high amounts of traffic. This presented problems in allowing utility crews to reach areas where aid in power restoration was needed. Additionally, there was a shortage of fuel leading up to and following the storm which also presented an impediment to utilities' restoration efforts.

Action: Commission staff should collect information on how each IOU prepares for and responds to roadway congestion, fuel availability, and lodging accommodation issues as part of the Commission's review of utility storm hardening plans.

Legislative Consideration: The Legislature may consider implementation of emergency procedures regarding roadway congestion, motor fuel availability, and lodging accommodations for mutual aid personnel.

Vegetation Management Coordination

Proactive tree trimming has been a key initiative of the Commission. Each year, IOUs trim a certain percentage of their total lateral and feeder miles as part of their hardening plans. However, the trees trimmed only include those that are in the utilities' rights of way. Utilities identified that a major contributor to outages continues to be vegetation outside of the utilities' rights of way. Therefore, more frequent tree trimming by utilities within rights of way would not alleviate this outage cause. Tree trimming outside of a utility's rights of way requires coordination and cooperation with local government and customers.

As mentioned above, Commission staff should gather additional details regarding the utilities' coordination with local governments as part of the Commission's review of utility storm hardening plans. In addition, the Commission suggests the following for consideration by the Legislature.

<u>Legislative Considerations</u>: Revision of vegetation management policies to improve the ability of electric utilities to conduct vegetation management outside of rights of way to reduce outages and restoration costs.

<u>Legislative Considerations</u>: Enhance statewide public education regarding tree trimming and problem tree placement and removal on private property. This program could be similar to a Right Tree, Right Place initiative already used by several utilities.

Post-storm Communication

Despite substantial, well documented improvement to the utilities' infrastructure, some customers who provided comments were dissatisfied with the extent of outages and restoration times associated with Hurricane Irma. Post storm communication with customers was not an impediment to power restoration, yet many customers expressed dissatisfaction with the information provided by utilities following Hurricane Irma. In particular, customers voiced frustrations with inaccurate power restoration estimates and cost responsibility for restoration.

<u>Action</u>: Commission staff should initiate a management audit to examine the procedures and processes used by the IOUs to estimate and disseminate outage restoration times following a major storm.

Appendix A
Summary of Stakeholder Comments

Date	Stakeholder	Summary of Comments
01/26/2018	City of Homestead	Regarding coordination on vegetation management, the majority of FPL's power lines are underground, but it should focus on the local level. City ordinances require new construction be underground. Stated that communication with the utility is good, but would like to see more "granular, city-specific" information and outage status.
01/29/2018	City of St. Petersburg Fire Rescue	Suggested continuing aggressive tree trimming program. Continue to support annual pre-storm meetings at city level, and DEF should provide representative to city's EOC. As well as develop a system to report downed lines and assure downed power lines are safe for city crews to work on. Difficult to establish reliable line to communicate with DEF.
01/30/2018	City of Boca Raton	Very little communication from FPL. FPL should make contact with City 48 hours before storm, implement distribution and street light GPS program, have FPL liaison at City or trained staff, and interactive map that provides updates.
02/01/2018	City of South Daytona	Suggested that tree trimming is too infrequent. FPL has tried to inform public of tree trimming, but no way for city/customers to submit tree trimming requests. More information to public about planting vegetation near power lines. For undergrounding, suggested removing requirement to bury additional conduit for future growth. Yearly review of critical infrastructure should be required, and not enough accurate/fast information available during Irma. More representatives to communicate information.
02/06/2018	City of Naples Fire-Rescue Department	FPL is doing well with tree trimming, but more information should be provided to the public about property rights. Good communication with FPL, but improvement on the removal of problem trees should be made. New construction policy requires electrical line to be underground, and there should be communication with FPL on connection. Critical infrastructure was not previously identified to FPL, but this should be done in the future. Great communication at the EOC level.
02/07/2018	City of Dunedin	Utility should remove trees/palms listed on Florida Exotic Pest Plant Council list, and use proper trimming techniques. Utility should provide notice of when and where trimming will occur, and issue information on proper plants below power lines. Ordinance requires new construction to be underground, but it would be helpful to establish metrics for where conversion to underground should occur. There were challenges with extent of the outages, response times, and communication during restoration with DEF. Suggested that representatives are provided to local EOCs.
02/09/2018	Town of Belleair	Would like to see area risk assessments from DEF and consistent tree trimming. More proactive communication from DEF of when they will be in an area, what they are planning, and what work was completed. Suggested having an area administrator or a single point-of-contact. DEF should provide a more active role in undergrounding, and a set amount of area that is set up for undergrounding. More proactive communication on critical facilities and better information on restoration (DEF did not meet set restoration deadline).

Date	Stakeholder	Summary of Comments
02/12/2018	St. Johns County	Suggested enacting a program for local and state agencies to notify utilities of problem trees and vegetation areas. Currently have policy/practice in place for new construction, which is to require undergrounding. FPL is implementing county wide hardening projects, which is a much cheaper alternative than undergrounding. Communication between county and utility is critical for new projects to discuss subjects such as cost sharing. Currently good communication and coordination with both FPL and JEA at EOC.
02/15/2018	City of Wilton Manors	There should be an aggressive, proactive schedule for tree trimming and notification of when/where trimming is occurring. FPL should devise a plan to transition overhead to underground, and complete a cost benefits analysis. City should have a part in the process of updating and maintaining a list of critical facilities, and communication could be improved. Also, there was no way for the city to report outages to FPL, so there should be more technology resources for tracking restoration efforts.
02/19/2018	City of Monticello	Suggested no change to vegetation management as the city does not believe it was a contributing factor to outages. However, the staging of repair equipment prior to storm by DEF could be improved. Action by legislature and/or PSC for promoting undergrounding (ex. possible monetary incentives from the state). Suggested continued improvements with local DEF representative, and more accurate post storm information.
02/19/2018	Citrus County Public Works	Suggested providing notifications to utility if tree trimming or removal is needed, and facilitating undergrounding with County ordinances and state statues. More proactive interaction at EOC prior to, during, and after storm event.
02/20/2018	City of Rockledge	Suggested implementing a survey to list potential trimming or tree removal, and joint meetings on potential problem areas. For undergrounding, explore shared costs by grant funding. Communication of real time events was lacking; therefore, utility representative(s) should have contact with field representatives and management for plan of action. It would be beneficial to have a representative in each Brevard County EOC.
02/21/2018	City of Sarasota	Currently have close coordination with FPL on vegetation management, and should continue to have utility review and comment on ordinances and code changes. Suggested providing incentives for undergrounding. Potential problems may arise due to limited spots on priority list; therefore, criteria should be established to prioritize critical facilities. Suggested having designated FPL crew for the city to remove their power lines, so the city crews can make repairs to infrastructure.
02/22/2018	Marion County Utilities	Suggested that each electric utility should have a website with a critical infrastructure list, dedicated outage phone number for critical facilities (rather than consumer outage phone number), and better communication with all utilities to address issues.

Appendix B
Peak Number of Account Outages

	Hermine		Matthew		Irma		Nate	
	Peak Accounts Out	% of Accounts Out	Peak Accounts Out	% Accounts Out	Peak Accounts Out	% Accounts Out	Peak Accounts Out	% Accounts Out
Alachua	30,065	24 9%	5,796	4 8%	68,557	52 7%	2	0 0%
Baker	3,810	34 4%	4,527	40 8%	10,731	94 4%	0	0 0%
Bay	116	0 1%	18	0 0%	3,533	3 1%	388	0 3%
Bradford	2,285	23 3%	4,757	48 5%	12,010	94 9%	0	0 0%
Brevard	2,921	1 0%	196,729	64 6%	268,343	86 4%	0	0 0%
Broward	420	0 0%	12,340	1 3%	709,360	76 0%	0	0 0%
Calhoun	0	0 0%	0	0 0%	1,018	25 9%	0	0 0%
Charlotte	200	0 2%	220	0 2%	73,230	63 7%	0	0 0%
Citrus	15,375	16 0%	1,317	1 4%	69,269	79 0%	0	0 0%
Clay	6,000	4 2%	33,965	23 5%	74,424	78 5%	0	0 0%
Collier	110	0 0%	400	0 2%	236,141	96 0%	0	0 0%
Columbia	9,605	29 7%	2,953	9 1%	30,734	92 1%	0	0 0%
Desoto	10	0 1%	10	0 1%	15,627	88 9%	0	0 0%
Dixie	4,853	48 8%	290	2 9%	7,540	75 3%	0	0 0%
Duval	8,500	2 1%	253,725	61 5%	257,261	57 2%	0	0 0%
Escambia	27	0 0%	0	0 0%	1,421	0 9%	5,384	3 4%
Flagler	370	0 7%	57,016	100 0%	52,746	90 9%	0	0 0%
Franklin	2,264	22 5%	172	1 7%	5,869	57 5%	0	0 0%
Gadsden	9,747	44 0%	0	0 0%	14,998	67 2%	0	0 0%
Gilchrist	5,370	61 2%	590	6 7%	7,029	79 0%	0	0 0%
Glades	0	0 0%	10	0 1%	6,272	86 5%	0	0 0%
Gulf	540	5 0%	83	0 8%	4,198	38 5%	0	0 0%
Hamilton	5,864	87 9%	255	3 8%	5,249	78 2%	0	0 0%
Hardee	0	0 0%	26	0 2%	11,976	97 4%	0	0 0%
Hendry	10	0 1%	10	0 1%	18,750	100 0%	0	0 0%
Hernando	5,514	6 1%	117	0 1%	58,644	61 8%	0	0 0%
Highlands	128	0 2%	472	0 8%	62,010	99 3%	0	0 0%
Hillsborough	17,956	2 8%	262	0 0%	265,542	42 0%	0	0 0%
Holmes	0	0 0%	0	0 0%	1,254	12 0%	77	0 7%
Indian River	60	0 1%	59,244	67 2%	73,311	80 1%	0	0 0%
Jackson	0	0 0%	0	0 0%	11,092	42 4%	0	0 0%
Jefferson	5,762	71 5%	107	1 3%	6,092	75 1%	0	0 0%
Lafayette	2,965	71 5%	199	4 8%	3,676	90 9%	0	0 0%
Lake	1,699	1 0%	16,849	10 0%	123,954	69 7%	0	0 0%
Lee	50	0 0%	400	0 1%	361,999	82 5%	0	0 0%
Leon	94,088	65 6%	2	0 0%	59,821	42 2%	0	0 0%
Levy	10,007	41 2%	254	1 0%	17,932	72 6%	0	0 0%
Liberty	438	13 5%	0	0 0%	3,303	81 2%	0	0 0%
Madison	7,278	69 0%	69	0 7%	7,171	67 0%	0	0 0%
Manatee	2,290	1 1%	113	0 1%	132,455	63 1%	0	0 0%
Marion	11,525	6 3%	27,389	14 9%	143,485	75 9%	0	0 0%
Martin	40	0 0%	44,600	48 1%	76,120	81 5%	0	0 0%
Miami-Dade	400	0 0%	16,850	1 5%	919,340	80 9%	0	0 0%
Monroe	0	0 0%	0	0 0%	52,855	84 4%	0	0 0%
Nassau	3,052	11 1%	19,092	43 5%	43,740	97 6%	0	0 0%
Okaloosa	2	0 0%	45	0 0%	323	0 3%	6,382	5 9%
Okeechobee	100	0 5%	1,680	7 7%	21,990	96 5%	0	0 0%
Orange	685	0 1%	69,231	12 3%	362,088	62 4%	0	0 0%
Osceola	306	0 2%	7,321	5 7%	55,352	36 2%	0	0 0%
Palm Beach	30	0 0%	58,870	7 7%	566,250	73 8%	0	0 0%
Pasco	10,213	3 9%	472	0 2%	190,567	70 6%	0	0 0%
Pinellas	24,179	4 4%	1,111	0 2%	434,037	78 6%	0	0 0%
Polk	535	0 2%	1,306	0 4%	216,839	65 6%	0	0 0%
Putnam	1,011	2 5%	27,393	66 8%	36,634	88 8%	0	0 0%
Santa Rosa	0	0 0%	0	0 0%	259	0 3%	1,712	2 2%
Sarasota	3,570	1 4%	280	0 1%	174,672	66 2%	0	0 0%
Seminole	184	0 1%	68,597	33 1%	158,065	75 1%	0	0 0%
St Johns	1,140	1 3%	78,610	89 6%	107,130	81 9%	0	0 0%
St Lucie	150	0 1%	57,477	38 3%	113,280	73 6%	0	0 0%
Sumter	2,643	3 9%	1,307	1 9%	28,598	38 9%	0	0 0%
Suwannee	11,493	52 9%	1,300	6 0%	20,991	92 2%	0	0 0%
Taylor	8,742	67 9%	138	1 1%	9,665	74 8%	0	0 0%
Union	990	19 0%	920	17 7%	4,695	86 3%	0	0 0%
Volusia	635	0 2%	257,718	92 0%	222,328	77 6%	0	0 0%
Wakulla	14,009	93 0%	153	1 0%	11,513	74 5%	1	0 0%
Walton	3	0 0%	0	0 0%	139	0 2%	613	1 0%
Washington	0	0 0%	0	0 0%	605	4 6%	29	0 2%
Totals	323,505	3 2%	1 13M	11 0%	6 52M	62 1%	13,539	0 1%

Source: State EOC power outage reports.

Appendix C
Utility Reported Weather Data - Hurricane Hermine

County	Maximum Sustained Wind (MPH)	Maximum Gusts (MPH)	Maximum Rainfall (inches)	Maximum Storm Surge (Feet)
Alachua	34	52	4.85	-
Baker	32	50	-	-
Bay	35	69	2	-
Bradford	32	50	-	-
Brevard	26	39	-	-
Broward	19	29	-	-
Calhoun	30	64	-	-
Charlotte	30	45	4.47	-
Clay	39	60	2.02	0.73
Collier	25	38	-	-
Columbia	34	52	-	-
Desoto	24	36	-	-
Dixie	-	48	-	7.3
Duval	41	61	2.53	1.4
Flagler	34	51	-	-
Franklin	-	58	4.41	-
Gadsden	60	64	4	-
Glades	20	30	-	-
Gulf	-	79	-	-
Hamilton	-	-	3.15	-
Hardee	24	36	-	-
Hendry	21	31	-	-
Highlands	21	31	3.28	-
Hillsborough	36.8	57.5	7	4.2
Indian River	21	32	-	-
Jackson	30	64	-	-
Jefferson	75	90	7	6.1
Lafayette	-	-	6.1	-
Lee	29	43	1.49	-
Leon	60	70	6	-
Levy	-	-	-	6.2
Liberty	30	64	-	-
Madison	65	80	7	-
Manatee	38	57	10	-
Marion	33	45	6.18	-
Martin	21	32	-	-
Miami-Dade	21	32	-	-
Monroe	29	44	-	-
Nassau	37	64	-	-
Okeechobee	20	29	-	-
Orange	25	37	3.5	-
Osceola	22	34	3.25	-
Palm Beach	21	32	-	-
Polk	29.9	41.4	-	-
Putnam	36	55	-	-
Sarasota	35	53	10.71	-
Seminole	24	37	-	-
St. Johns	39	60	0.84	0.61
St. Lucie	21	32	-	-
Sumter	-	-	3.27	-
Suwannee	41	62	4.52	-
Taylor	75	90	7	8.6
Union	32	48	-	-
Volusia	32	49	-	-
Wakulla	65	75	5.81	6.3

Source: Utilities’ responses to staff’s first data request, No. 27.

Appendix D
Utility Reported Weather Data - Hurricane Matthew

County	Maximum Sustained Wind (MPH)	Maximum Gusts (MPH)	Maximum Rainfall (inches)	Maximum Storm Surge (Feet)
Alachua	35	60	1.49	-
Baker	30	46	-	-
Bradford	40	65	6	-
Brevard	80	121	17.01	4.09
Broward	39	60	1.61	-
Calhoun	39	87	7	-
Charlotte	26	39	-	-
Clay	44	68	10.3	3.77
Collier	26	40	-	-
Columbia	26	40	-	-
Desoto	20	30	-	-
Duval	61	88	9.63	4.69
Flagler	68	102	6	6
Glades	30	45	-	-
Hardee	23	34	-	-
Hendry	30	42	-	-
Highlands	29	43	-	-
Indian River	64	97	13.85	-
Jackson	39	87	7	-
Lake	31	48	5.22	-
Lee	26	40	-	-
Leon	23	30	-	-
Liberty	39	87	7	-
Manatee	30	45	-	-
Marion	23	39	3	-
Martin	61	92	4.18	-
Miami-Dade	31	48	-	-
Monroe	30	46	-	-
Nassau	45	87	7	7
Okeechobee	34	50	-	-
Orange	48	73	6.17	-
Osceola	49	69	0.03	-
Palm Beach	49	75	-	-
Pinellas	24.2	40.3	-	-
Polk	36	44	-	-
Putnam	48	74	-	-
Sarasota	29	43	-	-
Seminole	47	72	8.99	-
St. Johns	73	109	9.97	8 39
St. Lucie	71	100	13.85	-
Suwannee	24	37	-	-
Union	29	45	-	-
Volusia	72	109	7.75	-

Source: Utilities' responses to staff's first data request, No. 27.

Appendix E
Utility Reported Weather Data - Hurricane Irma

County	Maximum Sustained Wind (MPH)	Maximum Gusts (MPH)	Maximum Rainfall (inches)	Maximum Storm Surge (Feet)
Alachua	64	99	13 07	-
Baker	65	100	9 76	-
Bay	34	46	1 5	-
Bradford	62	96	15	-
Brevard	75	114	13 74	4 2
Broward	83	127	9 72	2 7
Calhoun	50	71	12	-
Charlotte	70	104	-	4
Citrus	-	64	10 65	-
Clay	73	112	11 32	5 97
Collier	115	144	14 98	6 5
Columbia	62	95	9 63	-
Desoto	77	100	-	-
Dixie	-	56	-	-
Duval	89	136	11 11	6 44
Escambia	30	42 6	0 25	-
Flagler	64	97	9 83	4 19
Franklin	-	50	-	-
Gadsden	50	55	2	-
Gilchrist	-	-	6 68	-
Glades	71	106	8 38	-
Gulf	-	45	1	-
Hamilton	-	-	-	-
Hardee	100	111	12	-
Hendry	80	102	10 31	-
Hernando	-	-	7 67	-
Highlands	70	103	10 95	-
Hillsborough	56	68	16 08	3 1
Holmes	23	37	2	-
Indian River	75	116	14 15	3
Jackson	50	71	12	-
Jefferson	-	60	3	-
Lake	43	69	11 59	-
Lee	72	110	9 02	6
Leon	43	55	2	-
Levy	-	55	8 07	-
Liberty	50	71	12	-
Madison	-	62	4	-
Manatee	80	122	-	-
Marion	-	51	13 24	-
Martin	79	119	10 53	-
Miami-Dade	85	127	8	6
Monroe	120	160	12 54	8
Nassau	89	135	12 7	7 8
Okaloosa	27 7	42 5	1	-
Okeechobee	72	107	-	-
Orange	71	110	12 36	-
Osceola	70	108	10 61	-
Palm Beach	85	127	10 35	2 7
Pasco	-	55	9 83	-
Pinellas	49 4	88	5 6	2 17
Polk	115	130	11 1	-
Putnam	59	91	-	3 6
Santa Rosa	28 9	40 3	0 75	-
Sarasota	72	108	8	-
Seminole	66	101	12 14	-
St Johns	79	121	10 22	5 61
St Lucie	84	127	21 66	-
Sumter	70	75	11 3	-
Suwannee	58	88	-	-
Taylor	-	48	4	1
Union	62	95	-	-
Volusia	78	116	12 55	-
Wakulla	35	56	2	0 7
Walton	25 3	33	1 5	-
Washington	10	27	2	-

Source: Utilities' responses to staff's first data request, No. 27.

Appendix F
Utility Reported Weather Data - Hurricane Nate

	Maximum Sustained Wind (MPH)	Maximum Gusts (MPH)	Maximum Rainfall (inches)	Maximum Storm Surge (Feet)
County	Max	Max	Max	Max
Bay	38	50	2	-
Escambia	50	85	5	5
Franklin	29	37	0.18	4
Gulf	25	34	0.2	3
Holmes	-	-	2	-
Jackson	25.3	33.4	0.75	-
Leon	25	31	0.52	-
Okaloosa	45	65	10	-
Santa Rosa	52	85	8	5
Walton	40	60	4	-
Washington	8	17	2	-

Source: Utilities’ responses to staff’s first data request, No. 27.

Appendix G
FPL Outage Data - Hurricane Irma

FPL's Feeder and Lateral Outage Performance for Hurricane Irma

Irma - 2017	Overhead Non-Hardened			Overhead Hardened			Underground			Total		
	Out	Pop	% Out	Out	Pop	% Out	Out	Pop	% Out	Out	Pop	% Out
Distribution Feeders	1,609	1,958	82%	592	859	69%	85	470	18%	2,286	3,287	70%
Distribution Laterals	20,341	84,574	24%	N.A.	N.A.	N.A.	3,767	103,384	4%	24,108	187,958	13%

Pop = Population; Lateral population includes laterals with multi-stage fusing
Source: FPL's second supplemental amended response to staff's first data request No. 29.

FPL's Substation Line Section Outage Performance for Hurricane Irma

Irma - 2017	Overhead Non-Hardened			Overhead Hardened			Underground			Total		
	Out	Pop	% Out	Out	Pop	% Out	Out	Pop	% Out	Out	Pop	% Out
Trans. Line Section	60	306	20%	142*	884	16%	13**	51	25%	215	1,241	17%

* 4 sections were out because substations were proactively de-energized due to flooding.
** No underground section was damaged or failed causing an outage; however, the sections were out due to line termination equipment in substations.
Source: FPL's second supplemental amended response to staff's first data request No. 29.

Appendix H
Utility Reported Repairs- Hurricane Irma

FPL
Overhead vs. Underground – Repairs per Pole Line Mile for Hurricane Irma

	Underground Total	Underground Replaced/Repaired	Overhead Total	Overhead Replaced/Repaired
Transmission	105	0	6,857	0.1
Distribution	25,818	12.5	42,301	443
Feeder	3,830	0.5	12,850	48
Lateral	17,921	1	22,788	148

Notes:
All figures above are provided in pole line miles instead of repairs per mile.

While FPL does not track or maintain its records in the manner requested, it has estimated the amount of pole line miles replaced/repaired using certain assumptions and preliminary information available at this time. Repaired/replaced information is preliminary, as Hurricane Irma follow-up work and final accounting are still ongoing.

Source: Document No. 03308-2018 filed 4/30/18.

FPL
Hardened vs. Non-hardened – Pole/Tower Repairs for Hurricane Irma

	Hardened Overhead Total	Hardened Overhead Replaced/Repaired	Non-hardened Overhead Total	Non-hardened Overhead Replaced/Repaired
Transmission	60,694	0	5,991	5[(2)]
Distribution	124,518[(1)]	26[(2)]	1,063,684[(3)]	2,834[(2)]

Note: Hardened pole for Transmission = concrete/steel pole; Hardened pole for Distribution = poles replaced as a result of FPL's approved hardening projects (Extreme wind loading thresholds – 105 mph in the north central region; 130 in north, east, and west coastal and central regions; and 145 mph in southern region).

[(1)] Includes only distribution feeder poles hardened as a result of FPL's approved hardening plan projects. Additional poles currently installed may meet FPL's EWL hardening criteria or are otherwise hardened relative to NESC minimum requirements but are not included as "hardened" in the above table. For example, the total for Hardened OH excludes other feeder/lateral poles installed since 2007 that meet FPL's current stronger construction standards (in place since 2007) for new construction (e.g., new feeders or laterals) and/or daily work activities (e.g., maintenance, pole line extensions and relocation projects).

[(2)] Poles that failed (i.e., had to be repaired/replaced during restoration in order to restore service).

[(3)] Includes all remaining distribution poles (i.e., all poles not counted in the 124,518 poles installed as a result of FPL's approved hardening plan projects). Distribution poles installed pre-2007 meet Grade B construction, while poles installed in 2007 or later meet FPL's new stronger construction standards and may also meet extreme wind loading thresholds.

Source: Document No. 03308-2018 filed 4/30/18.

DEF
Overhead vs. Underground – Repairs per Circuit Mile for Hurricane Irma

	Underground Total	Underground Replaced/Repaired	Overhead Total	Overhead Replaced/Repaired
Transmission	69.83*	0	5139.32*	0
Distribution	14,140	4.3	17,993	324
Feeder	N/A	N/A	N/A	N/A
Lateral	N/A	N/A	N/A	N/A

*Circuit miles.

**DEF does not track repaired conductors during a major event. The information above shows the amount of conductor that was replaced during Hurricane Irma. This information is based on the material charged out during the storm; differentiating between feeder and lateral is not possible because the size of the conductor does not necessarily determine the type of circuit.

Additional information comparing the overall outage performance of overhead versus underground facilities, at the feeder and lateral level, is available on Page 13 of the PowerPoint Slide Deck provided by DEF for the Docket No. 20170215 [-EU] Workshop.

Source: Document No. 03296-2018 filed 4/27/18.

DEF
Hardened vs. Non-hardened – Pole/Tower Repairs for Hurricane Irma

	Hardened Overhead Total	Hardened* Overhead Replaced/Repaired	Non-hardened Overhead Total	Non-hardened Overhead Replaced/Repaired
Transmission	29,499	0	21,285	139 wood poles**
Transmission Towers	1,095 (replaced/rebuilt)	0	2,340 (replaced/rebuilt)	3 towers
Distribution***	N/A	N/A	N/A	N/A

*DEF defines hardened transmission structures as new, repaired or replaced structures since the 2006/2007 Storm Hardening Plan began. Hardened structures consist of any new structures (steel or concrete) or any previously wood structures replaced with steel or concrete materials. DEF considered steel & lattice structures in place prior to the Hardening Plan to be "non-hardened"—they were not part of the original baseline for "hardened" as they were in place prior to 2006/2007.

**DEF originally stated that 148 transmission structures were replaced; 142 structures were actually replaced/repaired and it was later determined that 6 of these structures did not need replacement.

***DEF does not record damaged poles as "hardened" or "non-hardened" during restoration activity. A total of 2,130 poles were replaced during the restoration of damage from Hurricane Irma. To better understand the nature of the storm damage on DEF's system, a forensic report was conducted on 526 randomly selected replaced poles after Hurricane Irma. The report found that none of the selected poles were part of a storm hardening project. Therefore, 29 storm hardening project areas were selected for further analysis; no broken poles were discovered in any of the selected storm hardening projects.

Source: Document No. 03296-2018 filed 4/27/18.

TECO
Overhead vs. Underground – Repairs per Mile for Hurricane Irma

	Underground Total	Underground Replaced/Repaired	Overhead Total	Overhead Replaced/Repaired
Transmission	27	0	5,307	0
Distribution	7,915	0.1	19,104	24.8
Feeder	1,629	0.1	7,008	7.3
Lateral	6,286	0	12,096	17.5

TECO
Hardened vs. Non-hardened – Pole Repairs for Hurricane Irma

	Hardened Overhead Total	Hardened Overhead Replaced/Repaired	Non-hardened Overhead Total	Non-hardened Overhead Replaced/Repaired
Transmission	19,447	2	5,834	15
Distribution	63,120	20	199,880	145

Source: Document No. 03213-2018 filed 4/25/18.

Maine Emergency Management Agency

October 2017 Storm/Power Outages

After Action Report and Improvement Plan

EMERGENCY MANAGEMENT AGENCY

STATE OF MAINE

Administrative Handling Instructions

This document should be safeguarded, handled, transmitted, and stored in accordance with State directives. It should be released to individuals on a strict need-to-know basis. Information contained herein was prepared for the exclusive use of Maine Emergency Management Agency (MEMA) staff, Maine Emergency Response Team (ERT) members, County Emergency Management Directors and other personnel involved in the operational and administrative aspects of this event.

Executive Summary

To effectively perform in accordance with the Comprehensive Emergency Action Plans among other State plans, policies and procedures, Maine Emergency Management Agency conducted a series of After Action Workshops to discuss and review the procedures for the management and operation of the State Emergency Operation Center (SEOC) and its effectiveness during its most recent activation after the October 30th, 2017 windstorm.

EVENT OVERVIEW

Event Name	October 30th Storm/Power Outages
Event Dates	October 29th through November 1, 2017
Threat or Hazard	Statewide power outage due to severe weather
Scope of Incident	Beginning on Sunday night October 29, winds from an intense low pressure system combined with the remnants of Tropical Storm Philippe to bring wind gusts of more than 70 mph and as much as five inches of rainfall in some areas of the state. The storm caused damage across New England, the provinces of Québec, and the Canadian Maritimes. In Maine, the winds caused widespread damage and the power outage count quickly rose to over 429,000 accounts by noon on Monday. As a result of the storm and in the days that followed during power restoration, more than 550,000 accounts, from Maine's two largest power utilities, Central Maine Power (CMP) and Emera, lost power at least one time. Adjusting for the number of persons per household in Maine (2.34, U.S. Census), virtually all of Maine except for Aroostook and Washington counties experienced widespread power outages during the storm.

Throughout the course of the storm, hundreds of roads were closed due to flooding and widespread debris, 91 school districts were closed, and the state experienced broad disruption to airline, ferry, and rail services. The strong winds and heavy rains caused extensive damage as trees, many still in full leaf and weakened by drought, snapped or uprooted in rain saturated soil. The falling trees pulled down wires, snapped more than 1,400 poles, and left many roads impassable.

Early on October 30, the State Emergency Operations Plan (EOP) was implemented and the State Emergency Operations Center (SEOC) was activated. The SEOC remained activated through November 6 when most of the state regained power. There was no large-scale safety mishaps or deaths as a result of the response.

Mission Area(s)

Response & Recovery

Incident Specific Core Capabilities by Mission Area

All Mission Areas	Planning
	Public Information and Warning
	Operational Coordination
Response	Critical Transportation
	Environmental Response/Health & Safety
	Logistics & Supply Chain Management
	Mass Care Services
	Operational Communications
	Public and Private Services and Resources
	Situational Assessment
Recovery	Infrastructure Systems
	Economic Recovery

SEOC Incident Objectives	1. Activate and coordinate key response and recovery personnel in support of response and recovery activities. 2. Maintain situational awareness and information flow between County Emergency Operation Centers (EOC) and the SEOC (by producing situation reports for decision-makers during every operational period). 3. Receive and fulfill resource requests from all counties and metros to support response and recovery activities during sustained response and recovery operations using available resources from State agencies, the Emergency Management Assistance Compact (EMAC), the Federal Emergency Management Agency (FEMA), the Maine National Guard Joint Operations Center (JOC), and other sources if necessary. 4. Coordinate State and County EOC support for recovery activities (by conducting and facilitating damage assessments if necessary).
Plans	Comprehensive Emergency Management Plan State Emergency Operations Plan (EOP)
Participating Organizations	This report was developed by MEMA in cooperation with members of the ERT and County Emergency Management Agencies, to include representatives from: • American Red Cross (ARC) • Attorney General's Office • Department of Administrative and Financial Services (DAFS) • Department of Agriculture, Conservation and Forestry (DACF) • Department of Corrections (DOC) • Department of Defense, Veterans, and Emergency Management (DVEM) • Department of Economic and Community Development (DECD) • Department of Education (DOE) • Department of Environmental Protection (DEP) • Department of Health and Human Services (DHHS) • Department of Inland Fisheries and Wildlife (IFW) • Department of Labor (DOL) • Department of Marine Resources (DMR) • Department of Public Safety (DPS)

- Department of Transportation (DOT)
- Governor's Office
- Maine State Housing Authority (MSHA)
- Maine Turnpike Authority (MTA)
- Maine National Guard (MENG),
- National Weather Service (NWS),
- Public Utilities Commission (PUC)
- U.S. Coast Guard (USCG)
- Aroostook Country EMA
- Somerset Country EMA
- Piscataquis County EMA
- Penobscot County EMA
- Washington Country EMA
- Hancock County EMA
- Waldo County EMA
- Kennebec County EMA
- Androscoggin County EMA
- Oxford County EMA
- Franklin County EMA
- Knox County EMA
- Lincoln County EMA
- Sagadahoc County EMA
- Cumberland County EMA
- York County EMA

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Analysis of Core Capabilities

Aligning incident objectives and core capabilities provides a consistent taxonomy for evaluation to support preparedness reporting and trend analysis. Table 1 includes the incident objectives, aligned core capabilities, and performance ratings for each core capability as observed during the incident and determined by the members whom participated in creation of this report.

Objective	Core Capability	Performed without Challenges (P)	Performed with Some Challenges (S)	Performed with Major Challenges (M)	Unable to be Performed (U)
1. Activate and coordinate key response and recovery personnel in support of response and recovery activities.	Planning Operational Coordination Operational Communications		S		
2. Maintain situational awareness and information flow between County EOC's and the SEOC (by producing situation reports for decision makers during every operational period).	Planning Public Information and Warning Operational Coordination Operational Communications Infrastructure Systems Logistics & Supply Chain Management Mass Care Services Situational Assessment		S		
3. Receive and fulfill resource requests from all (16) counties and metros to support response and recovery activities during sustained response and recovery operations using available resources	Planning Operational Coordination Critical Transportation		S		

from State agencies, the Emergency Management Assist Compact (EMAC), the Federal Emergency Management Agency (FEMA), the JOC, and other sources if necessary.	Operational Communications Situational Assessment				
4. Coordinate State and County EOC support for recovery activities (by conducting and facilitating damage assessments if necessary).	Planning Public Information and Warning Critical Transportation Operational Coordination Operational Communications Infrastructure Systems Logistics & Supply Chain Management Environmental Response/Health & Safety Situational Assessment		S		

Ratings Definitions:

- Performed without Challenges (P): The targets and critical tasks associated with the core capability were completed in a manner that achieved the objective(s) and did not negatively impact the performance of other activities. Performance of this activity did not contribute to additional health and/or safety risks for the public or for emergency workers, and it was conducted in accordance with applicable plans, policies, procedures, regulations, and laws.
- Performed with Some Challenges (S): The targets and critical tasks associated with the core capability were completed in a manner that achieved the objective(s) and did not negatively impact the performance of other activities. Performance of this activity did not contribute to additional health and/or safety risks for the public or for emergency workers, and it was conducted in accordance with applicable plans, policies, procedures, regulations, and laws. However, opportunities to enhance effectiveness and/or efficiency were identified.
- Performed with Major Challenges (M): The targets and critical tasks associated with the core capability were completed in a manner that achieved the objective(s), but some or all of the following were observed: demonstrated performance had a negative impact on the performance of other activities; contributed to additional health and/or safety risks for the public or for emergency workers; and/or was not conducted in accordance with applicable plans, policies, procedures, regulations, and laws.
- Unable to be Performed (U): The targets and critical tasks associated with the core capability were not performed in a manner that achieved the objective(s).

Table 1. Summary of Core Capability Performance

The following sections provide an overview of the performance related to each exercise objective and associated core capability, highlighting strengths and areas for improvement.

STRENGTHS & AREAS FOR IMPROVEMENT

The strengths and areas for improvement for each core capability aligned to this objective are described in this section.

Objective 1

Activate and coordinate key response and recovery personnel in support of response and recovery activities.

Core Capabilities

Planning; Operational Coordination; Operational Communication

Strengths

The partial capability level can be attributed to the following strengths:

Strength 1: Just a few months prior to this event MEMA staff, ERT members and County EMA Directors - among many other partners and agencies - participated in the Maine Fire & Ice 2017 Exercise Series. This EOC activation exercise series aimed to examine the response and recovery operations related to a catastrophic ice storm and space weather event to include statewide power outages. This exercise series included training and activation of the SEOC on three separate occasions earlier in 2017. For this reason, responders and participating agencies activated during this real-world event understood what resources they had at their disposal and as well developed a thorough understanding of their own individual roles within the SEOC for this type of incident. In addition, key working relationships with utilities and other partner relationships developed during the exercise which made for ease in coordination and a seamless transition from normal operations to full SEOC activation.

Areas for Improvement

The following areas require improvement to achieve the full capability level:

Area for Improvement 1: SEOC Communication and Staff Coordination

Analysis: Although storm forecasting predictably comes with a degree of uncertainty, it was the desire of ERT members, County EMA's, and MEMA staff to have been communicated with prior to the wind event by conference call (or other means) in order to attain a better understanding of both the storm and SEOC activation potential.

Participants agreed that reaching out in advance of the storm to collaborate with the NWS would have assisted with spot forecasts and weather modeling which may have provided additional situational awareness regarding the effects of this wind storm.

In addition, team members agreed that full ERT activation on day one would have been preferred as you can always back off later. During this event, full activation for ERT members was not complete until the second day of SEOC activation.

Area for Improvement 2: Maine 211 Engagement

Analysis: The Maine 211 information system plays a key role in engaging the public with information and resources available during a response. Maine 211 began as part of the national 211 movement designed to centralize and streamline access to health and human service information and resources with an easy-to-remember universal number and website for non-emergency help.

Better understanding and coordination of the process for utilizing and activating 211 capabilities earlier in the process would strengthen MEMA and the public's awareness. In addition, it was suggested that a 211 representative be invited into the Joint Information Center to assist in collaborative information sharing real-time and in close proximity to health and human services personnel.

Area for Improvement 3: Utility and Cellular/Telecommunication Liaisons

Analysis: Electrical utilities and cellular/telecommunication companies are critical infrastructure components during a response and recovery event. Coordination with electrical utilities at the SEOC generally performed well, although they were not physically present in the SEOC. It was suggested that liaisons from utilities and cellular companies be deployed to the SEOC during incidents to further build upon these relationships and accelerate coordination and response.

In addition, participants suggested field visits for MEMA and ERT staff to visit CMP and Emera headquarters to create more mutual understanding of roles and operations before, during and after a response.

Area for Improvement 4: MEMA Staff Turnover and New Personnel

Analysis: Strong relationships have been made over the years with regular training and exercises. With increased personnel turnover over the past year, it was suggested that MEMA develop regular meetings between MEMA staff and key ERT partners for planning, coordination and policy guidance development. These meeting should focus on a specific Emergency Support Functions (ESF) and involve the agencies identified with specific ESFs such as communications, logistics or search & rescue.

Objective 2

Maintain situational awareness and information flow between County EOC's and the SEOC (by producing situation reports for decision makers during every operational period).

Core Capabilities

Situational Assessment; Operational Coordination; Operational Communication; Public Information and Warning

Strengths

The partial capability level can be attributed to the following strengths:

Strength 1: Social media channels such as Facebook and Twitter are interactive channels that engage the public and were utilized extensively during this event, serving as both information dissemination and reception platforms. The Facebook live application was utilized during a media press briefing that broadcasted the event in real time straight from the SEOC.

Strength 2: The WebEOC platform was utilized by SEOC ERT members and County EOC's to maintain situational awareness, manage resource requests and promote communication. The previously held Fire and Ice exercises contributed towards statewide WebEOC proficiency during this real-world event.

Strength 3: The Health Alert Network (HAN) is MEMA's primary method of sharing cleared information about urgent incidents with public information officers; federal, state, territorial, and local emergency managers and ERT members. After the SEOC activation, regular briefings were conducted via conference call that were consistent, informative, and well organized.

Strength 4: The MEMA Public Information Officer (PIO) worked collaboratively to deliver accurate and timely disaster related information to the public. The PIO advised senior policy officials, including the Governor, on emergency communications priorities and key messages, and ensured that all Emergency Public Information functions were carried out.

Areas for Improvement

The following areas require improvement to achieve the full capability level:

Area for Improvement 1: Coordination of Health Alert Network (HAN) Messaging

Analysis: The HAN alert system sent out immediate, rapid and redundant messaging via cell phone, email and text all at the same time. During the SEOC activation a HAN alert was sent out while a Debris Management Meeting was being conducted. Consideration to the operational battle rhythm is needed before HAN alert activation during future activations.

Area for Improvement 2: Public Information Coordination and Staffing

Analysis: This number of personnel in the Joint Information Center (JIC) is dependent on the size and impact of the incident. During this activation the JIC was typically staffed solely by the MEMA PIO with one other member working remotely. This lack of staffing in the actual JIC lead to variations in the public information flow and on more than one occasion the PIO being inaccessible to county EMA directors. It was suggested that during future incidents, other MEMA staff or state government PIOs who were not otherwise engaged in the response should be assigned to provide assistance to the MEMA PIO during activations given the demands and workload of public information requirements such as social media monitoring. Separate JIC conference calls were suggested to assist counties with consistent and planned messaging. A plan for JIC staff augmentation is needed.

According to FEMA doctrine one person serving as the PIO is not sufficient for managing media and public requests for information within a JIC. The demand for verified information requires the PIO to have an access to adequate staffing to manage such requests to ensure that all involved have a common operating picture and understand expectations during an incident.

Area for Improvement 3: Road Closure Accuracy

Analysis: The Road Closures board within WebEOC allows you to document and track specific details on road closures, including a closure's status, location, damage, and suggested detours. This board should be used to update closures and restrictions for when roadways are reopened.

Both ERT members and Country EMA's stated that information flow on road closures was inconsistent, inaccurate or at times non-existent. Specific training on the road closure function in WebEOC and guided usage by all levels of responders and appropriate agencies would lead to better situational awareness for future incidents. Team members were unclear as to who provided road status and clearing updates (Utilities or DOT). Suggestions on exercising this piece with state entities and municipalities would be worthwhile.

Area for Improvement 4: Situation Report (SITREP) Guidance and Distribution List

Analysis: The twice daily SITREPS were distributed to a number of key partners but also to outdated contacts. During the activation and towards the conclusion of the incident, the SITREP distribution list was revised and updated to better prepare for another incident.

In addition, daily SITREP guidance for County EMA submission should be created and required to build a more robust SEOC SITREP which clearly states expectations of what information is needed by the SEOC. Suggestions for standardizing the core sources of information needed to populate SITREPS was also discussed.

County Directors stated that there were too many unofficial phone calls coming from the SEOC and that these need to be restricted during initial EOC activation.

Area for Improvement 5: WebEOC Proficiency

Analysis: Given that activations happen on an infrequent basis, WebEOC proficiency for all users will continue to be a challenge. Many team members highlighted the usefulness of this software. In addition, more utilization of the features of WebEOC was desired. Consistent training on a WebEOC topic via Adobe Connect or other webinar platforms on a regular basis would serve as a reasonable way to maintain proficiency by all users.

In addition, a process for standardizing incident names within WebEOC was desired by MEMA personnel.

Area for Improvement 6: Food, Lodging and Security Support

Analysis: The Emergency Operation Plan directs the business office to maintain an adequate supply of food, water, hot and cold drinks, toiletry items and lodging for ERT/staff on hand during the event.

During the SEOC activation, many staff members traveled great distances to and from their residences after 12-hour shifts. No lodging was provided for SEOC staff during this event. Should the activation lasted longer, this could have led to safety concerns due to fatigue. At the first sign of a prolonged SEOC activation, logistics staff should secure a block of local hotel rooms at the government rate for essential staff for the anticipated duration of the incident.

In addition, food supply was inconsistent and would be better served with pre-existing agreements with existing food establishments in the area for such activations.

Lastly, augmentation staff should be sought out for front-desk check-in and security thereby freeing up MEMA staff for SEOC roles such as in the JIC assisting the PIO. A more defined Logistics Section Chief position needs to be assigned within the SEOC that covers these important areas of security, food & lodging, and outstanding facility items.

Area for Improvement 7: SEOC Shift Changes and Briefings

Analysis: Although individual shift change briefings went well, command briefings for the entire SEOC staff were limited.

Standardize shift change briefings into the SEOC battle rhythm ensuring a consistent operational picture and personnel transition throughout entirety of activation.

Objective 3

Receive and fulfill resource requests from all counties and metros to support response and recovery activities during sustained response and recovery operations using available resources from State agencies, the Emergency Management Assist Compact (EMAC), the Federal Emergency Management Agency (FEMA), the JOC, and other sources if necessary.

Core Capabilities

Operational Coordination; Operational Communications; Critical Transportation; Public Information and Warning Planning; Situational Assessment

Strengths

The partial capability level can be attributed to the following strengths:

Strength 1: All players and response agencies were well versed in the National Incident Management System (NIMS)/Incident Command System (ICS) and were able to define incident objectives, determine tactical strategy, staff necessary ICS positions and begin the process of composing an Incident Action Plan (IAP).

Strength 2: All resource requests sent to MEMA were processed and administered in a timely manner.

Areas for Improvement

The following areas require improvement to achieve the full capability level:

Area for Improvement 1: Resource Request Process

Analysis: Flow of requests at times varied with a variety of people working on requests and not always coordinating approvals and status of the request or resource itself. Clear process for approval and vetting of resources is needed. Guidance for requesting resources is limited.

In addition, a statewide inventory of available resources is scattered at best and difficult to obtain in a timely manner.

Area for Improvement 2: Finance and Administration

Analysis: Integrate procurement and finance personnel into SEOC. The Emergency Operations Plan specifies that the Logistics Officer shall ensure that all costs are authorized, documented, and tracked leading to confusion of standardized roles and responsibilities as prescribed by the Incident Command System definitions. More consistencies needed for Finance, Logistics, Operations and Planning roles in SEOC plans and procedures (request for resources, spending, procurement, lodging/feeding of EOC activated staff).

Objective 4

Coordinate State and County EOC support for recovery activities (by conducting and facilitating damage assessments if necessary).

Core Capabilities

Operational Coordination; Operational Communications; Public Information and Warning; Infrastructure Systems; Economic Recovery.

Strengths

The partial capability level can be attributed to the following strengths:

Strength 1: After the three Fire and Ice functional EOC exercises, a recovery tabletop exercise was held with Recovery Support Function partners on October 26, 2017. The tabletop exercise walked key recovery partners through a long-term power outage scenario. The proficiency gained and contact list updates became essential as the SEOC shifted from response to recovery mode later in the week-long activation. Due to this, activating Recovery Support Function 1 (Community Planning and Capacity Building) for a meeting occurred in a timely manner and an initial planning meeting was held on Friday November 3rd.

Strength 2: The Preliminary Damage Assessment (PDA) process was initiated and carried out in the federally-required timeframe by FEMA, MEMA and County EMA staff during the month of November across 14 affected counties in the state.

Areas for Improvement

The following areas require improvement to achieve the full capability level:

Area for Improvement 1: Preliminary Damage Assessment Teams

Analysis: Pre-identify other state government personnel who could assist with future PDA initiatives. Given the small staff of MEMA, the initiative for this wind storm was achieved but all other activities within the Agency ceased to exist over this three-week period following an extended activation. Identifying and training other state government personnel who can carry out these recovery functions would reinforce the State's capability to carry out future PDAs.

APPENDIX A: IMPROVEMENT PLAN

This IP has been developed specifically for MEMA, ERT members and County EMA's as a result of the October 30th Event.

Objective	Issue/Area for Improvement	Corrective Action	Primary Responsible Organization	Organization POC	Start Date	Completion Date
1. Activate and coordinate key response and recovery personnel in support of response and recovery activities.	SEOC Communication and Staff Coordination	Implement Pre-Storm Conference Call Procedures.	MEMA	Operations & Response		On-going
	Maine 211 Engagement	Add Maine 211 Representative to JIC augmentation staff or Human Services ESF's. Incorporate Maine 211 rep in future exercises.	MEMA	Individual Assistance Officer & State Exercise Officer		On-going
	Utility and Cellular/Telecommunication Liaisons	Update SEOC layout to incorporate space for liaisons and support personnel. Update plans & policy accordingly	MEMA	Operations & Response		On-Going

	MEMA Staff Turnover and New Personnel	Initiate bi-monthly ERT and MEMA meetings	MEMA	Operations & Response		Not Started
2. Maintain situational awareness and information flow between County EOC's and the SEOC (by producing situation reports for decision makers during every operational period).	Coordination of Health Alert Network (HAN) Messaging.	Update plans & policy to require all HAN alerts be screened through Operations Desk or EOC Coordinator	MEMA	Operations & Response		Not Started
	Public Information Coordination and Staffing	Assign and train additional JIC staff. Identify additional augmentation staff	MEMA	Public Information Officer		On-Going
	Road Closure Accuracy	Develop WebEOC working group to draft WebEOC policy and guidance to include details for each board utilized.	MEMA	Operation & Response, IT, and County Rep.		Not Started
	Situation Report (SITREP) Guidance and Distribution List	Develop SITREP working group to draft SITREP policy and guidance to include details for each board utilized.	MEMA	Operations & Response, IT, and County Rep.		Not Started
	WebEOC Proficiency	Develop WebEOC training series specific to each ESF (Human Services, Public Safety, & Infrastructure)	MEMA	State Training Officer and IT		Not Started

	Food, Lodging and Security Support	Ensure assignment and training of Logistics duties within SEOC. Update plans & policy accordingly	MEMA	Operations & Response, State Training Officer		On-Going
	SEOC Shift Changes and Briefings	Draft standardize shift change process. Update plans & policy accordingly	MEMA	Operations & Response		Not Started
3. Receive and fulfill resource requests from all (16) counties and metros to support response and recovery activities during sustained response and recovery operations using available resources from State agencies, the Emergency Management Assist Compact (EMAC), the Federal Emergency Management Agency (FEMA), the JOC, and other sources if necessary.	Resource Request Process	Develop Resource Request working group to update plans, policy and guidance to include training series	MEMA	Operations & Response, IT, State Training Officer		On-going
	Finance and Administration	Ensure assignment and training of Finance & Admin staff and applicable duties within SEOC. Update plans & policy accordingly	MEMA	Operations & Response, State Training Officer		On-Going
4. Coordinate State and County EOC support for recovery activities (by conducting and facilitating damage	Preliminary Damage Assessment Teams	Identify, solicit, and train additional preliminary damage assessment team members	MEMA	Public Assistance Officer		Not Started

assessments if necessary).						