Filing Receipt

Filing Date - 2025-03-06 02:51:42 PM

Control Number - 57579

Item Number - 67

SOAH DOCKET NO. 473-25-11558
PUC DOCKET NO. 57579

APPLICATION OF CENTERPOINT	**§**	**BEFORE THE STATE OFFICE**
ENERGY HOUSTON ELECTRIC, LLC	**§**	
FOR APPROVAL OF ITS	**§**	**OF**
TRANSMISSION AND DISTRIBUTION	**§**	
SYSTEM RESILIENCY PLAN	**§**	**ADMINISTRATIVE HEARINGS**

March 6, 2025

Contact: Stacey Murphree
CenterPoint Energy Service Company, LLC
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Houston, Texas 77002
Telephone No: (713) 207-6537
stacey.murphree@centerpointenergy.com

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CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI01-01

QUESTION:

Identify the documents containing all reports, memos, and presentations memos, reports, presentations containing, discussing, describing, and analyzing the root cause analysis of any previously failed transmission poles that had previously been hardened. Additionally, please provide the following information related to the previously failed transmission poles:

a. Provide the date of the failures.

b. Provide the design criteria of those transmission poles that failed.

ANSWER:

a. There have been no failures of CenterPoint Houston transmission structures that had previously been hardened. For additional information regarding CenterPoint Houston hardening activities, see the storm hardening reports submitted by the Company in Project Nos. 38068 and 39339.

b. See answer to subpart (a), above.

SPONSOR:
David Mercado

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI01-02

QUESTION:

Please provide system SAIDI, SAIFI, and CAIDI values for the system over the last 10 years with the following details.

a. Non-major storm days

b. Major storm outages

c. Resiliency outages

d. Scheduled outages

e. Total outages

f. Peer comparisons.

ANSWER:

(a), (b), (d), and (e) - Please see HCC-RFI01-02.xls for system SAIDI, SAIFI, and CAIDI for the last 10 years as filed in the PUCT Annual Service Quality Report for the interruption classifications defined in TAC §25.52.

(c) The Company does not track "resiliency outages," and the term is undefined in the request. If the request for data on "resiliency outages" is for data on outages caused by Resiliency Events, as that term is defined in the Commission's rules and the Company's System Resiliency Plan, then please see the SAIDI, SAIFI, and CAIDI for the outages associated with the 2020-2024 Resiliency Events referenced in Figure APP-12 in the bottom section of HCC-RFI01-02.xls.

(f) To comply with TAC §25.52, each utility's methodology for calculating SAIDI, SAIFI, and CAIDI may vary so the data is not conducive for peer comparisons. To provide greater consistency in the assessment of system reliability among its peer group, CenterPoint Energy uses the IEEE Standard 1366-2012 and 2.5 Beta Method when it participates in the First Quartile benchmarking study annually. Please reference HCC-RFI01-0 2 - Benchmarking 2022.pdf and HCC-RFI01-0 2 - Benchmarking 2023.pdf for the comparison of CenterPoint Energy's SAIDI, SAIFI and CAIDI to its peer group for year ending 2023 and 2022, which also includes the historical comparison since 2013. These pages are part of a nonpublic document that CenterPoint Energy is providing with permission from First Quartile.

SPONSOR:
Deryl Tumlinson

RESPONSIVE DOCUMENTS:
HCC-RFI01-02.xls
HCC-RFI01-02 - Benchmarking 2022.pdf
HCC-RFI01-02 - Benchmarking 2023.pdf

HCC RFI 1-2: (a), (b), (d), and (e) System SAIDI, SAIFI, and CAIDI for the last 10 years as filed in the PUCT Annual Service Quality Report for the interruption classifications defined in TAC §25.52.

SAIFI	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Major Event	0.27	0.26	0.449	0.033	0.082	0.265	3.159	0.015	0.374	2.049
Forced Interruptions	1.46	1.22	1.038	1.163	1.263	1.144	1.207	1.414	1.376	1.476
Scheduled Interruptions	0.31	0.30	0.288	0.338	0.373	0.304	0.319	0.446	0.38	0.364
Outside Causes	0.12	0.13	0.086	0.142	0.107	0.113	0.094	0.111	0.099	0.079
Total Outages	2.16	1.91	1.86	1.68	1.83	1.83	4.78	1.99	2.23	3.97

SAIDI	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Major Event	59.65	63.46	312.17	4.85	26.73	63.24	2,189.01	2.69	177.57	4,143.98
Forced Interruptions	154.61	119.81	102.73	116.46	152.68	122.03	135.94	164.65	140.16	138.53
Scheduled Interruptions	36.80	34.12	36.84	50.05	45.31	37.47	37.46	59.65	32.16	30.94
Outside Causes	8.22	8.45	2.62	7.23	3.08	3.84	3.46	4.79	4.15	3.07
Total Outages	259.28	225.84	454.36	178.59	227.80	226.58	2365.87	231.78	354.04	4316.52

CAIDI	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Major Event	219.65	248.56	694.74	147.13	326.9	239.02	693.05	184.67	474.33	2022.74
Forced Interruptions	105.89	98.34	98.95	100.16	120.89	106.7	112.63	116.44	101.86	93.87
Scheduled Interruptions	120.09	112.26	127.73	147.93	121.56	123.33	117.27	133.68	84.7	84.97
Outside Causes	66.22	64.67	30.58	50.78	28.82	33.94	36.86	42.99	42.12	39.02
Total Outages	511.85	523.83	952.00	446.00	598.17	502.99	959.81	477.78	703.01	2240.60

(c) SAIDI, SAIFI, and CAIDI for the outages associated with the 2020-2024 Resiliency Events referenced in Figure APP-12

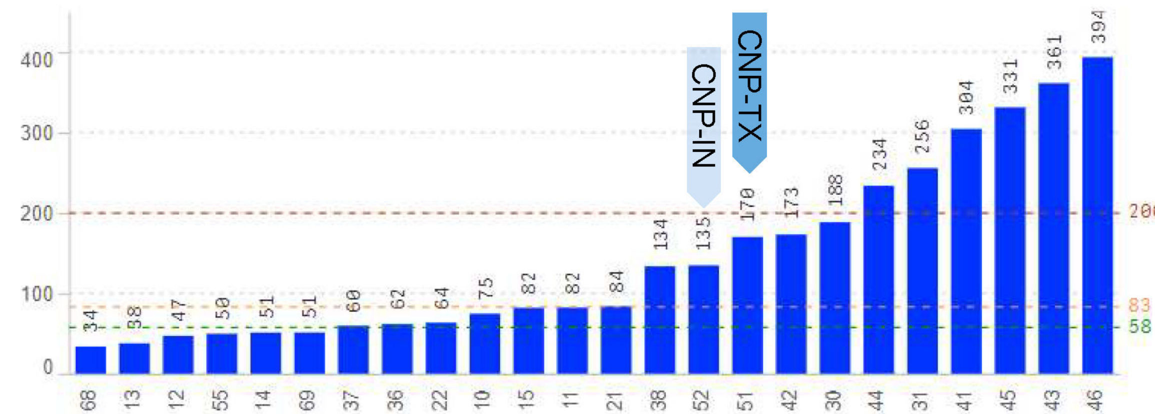
Resiliency Outages	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SAIDI	-	-	-	-	-	70.03	2,227.72	6.59	192.11	4,207.72
SAIFI	-	-	-	-	-	0.31	3.49	0.05	0.44	2.09
CAIDI	-	-	-	-	-	227.54	639.06	136.74	438.76	2,017.30

Peer Comparison for last 10 yrs

3rd quartile SAIDI performance improved (decreased) for the first time in several years

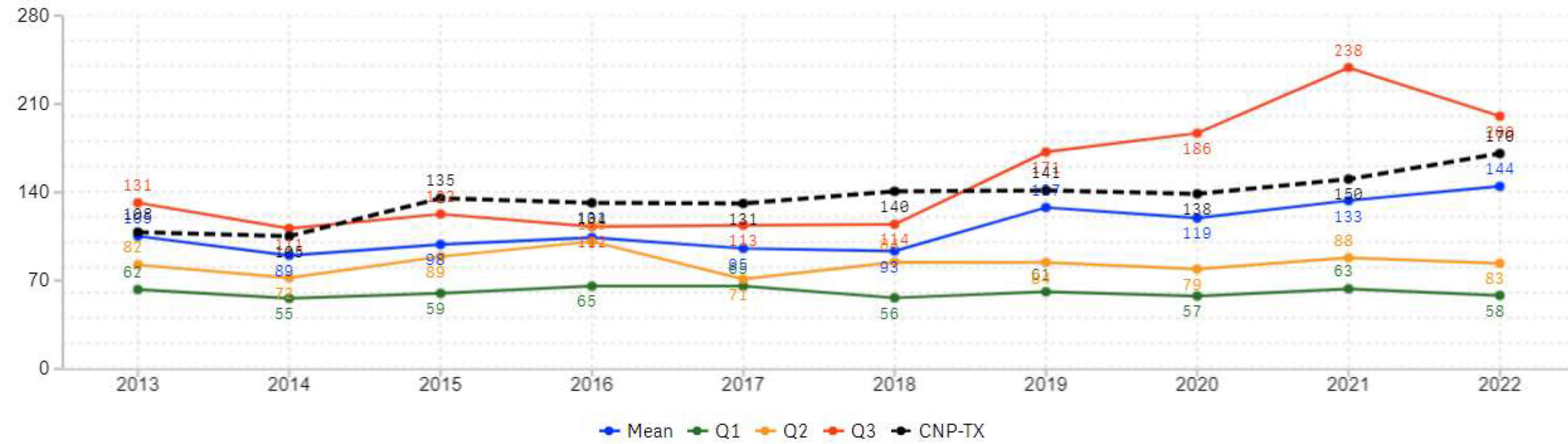
- Top performance has remained consistent over the same time frame.
- For CNP-TX, results have been fairly stable with a slight increase in recent years.

SAIDI (Excluding Major Events Using 2.5 Beta Method)



Source: DR0050 DR0100

SAIDI (Excluding Major Events Using 2.5 Beta Method)



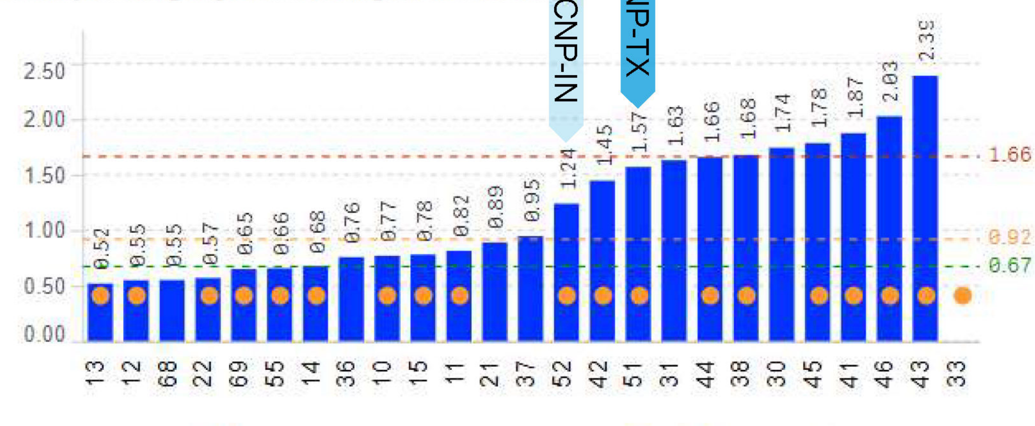
Source: DR0050.3

FIRST QUARTILE CONSULTING

3rd quartile SAIFI performance has increased (worsened) by about 67% over the past 5 years

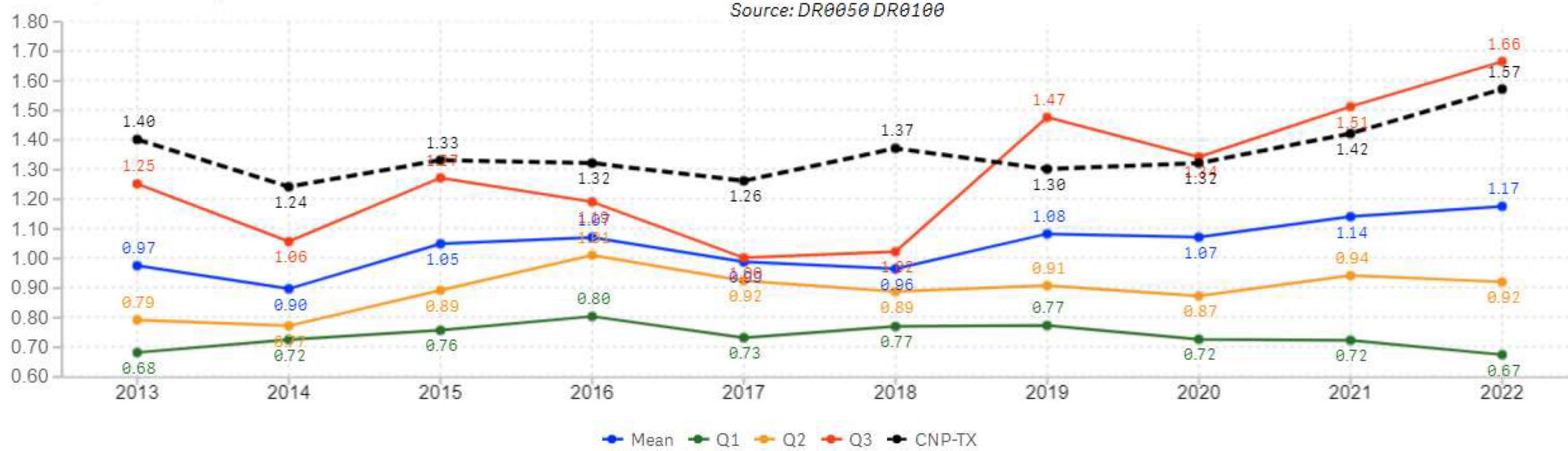
- As with SAIDI, leading performance has stayed consistent for the past decade.
- For CNP-TX, results have been increasing slowly for the past several years.

SAIFI (Excluding Major Events using 2.5 beta method)



Source: DR0050 DR0100

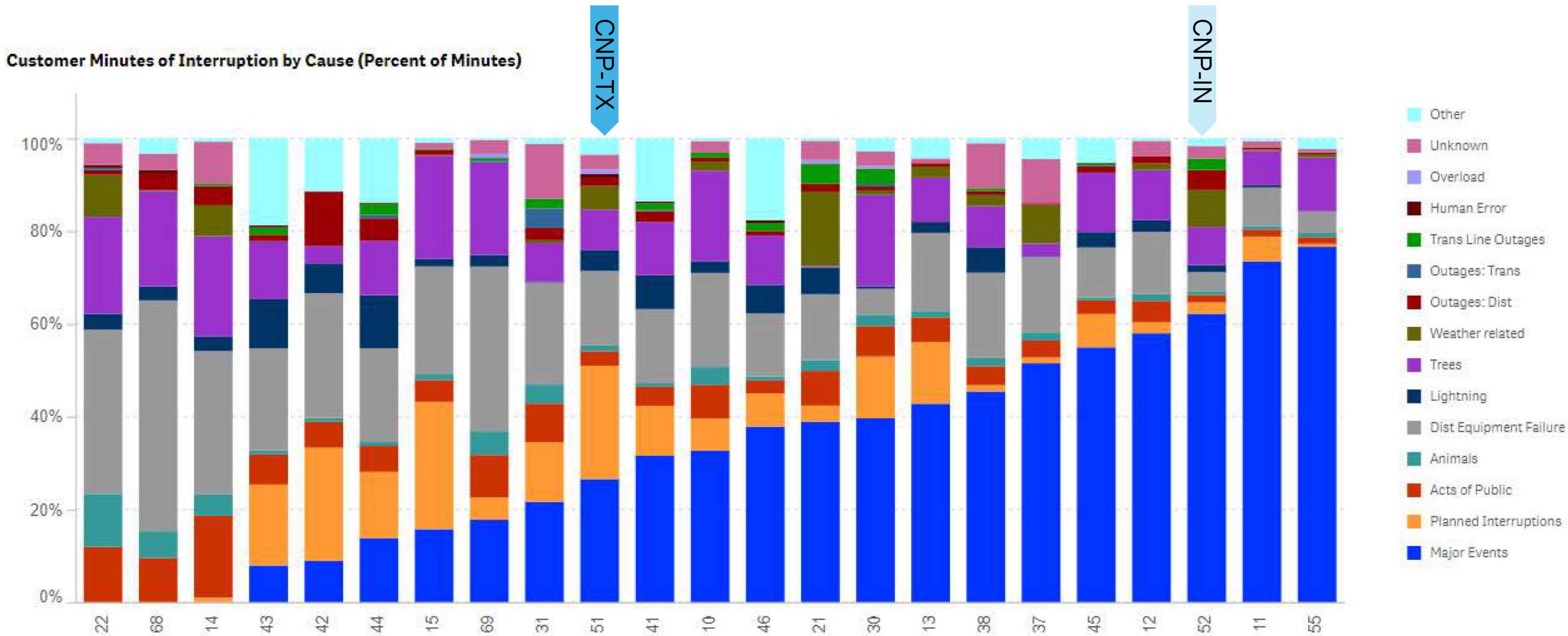
SAIFI Ex. Major Events using 2.5 Beta Method



Source: DR0050.6

Major events cause the majority of outages and minutes of outage for customers across the industry

- **About 25% of customer minutes of interruption were caused by major events for CNP-TX with planned outages making up another 25%.**



Source: DR0350

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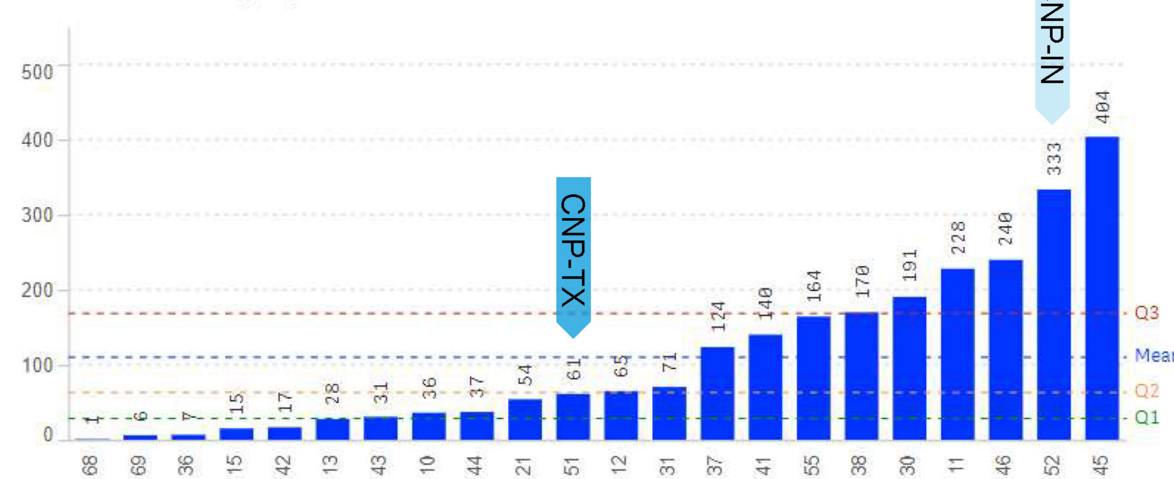
FIRST QUARTILE CONSULTING

Major events have a minor impact for some utilities and a more significant impact for others

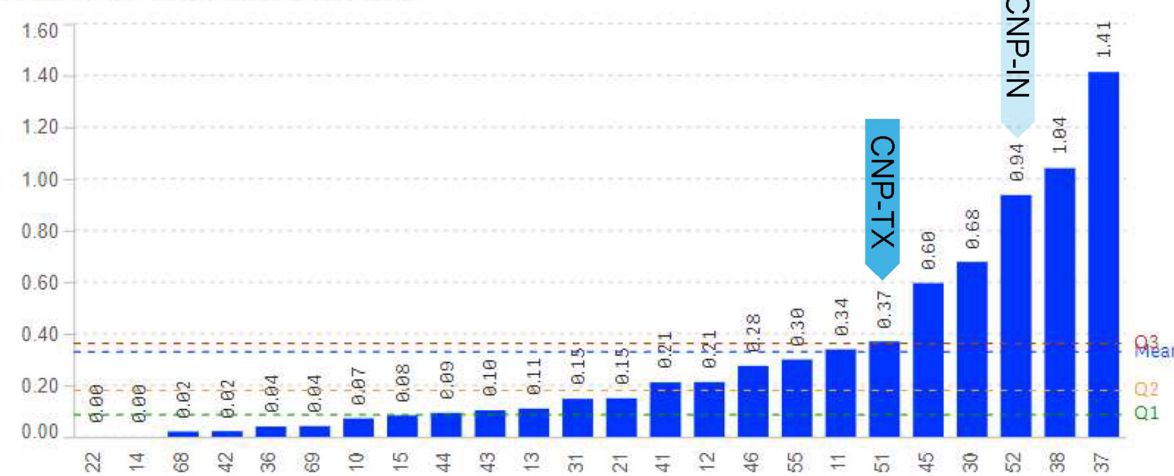
- **CNP-TX was one of the companies with the greatest impacts from major events during 2021.**
- **This year (2022), CNP-TX was closer to the median in terms of impact of major events.**

Minutes - SAIDI Caused by Major Events



Source: DR0050

Interruptions - SAIFI Caused by Major Events

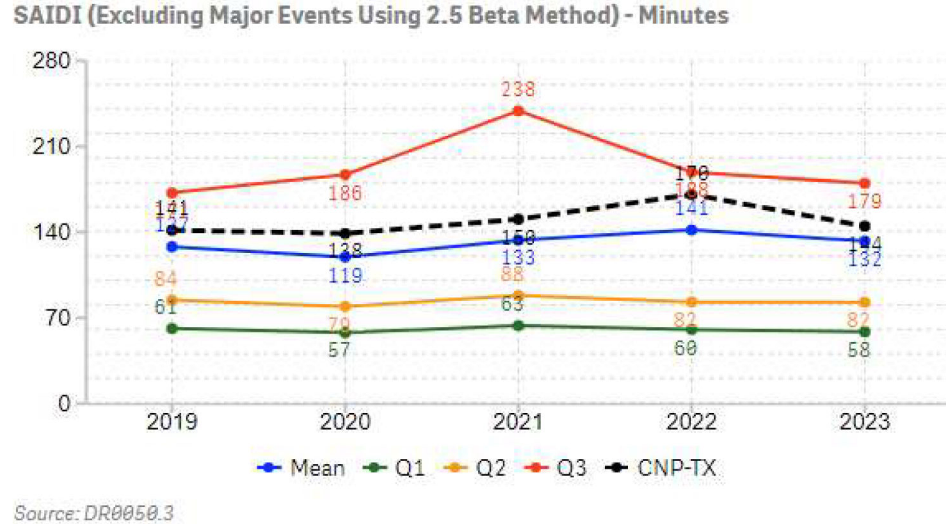


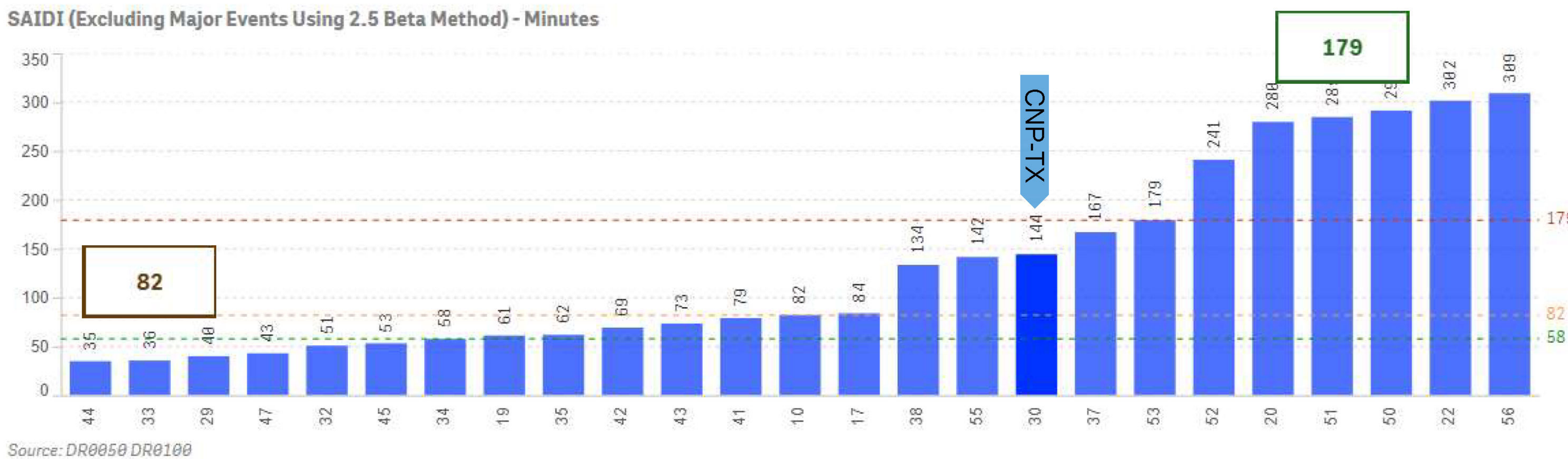
Source: DR0050

Peer comparison for YE 2023

SAIDI trends remain stable, with gaps 3x in minutes between 1st and 3rd quartile

- **While those with low average system interruption minutes have remained consistent over time, poorer performers have shown some improvement in the past 2 years**





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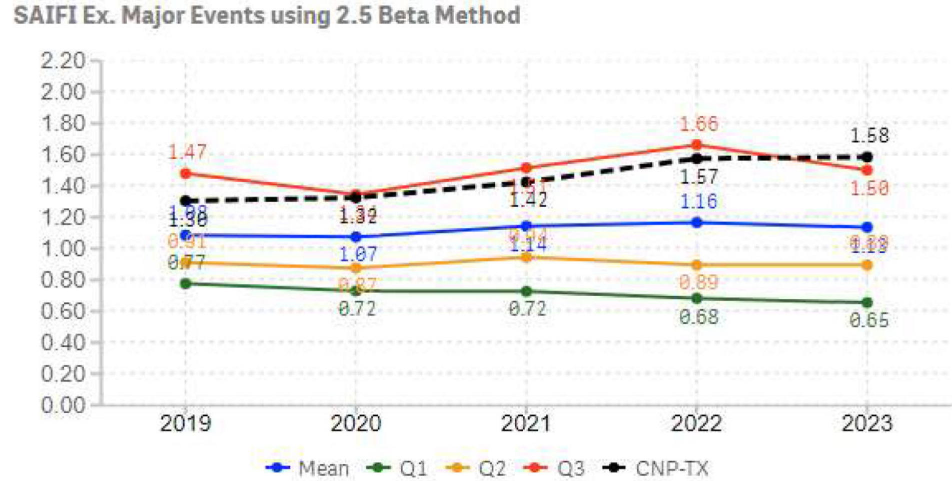
FIRST QUARTILE CONSULTING

3rd quartile SAIFI has returned to 2019 levels after worsening in the prior 2 years

- 1st and 2nd quartile performance has improved 10% over that same period
- For CNP-TX, the trend shows 5 years of slight, steady increases



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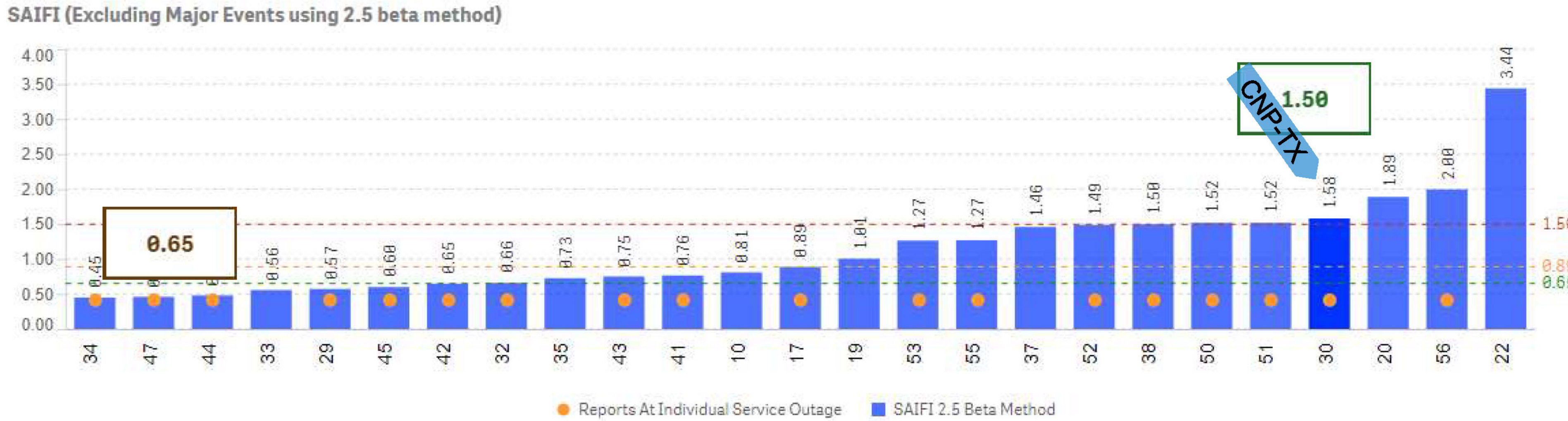

Source: DR0050 DR0100

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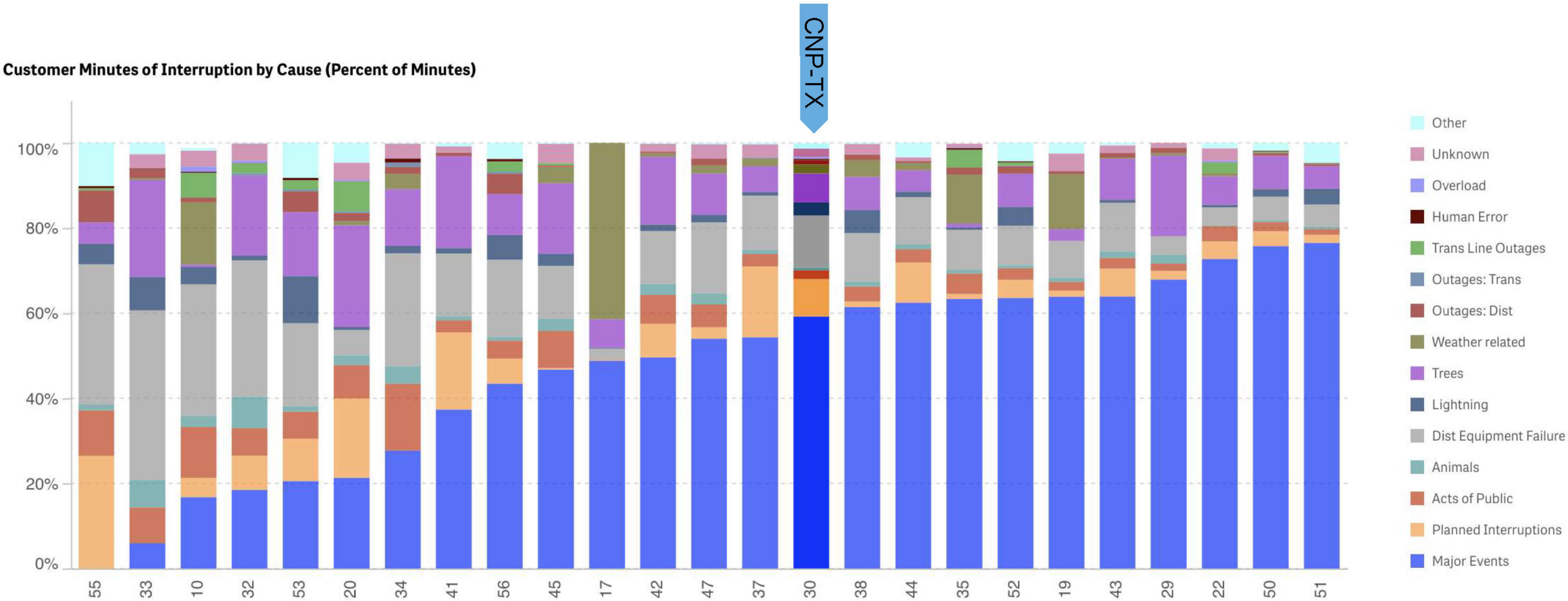
Major events cause the majority of outages and minutes of outage for customers across the industry

- **Almost 60% of customer minutes of interruption were caused by major events for CNP-TX with planned outages making up another 10%.**



Source: DR0350

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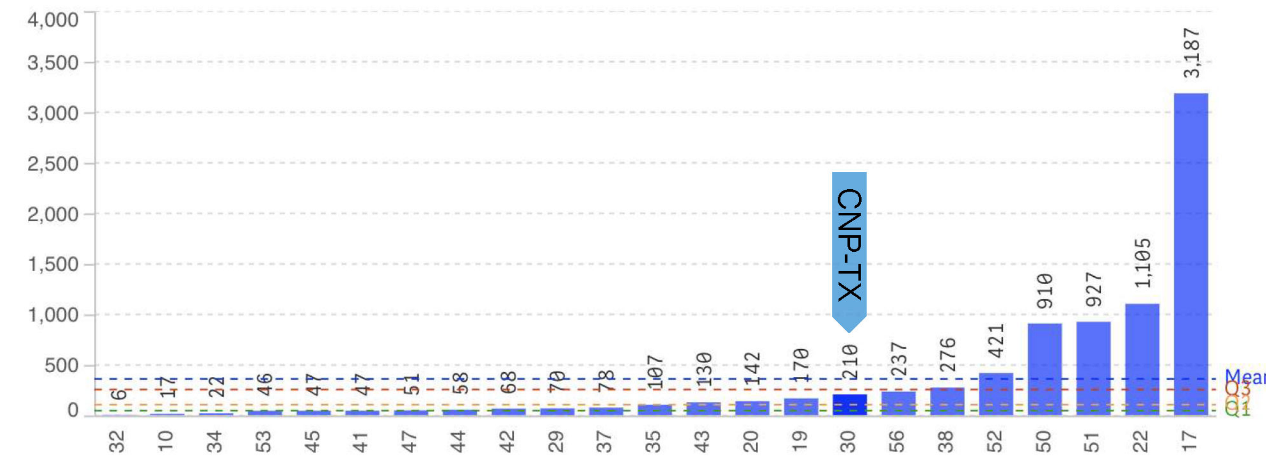
Major events have a minor impact for some utilities and a more significant impact for others

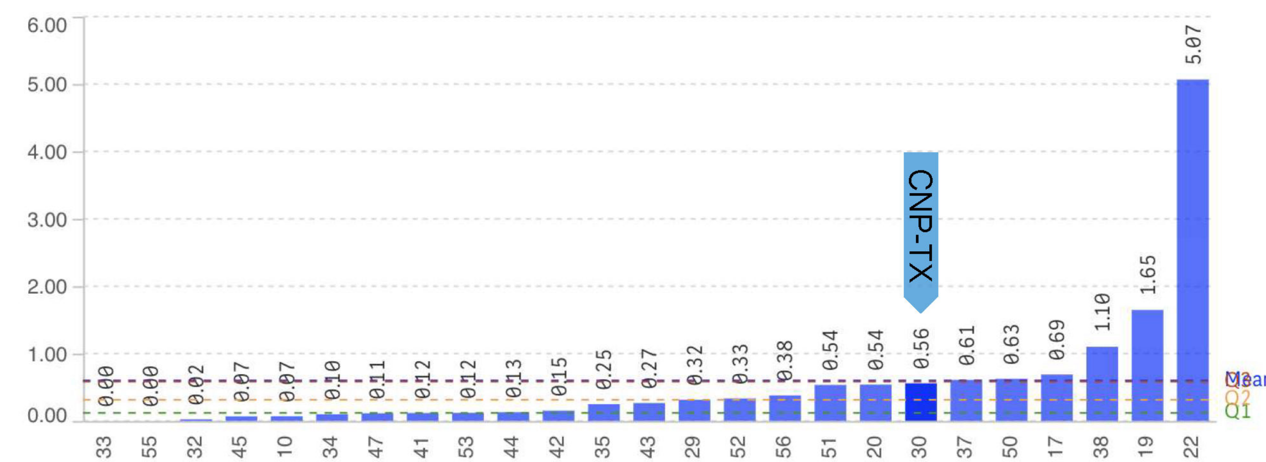
- **CNP-TX was above the median, but not extreme, in terms of both SAIDI and SAIFI impact from major events during 2023**

Minutes - SAIDI Caused by Major Events



Source: DR0050

Interruptions - SAIFI Caused by Major Events



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CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI01-03

QUESTION:

Provide expected forecasts of system SAIDI, SAIFI, and CAIDI values for the next five years:

a. Show forecast without the Resiliency Plan investments

b. Show forecast with the Resiliency Plan investment.

ANSWER:

Guidehouse and CEHE did not perform any calculations to project SAIDI/SAIFI/CAIDI for next five years. Guidehouse's analysis only determined the incremental reduction in CMI achieved by resiliency measures based on expected CMI impact limited to future resiliency events.

SPONSOR:
Eric Easton and Eugene Shlatz

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFI01-04

QUESTION:

Provide the expected impact of the Resiliency Plan on operations and maintenance expenses for each of the next five years

a. Totals by expenditure type

b. Increases by expenditure type

c. Decreases by expenditure type.

ANSWER:

a-c: Please see the response to TCUC RFI 01-01 and specifically TCUC-RFI01-01 Attachment 1 - 2026-2028 Resiliency Plan MASTER.xls for estimated incremental O&M cost for each resiliency measure for the three-year period.

SPONSOR:
Nathan Brownell

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFP01-01

QUESTION:

Provide the documents containing all reports, memos, and presentations containing, discussing, describing, and analyzing benchmarking studies, reports, presentations, etc., based on actual storm damage from 2020-2024 to validate the results of the modeling and analysis that help justify the different measures.

ANSWER:

CEHE:

Models used to identify project locations are risk-impact models based on tree-fall in probability and accessibility of assets obtained from LiDAR data. The same risk-impact model was used along with data from previous storms to develop a damage-prediction model to estimate the number of damages that could occur during wind related events. Since the model was built taking actual data from past storms, outputs match closely to past events by design. To validate and improve the accuracy of the model for future predictions, it needs to be run on a future event and compared with the actual damage from the future event. Since the Company did not experience any major wind events since the model was developed, benchmarking studies were not done to validate this model.

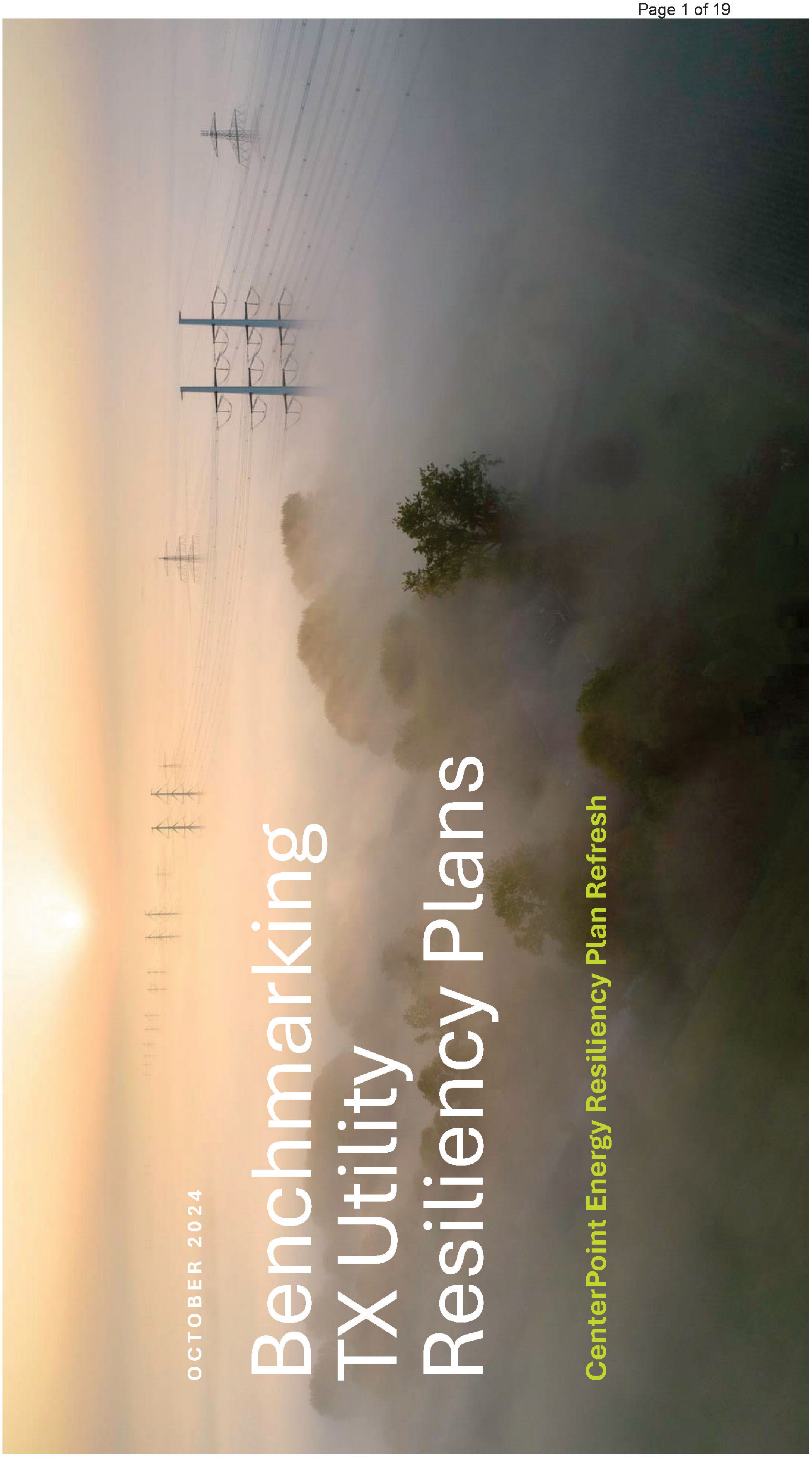
Guidehouse:

- Please see the response to TCUC 01-01, which provides underlying calculations and assumptions supporting derivation of BCA and CMI values for each applicable measure. The Guidehouse model is provided under protective order.
- In addition to the spreadsheet for BCA and CMI values, please refer to sources cited in Exhibit ELS-2 and Shlatz direct testimony for charts and tables presented in Sections 4 and 5 that Guidehouse relied upon to support results, findings and conclusions.
- In terms of the request above about storm damage, CEHE provided Guidehouse with information from CEHE's Outage Management System (OMS) which was used as input related to extreme event impacts (i.e., storm damage, restoration). Data from the OMS was incorporated into Guidehouse's analysis to derive inputs and to develop BCA ratios for proposed resiliency measures.
- Guidehouse conducted qualitative comparative benefit analyses for the technology and cybersecurity resiliency measures, please refer to sources cited in Exhibit ELS-2 and Baugh direct testimony for details.
- Guidehouse utilized historic storm-related outage data from 2019 to 2023 to support Circuit Level Analysis input development and model calibration as described in Exhibit ELS-2 Section 6.2.
- The benchmarking content included within ELS-2 – including within Section 5, Appendix A, and Appendix B – provides comprehensive discussion of relevant findings from research conducted by Guidehouse on peer utility resiliency planning and investments. Additional supporting information for Appendix B (jurisdictional benchmarking) is provided in HCC RFP 01-01 Attachment 1.pdf and HCC RFP 01-01 Attachment 2.pdf (wildfire benchmarking). Supporting information for Appendix A (peer utility survey) is provided in HCC RFP 01-01 Attachment 3 CONFIDENTIAL.pdf.

SPONSOR:
Eric Easton and Eugene Shlatz

RESPONSIVE DOCUMENTS:
HCC RFP 01-01 Attachment 1.pdf

HCC RFP 01-01 Attachment 2.pdf
HCC RFP 01-01 Attachment 3 CONFIDENTIAL.pdf

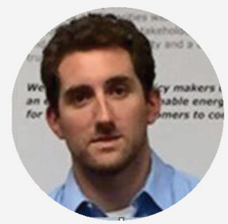

OCTOBER 2024
Benchmarking
TX Utility
Resiliency Plans
CenterPoint Energy Resiliency Plan Refresh

Guidehouse

Introductions

Peter Shaw
Director

Sam Crawford, PhD
Associate Director



Alexander Echele
Managing Consultant

Ensar Biscevic
Consultant

Disclaimer

This deliverable (the “Report”) was prepared for CenterPoint Energy Houston Electric, LLC (“CenterPoint Houston”), on terms specifically limiting the liability of Guidehouse Inc. (“Guidehouse”), for use in connection with a filing by CenterPoint Houston at the Public Utility Commission of Texas (“PUCT” or “Commission”) seeking approval of CenterPoint Houston’s transmission and distribution system resiliency plan pursuant to 16 Tex. Admin. Code § 25.62 (the “Resiliency Plan Proceeding”). Other than for use in the Resiliency Plan Proceeding as provided by applicable laws and rules, the Report is not to be distributed without Guidehouse’s prior written consent and subject to execution of a third-party access agreement. Guidehouse’s conclusions are the results of the exercise of its reasonable professional judgment and are based, in part, upon facts provided to Guidehouse by CenterPoint Houston, which Guidehouse has accepted with CenterPoint Houston’s permission as true and accurate without independent verification or inquiry.

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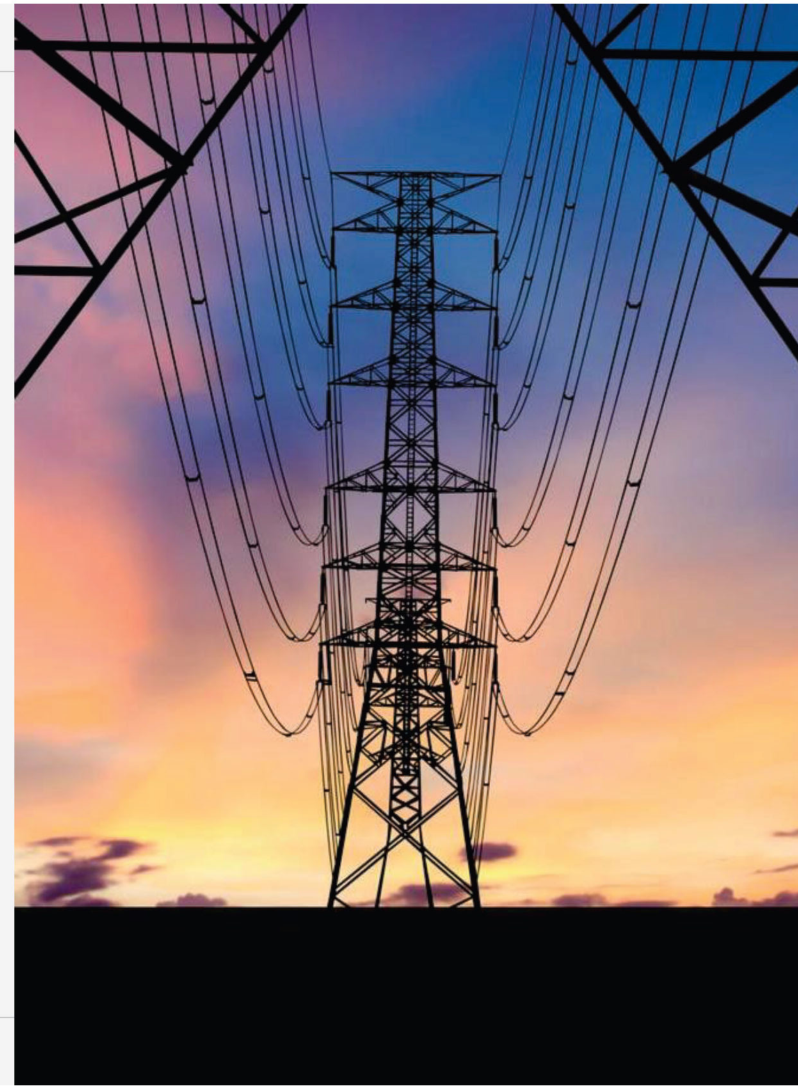
Guidehouse

Topics

Benchmarking TX Utility Resiliency Plans



Benchmarking Objectives

Inform filing content & narrative development based upon review of resiliency plans and proceedings of four (4) peer TX utilities

01

Identify potential content to include in the Guidehouse report *(update to existing benchmarking appendix)*

02

Identify recommendations to enhance communication and mitigate potential concerns

NOTE: Comparisons made between CenterPoint and other utilities generally refer to the CenterPoint's April 2024 filing, unless noted otherwise.

Findings & Recommend-ations *(1/2)*

SCOPE & OUTCOMES

Resiliency plans and proceedings for the four other TX utilities suggest a favorable outlook for CenterPoint, and CenterPoint could reference these proceedings to help bolster its case.

FINDINGS		RECOMMENDATIONS
PUCT orders for Oncor and Entergy both indicate **support for >99% of proposed resiliency investments**.*	→	While encouraging, do not presume support, as there are reasons for potentially greater scrutiny (e.g., significant $ increase).
Although **some intervenors voiced concern** and pushback, regulators still indicated overwhelming support	→	Focus narratives and messaging heavily on the PUCT audience. Address key stakeholder issues by exception or in proceedings.
$5B of investment would be **proportionally high** relative to others, but can be justified based upon **greater resiliency risks**.	→	Directly address and emphasize Houston's uniquely significant resiliency risks.
The **mix of investment** categories is relatively **similar** across TX utilities, with differences largely linked to resiliency risks.	→	Support justification based upon similarities while highlighting necessary differences (e.g., greater hurricane risk).
Technology resiliency risks and measures were consistently emphasized/prioritized less than natural disaster risks, but proposed investments still generally garnered approval.	→	Consider keeping proposed technology resiliency measures that address notable cybersecurity risks.
PUCT required additional metrics for Entergy, which had proposed limited proposed metrics in its filing.	→	Propose sufficient metrics that CNP is comfortable with to avoid having un-vetted metrics imposed by the PUCT.
PUCT explicitly provided **budget flexibility** for Oncor to support ongoing refinement of investment prioritization.	→	Explicitly address the value of flexibility in budgets, and propose certain parameters and mechanisms to support that.

**PUCT Order is limited to the reasonableness and prudency of the framework to evaluate investment decisions (the review of actual costs incurred for reasonableness, necessity, and prudence will be addressed in the appropriate rate proceedings)*

Findings & Recommend-ations *(2/2)*

ANALYSIS & NARRATIVES

The approaches that CenterPoint and Guidehouse are taking appear to be generally more thorough than other utilities, but there are some differences that may prompt questions from the PUCT or other intervenors.

FINDINGS		RECOMMENDATIONS
Guidehouse's **risk analysis** appears notably **more robust** than that for other utilities. The **BCA** methodology is more **similar** than different.	→	Highlight growing risk over time. Be prepared to address potential questions regarding differences in BCA methodology (e.g., program- vs. project-based approaches).
Other utilities provided **quantitative** analysis to inform **prioritization** of investments by network location (e.g., substation).	→	Provide discussion/justification clarifying how investments are prioritized. Be prepared to address questions regarding differences in approach relative to other utilities.
Other utilities did not appear to place clear emphasis on addressing **affordability and equity** considerations.	→	It is worthwhile to proactively address in testimony, but a concise summary is advised to build support without undue attention.
Other utilities did not provide clear communication of the precedent for their plans based upon **benchmarks**.	→	Include benchmarking analysis again, and update as appropriate, to further bolster case for approval.
For Oncor, PUCT noted that **BCR** for all investments should **exceed 0.8**, acknowledging that some benefits may be difficult to measure.	→	Note that all BCRs for proposed investments exceed the threshold of 0.8 that PUCT noted for Oncor, and make note of other benefits that may not be explicitly quantified (e.g., reliability impacts).
Oncor primarily focused on **wildfire risk** as a driver for investments, despite limited historical wildfire issues, and received PUCT support for proposed investments.	→	Highlight the significantly higher risk for CNP in comparison with other utilities while proposing a comparable level of investment per customer.

Summary of Proposed Plans

At $5B, CenterPoint's proposed cost per customer for resiliency investments would seem to be reasonable in comparison to peers:

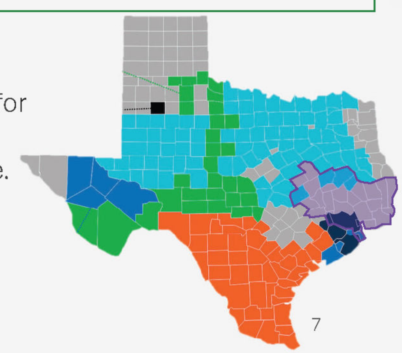
- ~2x ($/cust) vs. Oncor, but much greater resiliency risk
- ~2/3 ($/cust) vs. TNMP, which has a similar resiliency risk

SUMMARY COMPARISON

	Oncor	Entergy	AEP TX	TNMP	CNP
Total Request	$3,412M	$335.1M	$352.1M	$751.1M	New: ~$5B Orig: ~$2.3B
Utility Size (Customers)	3.9M	512,000	1.1M	270,000	2.8M
Normalized Cost ($/cust)	$870	$650	$350	$2,780	New: $1,790 Orig: $820
Filing Date	5/6/2024	6/21/2024	9/25/2024	8/28/2024	4/24/2024 1/31/2025
Filing Status	Proposed PUCT Order	Proposed PUCT Order	Intervenor Testimony Coming Soon	Intervenor Testimony Coming Soon	Withdrawn
Approved Amount[1]	$3.38B *(99%)*	$335M *([100%])*[2]	n/a	n/a	n/a

APPROVAL CLARIFICATIONS

1. The amounts approved for Oncor and Entergy indicate support for the proposed investments, but they do not assess prudency or guarantee cost recovery, which requires a subsequent rate case.
2. 59% of Entergy's approved investments are dependent on the level of grant funding received from the Texas Energy Fund



TX UTILITY BENCHMARKING

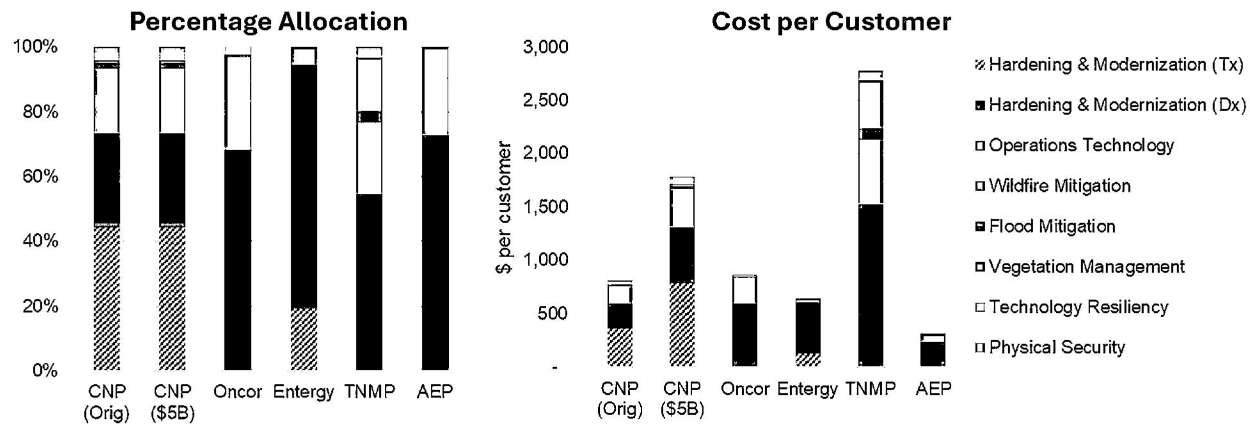
Investment Magnitude & Allocation

Despite different risk profiles, the level of proposed resiliency investment per customer is relatively consistent between CNP's original plan and plans from **Oncor** and **Entergy**.

Plans from **TNMP** and **AEP** are exceptions, with relatively high high (TNMP) and low (AEP) investment levels per customer.

CNP's original plan includes relatively high transmission investment, while some others have relatively high investment in wildfire mitigation and vegetation management.

INVESTMENT ALLOCATION[1,2,3]



[1] *Categorization are based upon how each utility grouped different measures, which may not be consistent in all cases*

[2] *Figures above assume that $5B investment will be invested proportionally the same as the originally requested $2.3B*

[3] *CNP's transmission costs include: Transmission System Hardening, S90 Tower Replacements, 69-138 kV Conversion Projects, and Coastal Resiliency Upgrades*

KEY TAKEAWAYS

- Original CNP filing relative to Oncor (Oncor more inland):
  - Similar cost per customer and relative allocation for most investment categories (except greater Tx)
  - Oncor = greater vegetation mgmt., less flood mitigation due to different service area and risk profiles
- New CNP filing relative to TNMP (similar service area and risks):
  - Somewhat similar cost per customer for hardening/modernization and operations technology
  - Significantly higher costs for TNMP in other areas, especially wildfire mitigation and vegetation mgmt.
  - TNMP included salt contamination mitigation within the scope of their distribution hardening activities

Investment Prioritization & Risk Focus

- Others' plans include explicit quantitative assessment and prioritization of investments based upon BCA
- Other utilities, including Oncor, place significant focus on wildfire risk
- Risks not related to weather events are given lower priority

ONCOR

- Oncor identifies **wildfire risk as its top priority** risk to mitigate and notes that the risk is **mitigated across several measure categories**:
  - Overhead System Resiliency & Modernization
  - Flexible and Self Healing Distribution System
  - Vegetation Management Plus ("VM+")
  - Wildfire Mitigation
- Other prioritization factors include:
  - Focus on underperforming areas
  - Foundational Investments (e.g., new tech and equipment investments for self-healing grid)
  - Highest ratio of customer benefits to implementation costs
  - Vegetation management
  - Information delivery systems

AEP

- Prioritize **highest resiliency benefit per dollar** invested based on reduced restoration costs and CMI
- Establish investment level and mix that maximizes customer benefits while working in labor and technical execution constraints

ENTERGY

- Entergy Texas **does not appear to prioritize a single type of risk** as the primary driver of its investments (appears to prioritize storm and wildfire resiliency events similarly)
- Entergy Texas also notes that **wildfire risk is mitigated across several measure categories** :
  - Distribution Feeder Hardening
  - Lateral Hardening
  - Lateral Undergrounding
  - Targeted Vegetation Management
- All projects are ranked based on their benefit-cost ratio under 3 future storm scenarios

TNMP

- Prioritization factors include:
  - Areas with **highest customer benefits relative to required investment**
  - **Wildfire risk** reduction
  - Focus on Low performing areas
  - Foundational investments in operation and cybersecurity
  - Physical protection

Outcomes & Evidence

In general, CenterPoint and Guidehouse are developing a more thorough and well-substantiated case for resiliency investment than other TX utilities did in their filings.

Nonetheless, CenterPoint should be prepared for potential questions regarding differences in BCA methodology relative to other Texas utilities and should be ready to support the rationale for the differences.

RISK ANALYSIS

Guidehouse's risk analysis methodology is significantly more robust than other utilities' analyses, including:

- Significantly increased locational granularity
- Use of forecasted future resiliency risks rather than just historical averages

BENEFIT-COST ANALYSIS

Guidehouse's BCA methodology is similar to that employed by other utilities, with a few notable differences:

- Others use ICE values (used nationally for reliability purposes) which vary by customer class, while Guidehouse uses a uniform (for all customer classes) VOLL value developed specifically for resiliency in Texas
- Guidehouse has calculated BCAs at the measure level across the network, while others have calculated BCAs at the circuit level for a combination of multiple measures
- Guidehouse has performed scenario analysis for different VOLL values, while others performed scenario analysis for different levels of event/CMI impacts
- Others have provided asset-level calculations to define thresholds for cost-effectiveness and total cost-effective investment potential, with proposed investment a fraction of that

OTHER ANALYSIS & DISCUSSION OF OUTCOMES

Other utilities notably did not provide clear, direct focus on other key considerations for justifying the proposed plans, including:

- Lack of clear discussion of affordability & equity considerations
- Lack of clear benchmarking analysis and justification based upon precedent

Resiliency Metrics for Investment Narrative and Reporting

- PUCT expects metrics for investments within each measure
- PUCT may impose metrics if proposed metrics are not deemed sufficient
- For most measures, CenterPoint's proposed metrics generally match or exceed those from other utilities

VARYING APPRORACHES TO METRICS

- Entergy and AEP have basic metrics and rely on overall reductions in restoration costs, CMI and $CMI to communicate their progress
- In addition to using their avoided restoration costs, CMI and $CMI, Oncor and TNMP take a multifaceted approach and combine their metrics into ratios and indexes which are used to communicate their progress
- Communication for cyber and physical security programs highlighted the difficulty estimating these risks
- Entergy was forced to settle on two additional metrics in their stipulation focused on comparing actual vs projected system CMI and resiliency system costs
- Oncor did face questions over its non-customer-focused metrics but did not have to make changes due to presence of other customer-focused metrics

METRICS USED TO EVALUATE THE EFFECTIVENESS OF INVESTMENTS

	Oncor		Entergy		AEP		TNMP	
Measure	*# of Metrics*	*Level of Detail*	*# of Metrics*	*Level of Detail*	*# of Metrics*	*Level of Detail*	*# of Metrics*	*Level of Detail*
Hardening and Modernization	4	Very High	3	Moderate	1	Basic	7	Very High
Wildfire Mitigation	2	High	1	Basic	2	Basic	2	Moderate
Flood Mitigation	0	N/A	0	N/A	0	N/A	1	Basic
Vegetation Management	5	Very High	0	N/A	1	Basic	7	Very High
Technology Resiliency	12	Very High	0	N/A	0	N/A	10	Very High
Other (Physical Security, operations and technology)	3	High	0	N/A	0	N/A	4	Basic

Level of Detail
N/A = no measurement of impact
Very High = consumer and measure level data, including comparisons with status quo

- CenterPoint generally provides a relatively high level of detail across all metrics
- CenterPoint specifies *how* each program will be evaluated using the specific metrics, while other utilities tend to simply note *what* metrics will be evaluated
- CenterPoint may still anticipate questions, especially in areas where the customer benefit is difficult to measure

Interrogatory and PUCT Orders

Oncor and Entergy proceedings provides valuable insights into how CenterPoint can prepare its SRP and testimony for success

- Highlight favorable BCRs, as well as identifying other difficult-to-quantify benefits
- Leverage thresholds & design standards that support resiliency investment
- Propose certain parameters and mechanisms to support budget flexibility
- Ensure adequate evaluation metrics that address customer value

ONCOR INTERROGATORY

- **Benchmark Proposed Investments to Historical**– Proposed investments that are similar to past investments prior to the SRP should have similar costs at a unit level (i.e., $/mi for vegetation mgmt)
- **BCR Results for Investment Screening**– PUCT Staff recommended approval of investment with a BCR >0.8
- **Evaluation Metrics**– Evaluation Metrics should demonstrate reductions in resiliency risk

ONCOR STIPULATION & ORDER

- **Implementation Flexibility**– Oncor will have the ability to be flexible in areas of investment, especially in wildfire risk and underperforming areas that change over time
- **Budget Flexibility**– Oncor will have a budget flexibility provision to allow for flexibility in spend over the SRP investment period to allow for resiliency investments to be prioritized as needed
- **Cost Recovery**– The review of actual costs incurred for reasonableness, necessity, and prudence will be addressed in an appropriate rate proceeding to determine cost recovery of SRP investments; the PUCT Order does authorize cost recovery of the SRP investments

ENTERGY TEXAS INTERROGATORY

- **Infrastructure Resiliency Thresholds**– Design standards that are used should be defensible and clearly understood by parties and PUCT staff in the analysis that supports the investment thesis (if standards are used above the National Electric Safety Code (NESC) 250C minimum, rationale should be made)
- **Defend Wildfire Risk Effectively**- Initial wildfire risk assessments should include wildfire activity in the utility service territory in addition to studies of potential future wildfire risks

ENTERGY TEXAS STIPULATION & ORDER

- **Evaluation Metrics** – In addition to its failure rate metric, Entergy will develop and report a CMI and SRC ratio that compares actual CMI or SRC of hardened circuits to models of unhardened circuits
- **Regulatory Asset Accounting** – Detailed records of Regulatory Asset accounting must be kept to allow for review and reconciliation of costs including the Texas Public Utility Regulatory Act (PURA) Chapter 36

See Appendix for additional details

Guidehouse

Thank You

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Appendix

Interrogatory and Order Review for Oncor and Entergy

Oncor Interrogatories Highlights

A review of testimony in the Oncor SRP proceeding provides valuable insights into how CenterPoint can prepare its SRP and testimony for success

- Rely on 16 TAC § 25.62 to support investment thesis and testimony
- Develop a strong narrative if a BCR is not used for wildfire mitigation
- Address interdependencies between measures and how those may affect resiliency impacts and prioritization

Intervenors: **Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC), & Committee of Cities Served by Oncor (OCSC)**

- Remove proposed investments that are not distinguishable from existing utility investments/programs
- Evaluation metrics must meet requirements of 16 TAC § 25.62 and have clear correlation to mitigate resiliency risk during resiliency event
- Proposed spend may be more expensive than previous programs; for example, Vegetation Management

Public Utility Commission of Texas Staff

- Supported Oncor SRP Investments aside from the Mobile Transformer Inventory Program
- An investment should be removed if it shows a BCR below 0.8
- Identify the interdependencies between different measures and how that may affect resiliency impacts (e.g., potential for diminishing returns for downstream measures due to resiliency benefits from upstream measures).

Oncor Rebuttal

- Lack of a quantitative BCR for Wildfire Mitigation should not be evidence for wildfire risk investment exclusion from the SRP
- 16 TAC § 25.62 does not require the SRP investments to meet a certain BCR threshold: BCR is a tool used to explain the expected benefits of a resiliency investment which is required by 16 TAC § 25.62
- Lack of a quantitative BCR for Wildfire Mitigation should not dismiss Wildfire Mitigation investments

Possible Next Steps

- Link proposed investments and evaluation metrics to 16 TAC § 25.62 in SRP investment narrative; ensure cost estimates align with similar investments before the PUCT in other proceedings
- Articulate full implementation of electric grid investments to deliver the level of resiliency required in 16 TAC § 25.62; mention proposed SRP investments will increase grid reliability during non-resiliency events; and state 16 TAC § 25.62 authorization to propose and accelerate existing investments
- Defend lack of a quantitative BCR for Wildfire Mitigation

Entergy Texas Interrogatories Highlights

A review of testimony in the Entergy Texas SRP proceeding provides valuable insights into how CenterPoint can prepare its SRP and testimony for success

- Efficacy metrics were singled out by all parties and new metrics with CMI and SRC were created
- By the PUC's response, Wildfire measures are not simply O&M programs
- Justified spending or BCR holds a lot of weight with PUCT and intervenors

Intervenors: **Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC) , & Walmart**

- Suggested wildfire is not a risk in Entergy service area, and cost recovery for wildfire mitigation programs should not receive a rate of return since they would otherwise be O&M programs
- Entergy should establish measurement mechanisms to evaluate outages, disruptions, and power irregularities, including resiliency-focused metrics based on SRC and CMI
- Entergy's adoption of extreme wind loading guidelines that exceed NESC Rule 250C increase SRP costs while delivering unknown incremental benefits

Public Utility Commission of Texas Staff

- Efficacy metrics should include an appropriate comparison group, or an estimation of CMI avoided that is attributable to the implemented resiliency measures
- Support all measures so long as the BCR is acceptable

Entergy Texas Rebuttal

- NESC Rule 250C is a minimum standard and not a recommendation. Given that hardening benefits are realized when infrastructure does not fail, exceeding the standard is acceptable
- The Texas A&M Forest Service Wildfire Risk assessment identifies portions of Energy's service area as high risk for wildfire ignition, based on past reports there have been wildfires and a clear risk for more in the future

Possible Next Steps

- Provide justification for why wildfire is a significant risk in the CenterPoint service area, and differentiate the proposed measures from past reliability and O&M activities
- Ensure SRC and CMI are used to evaluate of customer benefits and overall progress of resiliency program implementation
- Show benefits as attributable to the resiliency measures or in comparison to an appropriate group

Oncor Stipulation Agreement & Proposed Order

Oncor reached a Stipulation Agreement with SRP intervening parties, and the PUCT has issued a Proposed Order, both of which are favorable:

- 99% proposed investment approved
- Provided flexibility in allocating budgets

Stipulation Items

- **Implementation Flexibility:** Oncor may shift wildfire and underperforming areas-related work to other areas of the Oncor system if Oncor's wildfire modeling shows a material change in wildfire risk or underperforming areas without having to seek a good-cause exception under 16 TAC § 25.62(e)
- **Deferral:** Oncor will defer $309M of its three-year SRP to a fourth year 2028; the Commission should authorize the expenditure only if Oncor does not filed another proposed SRP before the end of the third anniversary of the Commission's final Order approving Oncor's SRP
- **Cost Management:** Oncor may reallocate the estimated expenditures across the measures in an amount not to exceed 20% of the estimated expenditures by measure except for VM+
- **Investments at Substations with a BCR below 0.8:** Signatories support a Commission finding that making investments at substations with a BCR below 0.8 is reasonable and prudent

Cost Recovery

- The approval **Stipulation** and **PUCT Proposed Order** is limited to the reasonableness and prudency of the framework **to evaluate investment decisions** (the review of **actual costs incurred for reasonableness, necessity, and prudence will be addressed in the appropriate rate proceedings** provided for by 16 TAC § 25.62(f)(3)
- In accordance with 16 TAC § 25.62(f), Oncor is authorized to **defer its distribution-related costs** relating to the implementation of Oncor' s SRP for recovery as a **regulatory asset**
- The Signatories agree that the Commission should **not approve in this proceeding an amortization period for the deferred regulatory asset** to which Oncor books its SRP-related distribution costs and expenses and that the appropriate amortization period **be determined in the proceeding in which Oncor requests recovery of SRP-related costs.**

Possible Next Steps

- Identify areas of compromise with parties, and view rebuttal testimony as laying the foundation for a settlement agreement
- Bring forth cost recovery strategies in the Stipulation to inform parties how future cost recovery will work

Entergy Texas Stipulation Agreement & Proposed Order

Entergy Texas reached a stipulation agreement with SRP intervening parties, and the PUCT has issued a Proposed Order, which are generally favorable with a couple notable exceptions:

- 59% of the proposed investment is subject to receiving grant funding
- Additional required reporting metrics were added

Stipulation Items

- **Evaluation metrics** – In addition to its failure rate metric, Entergy will develop and report a CMI and SRC ratio that compares actual CMI or SRC of hardened circuits to models of unhardened circuits
- **Deferral** - ETI may defer all or a portion of the distribution-related costs relating to the implementation of Phase I of its Resiliency Plan for future recovery as a regulatory asset including depreciation expense and carrying costs at its weighted average cost of capital
- **Wind hardening** – Cost comparison for hardened distribution and transmission structures using the NESC wind loading standard and Entergy's proposed standard to be included in its first annual resiliency report
- **Bookkeeping** - Must maintain detailed records related to the regulatory asset to allow review and reconciliation of costs. This includes tracking when resiliency projects began service and providing documentation for associated costs, ensuring compliance with PURA Chapter 36

Cost Recovery

- $198M of plan scope is contingent on Texas Energy Fund grant, additional $137M will be utility investment
- Entergy does not plan to use a resiliency cost recovery rider as per 16 TAC § 25.62(f)(1)
- Entergy can defer distribution-related costs for future recovery as a regulatory asset, including depreciation and carrying costs at the established weighted average cost of capital

Possible Next Steps

- Compromise may include trial periods on certain measures to ensure their efficacy i.e. Wind hardening
- CenterPoint should be prepared to defend its metrics, otherwise the commission may enforce their own


Guidehouse
CenterPoint Energy:
Wildfire Mitigation
Benchmarking
Analysis
OCTOBER 29TH, 2024
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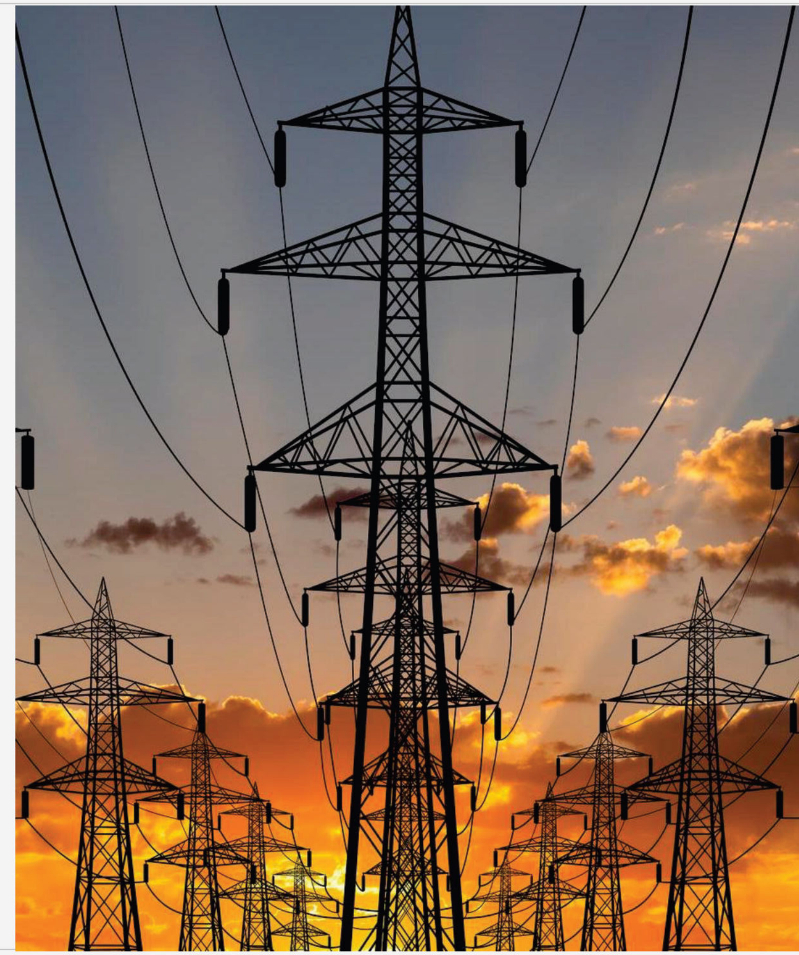
Agenda

Wildfire Mitigation Measures Benchmark



Wildfire Mitigation Measures Considered

Situational Awareness

- Drone Technology
- IGSD
- Weather Stations
- Wildfire Cameras
- Modeling/Analytics
- Fuel Moisture Sampling
- Inspections and Patrols

Infrastructure Hardening

- Substation Hardening
- Non-expulsion Fuses & Lightning Arresters
- Pole Replacements
- Lateral Hardening
- Lateral Undergrounding
- Transmission/Distribution line rebuilds

Asset Protection

- Fire Mesh
- Fire Retardant Sprays
- Animal Guards
- PSOM
- Enhanced Protocols

Ignition Mitigation

- Early Fault Detection
- Remote Switches
- Covered Conductors
- Intelligent Vegetation Management
- Targeted Grazing

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Texas Utility Environmental Considerations

CONSIDERATIONS

Wildfire Risk, Rainfall, Temperature, and Terrain

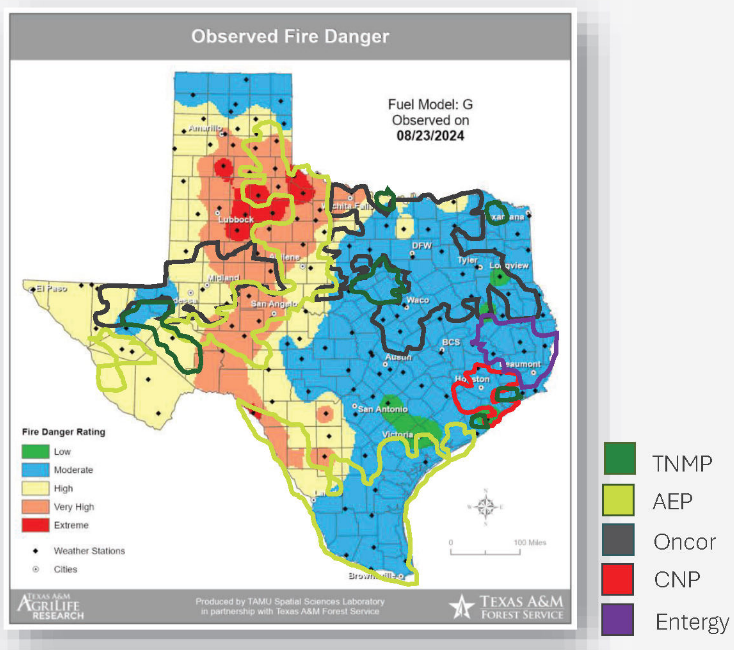
Geography Comparisons

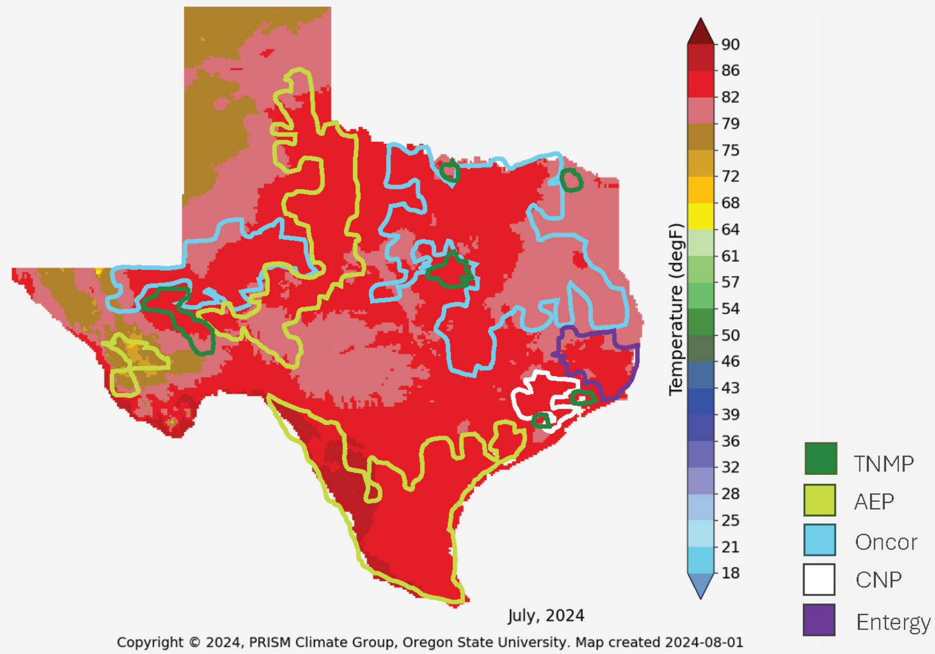
Environmental Considerations	CenterPoint	Oncor	Entergy	AEP Texas	TNMP
Wildfire Risk*	Moderate	High	Moderate	Very high	Moderate
Avg. Annual Rainfall	1 to 5 in.	0.01 to 2.8 in.	1 to 3.8 in.	0.01 to 2 in.	0.01 to 2 in.
Avg. Annual Temperature	~82° - 86°F	~82° - 86°F	~82° - 86°F	~72° - 90°F	~82° - 86°F
Terrain	Coastal Prairie, Coastal Saline Prairie	Backland Prairie, East Timberland, High Plains	East Timberland, Costal Prairie, Flatwoods	Central Rio Grande Plain, Costal Prairie, Rolling Plains	High-Plans, Coastal Prairie

*Source from Texas A&M AgriLife Research 2024

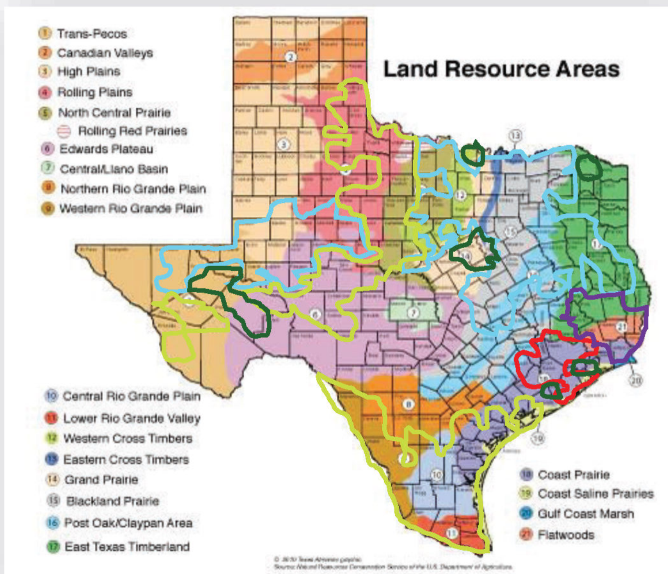
Fire Danger and Temperature Comparisons

CenterPoint located mostly in a moderate hazard zone, but subject to high average temperature

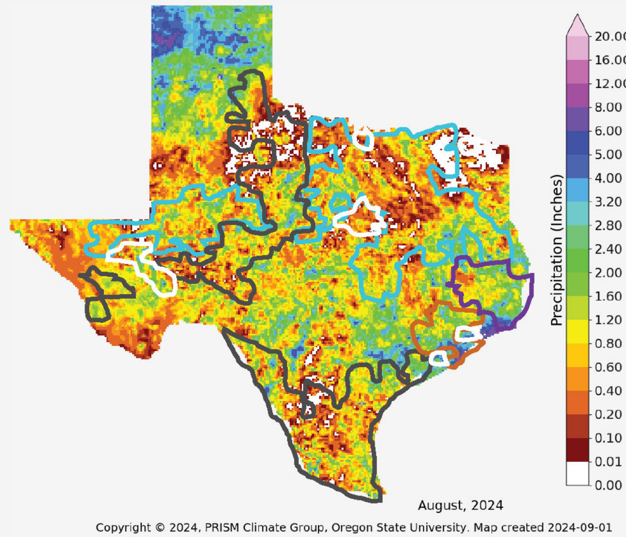




Terrain and Rainfall Comparisons



TNMP
AEP
Oncor
CNP
Entergy



TNMP
AEP
Oncor
CNP
Entergy

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Texas Utilities Wildfire Mitigation Plans

UTILITIES INCLUDED

Oncor Energy, Entergy, AEP Texas, and Texas New-Mexico Power

Oncor Current Wildfire Mitigation Measures

4 Million Customers

Current Mitigation Strategies

- Vegetation Management
  - LiDAR
  - General vegetation management
- Asset Management
  - Asset inspections
  - Limited replacement of wood structures
- Monitoring for Fire Weather Conditions
- Protective Devices
  - Smart switches to stop energy flow when there has already been an ignition.

Development Theme

Invest in a variety of measures to protect current infrastructure to have more targeted infrastructure hardening later.

- While there have been no substantially large wildfires since 2011, burn probability and risk of wildfire have increased substantially in Oncor's service area.
- Current mitigation measures lower risk, but there are still many gaps and a need for expansion.

Oncor 2024 Resiliency Plan Proposed Wildfire Mitigation

Wildfire BCA Completed by 1898&Co

- Expansion of Wildfire Risk Modeling
  - Leverage publicly and commercially available datasets
  - Conduct fire-spread modeling with Oncor's assets
  - Develop an asset and wildfire-caused ignition fire risk model
  - Prioritize and implement mitigation activities
- Expansion of Situational Awareness Program
  - Enhance situational awareness resources
  - Near real-time risk modeling and monitoring
- Expansion of Ignition Mitigation Program
  - Install remote operable switches, replace lightning arresters and fuses with non-expulsion equivalent, and install animal guards
  - Clear to bare ground around equipment poles, perform periodic enhanced inspections,
- Addition of Asset Protection Program
  - Wrapping wood poles with fire retardant material, establishing defensible space around critical facilities, and rebuilding wood-structure substations with steel structures.

Measure*	Capital Spend ($M)	O&M ($M)	Total Spend ($M)	Spend Per Customer
Modeling	$6.2	$1.1	$7.3	$1.8
Situational Awareness	$8	$1.4	$9.4	$2.35
Ignition Mitigation	$60	$5.7	$65.7	$16.4
Asset Protection	$70.9	$28.6	$99.5	$24.8
Total	**$145**	**$37**	**$182**	**$45.4**

*In 2023, Oncor replaced/upgraded 390 circuit miles of transmission lines, 42 substations, and underwent 34 major switching station projects.

Entergy Current Wildfire Mitigation Measures

512,000 Customers

Current Mitigation Strategies

- Transmission and Distribution Hardening
    - Some replacement of wooden infrastructure with steel.
- Weather Room Tracking
    - Weather tracking and burn probability modeling.
- Vegetation Management
    - Inspections and regular vegetation clearings.
- High Heat Protocols
    - Strict protocols surrounding operations when temperatures are high.

Development Theme
Harden more infrastructure now to prevent impact of all risks, not only wildfire.

- Entergy's greatest risks are extreme storm events and hurricanes and has tied wildfire risk mitigation into storm risk mitigation.
- Their spending includes the spending for storm and extreme weather preparedness.
- Entergy has taken the approach of infrastructure hardening over integration of technologies or asset protection.

Entergy 2024 Resiliency Plan Proposed Wildfire Mitigation

No wildfire BCA was completed

- Distribution Feeder Hardening (Rebuild to standard)
  - Rebuilding distribution feeders to withstand 150 mph winds and replace old or weakened infrastructure.
- Lateral Hardening (Rebuild to standard)
  - Rebuilding distribution laterals to withstand 150 mph winds and replace old or weakened infrastructure.
- Lateral Undergrounding
  - Undergrounding of targeted overhead lines.
- Targeted Vegetation Management
  - Analytics-based, proactive targeted inspections of the distribution system to identify and mitigate vegetation wildfire risks.

*Comprehensive Hardening Projects were found by 1898 & Co to enable ~40% reduction in storm restoration costs.

Measure	Capital Spend ($M)	O&M ($M)	Total Spend ($M)	Spend Per Customer
Distribution Feeder Hardening	$101	$19.4	$120.4	$235
Lateral Hardening	$124	$3.2	$127.2	$248.8
Lateral Undergrounding	$2.8	N/A	$2.8	$5.4
Targeted Vegetation Management	$12	$6.6	$18.6	$36.3
Total	**$239.8**	**$29.2**	**$269**	**$525.2**
Total Excluding Dist. and Lat. Hardening	$14.8	$6.6	$21.4	$41.7

AEP Texas Current Wildfire Mitigation Measures

1.1 Million Customers

Current Mitigation Strategies

- SCADA
  - Situational Awareness and Control
- General Vegetation Management
  - 4-year management cycle on key circuits
  - Performance-based prioritization using customer reliability on whole system
- Distribution Contamination Mitigation
  - High contamination of insulators leads to flashovers and risk of fire
  - Periodical assessments, power washing, and silicone grease

Development Theme

Invest in technology and increase situational awareness to better target risk mitigation activities.

- AEP Texas is looking to develop their wildfire risk mitigation programs and is starting with some of the most cutting-edge technology.

AEP Texas 2024 Resiliency Plan Proposed Wildfire Mitigation

Wildfire BCA Completed by Fortis Alberta

- Wildfire Mitigation Vegetation Intelligence
  - Utilize data to identify vegetation risks and make informed decisions
  - Actionable analysis of vegetation inside and near distribution system
  - Tool forecasts and ranks potential impacts to distribution system.
- Drone Technology
  - Autonomous drones conduct asset inspections
  - Docked at 50 substations operating autonomously
  - Complete panoramic scans to detect and alert smoke and fire
- Early Fault Detection
  - Install advanced monitoring equipment to scan distribution equipment using radio frequencies and locate defects
- SCADA Expansion
  - Installing SCADA in more areas
  - Provides AEP with real time system information that can quicken the response to wildfires and protect assets

Measure	Capital Spend ($M)	O&M ($M)	Total Spend ($M)	Spend Per Customer
Vegetation Intelligence	N/A	$4.2	$4.2	$3.8
Drone Technology	$11.33	$3.4	$14.73	$13.39
Early Fault Detection	$20.96	N/A	$20.96	$19
SCADA Expansion	$23.6	$0.2	$23.8	$21.6
Total	**$55.89**	**$7.8**	**$63.69**	**$57.79**

TNMP Current Wildfire Mitigation Measures

270,000 Customers

Current Mitigation Strategies

- Ignition Mitigation
  - Reactive Vegetation Management- only tree trimming
  - Level 1 Tree Risk Assessment: Limited Visual Assessments
  - The Company captures UAS imagery periodically.
  - Periodic replacement of equipment (reclosers, capacitors, fuses)
- Asset Protection
  - Restores and replaces some poles and crossarms on an as-needed basis
- Situational Awareness
  - Partners with an outside vendor to receive daily 5-day forecast emails that provides guidance on wildfire risk in operating regions

Development Theme

Building on what they currently have to create a more proactive mitigation strategy after the Smokehouse Creek Fire, the single largest wildfire in Texas history in February 2024.

Burned over 1 million acres in north TX, took nearly 3 weeks to fully contain.

TNMP 2024 Resiliency Plan Proposed Wildfire Mitigation

1898&Co Wildfire BCA Redacted

- Asset Protection Program
  - Hardening facilities
  - Conducting fuels management
- Improvement of Situational Awareness Program
  - Deployment of weather stations, **early fire detection cameras,** TNMP-specific Fire Potential Index, Fire Danger Operating Plan
  - Enhancement of wildfire resiliency event coordination and communication
  - Pilot new wildfire sensor technology
- Expansion of Ignition Mitigation Program
  - Replacement and upgrading of expulsion-type fuses, capacitor banks, reclosers, and copper wire
  - Assessment and mitigation of wildfire-related ignitions
  - Vegetation Management
    - Proactive Vegetation Management
    - Enhanced Tree Risk Assessment and Mitigation
    - Remote Sensing
    - Risk-Based System Utilizing Vegetation Inspection and Data Analysis

Measure	Capital Spend ($M)	O&M ($M)	Total Spend ($M)	Spend Per Customer
Asset Protection	$35	$4.1	$39.1	$144.8
Situational Awareness	$22.6	$2.5	$25.1	$92.96
Ignition Mitigation	$35	$3.4	$38.4	$142.2
Total	**$92.6**	**$10**	**$102.6**	**$379.96**

Spending per Customer

Total

CenterPoint*	Oncor	Entergy**	AEP Texas	TNMP
$64.57	$45.4	$41.7	$57.79	$379.96

Capital

CenterPoint	Oncor	Entergy	AEP Texas	TNMP
$48.98	$36.25	$28.9	$50.8	$342.9

O&M

CenterPoint	Oncor	Entergy	AEP Texas	TNMP
$15.58	$9.25	$12.8	$6.99	$37.06

*As reported in CenterPoint's April 2024 Resiliency Plan filing before the PUCT
**Spend per customer excluding Lateral and Distribution Hardening Measures

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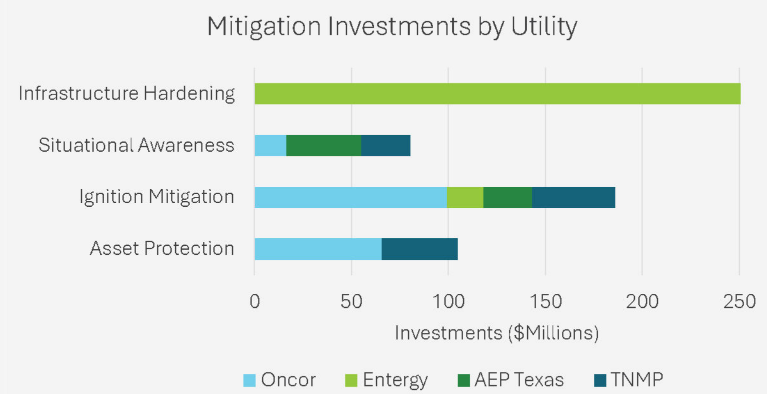
OCTOBER 29TH, 2024

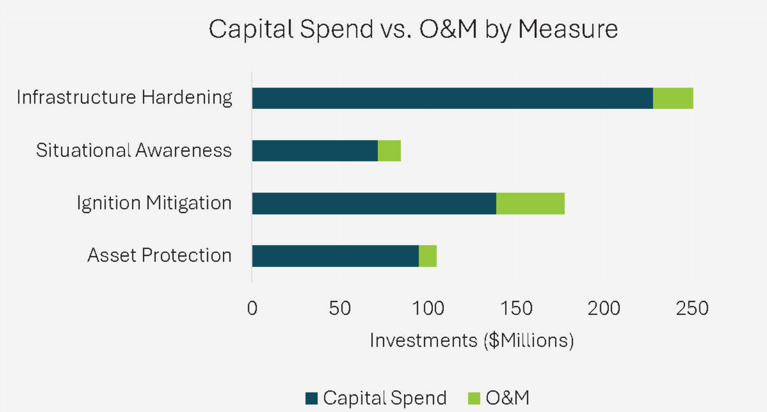
CNP Priority Program Overlap

Program	CenterPoint	Oncor	Entergy	AEP Texas	TNMP
Wildfire Vegetation Management					
Early Fire Detection Cameras					
Undergrounding					
Modeling/Analytics					
IGSD					
Drone Technology					
Remote Switches					
Fire Retardant Sprays/Wraps					
Early Fault Detection					
Dist. Feeder Hardening					
Lateral Hardening					
Animal Guards					
SCADA Expansion					
Enhanced Protocols					
Non-Expulsion Fuses					

Budget per Mitigation Measure Category

Mitigation	Capital	O&M	Total Proposed Spend ($M)	Avg. Spend per Customer
Infrastructure Hardening	$227.8	$22.6	$250.4	$42.57
Situational Awareness	$71.7	$12.8	$80.3	$13.65
Ignition Mitigation	$138.8	$38.6	$181.6	$30.87
Asset Protection	$95	$9.8	$104.8	$17.82





Evaluation Metrics

Oncor	Entergy	AEP Texas	TNMP	Centerpoint*
Resiliency Index	Hardened Infrastructure Failure rate	Hardened Infrastructure Failure rate	Ignitions and Thermal Events	Wildfire events and estimated extent that resiliency measure reduced risk.
Normalized Event Impact	Data on execution of vegetation management	Data on execution of vegetation management	Wire-Down Events	Number of fire detections through monitoring
System outage minutes		Report on efficacy of wildfire related activities	Vegetation-Related Ignitions	Miles of ROW inspected, and amount spend on vegetation management
System Restoration Duration				Total circuits inspected
Wildfire Mitigation Zone Outage Events				Number of relays replaced for wildfire mitigation
				Number of IGSD opperations
				Analysis of accuracy of algorithms in real time

*As reported in CenterPoint's April 2024 Resiliency Plan filing before the PUCT

Guidehouse

Other US Utilities

UTILITIES INCLUDED

Southern California Edison and Nevada Energy

Key Differences in Filings

Filing	Legislation Passed	Events Covered	Other Notes
TX Resiliency Plan	2023	Storms, Wildfires, Security breaches, Hurricanes	Covers a variety of risks and is not limited to natural disasters
CA Wildfire Mitigation Plan	2016, 2018, 2020, 2024	Wildfires	Highly technical plan detailing how, why, and when wildfires occur.
NV Natural Disaster Protection Plan	2019	Storms, Hurricanes, Wildfires	Must include protocols

Southern California Edison 2020-2022 Achievements

Covered Conductor
Installed 3,880+ circuit miles

Weather Stations
1,150 weather stations installed across our HFRA

Sectionalizing Devices
Installed 80+ devices, resulting in 150 total

Customer Resiliency Program
Delivered more than 10,200 Critical Care Backup Batteries to medical baseline customers

Undergrounding
Completed 19+ miles

High-Def Cameras
Installed 21 HD cameras, resulting in 180 in HFRA

Fast-Acting, Current-Limiting Fuses
Installed/replaced 3,740+ fuses

High Fire Risk Inspections & Remediations
Completed 541,400 distribution and 73,600 transmission structure inspections. Performed repairs and replacements

Vegetation Management
Completed hazard tree assessments on 1,325+ circuits, performed 21,000 hazard tree mitigations, and cleared brush at the base of 502,400+ poles

Public Safety Power Shutoff
Grid hardening measure on 140+ circuits, advanced risk modeling for FPI thresholds, and enhanced customer notification process

** Total actuals for 2020-2022: $4,586,212 (spend thousands $)

Southern California Edison 2023-2025 Updates

Advancements in Risk Modeling Capabilities

Update risk models with improved ML models, weather and fuels information, forward-looking climate scenarios, and risk reduction from completed grid hardening projects.

Grid Design, O&M, Expanded Measures

To install more than 2,850 additional circuit miles of covered conductor, replace 7,200+ circuit miles, underground 100 miles of lines in SRA, and have higher-frequency inspections.

Vegetation Management and Inspections

Maintaining required distance between trees and lines, implementing new software that will facilitate advanced analytics. Evaluate remote sensing technologies such as LiDAR and satellite imagery.

Situational Awareness and Forecasting

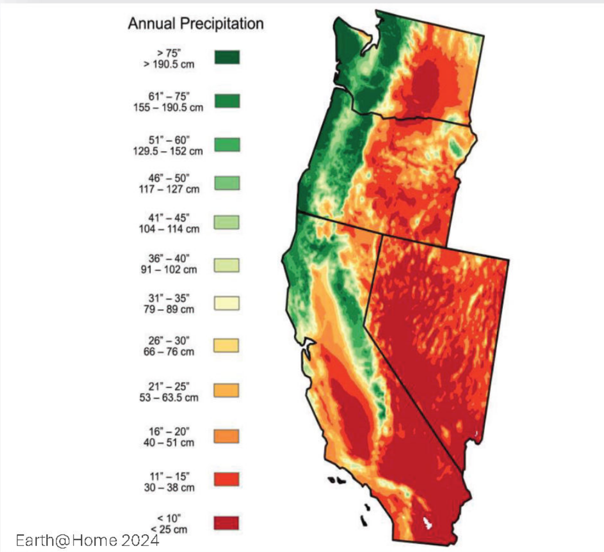
Adding WF cameras to monitor ignitions and fire progress, an additional 150 weather stations, satellite imagery, and advanced technology to better fire spread modeling, and increase ability to response.

Emergency Preparedness

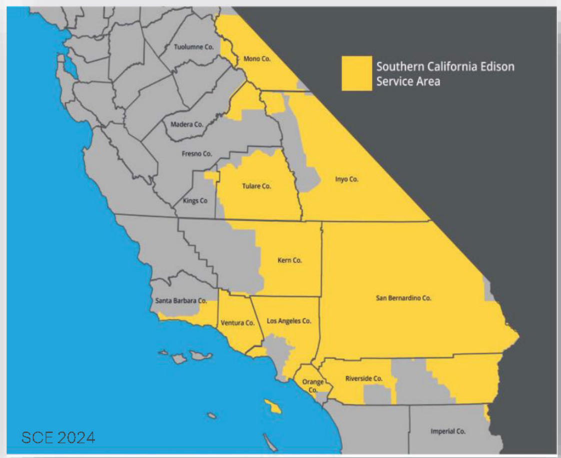
Trained workforce is ready to restore power and assist customers. There is a dedicated and trained Incident Management Team to manage the emergency response. Extending partnership with fire agencies in the service area.

** Total planned for 2023-2025: $5,625,332 (spend thousands $)

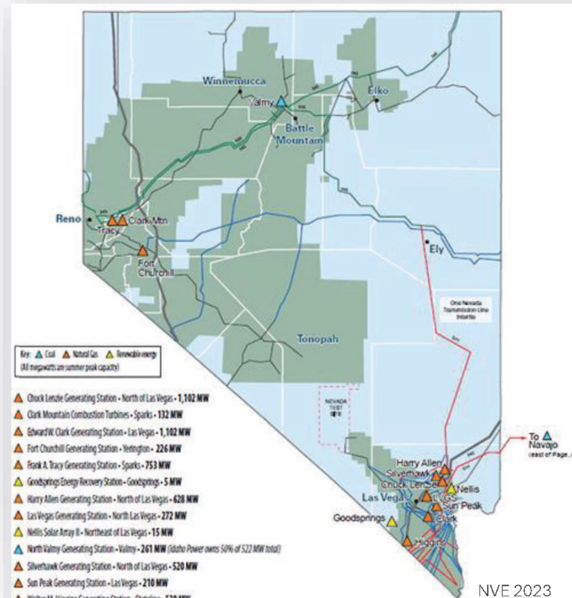
Utility Service Territory and Rainfall



Earth@Home 2024



SCE 2024



NVE 2023

Nevada Energy 2020-2023 Natural Disaster Protection Plan

Vegetation Management
Tree-trimming, pole grubbing, and fuel inventory

Risk-Based Approach
Emergency response, proactive technology assessment and asset management, and resource sufficiency

System Hardening
Fire mesh, lightning arrestors, and non-expulsion fuses

Situational Awareness
Weather stations and wildfire cameras

Inspections, Patrols, and Corrections
Circuit resiliency, and inspections, patrols, corrections

Public Safety Outage Management
Shutting off power in extreme cases to protect utility and customer property

Nevada Energy 2023-2026 Natural Disaster Protection Plan

Proposed Measures

Risk Based Approach
- Wildfire risk modeling
- Emergency response

Situational Awareness
- Wildfire alert cameras
- Weather stations
- Staff meteorologist

Vegetation Management
- Logging
- Targeted Grazing
- Increased clearing radius
- Fuel Moisture Sampling

Inspections and Corrections
- Pole and fire tier inspections at a high frequency.
- Removal of copper wire
- Replacing traditional fuses with non-expulsion fuses

System Hardening
- Fire mesh
- Lateral Undergrounding
- Covered conductors
- Pole upgrades/replacements
- "Pole stopper" approach, replacing every 5th pole.

Outreach and Collaboration
- Collaborative plans with local government, emergency responders, and public agencies

Additional Measures
- Operational Practices
- Pro-active de-energization and emergency response
- PSOM

Nevada Energy 2023-2026 Proposed Spend

Measure	Capital Spend ($M)
Circuit Resiliency	$3.52
Copper Wire Replacement	$19.3
Line Rebuild- Distribution	$28.4
Lines Ruggedization	$10.9
Pole Replacements	$2.8
Resource Sufficiency	$0.046
Undergrounding	$64
Wildfire Cameras	$1.84
Expulsion Fuse replacement	$12.8
Line Rebuild- Transmission	$3.71
Reclosers	$2.9
Substation Hardening	$14.4
Tree Attachments	$6.36

Evaluation Metrics

CenterPoint	Southern California Edison	Nevada Energy
Resiliency Index	Multi-Asset Risk System (MARS) risk reduction	Mitigation-Cost Ratio
Normalized Event Impact	% Risk Impact (Unit per High Fire Risk Area)	Fault Clearing Times
System outage minutes	Number of Outages in High Fire Risk Areas	Relative mitigation effectiveness factor
System Restoration Duration	Number of Asset Management ignition risk-related work orders past due	
Wildfire Mitigation Zone Outage Events	Frequency, Scope, and Duration of Public Safety Outage events	
	Number of CPUC reportable ignitions	

CNP Priority Program Overlap

Program	CenterPoint	SCE	NVE
Wildfire Vegetation Management			
Early Fire Detection Cameras			
Undergrounding			
Modeling/Analytics			
IGSD			
Weather Stations			
Covered Conductors			
Fire Retardant Sprays/Wraps			
Targeted Grazing			
Fuel Moisture Sampling			
Pole Inspections			
Fire Tier Inspections			
Fire Mesh			
Enhanced Protocols			
Non-Expulsion Fuses			
PSOM			

Overall Findings

Wildfire Mitigation Plan Trends:

1. Protect current assets and expand situational awareness measures to gain more insight before completing infrastructure hardening.
2. Harden infrastructure as much as possible to mitigate risks not only from wildfire but from hurricanes and other extreme weather events.
3. Invest in technology-based solutions like smart switches and drones to be on the forefront of wildfire mitigation technology, but still prioritizing situational awareness.
4. Greatly expand vegetation management and prioritize proactive rather than reactive measures.
5. Broad range of measures being considered depending on the utility (23 measures).

Investment Takeaways:

1. The average highest spend per customer categories are infrastructure hardening and ignition mitigation.
2. Investment in vegetation management and situational awareness is common across all utilities.

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Thank You

Appendix

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1898 List of Extreme Weather Resiliency Events

Table 4-7: Extreme Weather Resiliency Events[25]

No.	Resiliency Event Type	Resiliency Event	Definition
8	Wind	High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
9		Strong Wind	Non-convective winds gusting less than 50 knots (58 mph), or sustained winds less than 35 knots (40 mph), resulting in a fatality, injury, or damage.
10		Funnel Cloud	A rotating, visible extension of a cloud pendant from a convective cloud with circulation not reaching the ground. The funnel cloud should be large, noteworthy, or create strong public or media interest to be entered.
11		Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.
12	Thunderstorm	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.
13	Rain	Heavy Rain	Unusually large amount of rain which does not cause a Flash Flood or Flood event, but causes damage, e.g., roof collapse or other human/economic impact.
14		Flood	Any high flow, overflow, or inundation by water which causes damage.
15		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge, posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
16		Coastal Flood	Flooding of coastal areas due to the vertical rise above normal water level caused by strong, persistent onshore wind, high astronomical tide, and/or low atmospheric pressure, resulting in damage, erosion, flooding, fatalities, or injuries. Coastal areas are defined as those portions of coastal land zones (coastal county/parish) adjacent to the waters, bays, and estuaries of the oceans. Farther inland, the Storm Data preparer determines the boundary between coastal and inland areas, where flood events will be encoded as Flash Flood or Flood rather than Coastal Flood. Terrain (elevation) features will determine how far inland the coastal flooding extends
17		Storm Surge/Tide	For coastal and select lakeshore areas, the vertical rise above normal water level associated with a storm of tropical origin (e.g., hurricane, typhoon, tropical storm, or subtropical storm), caused by any combination of strong, persistent onshore wind, high astronomical tide and low atmospheric pressure, resulting in damage, erosion, flooding, fatalities, or injuries.
18	Winter	Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather
			event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
19		Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.
20		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24 hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less. Heavy snow criteria range from 1 inch per event in the southernmost portions of Texas to 4 inches in 12 hours and 6 inches in 24 hours in the northernmost portions.
21		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is ¼ or ½ inch or more)." The ice accumulation criteria for the southern portion of Texas is 1/8 or more, while the criteria is ¼ inch or more throughout the remainder of the state.
22		Cold/Wind Chill	Period of low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined advisory (typical value is -18 °F or colder) conditions.
23		Extreme Cold/Wind Chill	A period of extremely low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined warning criteria (typical value around -35 °F or colder).
24		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts of 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than ¼ mile.
25		Frost/Freeze	A surface air temperature of 32 degrees Fahrenheit (°F) or lower, or the formation of ice crystals on the ground or other surfaces, for a period of time long enough to cause human or economic impact, during the locally defined growing season.
26		Freezing Fog	Fog which freezes on contact with exposed objects and forms a coating of rime and/or glaze, resulting in an impact on transportation, commerce, or individuals. Even small accumulations of ice can have an impact. Freezing fog can occur with any visibility of six (6) miles or less.

*AEP Texas 1898&Co Resiliency Plan

Key Differences in Filings

PUCT- Resiliency Plan

- Plan filed to prevent, withstand, or mitigate risks to a utility's transmission and distribution systems
- Covers a variety of risks and is not limited to natural disasters.
- Filed to seek approval from a commission for reconciliation/recovery of costs to develop and implement the plan.
- Texas legislation passed in 2023

PUCN- Natural Disaster Protection Plan

- Plan filed to prevent, withstand, and recover from natural disasters
- Must include protocols alongside plans, and descriptions of measures currently in place
- Filed to seek approval from a commission to recover expenditures made by the utility to develop and implement the plan
- Nevada legislation passed in 2019

CPUC- Wildfire Mitigation Plan

- Plan filed to prevent, withstand, and mitigate wildfires
- Highly technical and detailed plan that includes information about how, when, and where wildfires occur as supporting evidence for investments
- Must include descriptions of measures that are currently in place
- Filed to seek approval from a commission to recover costs to develop and implement the plan
- First California legislation passed in 2016, updated legislation in 2018, 2019, 2020, and eventually 2024

Southern California Edison 2020-2022 Achievements

- High Fire Risk Inspections & Remediations
  - 541,400 distribution and 73,600 transmission structure inspections, repairs, and replacements
- Vegetation Management
  - Hazard tree assessments on 1,325+ circuits, 21,000 hazard tree mitigations, and cleared brush at the base of 502,400+ poles
- Public Safety Power Shutoff
  - Grid hardening measure on 140+ circuits, advanced risk modeling for FPI thresholds, and enhanced customer notification process
- Customer Resiliency Program
  - 10,200 Critical Care Backup Batteries delivered to medical baseline customers
- Covered Conductor
  - Installed 3,880+ circuit miles
- Undergrounding
  - Completed 19+ miles
- Weather Stations
  - 1,150 weather stations installed across our HFRA
- High-Def Cameras
  - Installed 21 HD cameras, resulting in 180 in HFRA
- Sectionalizing Devices
  - Installed 80+ devices, resulting in 150 total
- Fast-Acting, Current-Limiting Fuses
  - Installed/replaced 3,740+ fuses

Nevada Energy 2020-2023 Natural Disaster Protection Plan

- Inspections, patrols and corrections
  - Circuit resiliency
  - Inspections, patrols, corrections
- PSOM
  - Public safety Outage Management
- Risk-based approach
  - Emergency response
  - Proactive technology assessment and asset management
  - Resource sufficiency

- Situational Awareness
  - Weather stations
  - Wildfire Cameras
- System hardening
  - Fire mesh
  - Lightning arrestors
  - Non-expulsion fuses
- Vegetation Management
  - Tree-trimming
  - Pole grubbing
  - Fuel inventory

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 57579
SOAH DOCKET NO. 473-25-11558

HOUSTON COALITION OF CITIES
REQUEST NO.: HCC-RFP01-02

QUESTION:

Provide, both separately by storm and in the aggregate of one or more storms to the extent maintained that way, the documents containing all reports, memos, and presentations containing, discussing, describing, and analyzing the benchmarking studies, reports, presentations, etc. on the performance of CEHE's system through the following events:

a. Hurricane Ike in 2008
b. The thunderstorm and wind event in 2013
c. The flooding in 2015
d. Hurricane Harvey in 2017
e. The microburst event in 2017
f. The ice storm in 2018
g. The tornadoes in 2019
h. Winter Storm Uri in 2021
i. Hurricane Nicholas in 2021
j. The tornado in 2022
k. The tornado in 2023
l. The microburst event in 2023.
m. The May 2024 Storms
n. Hurricane Beryl in 2024.

ANSWER:

Please see the attachments for the events requested. The information contained in internal storm reports is only as current as when the report was generated and is subject to change due to quality assurance / quality control procedures. As such, it should not be treated as a comprehensive analysis of the Company's performance during a particular extreme event.

Please also see the Significant Interruption Summary Reports pursuant to PUC Substantive Rules, Section 25.52 (e)(2) below:

Docket	Year	Storm	Link
51674	2021	Uri	https://interchange.puc.texas.gov/Documents/51674_5_1112965.PDF
51674	2021	Hurricane Nicholas	https://interchange.puc.texas.gov/Documents/51674_22_1155481.PDF
54480	2023	Jan 24-26	https://interchange.puc.texas.gov/Documents/54480_4_1268756.PDF
54480	2023	June 8-10	https://interchange.puc.texas.gov/Documents/54480_16_1303851.PDF
54480	2023	June 21-25	https://interchange.puc.texas.gov/Documents/54480_23_1307544.PDF
56058	2024	May 2-3	https://interchange.puc.texas.gov/Documents/56058_6_1392074.PDF
56058	2024	May 16-24	https://interchange.puc.texas.gov/Documents/56058_10_1399571.PDF
56058	2024	Beryl	https://interchange.puc.texas.gov/Documents/56058_26_1414508.PDF

SPONSOR:
Eric Easton

RESPONSIVE DOCUMENTS:
HCC RFP 1-2 Attachment A1 Quanta Benchmark Report - Hardening - 4AUG09.pdf
HCC RFP 1-2 Attachment A2 Quanta Benchmark Report - Hazard Trees - 4AUG09.pdf
HCC RFP 1-2 Attachment A3 Testimony for Hurricane Ike 2008.pdf
HCC RFP 1-2 Attachment B1 Storm Report 2013-04-2728 - Thunderstorm 2013.pdf
HCC RFP 1-2 Attachment B2 Storm Report 2013-08-16 - Wind Event 2013.pdf
HCC RFP 1-2 Attachment C Storm Report 2015 05 25-28 - Flooding 2015.pdf
HCC RFP 1-2 Attachment D1 How We Define Resiliency- One Year After Harvey_09-05-18.pdf
HCC RFP 1-2 Attachment D2 Hurricane Harvey Lessons Learned 6-25-21.pdf
HCC RFP 1-2 Attachment D3 Storm Report 2017 08 25 - Hurricane Harvey 2017.pdf
HCC RFP 1-2 Attachment E Storm Report 2017 05 23-24 - Microburst 2017.pdf
HCC RFP 1-2 Attachment F Storm Report 2018 01 16 - Ice Storm 2018.pdf
HCC RFP 1-2 Attachment G1 Storm Report 2019 04 07-08 - Tornado 2019.pdf
HCC RFP 1-2 Attachment G2 Storm Report 2019 09 17-20 - Tornado 2019.pdf
HCC RFP 1-2 Attachment H Storm Report 2021 02 14-19 - Winter Storm Uri 2021.pdf
HCC RFP 1-2 Attachment I1 Hurricane Nicholas Response and Restoration.pdf
HCC RFP 1-2 Attachment I2 Storm Report 2021 09 13-18 Hurricane Nicholas 2021.pdf
HCC RFP 1-2 Attachment J1 Storm Report 2022 01 08-09 - Tornado 2022.pdf
HCC RFP 1-2 Attachment J2 Storm Report 2022 03 22 - Tornado 2022.pdf
HCC RFP 1-2 Attachment K Storm Report 2023 01 24-26 - Tornado 2023.pdf
HCC RFP 1-2 Attachment L Storm Report 2023 06 21-25 - Mircoburst 2023.pdf
HCC RFP 1-2 Attachment M1 Storm Report 2024 05 16-24 - Derecho May 2024.pdf
HCC RFP 1-2 Attachment M2 Storm Report 2024 05 28-30 - May Storm 2024.pdf
HCC RFP 1-2 Attachment N1 Bingel Report - CenterPoint Energy Wood Pole Asset Management.pdf
HCC RFP 1-2 Attachment N2 CenterPoint Beryl After-Action Final Report.pdf
HCC RFP 1-2 Attachment N3 Storm Report 2024 07 08-19 - Hurricane Beryl.pdf

QUANTA TECHNOLOGY

Distribution Hardening: Benchmark Survey and Best Practices

FINAL REPORT

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

Prepared by: **Quanta Technology**

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August 4th 2009

Table of Contents

Executive Summary

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

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

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

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

First Stage

1. **Pole test-and-treat.** Wood poles are susceptible to decay, causing a reduction in strength and a corresponding increase in failure probability during a major storm. As such, utilities should establish and maintain a test-and-treat cycle for its wood distribution pole population. This program should focus on (but not necessarily be limited to) decay at the groundline since this is typically the failure point for distribution structures under wind loading, and is typically the part of the pole most susceptible to decay. The goals of the test-and-treat program are to ensure that (1) no pole has lost more than one third of its original strength, and (2) no pole is likely to have lost more than one third of its original strength before its next scheduled inspection. This program should ensure that deficient poles are reinforced or replaced in a timely manner.

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

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

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

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

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

Second Stage

7. **Grade B construction.** Most utilities will already have a stronger distribution grade of construction that is used in special situation such as those used for railway and highway crossings. For most US utilities, the stronger standard corresponds to NESC Grade B. Based on the survey, the use of Grade B for storm hardening is popular, effective, and easy to implement. This recommendation calls for utilities to have an explicit process to review new construction and rebuilds to decide whether the system should be built to Grade B (or equivalent) rather than a weaker standard. The intent of this recommendation is not to have utilities build all new distribution construction or upgrade all existing distribution structures to Grade B. Rather, its intent is to have utilities review distribution construction projects and decide whether Grade B is appropriate or not. For example, a relocation due to the widening of a coastal road may be worthwhile to consider for Grade B if the exposure to extreme winds is high enough.

8. **Non-wood poles.** There are many reasons, including hardening, why a utility may in certain cases wish to use a non-wood distribution pole. Perhaps the two most compelling are (A) they are not susceptible to decay, and (B) steel and composite poles can be very strong while remaining light enough to work without requiring the use of heavy cranes. Utilities should, at a minimum, have standards for at least one type of non-wood distribution pole and should install some on their system to gain field experience. The intent of this recommendation is not to have utilities build new distribution construction or upgrade existing distribution structures with non-wood poles. Rather, its intent is for utilities to have a viable alternative to wood should this be necessary in certain hardening situations.

9. **Post-storm data collection.** A lot of distribution damage occurs during major storms. This data is invaluable when trying to address system hardening in a manner that is most beneficial during major storms. Therefore, a utility should have a plan that has trained staff collect data on distribution damage sites immediately after the storm subsides. This data should be collected in a way that is statistically representative of the entire system. The intent of this recommendation is not to have a large number of data collectors that otherwise could be helping with storm restoration. Rather, a utility should train a few data collection teams (e.g., three teams of two engineers) and have these teams spend the first two days of storm restoration collecting data.

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

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

12. **Strengthen critical poles.** A good way for a utility to gain experience in hardening is to identify critical poles that are highly undesirable to fail during a major storm. The utility can then take targeted actions to strengthen these poles (such as upgrading them to Grade B or stronger), and monitor their performance during future major storms. The intent of this recommendation is not to replace a large percentage of poles. Rather, the utility should address only the most important poles. For example, a utility with one million poles may choose to initially strengthen one thousand poles, or 0.1%. More aggressive hardening activities should be addressed in a hardening roadmap (see Recommendation 18).

Third Stage

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

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

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

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

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

cluding the reduction in damage, reduction in restoration costs, and reduction in total restoration time. This will allow a cost-versus-benefit curve to be developed that shows the impact of various levels of hardening expenditure.

16. **Substation automation.** For the purposes of this recommendation, substation automation refers to the ability of substation feeder breakers to be remotely opened and closed. Although substation automation will not reduce the amount of damage in a storm, it greatly aids in the restoration process and can be considered one of the first steps in creating a "smart grid." The intent of this recommendation is not to mandate the automation of all substations. Rather, its intent is for utilities to examine the costs and benefits of substation automation, and to automate those substations where the benefits exceed the costs. For example, very small rural substations may be relatively expensive to automate with relatively small benefits.

17. **Smart meters.** A feature of a typical smart meter is to communicate when it is energized. During storm restoration, this feature is useful. Before a crew leaves an area, it can have all of the smart meters polled to determine whether every customer is actually restored. Doing this has several advantages. First, crews will less frequently have to return to the area to addressed missed problems. Second, crews can investigate customers that remain interrupted before leaving the area, informing them about why they are still interrupted and whether they need to call an electrician to fix damage on customer-owned facilities. Last, the utility will have a more accurate count of interrupted customers throughout the restoration process. The intent of this recommendation is not to mandate the installation of smart meters. Rather, it is to use smart meter data during storm restoration if a utility already has smart meters installed.

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

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

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

1 Introduction

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

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

2 Distribution Hardening

Most utilities have goals to maintain or improve reliability and use a variety of techniques to achieve these goals. However, most measures of reliability exclude outages and interruptions that occur during major storms such as hurricanes, linear wind storms, tornadoes, and ice storms.

Distribution systems are rarely designed explicitly for extreme weather. As a result, reliability efforts typically focus on customer interruptions during normal weather and efficient restoration during major storms. Storm-related interruptions may still be tracked, but are typically not used for examining system reliability characteristics.

Efficient restoration may no longer be enough. Since the turn of the new century there have been a number of highly visible extreme weather events that have caused extensive damage to electric power systems and have received high public awareness. Some of these recent weather events are listed in Table 2-1.

Table 2-1. Some major weather events since the turn of the century.

2002 Events	January Central Plains Ice Storm
2003 Events	Hurricane Isabel
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
2008 Events	Hurricane Ike December Northeastern Ice Storm

Consider the 2006 wind storm in the Pacific Northwest, which was the worst in the region in more than a decade. This storm knocked out power to more than 1.5 million homes and businesses and killed at least six people. Wind gusted to a record 69 mph at Seattle-Tacoma International Airport (SEATAC), breaking the old mark of 65 mph set in 1993. Wind was clocked at 113 mph near Mount Rainier. Power was knocked out at one of the SEATAC concourses, canceling dozens of flights. Flights were also canceled at Portland International Airport in Oregon. Widespread electric distribution system damage occurred in Oregon, Washington State, and British Columbia.

Consider also 2004 and 2005, in which nine hurricanes made landfall in the southeastern states. These storms caused repeated widespread damage to utility distribution systems, millions of customer interruptions, and billions of dollars in restoration costs.

On September 13th 2008, Hurricane Ike made landfall at Galveston, Texas. 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.

At a certain point, customers and regulators begin asking themselves questions such as, "Wouldn't it be better to make the system stronger rather than rebuild it after every severe storm?" To answer this question, it is necessary to look at typical design criteria, and the ability of systems built according to these criteria to withstand major storms.

2.1 Storm Design Criteria

There are three primary justifications for design standards: safety, economy, and reliability. At a minimum, electrical equipment must be designed and maintained so that they ensure worker and public safety. The safety standard used by most US states for utility electrical facilities is the National Electrical Safety Code (NESC).

Distribution structures built to minimum NESC requirements (Grade C) often experience extensive damage during major storms. This is expected since major storms often exceed the wind loading corresponding to Grade C strength. Transmission structures generally perform much better during major storms. This is also expected since they are built to withstand extreme summer and winter weather.

A utility can justify exceeding minimum safety standards if the additional cost is offset by future financial benefits. For example, a utility may decide to standardize on a single pole size to simplify inventory and to receive quantity discounts. In many cases, this pole size will exceed minimum NESC requirements. The structure is stronger and safer, but these benefits are incidental. The motivation for using the stronger pole is to reduce cost.

It is rare for utilities to exceed minimum safety standards for distribution structures to achieve economic efficiencies. Most costs associated with installed distribution facilities do not depend upon design standards, or increase with stronger design standards. For example, pole inspections are a fixed cost per pole. If a distribution system uses stronger poles, pole inspection costs remain the same. If a distribution system uses more poles of the same size, pole inspection costs increase.

Some utilities are beginning to use nonwood poles for distribution system. These poles are more expensive than wood, but have economic advantages. For example, a California utility has started using composite distribution poles in certain locations to control maintenance expenses and to prevent woodpecker damage. An Arizona utility has adopted steel poles as the standard for all overhead distribution construction to reduce transport costs (steel is lighter than wood) and to increase expected life. In most cases, the same loading criteria are used so that the nonwood poles are essentially the equivalent strength of wood poles.

Utilities also have the option to spend more money to achieve higher reliability during major storms. However, there are not standard reliability measures for a system during extreme weather. Perhaps the closest is construction grade. For example, several US utilities build their distribution system to Grade B, which is 50% to 100% stronger than Grade C. Utilities also have the option of using extreme wind ratings as described in the NESC.

Extreme wind ratings allow a utility to examine each structure and manage its ability to withstand extreme winds. For example, a utility may choose to build all of its coastal structures to an extreme wind rating of 130 mph, even though this exceeds NESC requirements. Similar ratings can be developed for extreme ice with concurrent wind for utilities with severe winter conditions.

2.2 Storm Hardening

State utility commissions are increasingly investigating the response of utilities after a major storm and investigating infrastructure damage that occurs during the major storm. Utilities are taking notice and are beginning to consider the possibility of exceeding minimum safety standards so that structures will be less likely to fail during extreme winds. This process is typically referred to as "storm hardening," or simply "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 compute the expected damage reduction 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 a structure to a specific wind speed.

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

2.3 Implementation Strategy

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

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

After circuits serving critical facilities and essential services are hardened, the remaining circuits must be prioritized. A pragmatic method for this is to allow individual counties to prioritize circuits within each county, and to equalize hardening effort across all counties. A more analytical approach for circuit prioritization is to direct hardening efforts where it will result in the most benefits including damage reduction and customer impact. The best approach to circuit ranking will vary by utility, but keeping the above factors under consideration will help to add some rigor to the process and some added justification to the final prioritized list.

After a utility identifies a circuit that it wishes to harden, a specific set of projects must be identified. It is beneficial for this set of projects to be based on specific criteria and to be the result of a documented process. Three promising ways to approach circuit hardening are full hardening, critical pole hardening, and value hardening.

Full hardening ensures that the extreme summer and winter storm ratings of each structure meets NESC requirements (even though this is not required for safety reasons). For example, the extreme wind level for much of Southern Florida is 145 mph. Full hardening of a circuit in this area requires each structure to have an extreme wind rating of at least 145 mph. Full hardening of existing systems is very expensive, and will typically only be practical on three-phase main trunks.

A minimalist approach to hardening is to identify all critical poles on a circuit and ensure that all critical poles meet NESC extreme storm criteria. Critical poles will generally be poles that impede restoration when down, are difficult to repair, or are expensive to repair. For example, at a southern US utility it is critical to energize the substation feeder breaker as the first step in restoration. This means that the first switch downstream of the feeder breaker is considered a critical pole and is given a high priority for hardening.

Value hardening attempts to prioritize potential hardening projects on a circuit in terms of cost-to-benefit analysis. For example, an existing Class 5 pole may have an extreme wind rating of 100 mph and has a 5% chance of failing in a Category 3 Hurricane. Replacing it with a Class 2 pole may increase the extreme wind rating to 130 mph, and reduce the chance of failing to 1%. The benefit of this potential project is the number of man-hours required to repair a broken pole multiplied by the failure rate reduction of 4%. The cost-to-benefit ratio of other potential projects for this pole and all other poles can then be calculated and used to create a ranked list. Projects for this circuit can then be approved until a threshold cost-to-benefit ratio is reached.

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

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

3 Survey Results

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

The survey was sent out to a total of 83 utilities, all in the US and Canada. A total of 26 utilities responded, a response rate of 31%. One utility provided a separate response for three operating company, for a total of 28 surveys. Two of the responding utilities are Canadian and the remainder are domestic. The survey was sent to Texas utilities through the PUCT, which may have led to more careful responses when compared to non-Texas utilities.

A summary of the responding utilities is shown in Table 4-1. The number of electrical customers ranged from a low of 42,000 to more than 5 million, with an average of 1.2 million. There was a similar wide range of overhead distribution circuit miles with a low of 451, a high of 113,500, and an average of about 21,000.

The approximate geographic distribution of responding utilities is shown in Figure 3-1. The dots show the location of the utility headquarters, but the utility service territories may include areas far away from this location. The responses span the US from east to west and from north to south. Since the PUCT required Texas investor-owned utilities to respond to the survey, Texas is heavily represented. The two responding Canadian utilities are both in close proximity to the US.

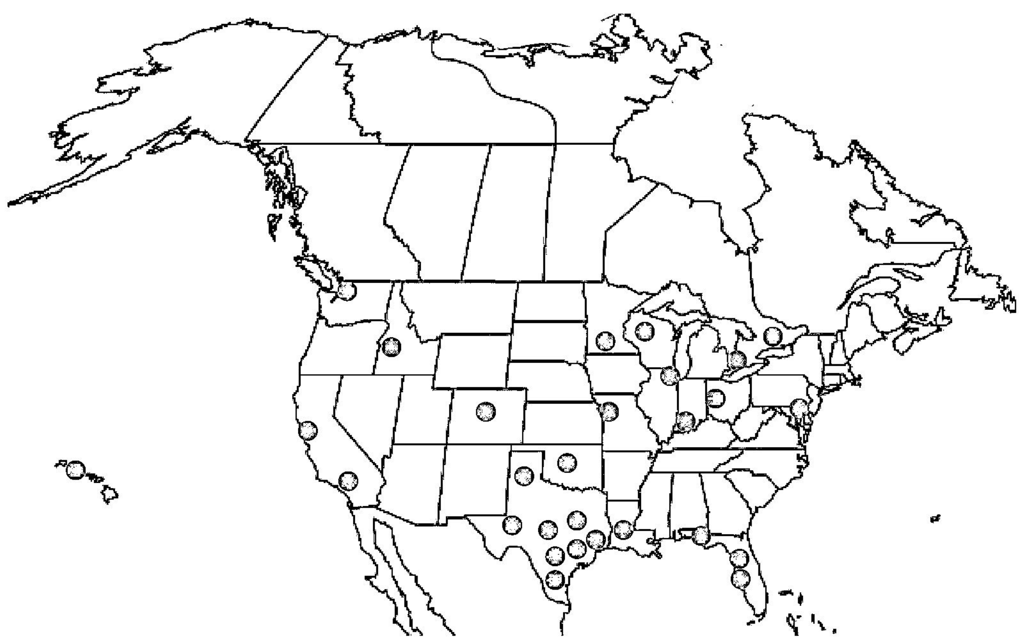

Figure 3-1. Approximate locations of responding utilities.

Table 3-1. Summary of Responding Utilities

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

All of the responding utilities reported being affected by at least one type of major storm, with most reporting at least three. Eighty-six percent of responding utilities reported themselves being subject to linear winds, with high percentage also reporting exposure to tornadoes, and ice storms. Over forty percent of responding utilities reported themselves being subject to hurricanes. The least-reported was wild fires, at 32%.

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

3.1 Existing System

Question 6:
Do you ever exceed minimum NESC design criteria for distribution? Explain.

Only three of the 28 responding utilities gave an unequivocal "yes" to this question, all designing their distribution system to Grade B instead of the minimum Grade C. Fifteen of the responses can be interpreted as generally "no," although minimum standards might be exceeded in some circumstances. The remaining ten utilities sometimes design their distribution facilities to exceed the minimum NESC requirements for a variety of reasons. Some of these reasons include the following:

<u>Some criteria used for exceeding minimum NESC design criteria</u>

- Large self supporting structures, like major highway and river crossings.
- On major junction poles.
- Conductors near and over swimming pools.
- Where it has been determined to provide Storm Hardening.
- On large conductor sizes.
- In coastal areas.

Question 7:
What percentage of your distribution poles are: wood, concrete, steel, composite, and other (explain)?

Statistics of responses to this question are shown in Table 3-2. As expected, wood distribution poles are the most used by far, with four utilities using exclusively wood poles and the average being 97%. Only two utilities reported a wood pole population of less than 90% wood. Concrete and steel poles are also common, each being utilized by more than half of the responding utilities. Although fewer utilities are using concrete as compared to steel, more concrete poles are used overall. Only 27% of responding utilities are using composite poles (fiberglass is included in this category), representing 0.1% of all distribution poles.

Table 3-2. Distribution Pole Usage (%)

	Low	Avg.	High	% Using
Wood	75	96.55	100	100
Concrete	0	1.90	23	54
Steel	0	1.42	10	62
Composite	0	0.10	1	27

Only one utility reported the use of distribution poles other than wood, concrete, steel, or composite. This utility has 0.5% of its distribution poles made from iron. Most likely, this refers to centrifugally-cast ductile iron poles similar to ductile iron pipes.

Question 8:
If applicable, why are you using non-wood poles?

Some utilities supplied multiple reasons for using non-wood pole. The most common response was that non-wood poles are used when necessary for strength, but are sometimes used when requested by a customer or geographic region for aesthetic reasons. In total, eight responses listed strength as a reason and seven listed aesthetics as a reason. Some representative responses include:

Strength Justification
- For larger self supporting structures, like major highway and river crossings.
- Commission requirements of system hardening.
- Where guying is an issue for wood poles.
- For interstate crossings and along hurricane interstate evacuation routes.

Aesthetic Justification
- Aesthetics
- On arterial roads for aesthetics
- To satisfy the aesthetic requirements of certain municipalities.
- The predominant reason for using non-wood poles is aesthetics.
- Customer preference, if the customer pays the difference in installed cost.

Three of the responses justified the use of non-wood poles due to less susceptibility to damage from various sources. These responses are summarized as follows:

Durability Justification
- To prevent termite damage
- Woodpeckers
- Decay zones

Other reasons cited include price, the availability of wood poles, and use in limited access areas where there is an advantage to having lighter poles (e.g., rear lot construction).

Question 9:
How are setting depths for poles determined?

Fifteen utilities out of the 28 responses cited the "10% plus 2 feet" rule as the primary guideline for determining distribution pole setting depth. Six utilities cite specific industry standards such as REA, ANSI, NESC, and G.O. 95 (in California). The remaining seven utilities have developed internal standards or guidelines.

Question 10:
When adding a pole-mounted device, is a loading calculation performed?

Eight of the responding utilities do not generally perform loading calculations when a pole-mounted device is added to a distribution pole. The remaining twenty utilities perform an analysis, often based on pre-developed tables and standards and sometimes involving a detailed calculation. Some representative responses include the following:

Approaches to Loading Calculations

- For all self supporting structures (no guy supports).
- Guidelines and rules of thumb are use.
- Our standards have pre-calculated loading for most devices and attachments.
- The design engineer will run a load calculation.
- Calculations are performed to create construction standards. A detailed design is completed when an applicable standard does not exist.

Question 11:
When becoming aware of a new attachment, is a loading calculation performed?

Twelve of the responding utilities always perform a pole loading calculation when becoming aware of a new attachment. Six utilities perform pole loading calculations in special cases. The remaining utilities do not generally perform calculations, but several require the attaching entity to performs a calculation and several others make the initial design able to accommodate a certain number of attachments without overloading the pole. Some of the approaches include the following:

Approaches to Attachment Loading

- Our utility designs its poles to accommodate one additional attachment. If additional attachments are identified, the pole is replaced.
- Pole design allows for unplanned attachments.
- We are requiring the attaching company to provide engineering on impacts.

Question 12:
If a pole is identified as overloaded, what mitigation actions are typically performed?

Fifteen of the responding utilities stated that overloaded poles are replaced, without providing any other alternatives. Most of the remaining responses also listed pole replacement, but included other approaches as well. The identified approaches in the responses can be summarized as follows:

Pole Overload Mitigation Approaches

- Replace with stronger pole
- Shorten spans
- Remove or move equipment
- Add guying
- Replace with concrete or steel pole

3.2 Inspection

Question 13:
How often, if ever, are attachment audits performed?

Nineteen of the responding utilities gave a specific cycle tome for attachment audits. By far, the most common answer was every five years. Only three utilities perform audits more frequently. Several utilities gave the same range of 5-10 years. Six utilities perform periodic attachment audits, but not on a regular schedule. Two utilities state that they never perform attachment audits, and one utility did not respond to the answer. A summary of responses is:

<u>**Attachment Audit Cycle**</u>

- 3 years (x2)
- 4 years (x1)
- 5 years (x10)
- 5-7 years (x2)
- 5-10 years (x3)
- 10 years (x1)
- Periodically (x6)
- Never (x2)
- No answer (x1)

One of the utilities performs audits on its telephone attachments every five years, but performs audits on cable company attachments every year. Most likely, this is a result of the ability and/or inclination of cable companies to attach without providing advanced notice to the utility pole owner.

Question 14:
What is your target cycle for wood pole testing?

There were a wide range of answers to this question spanning a three year cycle to a twenty year cycle. By far, the most common response was a ten year cycle (fourteen responses) followed by an eight year cycle (three responses). Five utilities stated that they do not have a target cycle, and one utility did not respond to the question. A summary of responses is the following:

<u>**Test and Treat Cycle Target**</u>

- 3 year (x1)
- 5 year (x1)
- 8 year (x3)
- 10 year (x14)
- 12 year (x1)
- 15 year (x1)
- 20 year (x1)
- No target cycle (x5)
- No answer (x1)

It should be noted that the appropriate test and treat cycle for each utility will vary for a number of reasons. Some regions are much more conducive to pole rot than others. In addition, some utilities are required by regulation to maintain a specific test ant treat cycle.

Question 15:
Are you, for the most part, meeting your target cycle for wood pole testing?

Eighteen of the twenty-eight utilities states that they are, for the most part, keeping up with their target for wood pole testing (64%). Six said that they were not (21%), and the remaining utilities do not have a target cycle.

Question 16:
When a wood pole is inspected, are other aspects of the pole systematically inspected at the same time (e.g., broken crossarms, rusty equipment)?

This question is potentially confusing. It was intended to refer to additional inspections performed during test and treat inspections. Almost all utilities responded with some type of "yes" to this question, with only three utilities either responding "no" or not providing an answer. Twelve of the "yes" responses were provided without comment. Some representative elaborations provided along with the "yes" responses include the following:

Additional Activities During Pole Inspections
- All parts of pole (x4)
- Top of the pole (x2)
- Broken ground wires and missing guy markers.
- Cross arms, guys, and attachments.
- Obvious damage such as broken crossarms, woodpecker damage, and missing ground wire.

Question 17:
When a wood pole is found to have lost more than one-third of its original strength, is it always replaced, or is a loading calculation performed?

This question is potentially confusing. The intent was to see if a loading calculation is performed prior to addressing a deteriorated wood pole; even if the pole is deteriorated, it may not violate loading criteria if it is not fully loaded. Nine utilities responded that they always replace the pole, and another six responded that they always either replace or reinforce the pole. Some of these also perform a loading calculation, but do not use the results of this calculation to defer mitigation. Therefore, 17 of the 28 utilities always mitigate a significantly deteriorated wood pole (61%). Only five use the results of the loading calculations to potentially defer replacement or reinforcement (18%). Six utilities either did not provide answers or simply stated that deteriorated poles are not always replaced, which could be for a variety of reasons. A summary of responses to this question is:

Action When a Deteriorated Pole is Identified

- Always replace (x9)
- Replace or reinforce (x8)
- Act based on loading calculation (x5)
- Do not always replace / ambiguous (x6)

Question 18:
About how long, on average, does it take to replace a pole that has been identified as needing replacement?

There are a wide range of answers to this question. Many of the responses distinguish between an emergency situation requiring immediate attention and less critical situations that can be scheduled further out into the future. Short timeframe replacements ranged from "immediately" to "a few days." Longer timeframe replacements ranged from "under a month" to "within three years." Two utilities did not provide responses. Representative answers for both short timeframe replacements and longer timeframe replacements are as follows:

Short Timeframe Replacements

- Replaced immediately
- 2 hours to 8 hours
- 2-5 days
- On average 4 hrs
- A few days
- One day if it is in imminent danger of failing

Longer Timeframe Replacements

- Under a month
- One month if not critical
- Priority poles within six weeks
- 45 days for priority pole
- 3 to 6 months
- 6-12 months (x2)
- 1 year (x4)
- On average 18 months
- Defective Pole – within 3 years

Question 19:
Do you perform dedicated distribution circuit inspections on a regular basis? If so, please describe (scope, methodology, extent, cycle).

There was a wide variety of responses to this question. Six utilities stated that they do not have regular dedicated distribution circuit inspections. Twelve utilities have inspection cycles, ranging from annual to every ten years. A summary of utilities with inspection cycles is:

<u>**Utilities with Inspection Cycles**</u>
- Annually (x2)
- 2 year
- 3 year
- 4 year
- 5 year (x4)
- 8 year
- 10 year (x2)

Three utilities have an infrared inspection program. Two perform an infrared on the three-phase backbone every year. The third performs infrared inspections on a five year cycle, plus on the 10% of worst circuits annually.

Five utilities perform patrols on targeted circuits with poor reliability Four of these utilities perform reliability patrols annually on their identified worst circuits (typically the worst 5%), while one performs inspection on an "as needed basis, generally reliability driven."

3.3 Motivation

Question 20:
In the last ten years, has there been any negative publicity for your utility related to major storm damage and/or restoration?

Seventeen utilities state that there has been no, or minimal, negative publicity related to major storm damage and/or restoration efforts (61%). The remaining respond "yes," with several of these providing elaboration. Interestingly, these elaborations included hurricanes, ice storms, and fires, but not linear winds, are the most common type of major storm exposure for the responding utilities (see Table 3-1). A summary of the elaborations is the following:

<u>**Descriptions of Negative Publicity**</u>
- Hurricane Floyd in 1999, and again to a lesser extent from Hurricane Isabel in 2003.
- We had a massive, destructive ice storm in December 2007 that left a lot of customers complaining. The Commission was bombarded with complaints and we began investigating system hardening.
- Had a big fire with the loss of many houses due to arcing connector during wind storm.
- Tropical Storm Allison in 2001, Hurricane Rita in 2005, and Hurricane Ike in 2008.

Question 21:
In the last ten years, have there been any recent regulatory investigations for your utility related to major storm damage and/or restoration?

Fourteen of the responding utilities simply replied "no" to this question (50%). Another 4 responses describe routine storm reports submitted to regulators, routing requests for information, or something similar. The remaining ten utilities responded "yes," with four providing elaboration. A summary of the elaborations is the following:

Descriptions of Regulatory Investigations

- There have been several dockets requesting input about hardening and a docket requiring us to internally critique ourselves following hurricane Gustav.
- The commission initiated investigations in October 2006, December 2007, and January 2009.
- Yes, for a big fire with loss of many houses due to arcing connector during wind storm.
- After Hurricane Rita, the Public Utility Commission of Texas (PUCT) reviewed the practices concerning vegetation management, inspections, and system hardening of all utilities in Texas, including our utility.

Question 22:
Has there been any regulatory interest in your state related to underground conversion of the electric distribution system in order to reduce storm damage?

Thirteen of the responding utilities state that there has been regulatory interest in their state related to underground conversion of the electric distribution system in order to reduce storm damage (46%). Of course, some states are represented by multiple responding utilities and many states are not represented. Thirteen utilities state that there has not been any regulatory interest in this area and the remaining two utilities did not provide an answer.

Question 23:
Has there been any regulatory interest in your state related more general hardening of the electric system (i.e., other than undergrounding)?

Sixteen of the responding utilities state that there has been regulatory interest in their state related to general hardening of the electric distribution system (57%). Interestingly, this number is higher than the response to the undergrounding inquiry in Question 22. Again, some states are represented by multiple responding utilities and many states are not represented. Nine utilities state that there has not been any regulatory interest in this area and the remaining three utilities either did not know or did not provide an answer.

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

There were a wide range of responses to this question. Many utilities that are not considering hardening simply did not select any options. Other responses selected most of the options. Most of the responding utilities selected about three reasons (the average number is 2.7). The specific numbers of responses for each reason are as follows:

a.	We are not considering hardening:	5
b.	Respond to regulator concerns:	16
c.	Strengthen weak poles:	7
d.	Minimize damage on important poles:	13
e.	Minimize damage on critical circuits:	13
f.	Reduce overall storm damage:	18
g.	Reduce societal cost:	5

All of reasons were selected at least five times. The most popular reason was to reduce overall storm damage (an easy response) followed by responding to regulator concerns (also an easy response). Interestingly, close behind these two are hardening on important poles and critical circuits, showing that many utilities are thinking about hardening in a targeted rather than broadly-applied manner.

3.4 Post-Storm Data

Question 25:
After restoration is complete, what sources of data are used to determine what failed and how much failed?

The most common response to this question is the use of data collected by an outage management system (OMS). Thirteen of the 28 responses listed an OMS as the sole source of failure data. Eight responses cite accounting, and/or material requisition records. Another four responses refer to a combination of these two sources. Two utilities specifically cite the use of forensic data, while one simply states that an "investigation is performed." A summary of responses is the following:

• Outage Management System (OMS):	13
• Accounting and material requisition data:	8
• OMS and accounting data:	4
• Forensic data:	2
• Not clear:	1

In addition to their primary data source, several responses referred to data collected in the field in the damage assessment process. Examples include damage assessment reports, outage reports, and work orders. Although similar to forensic data, these sources are collected with the goal of restoration, and are therefore not as rich or as statistically significant as true forensic data.

It is interesting that OMS data is, by far, the most common source of information. During a major storm, many utilities find that the OMS system becomes overloaded, work orders based on outage reports become inefficient, and it is often times beneficial to forgo the use of the OMS system until the main feeder trunks are restored. Therefore, OMS system data, at least for the most severe storms, may not be the best source of outage data.

Question 26:
Does your utility attempt to collect detailed damage data at a certain number of damage locations before system restoration begins? If so, please explain.

This question was interpreted differently by different utilities. Clearly, all utilities must perform some sort of initial damage assessment after a major storm so that they can assess manpower needs, develop a restoration plan, and generate initial work orders. The intent of this question was whether the utilities goes beyond these requirements and performs a more "detailed" assessment that is suitable for forensic analysis.

Fourteen utilities responded "no" to this question, reflecting an unambiguous correct interpretation of the intent. Two utilities simply state "yes." Nine utilities provide descriptions indicative of a standard storm damage assessment process, with some explicitly stating that a forensic analysis is not performed. Two are clear that data is collected specifically for the intent of forensic analysis. One answer is ambiguous. Of the two responses indicating a forensic analysis, the more detailed states the following:

> *We have a damage assessment (DA) process that starts when the storm subsides and continues through the process. We start with a statistical DA to determine extent of damage and assess resources needed. We then proceed to a pole by pole DA. We have a third forensic assessment to satisfy the commission requirements on cause of damage.*

The responses are in agreement with Question 25, which shows that two utilities are performing forensic assessment. Of course, a utility cannot perform a forensic assessment without first collecting forensic data.

The utilities are thanked for providing insightful information on their post-storm damage assessment process. The interested reader is referred to Appendix B for the detailed responses. However, the focus of this report is on system hardening and, therefore, this information will not be analyzed further.

Question 27:
If the answer to the previous question is "yes," is a process followed to ensure that the collected data is statistically representative of the overall system?

Like Question 26, this question was intended to address whether collected forensic data is statistically representative of the entire system. Three utilities answer "yes" within this context, with one stating, "Yes, we use a consultant that performs a statistical sampling." Nineteen utilities either responded "no" or did not provide an answer. The remaining six utilities provided answers that addressed the statistical significance of the initial damage assessment to estimate the total restoration work on the system, which is not the focus of this report. The interested reader is referred to Appendix B for the detailed responses.

The responses to this question are in agreement with the responses to Question 25 and Question 26.