which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Coastal Contamination Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.4.5.5. Substation Fire Barrier (RM-20)

Description. The Company's Substation Fire Barriers Resiliency Measure will install physical fire protection barriers, either concrete or metal, to protect power transformers and other equipment vulnerable to damage caused by the catastrophic failure of adjacent transformers. The Company proposes to install four fire protection barriers a year. Although substation transformer failures are uncommon compared to other distribution equipment failures (e.g., broken poles), the consequences and impact of a catastrophic failure can be severe. An enormous amount of energy is released when a transformer catastrophically fails, with the possibility of extensive damage to nearby equipment from associated fire and debris. The potential for lengthy outages and costly repairs if this were to occur is high. Extinguishing the fire also presents challenges to fire department personnel.

The Company will identify the substations that will have fire protection barriers installed, commence the design and engineering phase, place work orders, and dedicate appropriate resources for the work. A complete system outage is not required for installation, though segment outages may be required.

The following figure illustrates a transformer fire that occurred at a Company substation in 2016.

Figure SRP-98
2016 Substation Fire

Relevant Details. The following figure summarizes the Substation Fire Barriers Resiliency Measure.

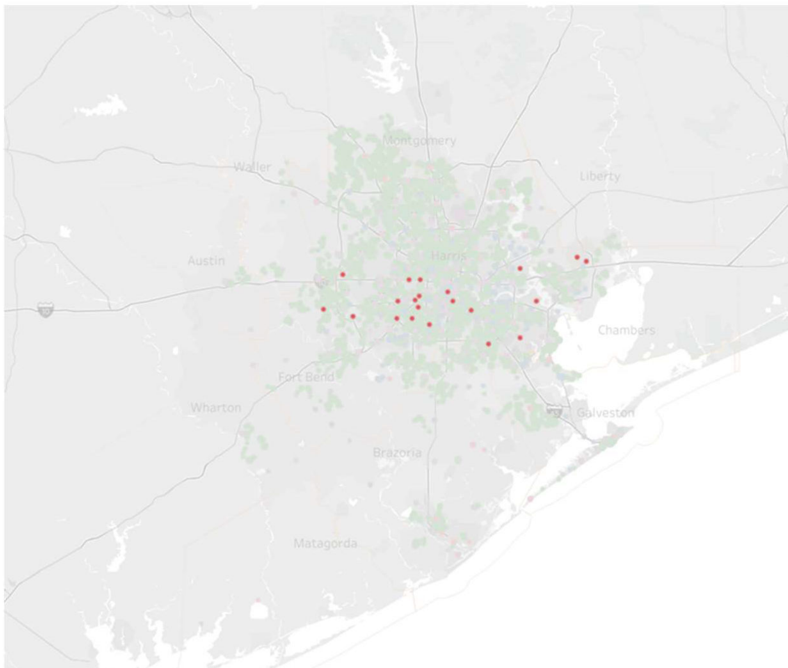
Figure SRP-99
Substation Fire Barriers Resiliency Measure (RM-20)

Substation Fire Barriers	
Estimated capital costs from 2026-2028	$9.0 million
Estimated incremental O&M expense from 2026-2028	None
Estimated overall project duration	2026-2028 (approximately 38% complete, but extends through the next 10 years)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Extreme Temperature Heat Wildfires
Anticipated benefits	Mitigate damage from substation fires Reduce the number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Other relevant details	Availability of material and personnel may impact cost estimates

Prioritization. To determine which substations will have fire protection barriers installed, the Company will consider factors such as: geographic location, the number of transformers at a substation, the number of distribution circuits connected to a substation, whether a substation serves a critical load public safety customer.

Based on these considerations and underlying data analyses, as shown in Figure SRP-100 below, the Company determined at the polygon level where it anticipates implementing this measure.

Figure SRP-100
Substation Fire Barriers Projects Map



History of Effectiveness. The addition of fire protection barriers in substations has been proven effective in containing or limiting fire damage to just the affected transformer or connected equipment without affecting adjacent transformers and equipment.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, concluded that there are no viable alternatives for protecting equipment from catastrophic transformer failures, as the alternative is to not build the Substation Fire Barriers.

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the Substation Fire Barriers Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

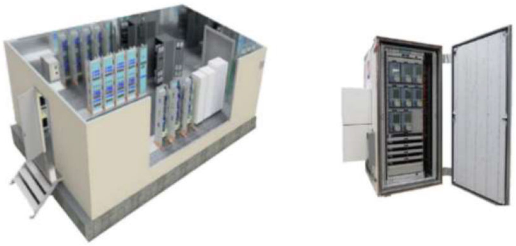
Section 5.4.5.6. Digital Substation (RM-21)

Description. The Digital Substation Resiliency Measure will upgrade the relaying equipment at the Company's substations by converting from an analog, copper-based protective relay system and use digital protective relays leveraging fiber optic communications. The Company's proposed Digital Substation Resiliency Measure is in the early stages of design and development. In support of this Resiliency Measure, the Company is evaluating the benefits of adopting increased digitization and automation in accordance with the IEC's 61850 communications protocol. The 61850 protocol promotes use of digital equipment, adoption of cybersecurity measures, and large amounts of data capture to enhance resiliency and reliability and offers real-time monitoring of critical substation equipment. Key features of the Company's Digital Substation program include the replacement of copper wiring with less costly fiber optics for easier conversion to digital communications, enhanced situational awareness for better and faster operational decisions, adoption of compact digital protective relays allowing for a more compact substation control facility, standardized configurations for increased speed of installation, centralized communications/data collection busses (i.e., via merging units), provide the opportunity for special protection schemes across the service footprint and proactive detection of equipment abnormalities and incipient failure with an overall smaller substation design footprint. These features will help drive down O&M costs, collectively enhance reliability and resiliency, and, over time, lower the cost of constructing new substations.

The Digital Substation Resiliency Measure will upgrade equipment at approximately three substations per year, and approximately nine from 2026 - 2028. The Company will identify the substation equipment that will be upgraded, commence the design and engineering phase, place work orders, and dedicate appropriate resources for the work. No system outage is required for installation.

The following figure illustrates an example of an existing substation control house and a digital substation module.

Figure SRP-101
Existing Substation Control House vs. Proposed Digital Substation Module



Relevant Details. The following figure summarizes the Digital Substation Resiliency Measure.

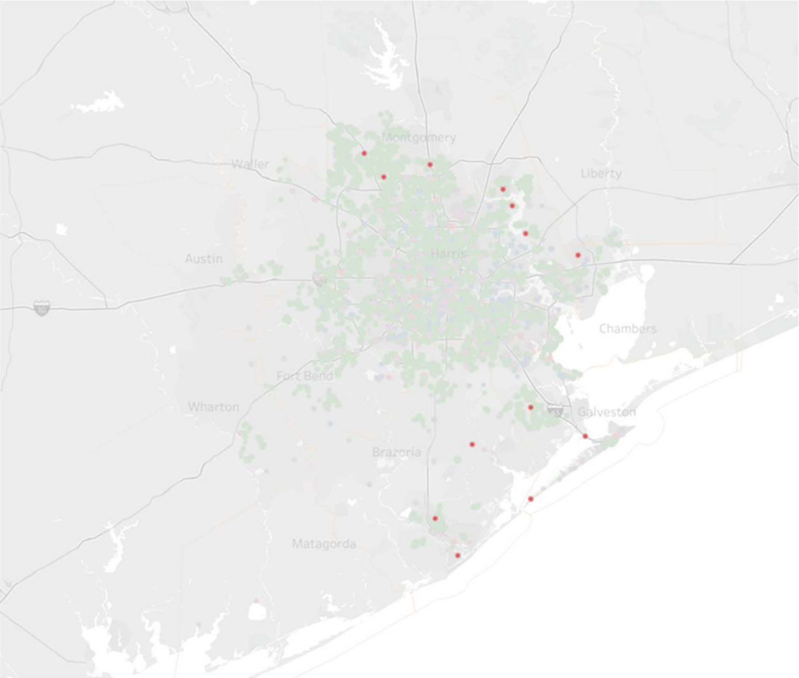
Figure SRP-102
Digital Substation Resiliency Measure (RM-21)

Digital Substation Resiliency Measure (RM-21)	
Estimated capital costs from 2026 - 2028	$31.8 million
Estimated incremental O&M expense from 2026 - 2028	None
Estimated overall project duration	2026 - 2028 (approximately 6%, but extends through the next ten years)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Resiliency Events related to extreme weather events Physical threats
Anticipated benefits	Enhanced ability to proactively plan and implement projects to mitigate outages attributable to extreme weather events Make data transmission from the Company's substations to the Company's control center more efficient and secure Allow the Company to make better and timelier assessments of substation operations Provide modern physical protection for substation control house equipment
Other relevant details	Availability of inventory and personnel may impact cost estimates The Company has applied for DoE grants related to this Resiliency Measure

Prioritization. The Company has ordered the substations so to maximize efficiency and prioritize reliability. Specifically, the Company identified and grouped similar projects to provide efficiency in engineering design. Once the similar projects were identified, the Company considered the age of the existing infrastructure, such as electromechanical relays, their geographic relationship to a high fire risk area, and the ability to coordinate the projects with the concurrent flood mitigation program. The resulting substation order is designed to streamline the project process to reduce the total engineering and design time to aid in fast turnaround and quick repeatability.

Based on these considerations and underlying data analyses, as shown in Figure SRP-103 below, the Company determined at the polygon level where it anticipates implementing this measure.

Figure SRP-103
Digital Substations Projects Map



History of Effectiveness. The Digital Substation Resiliency Measure is a new program that the Company is developing. However, this new protocol process is recognized within the electric utility industry as an effective tool for making data transmission from substations to control centers more efficient and secure, allowing the Company to make better and more timely assessments of substation operations.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined an alternative is to continue utilizing the analog and copper-based communication system for the Company's substation control houses. Continued use of an analog and copper-based communication system is less secure and more costly compared to a digital and fiber-based communication system. The Company believes that using a digital and fiber-based communication system is more cost efficient and has additional operational benefits and aligns with good utility practices seen within the industry.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Digital Substation Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.4.5.7. Wildfire Advanced Analytics (RM-22)

Description. The Company's Wildfire Advanced Analytics Resiliency Measure is an analytical tool that the Company plans to use in conjunction with the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure. The Wildfire Advanced Analytics Resiliency Measure entails combining and inputting data—such as LiDAR imagery data, device data (meters, IGSDs, sensors, etc.), weather data, inspection data, and monitoring data—into the advanced analytics software module. Doing so then enables the Company to overlay imagery, determine wildfire risks, and analyze potential improvements. When used in tandem with the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure, the Company can leverage this model analysis to proactively "rank" improvement regions based on their value add to customers and strategically optimizing the higher fire risk locations. Doing so will help reduce costs over time by focusing on improvements having the greatest benefit in reducing the risk, mitigating the spread, or mitigating the impact of a wildfire. No system outages are required for the Wildfire Advanced Analytics Resiliency Measure.

Relevant Details. The following figure summarizes the Wildfire Advanced Analytics Resiliency Measure.

Figure SRP-104
Wildfire Advanced Analytics Resiliency Measure (RM-22)

Wildfire Advanced Analytics Resiliency Measure (RM-22)	
Estimated capital costs from 2026 – 2028	None
Estimated incremental O&M expense from 2026 - 2028	$0.9 million
Estimated overall project duration	2026 - 2028 (but ongoing thereafter)
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Enhanced ability to proactively plan and implement projects to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Determine future improvements to the Company's transmission and distribution system to reduce the risk, mitigate the spread, or mitigate the impact of a wildfire Reduce restoration times Reduce the frequency and number of customers impacted by outages attributable to a wildfire Reduce total outage times attributable to a wildfire Reduce system restoration costs attributable to a wildfire

Wildfire Advanced Analytics Resiliency Measure (RM-22)	
Other relevant details	Cost estimates may be impacted by the need to reformat data to align with advanced data analytics techniques The Company has applied for DOE grants related to this Resiliency Measure

Prioritization. The Wildfire Advanced Analytics Resiliency Measure will be for the Company's entire service area.

History of Effectiveness. The Wildfire Advanced Analytics measure is a new program that the Company is developing. However, the Company has previously utilized mapping tools to visualize areas of impact for potential weather events to coordinate response, which has proven useful when preparing for Resiliency Events.

Alternatives Considered. With wildfires beginning to be a larger issue in Texas, the Company made a decision to add wildfire measures within the SRP. The only real alternative to adding these measures is to not provide and prepare for wildfire mitigation. In the recent history, there have been a significant uptick in the number of drought and heat days, lending to the higher possibility of fuel for wildfires. Taking this into account, the risk of wildfire is becoming greater within the Company's territory and mitigation measures need to begin. The option of not proactively preparing for wildfires was not a viable option due to the increased risk seen within the territory (drought conditions in recent years, wildfire in Brazoria County in 2024, the Smokehouse Creek fire, and most recently the Los Angeles fires are just a few examples of the risk).

The Company has identified and is proposing four extreme temperature (drought) wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Wildfire Advanced Analytics Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.4.5.8. Wildfire Strategic Undergrounding (RM-23)

Description. The Wildfire Strategic Undergrounding Resiliency Measure will bury select portions of transmission or distribution lines underground that have elevated wildfire risk, as analyzed and identified by the Company. The Company will implement the Undergrounding Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Undergrounding Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. A complete system outage is not required for the Undergrounding Resiliency Measure, though segment outages may be required. Estimates are based on these assumptions and may change as additional analysis is completed.

Relevant Details. The following figure summarizes the Wildfire Strategic Undergrounding Resiliency Measure.

Figure SRP-105
Wildfire Strategic Undergrounding Resiliency Measure (RM-23)

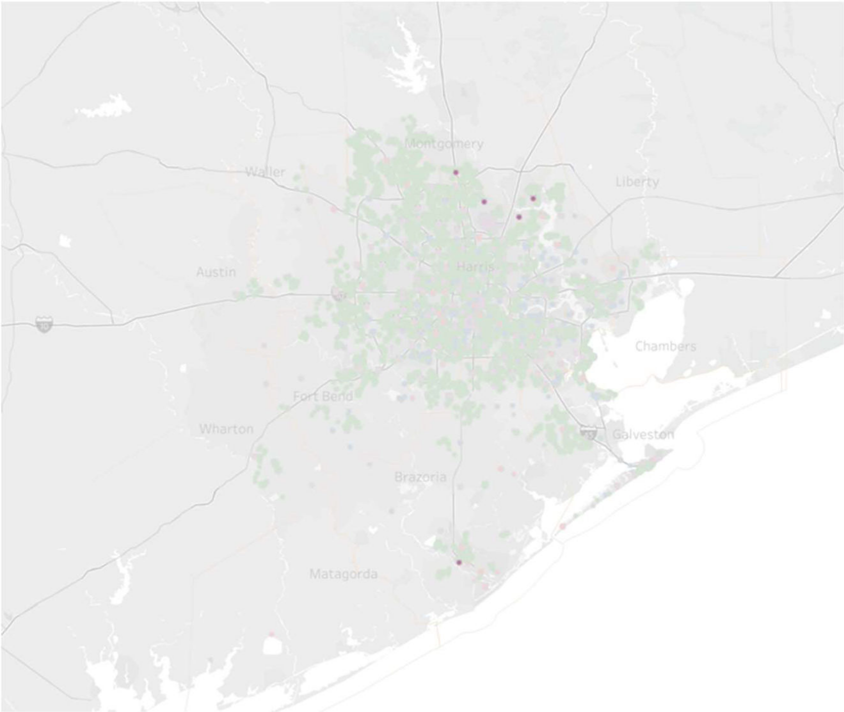
Wildfire Strategic Undergrounding Resiliency Measure (RM-23)	
Estimated capital costs from 2026 - 2028	$50.0 million
Estimated incremental O&M expense costs from 2026 - 2028	None
Estimated overall project duration	2026-2028 (but ongoing thereafter)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Wildfire

Wildfire Strategic Undergrounding Resiliency Measure (RM-23)	
Anticipated benefits	Reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Reduction of risk that a fault is the source of wildfire ignition
Other relevant details	Undergrounding of transmission or distribution line may result in de-rating Availability of material and personnel may impact cost estimates

Prioritization. The Company will prioritize the portions of the Company's transmission and distribution lines that have elevated levels of wildfire risk through analysis by a third-party vendor and analyzed and identified by the Company ultimately being shown within the high wildfire risk area map included in Appendix D.

Based on these considerations and underlying data analyses, as shown in Figure SRP-106 below, the Company determined at the polygon level where it anticipates implementing this measure.

Figure SRP-106
Wildfire Strategic Undergrounding Projects Map



History of Effectiveness. The electric utility industry has recognized that burying transmission or distribution lines may potentially reduce the risk, mitigate the spread, or mitigate the impact of a wildfire. Efforts to bury transmission or distribution lines at scale are still in the early stages, so empirical data on effectiveness is not readily available.

Alternatives Considered. With wildfires beginning to be a larger issue in Texas, the Company made a decision to add wildfire measures within the SRP. The only real alternative to adding these measures is to not provide and prepare for wildfire mitigation. In the recent history, there have been a significant uptick in the number of drought and heat days, lending to the higher possibility of fuel for wildfires. Taking this into account, the risk of wildfire is becoming greater within the Company's territory and mitigation measures need to begin. The option of not proactively preparing for wildfires was not a viable option due to the increased risk seen within the territory (drought conditions in recent years, wildfire in Brazoria County in 2024, the Smokehouse Creek fire, and most recently the Los Angeles fires are just a few examples of the risk).

The Company has identified and is proposing four extreme temperature (drought) wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Wildfire Strategic Undergrounding Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;

3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and

4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.4.5.9. Wildfire Vegetation Management (RM-24)

Description. The Wildfire Vegetation Management Resiliency Measure will inspect ROW and extensively trim trees and other vegetation. The Company will implement the Wildfire Vegetation Management Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire Vegetation Management Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. If implemented, the Wildfire Vegetation Management Resiliency Measure will inspect ROW and trim trees and other vegetation on specific portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated wildfire risk, as analyzed and identified by the Company's third-party vendor. Fire retardant material will also be placed near transmission tower structures. Outages are typically not required for the Wildfire Vegetation Management Resiliency Measure. This resiliency measure utilizes any necessary cranes, boom trucks, and tree-cutters, as needed, to reach and trim vegetation. For most tree trimming, outages are not required, but there may be timeframes where outages are necessary for the safety of the tree trimming crews.

Relevant Details. The following figure summarizes the Wildfire Vegetation Management Resiliency Measure.

Figure SRP-107
Wildfire Vegetation Management Resiliency Measure (RM-24)

Wildfire Vegetation Management Resiliency Measure (RM-24)	
Estimated capital costs from 2026 - 2028	None
Estimated incremental O&M expense from 2026 - 2028	$30.0 million
Estimated overall project duration	2026 – 2028 (but ongoing thereafter)
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire

Anticipated benefits	Reduction of risk that a failed overhead structure or conductor is the source of wildfire ignition Reduction of risk that vegetation contact with a conductor is the source of wildfire ignition Reduction of risk vegetation is the source of wildfire ignition
Other relevant details	Availability of personnel may impact cost estimates

Prioritization. In areas the Company identifies within the wildfire advanced analytics tool and implements the Wildfire Vegetation Management Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system or specific areas in the Company's service area that have elevated levels of wildfire risk, as analyzed and identified by the Company.

History of Effectiveness. Vegetation management is a well-known measure within the utility industry that enhances resiliency, including resiliency against wildfires. The Company has seen vegetation management be effective at mitigating fault conditions caused by vegetation along backbone and lateral distribution feeders, resulting in reduced outage durations and the total number of customers impacted by an outage when implemented. To further this, wildfire vegetation management attempts to clear to the ground and reduces possible fuel sources if utility equipment inadvertently become ignition sources.

Alternatives Considered. With wildfires beginning to be a larger issue in Texas, the Company made a decision to add wildfire measures within the SRP. The only real alternative to adding these measures is to not provide and prepare for wildfire mitigation. In the recent history, there have been a significant uptick in the number of drought and heat days, lending to the higher possibility of fuel for wildfires. Taking this into account, the risk of wildfire is becoming greater within the Company's territory and mitigation measures need to begin. The option of not proactively preparing for wildfires was not a viable option due to the increased risk seen within the territory (drought conditions in recent years, wildfire in Brazoria County in 2024, the Smokehouse Creek fire, and most recently the Los Angeles fires are just a few examples of the risk).

The Company has identified and is proposing four extreme temperature (drought) wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Wildfire Vegetation Management Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.4.5.10. Wildfire IGSD (RM-25)

Description. The Wildfire IGSD Installation Resiliency Measure will install 150 additional IGSDs on select locations of the Company's distribution system to enable the isolation of portions of the Company's distribution system that have an elevated level of wildfire risk. The Company will implement the Wildfire IGSD Installation Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire IGSD Installation Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. This measure is in addition to what is proposed in the stand alone IGSD Installation Resiliency Measure described earlier in this SRP. A complete system outage is not required for the Wildfire IGSD Installation Resiliency Measure, though segment outages may be required. Estimates are incremental to the current ongoing IGSD resiliency program, are based on the above assumptions, and may change as additional analysis is completed.

Relevant Details. The following figure summarizes the Wildfire IGSD Installation Resiliency Measure.

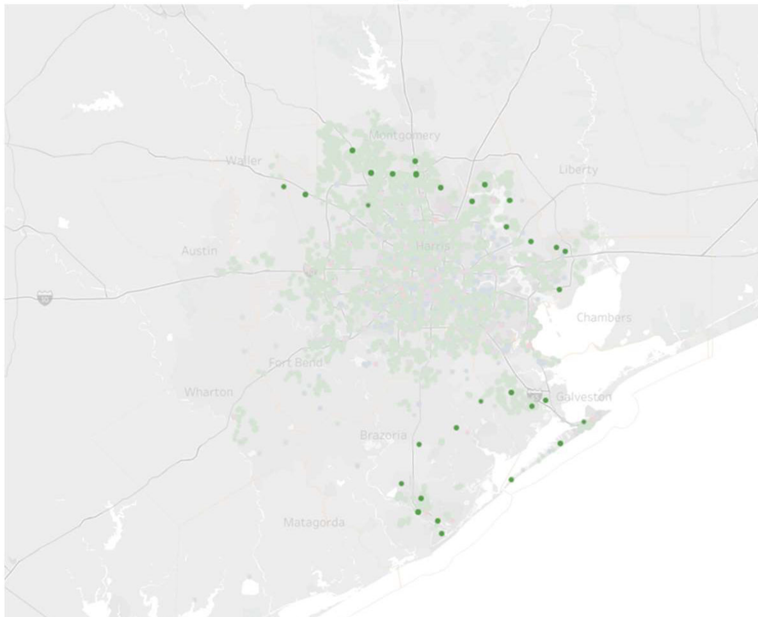
Figure SRP-108
Wildfire IGSD Installation Resiliency Measure (RM-25)

Wildfire IGSD Installation Resiliency Measure (RM-25)	
Estimated capital costs from 2026 – 2028	$19.4 million
Estimated incremental O&M expense from 2026 - 2028	$0.3 million
Estimated overall project duration	2026 – 2028 (but ongoing thereafter)
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Faster restoration due to reduced exposure of number of customers subject to PSPS Reduce time and expense associated with dispatching field personnel to restore an outage by reducing the need to perform ground patrol on the segment of the sectionalized circuit Reduce number of customers impacted by an outage Reduce total outage time
Other relevant details	Availability of material and personnel may impact cost estimates

Prioritization. Analyzing the results of the predictive models, the Company implements the Wildfire IGSD Installation Resiliency Measure and will install additional IGSDs on select portions of the Company's distribution system that have elevated levels of wildfire risk, as analyzed and identified by the Company's third-party vendor and based on risk factors accounted within this wildfire modeling.

Based on these considerations and underlying data analyses, as shown in Figure SRP-109 below, the Company determined at the polygon level where it anticipates implementing this measure.

Figure SRP-109
Wildfire IGSD Projects Map



History of Effectiveness. IGSD Installation has resulted in fewer sustained outages and reduced the time and expense associated with the Company dispatching personnel to restore outages. The capability of IGSD to significantly reduce the number of sustained customer interruptions during a Resiliency Event at relatively low cost is high. The installation of IGSD schemes is consistent with practices deployed at other utilities based on peer utility benchmarking survey results. IGSD installations at targeted locations on distribution circuits that are part of a high fire risk area can result in further sectionalization of a circuit which reduces the exposure of the number of customers subject to PSPS, expedites restoration by reducing the need to perform ground patrol on the segment of the sectionalized circuit, and further narrowing the circuit mileage located in high fire risk areas.

Alternatives Considered. With wildfires beginning to be a larger issue in Texas, the Company made a decision to add wildfire measures within the SRP. The only real alternative to adding these measures is to not provide and prepare for wildfire mitigation. In the recent history, there have been a significant uptick in the number of drought and heat days, lending to the higher possibility of fuel for wildfires. Taking this into account, the risk of wildfire is becoming greater within the Company’s territory and mitigation measures need to begin. The option of not proactively preparing for wildfires was not a viable option due to the increased risk seen within the territory (drought conditions in recent years, wildfire in Brazoria County in 2024, the Smokehouse Creek fire, and most recently the Los Angeles fires are just a few examples of the risk).

The Company has identified and is proposing four extreme temperature (drought) wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Wildfire IGSD Installation Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.5. Physical Security Events

The Company's SRP has two Resiliency Measures that will enhance the physical security at the Company's substations. The Company estimates that the two Resiliency Measures that will enhance physical security will cost approximately $37.4 million in capital costs and $0.1 million in incremental O&M expense. The two measures will be implemented over a three-year period from 2026 - 2028. The Company's two physical security Resiliency Measures are summarized in the figure below.

Figure SRP-110
Physical Security Resiliency Measures

Physical Security Resiliency Measure	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	# of Assets	Estimated 3-Year CMI Savings (millions)
Substation Physical Security Fencing	$18.0	None	21 substations	17.6
Substation Security Upgrades	$19.4	$0.10	30 substations	25.1
Subtotal	**$37.4**	**$0.10**		**42.7**

Section 5.5.1. Substation Physical Security Fencing (RM-26)

Description. The Substation Physical Security Fencing Resiliency Measure will replace chain link fences with more resilient and less permeable wire mesh fences (such as shown in the figure below) at substations to better deter unauthorized access and equipment damage caused by third parties. The Company's Substation Physical Security Fencing Resiliency Measure will replace chain link fences with more resilient and less permeable wire mesh fences at critical substations to thwart unauthorized access and equipment damage from vandals (stealing copper wire) or terrorists.

The Substation Physical Security Fencing Resiliency Measure will replace security fencing a total of 21 substations from 2026 - 2028. The Company estimates that the Substation Physical Security Fencing Resiliency Measure will cost approximately $18.0 million in capital costs and no incremental O&M expense. A system outage is not required for installation.

Figure SRP-111
Wire Mesh Fencing

Relevant Details. The following figure summarizes the Substation Physical Security Fencing Resiliency Measure.

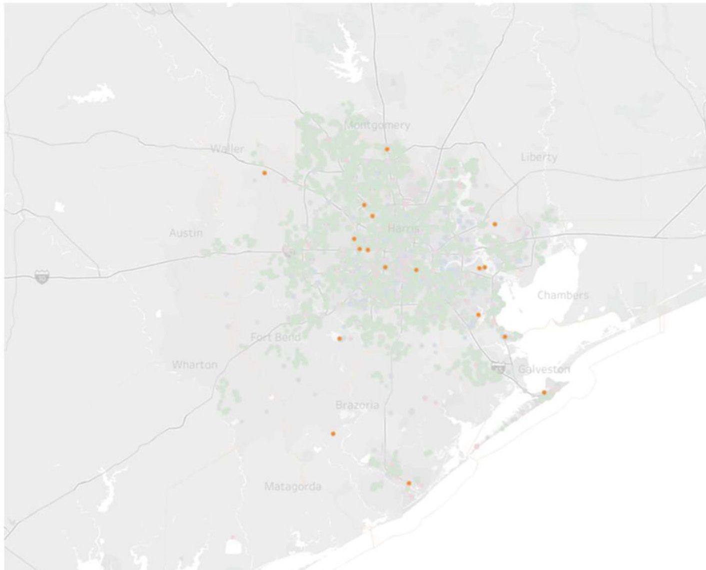
Figure SRP-112
Substation Physical Security Fencing Resiliency Measure (RM-26)

Substation Physical Security Fencing Resiliency Measure (RM-26)	
Estimated capital costs from 2026 - 2028	$18.0 million
Estimated incremental O&M expense from 2026 – 2028	None
Estimated overall project duration	2026 – 2028 (approximately 15% complete, but ongoing thereafter)
Net salvage value	None
Resiliency Event(s) addressed	Physical intrusion and vandalism
Anticipated benefits	Enhance physical deterrence capability Physical threats to substations, including unauthorized entry, theft, and vandalism
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. Substations targeted for enhanced fencing will be chosen based on network vulnerability, load criticality, and location (e.g., those located in remote or hidden areas). Substation security in locations targeted for enhanced fencing will typically be supplemented with mobile cameras to monitor and detect intrusions.

Based on these considerations and underlying data analyses, as shown in Figure SRP-113 below, the Company determined at the polygon level where it anticipates implementing this measure.

Figure SRP-113
Substation Physical Security Fencing Projects Map



History of Efficacy. Like most electric utility substations, the Company's substations are located above ground and in view of the general public. Unauthorized entry, theft, or vandalism at the Company's substations are rare, largely because of the various physical security measures the Company has in place. The Company takes seriously the physical security of its transmission and distribution system, including substations, and previously implemented physical security measures designed to minimize the risk of physical intrusions or physical attacks on the Company's substations. The electric utility industry nationally has seen an increase in the number of instances of physical attacks on its infrastructure. In 2023 alone, the electric utility industry reported to the DOE over 90 instances of physical attack, vandalism, and suspicious activity. The order of upgrades will be based on the condition of the existing fence, the age of the fence, and the number of times there have been attempted intrusions within each substation.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated three alternatives to address substation security:

First, concrete fences would aid in preventing unauthorized access equally as well as wire mesh fencing but at a much higher cost. The Company may consider concrete fencing in lieu of mesh fencing in key high-risk locations if further analysis determines that this option be recommended.

Second, mobile cameras and motion detection systems can detect intrusion but are unlikely to completely prevent access into substations equipped with chain link fences (chain link fencing is cut more easily than the proposed firewall fencing). As noted above, the Company proposes to install security cameras as an additional security measure in some substations where chain link fences will be replaced with wire mesh.

Third, the addition of full-time security personnel at each site to continually monitor substations is also an option but is extremely expensive and deemed not feasible simply due to the number of substations requiring active 24-hour monitoring (well over 250).

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the Substation Physical Security Fencing Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

Section 5.5.2. Substation Security Upgrades (RM-27)

Description. The Substation Security Upgrades Resiliency Measure will upgrade existing security monitoring systems at critical transmission substations to enhance the detection of unauthorized access from individuals committing vandalism or terroristic activities. Substation security includes unauthorized entry detection systems, video surveillance cameras, and associated communications that link to the Company's control center. These systems will enable operating center staff to rapidly notify law enforcement of an effort or active intrusion to mitigate potential equipment damage and customer outages caused by vandals or individuals with terroristic intentions. Substations targeted for security will be chosen based on network vulnerability, load criticality, and location (e.g., those located in remote or hidden areas). Enhanced security in some substations will include upgraded perimeter fencing.

The Substation Security Upgrades Resiliency Measure will upgrade security monitoring systems at a total of 30 substations from 2026 - 2028. The Company estimates that the Substation Security Upgrades Resiliency Measure will cost approximately $19.4 million in capital costs and $100,000 in incremental O&M expense. To determine the effectiveness of the Substation Security Upgrades Resiliency Measure, the Company will monitor substation physical intrusions and report to the Commission the Company's findings. No system outages are required for installation.

Relevant Details. The following figure summarizes the Substation Security Upgrades Resiliency Measure.

Figure SRP-114
Substation Security Upgrades Resiliency Measure (RM-27)

Substation Security Upgrades Resiliency Measure (RM-27)	
Estimated capital costs from 2026 - 2028	$19.4 million
Estimated incremental O&M expense from 2026 – 2028	$100,000
Estimated overall project duration	2026 – 2028 (but ongoing thereafter)
Net salvage value	None
Resiliency Event(s) addressed	Physical intrusion and vandalism
Anticipated benefits	Deter, prevent, and mitigate unauthorized entry into, theft at, and vandalism of the Company's substations Prevent outages from physical threats Increase difficulty for bad actors to gain undetected and unauthorized access to the Company's substations
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. The Company takes seriously the physical security of its transmission and distribution system, including substations. The Company has implemented physical security measures to minimize the risk of physical intrusions into or physical attacks on the Company's substations. In 2023 alone, the electric utility industry reported to the DOE over 90 instances of physical attack, vandalism, and suspicious activity. Notably, there have been instances in which substations have been physically attacked. This measure responds to a concern throughout the Company's system, and the order of upgrades will be based on the age of the security system and number of maintenance requests that a substation has received. Older systems will be replaced first followed by the systems with a greater number of maintenance requests. Then, systems of similar age that are replaced with lower maintenance requests will be replaced last. The Company may also consider factors such as: network vulnerability, load criticality, and location in determining which substations will have security monitoring systems upgraded.

History of Effectiveness. Like most electric utility substations, the Company's substations are located above ground and in view of the general public. Unauthorized entry, theft, or vandalism at the Company's substations are rare, largely because of the various physical security measures that the Company has in place.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, evaluated other viable alternatives to security monitoring systems such as upgrade perimeter fences to prevent or discourage unauthorized access or increase security personnel to monitor substations. Increasing security personnel will increase costs and is not as feasible from a resource perspective, especially considering that the Company has almost three hundred (300) substations. The Company proposes to upgrade chain link fences to wire mesh as a separate program as described in the prior section to work concurrently with this resiliency measure to maximize substation security.

Measuring Efficacy. The Company transitioned from an asset centric program-based approach to a project-based approach using co-optimized sets of project types to address resiliency challenges specific to geographic regions in its service area. Using an array of best practice project type alternatives, different project types were selected in each area to enhance resiliency as well as structural hardening at a discrete asset level.

For substations and transmission assets these mitigations were primarily structural enhancements such as elevating substations above inundation levels or replacing existing transmission structures with designs capable of withstanding higher wind speeds. The discrete nature of these projects results in efficacy measurements which are more asset centric.

Accordingly, the Substation Security Upgrades Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage of resilient power delivery asset failures projected to fail during a Resiliency Event; and
3. Percentage of resilient power delivery asset failures occurring during a Resiliency Event.

Section 5.6. Technology & Cybersecurity Resiliency Events

The Company's SRP has five Technology and Cybersecurity Resiliency Measures. The Company estimates that the five Technology & Cybersecurity Resiliency Measures will cost approximately $79.6 million in capital costs, approximately $13.5 million in incremental O&M expense, and will be implemented over a three-year period from 2026 - 2028. The Company's five technology and cybersecurity Resiliency Measures are summarized in the figure below.

Figure SRP-115
Technology & Cybersecurity Resiliency Measures

Technology & Cybersecurity Resiliency Measures	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	# of Assets	Estimated 3-Year CMI Savings (millions)
Spectrum Acquisition	$42.0	None	N/A	N/A*
Data Center Modernization	$12.7	$1.3	N/A	N/A*
Network Security and Vulnerability Management	$7.5	$2.0	N/A	N/A*
IT/OT Cybersecurity Monitoring Program	$13.4	$4.2	N/A	N/A*
Cloud Security, Product Security & Risk Management	$4.0	$6.0	N/A	N/A*
Subtotal	**$79.6**	**$13.5**		
***Note:** *Please see Section 5 of Exhibit ELS-2 for a qualitative benefit analysis of this Resiliency Measure.*				

Section 5.6.1. Spectrum Acquisition (RM-28)

Description. CenterPoint Houston Electric (CEHE) currently employs the use of a highly redundant and resilient Smart Grid field area network that leverages redundant backhaul communications to datacenters. CEHE currently leverages mobile carriers such as FirstNet, AT&T, and Verizon as well as a privately owned transport network that uses a private 700 MHz A block radio spectrum band. To maintain future levels of reliability and resiliency, along with accommodating new communication demands on the power grid, additional spectrum needs to be acquired.

The spectrum acquisition is the long-term solution to support the multitude of utility use cases to satisfy the T&D systems and functions. This is based on global standards with an active ecosystem and well-aligned with long-term trends in communications technology. Current modeling predicts that additional spectrum is needed to support future capacity needs. The future holds a more complex and dynamic power grid and more end points that will deliver information. The investment needed to secure a resilient future is the ownership of radio spectrum that will meet future needs and technologies.

Spectrum refers to the frequency ranges that are divided into different bands that are used for wireless communications. Wider spectrum (broadband) is needed to support smart communicating devices that requires lower latencies, higher bandwidths and increased reliability. The future need for additional system automation, advanced protection schemes and system visibility to increase reliability / resiliency of the system is driving the need for expanding telecommunication capabilities and in turn additional spectrum. No transmission system outage is required for the Spectrum Acquisition resiliency measure.

Relevant Details. The following figure summarizes the Spectrum Acquisition Resiliency Measure.

Figure SRP-116
Spectrum Acquisition Resiliency Measure (RM-28)

Spectrum Acquisition Resiliency Measure (RM-28)	
Estimated capital costs from 2026-2028	$42.0 million
Estimated incremental O&M expense from 2026 – 2028	None
Estimated overall project duration	2026-2028 (purchase will be 100% complete)
Net salvage value	Salvage Value: None
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Maintain communications capability including during resiliency events Provide visibility, and command and control for substations operations; avoid radio frequency interference; Avoid hardware failures; Support communication during restoration
Other relevant details	Availability of inventory and personnel may impact cost estimates Design changes and vendor selection could impact the cost estimates Completion of the Enterprise Telecommunications strategy

Prioritization. Currently, there is not a single existing CenterPoint Energy owned communication network solution that will support the demand of future field area devices.

Spectrum acquisition is the initial step to expansion of the telecommunication network and is targeted for 2026. Spectrum is a finite resource and available spectrum for purchase is very limited. Spectrum lease options also exist for a contractual timeframe. The benefits of having control of a spectrum acquired includes extensibility (ability to scale new services), quality of service (application-level traffic differentiation for different areas of the utility), security (minimize attack surface), reliability & resilience (match utility needs and priorities), restoration (authority over service and grid restoration), security (implementation and practices) and migration timing (control over lifecycle upgrades).

The project will be implemented in a phased approach. This will provide the capability to augment the current narrowband network with supplemental wireless spectrum solution as well as to provide a cost-effective way to remediate potential capacity constraints in the near-term. Long-term, the augmentation of the existing spectrum will allow the 'slow-roll' of a pathway to a broader pLTE deployment, while following the learnings from the Southern Indiana territory.

History of Effectiveness. Utilities require communication capabilities to support devices used for operational control and system visibility. As the need for reliability and resiliency increases, so does the dependence on a robust communication network. CenterPoint Energy currently owns the 700 MHz spectrum that provides resiliency in the environment for communications. In addition, there are 3rd party cellular carriers used for communications. Houston Electric CHCE has a history of delivering communications reliably, despite infrastructure damage which increases situational awareness during critical times of grid restoration.

With future needs to deploy next generation meters, additional distribution automation, 2-way communications capacitor bank deployment, sensors, etc., the sector capacity planning limit is anticipated to be reached in 2030.

There are many things that can impact 3rd party cellular carriers. These include, but are not limited to:

- Power Outages
- Physical Damages
- Terrorist Attacks
- Cyber Attack
- Natural Disaster

A privately owned network in combination with 3rd party carrier drastically increases network reliability which is crucial during emergency. The likelihood of private and third-party communication both being unavailable, and in the event, this takes palace, a utility can prioritize restoration of their private network for critical areas.

After the initial purchase, there will not be additional on-going costs for spectrum.

Alternatives Considered. The Greater Houston area currently has the 700MHz spectrum, but there is a need to remediate capacity constraints in the near term (5-10 years) while offering the capabilities to support the long term (10-20 years) use cases and business needs.

The difference between acquiring spectrum as opposed to leasing it is that there is an initial expenditure for the spectrum with no on-going costs. The spectrum lease is a cost incurred with no fixed costs or guarantee of usage after the contract term.

While maintaining the 700 MHz, there have been multiple alternatives in consideration:

- Commercial cellular: commercial cellular has no control of restoration and priorities.
- Keep 700 MHz and augment with 850 MHz offered a larger 7x7 channel that allows 5G capabilities.
- Keep 700 MHz and augment with 900 MHz that is offered only as a lease and not currently 5GG capable.
- Keep 700 MHz and augment with 1.6 GHz that is an early adopter compared to other options with a pathway to spectrum ownership and is 5G capable.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Downlink latency;
- Link utilization; and
- Throughput.

Section 5.6.2. Data Center Modernization (RM-29)

Description. The Data Center Modernization Resiliency Measure consists of the following projects:

Disaster Recovery Enterprise Toolset: This project is a new cloud-based recovery plan that will replace the Company's existing data center-based recovery process. This toolset enables partial automation and greater redundancy, improving the Company's overall recovery process during disasters.

On-Premises Infrastructure Refresh: This project will replace aging equipment with cloud-enabled equipment, that will enable the utilization of newer and more cost-effective resiliency applications.

SAN Fabric Redesign: This project involves designing and implementing a new, comprehensive SAN fabric to support the company's data center services. The redesign reduces the risk of SAN related outages, which have occurred in the past due to isolated storage packets.

Data Protection Storage: This project will replace aging equipment, that will enable more cost-effective and modern hardware. This will continue the enablement of effectively backing up our systems and data to allow for recovery.

Active-Active Business Resiliency: Implement Active - Active (Business Resiliency) Solution which enables the capability to have load spread across two Data Centers and have the Business continuity mechanism if one of the Data Center is unavailable due to any reason (Weather, Power, Network, Hardware Failures etc..). This has been implemented for GIS Outage Tracker. This is one of the first applications with this approach and will be the foundation for future SAP and non-SAP application Business Resiliency.

Smart Grid Data Resiliency: This initiative is to set up a redundant smart grid SCADA communication link at AOC so that Distribution Control will still be able to monitor/control smart grid devices in CEHE's distribution network at AOC if the ECDC link is unavailable. This initiative is also to configure a fully redundant ADMS at both control centers.

Relevant Details. The following figure summarizes the Data Center Modernization Resiliency Measure.

Figure SRP-117
Data Center Modernization Resiliency Measure (RM-29)

Data Center Modernization Resiliency Measure (RM-29)	
Estimated capital costs from 2026 - 2028	$12.7 million
Estimated incremental O&M expense from 2026 – 2028	$1.3 million
Estimated overall project duration	2026-2028 2028 (approximately 90% complete; ongoing thru 2030)
Net salvage value	N/A
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Provide visibility, and command and control for substations operations Avoid radio frequency interference Avoid hardware failures Support communications during restoration Faster recovery times of critical applications
Other relevant details	N/A

Prioritization

Disaster Recovery Enterprise Toolset: This effort is a singular task, so no prioritization needed.

On-Premises Infrastructure Refresh: This effort will replace hardware based on age, beginning with the oldest.

SAN Fabric Redesign: This effort will redesign based on physical data center, beginning with the primary data center.

Data Protection Storage: This effort will replace hardware based on age and physical data center, beginning with the oldest at the primary data center.

Active-Active Business Resiliency: This effort will enable resiliency of critical applications between the primary and secondary data centers. Priority will align with the criticality of the application and awareness of the application to be more resilient.

Smart Grid Data Resiliency: In order to continue to have visibility and controllability of CEHE's distribution network in the event of loss of ECDC smart grid communication, we will need to establish a separate smart grid communication link at AOC. Smart grid telecom infrastructure will need to be set up first. We will also need to install network security appliances such as firewalls to ensure the integrity of CEHE's distribution SCADA communication. The ADMS (Advanced Distribution Management System) also is required to be enhanced so that it will be able to communicate with CEHE's smart grid devices through a redundant distribution SCADA link at AOC.

History of Effectiveness

Disaster Recovery Enterprise Toolset: This is a new program the company is developing. However, this program is based on a recognized industry standard for quicker recovery times of critical systems supporting critical business processes following resiliency events.

On-Premises Infrastructure Refresh: This is a new program the company is developing; however, this enhancement is well-known within the utility industry as proven to enhance resiliency and to allow for more agility in managing these needed resources when responding to resiliency events.

SAN Fabric Redesign: The company has general experience operating SAN fabrics and anticipates the redesigned fabric will simplify its operations, increasing reliability and speed.

Data Protection Storage: This is a new program the company is developing; however, this enhancement will support quicker recovery times of systems supporting business processes.

Active-Active Business Resiliency: The company has some experience with enabling applications for active-active resiliency. This program will bring in additional critical applications and provide business resiliency between the data centers.

Smart Grid Data Resiliency: CEHE has been using ADMS to monitor and control distribution smart grid SCADA devices successfully for many years at ECDC. This is to add another distribution SCADA communication link at CEHE's AOC site. Situational awareness is critical for CEHE in managing any resilience event. To have a separate redundant distribution SCADA communication path will enable CEHE to monitor and control its distribution network in the event of loss of ECDC or disruption of ECDC SCADA communication.

Alternatives Considered

In reviewing the SRP, the Company, in collaboration with Guidehouse, considered the following alternatives:

Disaster Recovery Enterprise Toolset: The Company considered continuing operations without the Disaster Recovery Enterprise Toolset, but determined the increased efficiency, redundancy, and reduced recovery time justified the program.

On-Premises Infrastructure Refresh: The alternative to the On-Premises Infrastructure Refresh program is to continue utilizing non-cloud-based infrastructure. The Company determined that cloud-based infrastructure is more efficient and cost-effective.

SAN Fabric Redesign: The Company considered leaving the existing multiple SAN Fabric Solutions in place but determined the reduction in outage risk associated with the SAN Fabric Redesign and the reduction in monitoring/managing activities justified the program.

Data Protection Storage: The alternative is to continue running the existing hardware with limited hardware and software support from the vendor. New capabilities and efficiencies justify the program.

Active-Active Business Resiliency: The alternative is to continue running critical applications at the primary data center and recover in secondary data center if the primary fails. This is less resilient and takes more time to recover.

Smart Grid Data Resiliency: CEHE has two control centers: ECDC and AOC. There are no other alternatives to consider for the redundant SCADA communication link.

Measuring Efficacy

In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following efficacy measures:

Disaster Recovery Enterprise Toolset: The efficacy metric will be the time required for critical system recovery and associated testing.

On-Premises Infrastructure Refresh: The efficacy metric will be the duration it takes to add storage, server, or network capacity to existing/new environments when necessary for performance efficiencies.

SAN Fabric Redesign: The efficacy metric will be annual counts of SAN Fabric related outages causing issues for the business accessing customer information. Collapsing onto one SAN Fabric Solution should reduce SAN related issues accessing customer data.

Data Protection Storage: The efficacy metric will be the duration it takes to recover system and file level data.

Active-Active Business Resiliency: The efficacy metric will be the duration it takes to recover system at secondary data center.

Smart Grid Data Resiliency: Field tests using the AOC smart grid communication link to monitor and control smart grid devices.

Overall, the Company determined the following metrics will be tracked:

- Number of replaced systems;
- Number of manual processes replaced by automation;
- Decreased storage footprint (on premises) vs. Increased resource management/storage efficiency improvements (cloud-based system);
- Decreased data compression rates; and
- Decreased application recovery time.

Section 5.6.3. Network Security & Vulnerability Management (RM-30)

Description. The Network Security and Vulnerability Management Resiliency Measure will consist of the following projects:

Application Security: This project will develop and operationalize tools and processes to complete all application development securely with control of the point of origin/subcomponents of every in-house developed software product. The implementation process consists of assessing the current development environment; understanding gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; implementing the chosen cybersecurity application development tool; and implementing process changes to meet Company objectives.

Vulnerability Management: This project will be an ongoing process of identifying, assessing, prioritizing, and mitigating cybersecurity vulnerabilities across endpoints and systems. This project reduces the likelihood and impact of security incidents by addressing weaknesses that could be exploited and allows the Company to stay ahead of potential threats and minimize the likelihood of security breaches. This project will include both comprehensive patching of all operating system and application vulnerabilities and a penetration testing program. The implementation process consists of assessing the current development environment, understand gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; implementing the chosen cybersecurity application development tool; and implementing process changes to meet Company objectives.

Security Infrastructure/Network Segmentation: This project is a comprehensive program that will include deployment of advanced firewalls, passive network sensors, and other cyber technologies to over four hundred sites. This project will also include the re-design/re-build of the Cybersecurity Operations Center and the build-out of a dedicated operations technology lab and technology deployment factory. The implementation process will consist of assessing the current development environment, understanding gaps in current processes; working with development teams and leadership to evaluate products in the market that facilitate a consistent, measurable, auditable development process that includes software vulnerability scanning during the development process; and implementing the chosen process changes to meet Company objectives.

No transmission system outage is required for the Network Security & Vulnerability Management measure.

Relevant Details. The following figure summarizes the Network Security & Vulnerability Resiliency Measure.

Figure SRP-118
Network Security & Vulnerability Resiliency Measure (RM-30)

Network Security & Vulnerability Resiliency Measure (RM-30)	
Estimated capital costs from 2026 - 2028	$7.5 million
Estimated incremental O&M expense from 2026 - 2028	$2.0 million
Estimated overall project duration	2026-2028 (but ongoing thereafter)
Net salvage value	None

Network Security & Vulnerability Resiliency Measure (RM-30)	
Resiliency Event(s) addressed	Cybersecurity Unauthorized access Loss of critical or sensitive data
Anticipated benefits	Provide capability to monitor and control certain distribution grid components during the resilience event Reduce risk of disruption of critical computing systems or energy delivery systems Prevents loss of critical/sensitive data Increase compliance with regulatory requirements by implementing measures to protect software and its components from vulnerabilities and threats
Other relevant details	N/A

Prioritization

Application Security: Implementation will be prioritized by risk, considering impact and likelihood, including criticality, risk exposure, compliance requirements, and user impact which will create a prioritization framework to effectively manage security within development, security, and operations pipeline.

Vulnerability Management: Implementation will be prioritized by age of the equipment and software lifecycle management.

Security Infrastructure/Network Segmentation: Implementation will be prioritized by age of the equipment and software lifecycle management.

History of Effectiveness. The Network Security & Vulnerability Management Program Resiliency Measure is known in the Company's experience and within the industry to protect digital assets including, but not limited to, network, network equipment, client computers, control systems. Without a Network Security & Vulnerability Management Program in place, the Company's digital assets and data would be at risk of vulnerabilities that may allow unauthorized access or attacks by threat actors.

While the three elements of this resiliency measure are not dependent on one another, they are complimentary and together are more effective in providing increased resiliency to the Company's system.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined additional due diligence will be performed to consider vendor alternatives and solution options. This is foundational and needed for protection. The alternative is to take no action, which the Company determine is not a viable option.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Number of applications in scope having gone through their respective secure software development lifecycle process;
- Amount of peer reviews, code reviews, code scans;
- Number of application security vulnerabilities detected/remediated;
- Number of network segments ingested on a daily basis;
- Number of suspicious/malicious alerts;
- Number of packets stopped at firewalls;
- Number of packets inspected; and
- Net number of rules moved from layer 4 to layer 7 load balancing.

Section 5.6.4. IT/OT Cybersecurity Monitoring Program (RM-31)

Description. The IT/OT Cybersecurity Monitoring Program Resiliency Measure is a comprehensive program that will include deployment of advanced firewalls, passive network sensors and other cyber technologies to over 400 sites. The IT/OT Cybersecurity Monitoring Program Resiliency Measure will also include re-design/re-build of the Company's Cybersecurity Operations Center and build-out of a dedicated operational technology lab and technology deployment factory. The IT/OT Cybersecurity Monitoring Program Resiliency Measure will promote business continuity by protecting downtime of systems and preventing disruption of operations; will work to respond to the ever-evolving cyber threat landscape investments; will mitigate risk associated with data breaches; and protect the Company's digital assets, confidential data, intellectual property, and critical infrastructure from damage, unauthorized access, or theft. No transmission system outage is required for the IT/OT Cybersecurity Monitoring Program.

Relevant Details. The following figure summarizes the IT/OT Cybersecurity Monitoring Resiliency Measure.

Figure SRP-119
IT/OT Cybersecurity Monitoring Program Resiliency Measure (RM-31)

IT/OT Cybersecurity Monitoring Program Resiliency Measure (RM-31)	
Estimated capital costs from 2026 - 2028	$13.4 million
Estimated incremental O&M expense from 2026 - 2028	$4.2 million
Estimated overall project duration	2026 – 2028 (but ongoing thereafter)
Net salvage value	None
Resiliency Event(s) addressed	Cybersecurity Unauthorized access Loss of critical or sensitive data
Anticipated benefits	Provide capability to monitor and control the distribution grid during the resilience event Identify and respond to outage events
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. Sites have been prioritized based on the following criteria; NERC Medium, NERC Low, Non-NERC/Distribution and Non-Company-owned substations. The implementation schedule is still being finalized for the next four years however the schedule will account for prioritization of site and ability to adjust specific implementation dates due to unplanned events (e.g., unexpected hands off or outages, technician availability) and alignment with similar projects (e.g., router refresh).

History of Effectiveness. Threat and intelligence data and scanning systems data employed by the Company indicate that the IT/OT environment has a continuous target of threat actors. The IT/OT Cybersecurity Monitoring Program Resiliency Measure is known within the industry to protect all digital assets including the IT network, network equipment, client computers, and control systems.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, assessed various alternatives considering the technological capabilities of the hardware and software chosen, cost, experience in the industry yielding success, organizational reputation, sustainability, and supportability. The selected measures are well-known within the utility industry as being proven to mitigate against cyber-attacks via prevent, detection, and response functionalities and thus enhance resiliency.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Number of alerts;
- Number of systems being monitored (system transparency);
- Incident response time;
- System information ingestion rates;
- Volume of recorded malicious behavior;
- Volume of data inspected;
- Number of data sources migrated to SOC; and
- Number of SOC rules, use cases, and SOC playbooks developed.

Section 5.6.5. Cloud Security, Product Security & Risk Management (RM-32)

Description. Cloud Security, Product Security, and Risk Management is required to provide resiliency from design, development, build, and operations of critical infrastructure. The product and cloud security is required to protect the grid and consumers through protections of the products in the field, protections of the data captured from those products, and protections of the cloud connectivity required to be able to provide visibility, assessment, and response/recovery as expected by our rate payers. By building a resilient ecosystem of products such as smart sensors, smart meters, intelligent grid switching devices and others, there is a need to provide PMT (Process/Methods/Tools) that provide visibility to the threats of the products, the risks of the products, the data protection and flow of data to/from those products, and the response and recovery mechanism required for those products to bring back to secure state at any point in the lifecycle. The product and cloud security will need to understand the underlying supply chain which has been built into the products. Product and cloud security need to provide appropriate risk management methods to address third party risks that may be introduced to the hardware and or the software.

Relevant Details. The following figure summarizes the Cloud Security, Product Security & Risk Management Resiliency Measure.

Figure SRP-120
Cloud Security, Product Security & Risk Management Resiliency Measure (RM-32)

Cloud Security, Product Security & Risk Management Resiliency Measure (RM-32)	
Estimated capital costs from 2026-2028	$4.0 million
Estimated incremental O&M expense from 2026 – 2028	$6.0 million
Estimated overall project duration	2026-2028 (but ongoing thereafter)
Net salvage value	None
Resiliency Event(s) addressed	All Resiliency Events that could cause an outage
Anticipated benefits	Visibility to the threats and risks of products Data flow protection Response recovery mechanisms
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. In year one of the SRP, the Company will prioritize developing a stronger foundation for Cloud Security and Product Security (mission, goals, visions), as well as identify necessary activities to upgrade CEHE's current Risk Management. Year one will also include prioritizing analysis of the efficacy of each proposed tool and process, procuring identified tools, and developing processes and procedures, all of which will prioritize the tools and processes with the greatest impact. In year two, prioritization will shift to implementing the tools and processes and developing baseline data. Year three will target stabilizing and improving the year two baselines to ensure CEHE has the right processes in place and is achieving the goals of this proposed Resiliency Measure.

History of Effectiveness. The CSPSRM resiliency measure targets increased data visibility, identification of risks that were reduced or eliminated in the design phase, implementations of effective protective measures and controls, and baselining CEHE's understanding of alerts and findings across the cyber system lifecycle.

Alternatives Considered. Alternatives to this resiliency measure include doing nothing and maintaining the status quo of cyber systems and associated application physically located within CEHE facilities. Doing nothing is not a viable option, as cyber attacks are expected to increase in volume and severity, as identified in the Cyber Risk Profile section of this report. Maintaining the status quo also reduces CEHE's ability to rapidly respond to and recover from cyber attacks and prevents CEHE from leveraging cloud-based cyber systems in a more resilient manner.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- The number of identified risks;
- The number of implemented protective measures and controls;
- The number of developed baselines;
- The number of alerts and findings received by monitoring systems; and
- Reduced response and recovery times in the event of cyber attacks.

Section 5.7. Situational Awareness

The Company's SRP has seven situational awareness Resiliency Measures that will modernize and enhance the technology software and equipment used in support of Company operations. The Company estimates that the seven situational awareness Resiliency Measures that will support the Company's transmission and distribution system operations will cost approximately $209.5 million in capital costs, approximately $9.2 million in incremental O&M expense, and will be implemented over a three-year period from 2026 - 2028. The seven Situational Awareness Resiliency Measures are summarized in the figure below.

Figure SRP-121
Situational Awareness Resiliency Measures

Situational Awareness Resiliency Measures	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)	# of Assets	Estimate 3-Year CMI Savings (millions)
Advanced Aerial Imagery Platform/Digital Twin	$18.4	$2.0	N/A	10.8
Weather Stations	None	$0.3	N/A	N/A*
Wildfire Cameras	None	$0.9	N/A	N/A*
Voice & Mobile Data Radio System	$20.9	None	27 sites	N/A*
Backhaul Microwave Communication	$12.7	None	165 radios	N/A*
Emergency Operations Center	$50.0	$6.0	1 location	N/A*
Hardened Service Centers	$107.6	None	4 service centers	N/A*
Subtotal	**$209.5**	**$9.2**		**10.8**
****Note:** *Please see Section 5 of Exhibit ELS-2 for a qualitative benefit analysis of this Resiliency Measure.*				

Section 5.7.1. Advanced Aerial Imagery Platform/Digital Twin (RM-33)

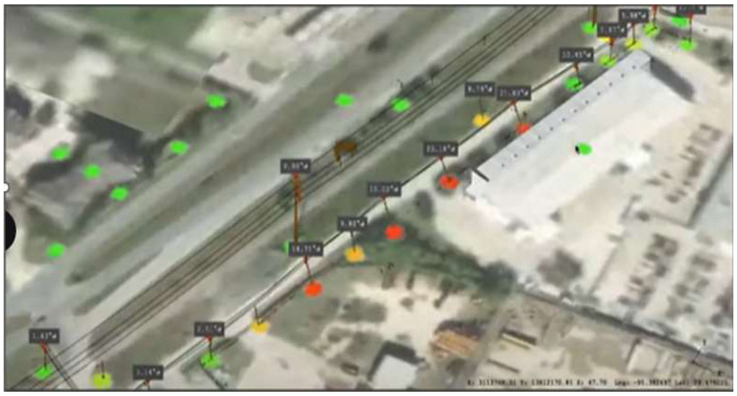
Description. The Company's Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure is designed to improve and enhance the visibility of the transmission, substation, and distribution systems managed by the Company by creating a virtual replication of the physical infrastructure and equipment installed. The Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure works in conjunction with other resiliency measures to combine LiDAR imagery data, device data (meters, IGSDs, sensors, etc.), weather data, inspection data, wildfire data, and monitoring data into advanced software platforms. This allows for the overlay of imagery to better determine vegetation management risk, to utilize and analyze data analytics for equipment and infrastructure failure, and to improve performance by modeling the impact of extreme weather events. This data analysis will improve and streamline processes, including for other resiliency measures, leading to a reduction in engineering design time, improvements in installation expediency and replacement of equipment before failure, and increased resiliency and ultimately lead to customer benefits.

The Company proposes to leverage this software in tandem with other software to "rank" improvement projects based on the value added to customers by optimizing the project portfolio. Utilizing this software's data analytics capabilities will help improve efficiencies, reduce costs over time, and allow for greater optimization and focus on system improvements that will have the greatest resiliency benefits for customers. The software is also capable of "learning" from historical data and leverages prior analyses to improve current model performance by identifying system resiliency patterns and trends for upgrades needed to address extreme weather events, encroachments from vegetation (or other sources), and remediation of broken/leaning equipment.

The Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure will enhance the Company's ability to identify and determine extreme weather-related risk to the Company's transmission and distribution system and to identify and determine potential projects that may mitigate the impact of such risk. No system outages are required for installation.

The following figure illustrates a screen shot example of the Digital Twin program which will improve and enhance the visibility of the transmission, substation, and distribution systems by digitizing a complete replication of the physical infrastructure and equipment installed.

Figure SRP-122
Digital Twin



Relevant Details. The following figure summarizes the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure.

Figure SRP-123
Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure (RM-33)

Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure (RM-33)	
Estimated capital costs from 2026 - 2028	$18.4 million
Estimated incremental O&M expense from 2026 - 2028	$2.0 million
Estimated overall project duration	2026 - 2028 (but ongoing thereafter)
Net salvage value	N/A
Resiliency Event(s) addressed	Extreme wind events • Microburst • High wind • Tornado • Hurricane Extreme Water • Flooding Extreme temperature event • Heat • Freeze Wildfires
Anticipated benefits	Enhanced ability to proactively plan and implement projects to mitigate outages attributable to extreme weather events Determine future improvements to the Company's transmission and distribution system to mitigate the impact of future resiliency events

Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure (RM-33)	
	Reduce restoration times Preemptively mitigate damage from resiliency events Reduce the frequency and number of customers impacted by outages Reduce total outage times Reduce system restoration costs
Other Relevant Details	Cost estimates may be impacted by the need to reformat data to align with advanced data analytics techniques The Company has applied for DoE grants related to this Resiliency Measure but unfortunately was not awarded the grant in this round. The Company will continue to apply for grants to assist in subsidizing this measure.

Prioritization. The Advanced Aerial Imagery/Digital Twin Resiliency Measure will be for the Company's entire service area. There is not a relevant order of installation, as information is collected and analyzed for all locations and potential Resiliency Events concurrently.

History of Effectiveness. The Advanced Aerial Imagery/Digital Twin is a new program that the Company is developing. The Company has previously used mapping tools to visualize areas of impact for potential weather events to help coordinate a response that has been effective versus not preparing for resiliency events.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, compared the benefits of the proposed Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure to the Company's existing methodology. Together with Guidehouse, the Company determined that the Advanced Aerial Imagery Platform/Digital Twin Resiliency Measure software offers significant improvements, including reduced analysis time and a progression of improvements in design and project location achieved by AI "learning."

An alternative the Company considered was to build in-house software to perform similar functions. This option was rejected by the Company because it would take much more time to complete versus the immediate availability of the proposed Advanced Aerial Imagery/Digital Twin. Though this alternative over the long term would be less costly, the time-value of an immediately available program is material to the Company and frees human-resources within the Company to focus on other duties to best serve our customers.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, proposes to perform an analysis of events to determine the correctness of the algorithms for the digital twin models.

The Company will track and report to the Commission annually the percentage of programmatic decisions made using the digital twin. Adjustments may need to be made, but the Company believes that improvements in resiliency of the Company's transmission and distribution system should be seen.

Section 5.7.2. Weather Stations (RM-34)

Description. Weather Stations provide high resolution monitoring of weather data and measurements. These can be used to inform and create weather-based risk profiles and enable more accurate weather risk modeling. Examples of the models that leverage weather data include contamination models, transformer failure models, wildfire risk models, and damage prediction models. These will also be used for real time situational awareness across the Company's service territory. The cost included within this filing is limited to performing routine maintenance in support of the weather systems and data that is critical to the models mentioned above. This is critical as having immediate accurate high resolution weather data can enable faster response post resiliency events to begin optimal deployment of resources to targeted regions severely impacted that are now safe to enter and perform restoration work.

Relevant Details. The following figure summarizes the Weather Stations Resiliency Measure.

Figure SRP-124
Weather Stations Resiliency Measure (RM-34)

Weather Stations Resiliency Measure (RM-34)	
Estimated capital costs from 2026-2028	None (capital expenditures to occur in 2025)
Estimated incremental O&M expense from 2026 – 2028	$0.3 million
Estimated overall project duration	2026-2028 (but ongoing thereafter)
Net salvage value	Salvage Value: None Removal costs: Are included as part of capital project costs
Resiliency Event(s) addressed	Extreme weather events Extreme Wind • Tornado • High Wind • Derecho • Microburst • Hurricane Extreme Temperature • Heat • Freeze Wildfire

Weather Stations Resiliency Measure (RM-34)	
Anticipated benefits	Faster restoration Reduce time and expense associated with dispatching field personnel to restore an outage Reduce number of customers impacted by an outage Reduce total outage time
Other relevant details	Availability of material and personnel may impact cost estimates; costs may also be impacted by commercial carrier rate changes

Prioritization. This measure is centered around maintaining the weather stations and is performed to keep these stations in top working order for input into the various models before (and when) high impact low frequency events occur. As such, there is no real prioritization as they are all critical to the overall weather perspective of the entire Company territory and are maintained as such.

History of Effectiveness. As these are new systems, there is no real history of the effectiveness of these units. These weather stations are, however, critical to feeding data into various models as mentioned above and serve a significant purpose in determining the methodology in restoration. This plan was recommended by the developer in order to keep these units in top working order and, per the third-party vendor, they have had good success in keeping the units functional in critical times when leveraging this plan.

Alternatives Considered. There are very few options for gathering the granularity of weather data necessary to feed the various models to ascertain reliable results. One such option was to only leverage outside data, but the granularity of data was not enough to model to the level of accuracy necessary to provide sustainable results for preparation and deployment of resources and this was not a viable option. The only other option was not to maintain these stations, but this would potentially lead to times where weather stations were down and not delivering the necessary data to feed models and ascertain the granular results needed. This too was not a viable option.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Weather Stations Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.7.3. Wildfire Cameras (RM-35)

Description. The Wildfire Camera Monitoring Resiliency Measure will install a camera system and/or other monitoring equipment at select locations on or near the Company's transmission and distribution system that have elevated wildfire risk, as analyzed and identified by the Company. These cameras are similar to those used in the Substation Security Upgrades, but serve a different purpose based on where they are placed. The Company will implement the Wildfire Camera Monitoring Resiliency Measure if, under Good Utility Practice and in the Company's engineering and operational judgment, the Wildfire Camera Monitoring Resiliency Measure will reduce the risk, mitigate the spread, or mitigate the impact of a wildfire on the Company's transmission and distribution system. Outages are not required for the Wildfire Camera Monitoring Resiliency Measure.

Relevant Details. The following figure summarizes the Wildfire Camera Monitoring Resiliency Measure.

Figure SRP-125
Wildfire Cameras Resiliency Measure (RM-35)

Wildfire Cameras Resiliency Measure (RM-35)	
Estimated capital costs from 2026 - 2028	None (capital expenditures to occur in 2025)
Estimated incremental O&M expense from 2026 - 2028	$0.9 million
Estimated overall project duration	2026-2028 (but ongoing thereafter)
Net salvage value	N/A
Resiliency Event(s) addressed	Wildfire
Anticipated benefits	Real-time monitoring capability in select regions Faster response time in the event that issues are identified or in the event of a wildfire
Other relevant details	Availability of material and personnel may impact cost estimates

Prioritization. Where the Company implements the Wildfire Camera Monitoring Resiliency Measure, the Company will prioritize the portions of the Company's transmission and distribution system that have elevated levels of wildfire risk, as analyzed and identified by the Company.

History of Effectiveness. Camera monitoring has proven to be effective in providing data in real-time, thus enabling faster response times. The Company utilizes real-time camera monitoring as part of its wildfire measures within the Company's territory.

Alternatives Considered. With wildfires beginning to be a larger issue in Texas, the Company made a decision to add wildfire measures within the SRP. The only real alternative to adding these measures is to not provide and prepare for wildfire mitigation. In the recent history, there have been a significant uptick in the number of drought and heat days, lending to the higher possibility of fuel for wildfires. Taking this into account, the risk of wildfire is becoming greater within the Company's territory and mitigation measures need to begin. The option of not proactively preparing for wildfires was not a viable option due to the increased risk seen within the territory (drought conditions in recent years, wildfire in Brazoria County in 2024, the Smokehouse Creek fire, and most recently the Los Angeles fires are just a few examples of the risk).

The Company has identified and is proposing four extreme temperature (drought) wildfire Resiliency Measures—each a recognized best practice within the utility industry—as measures most likely to be useful in mitigating the risk of wildfires in the Company's service area and areas outside its service area in which it operates facilities. The Company will consider how all or some of the measures can work in combination to address most appropriately the specific service area risk confronting the Company.

Measuring Efficacy. Distribution system mitigations are focused on areas of higher predicted damage concentration to maximize overall system restoration efficiency. These mitigations, when optimized at the project level, require the consideration of interdependencies between mitigations contemplated for the same distribution feeder/area. For example, strategic undergrounding changes the needs for automation and vegetation management frequency. As a result of using the co-optimized project-based approach, the Company will use efficacy measures which capture the complementary nature of project-based system resiliency plans. This approach is consistent with industry best practice and measures success as a product of regional performance as opposed to individual asset performance.

The Wildfire Cameras Resiliency Measure Measurements of Efficacy are:

1. Percentage of planned asset installations complete by County;
2. Percentage change in predicted damage for areas of higher damage concentration based on the event type;
3. Normalized total system restoration performance during Resiliency Events pre and post completion of mitigation projects based on the event type; and
4. Normalized restoration performance of predicted high damage concentration area restoration performance compared to Normalized total system restoration performance pre and post completion of mitigation projects during Resiliency Events based on the event type.

Section 5.7.4. Voice and Mobile Data Radio System (RM-36)

Description. The Voice and Mobile Data Radio System Resiliency Measure will upgrade the fleet mobile and portable radio communications equipment used to dispatch and communicate with the Company's field personnel that are responsible for repair and maintenance work in the field, including during outage restoration work. Manufacturer support for the Company's current mobile data radio system is "end of life" and spare equipment is limited. This is the short term to medium term solution while the long-term solution utilizing additional spectrum cannot be implemented in time to satisfy the immediate need. Upgrading portable radio communications equipment helps the Company to continue to be able to communicate with field personnel in areas or periods with limited cellular communications. The upgraded equipment will also have operational improvements over the Company's existing system, such as GPS tracking, over-the-air programming, text messaging, and enhanced encryption.

The voice and mobile data radio system will be implemented in a phased approach by service area to minimize disruptions to personnel and prioritized by areas where we can provide overlapping coverage with the existing system with minimal capacity losses. As each group is transitioned to the new equipment, training will be provided at or near the time of installation and the talk groups will be "tied" together from the new and old system to allow for a seamless transition.

Relevant Details. The following figure summarizes the Voice and Mobile Data Radio Resiliency Measure.

Figure SRP-126
Voice and Mobile Data Radio System Resiliency Measure (RM-36)

Voice and Mobile Data Radio System Resiliency Measure (RM-36)	
Estimated capital costs from 2026 - 2028	$20.9 million
Estimated incremental O&M expense from 2026 - 2028	None
Estimated overall project duration	2026 - 2028 (100% complete with 27 DMR Tier 3 sites)
Net salvage value	None
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Maintain communications capability to and with the Company's field personnel in instances with limited cellular coverage, including during resiliency events.
Other relevant details	Availability of inventory and personnel may impact cost estimates Design changes and vendor selection could impact the cost estimates

Prioritization. There will be an initial pilot with three pilot tower sites identified and grouped. After testing this, the voice and mobile data radio system will be implemented in a phased approach by service area to minimize disruptions to personnel and prioritized by areas where we can provide overlapping coverage with the existing system with minimal capacity losses. As each group is transitioned to the new equipment, training will be provided at or near the time of installation and the talk groups will be "tied" together from the new and old system to allow for a seamless transition.

History of Effectiveness. In the Company's experience, the voice and mobile data radio system has been critical to the safety of personnel and safe operations. During restoration events, areas regularly do not have adequate cell coverage and the system has been the only means for field personnel to communicate with management and other team members. The ability to communicate with other individuals in the organization about status and issues is important to the restoration activities, in addition to standard operating procedures.

The Company has also found radio communications to be efficient for notifying all crews in a given area, which is critical to the safety of personnel and safe operations. Cellular communications are inherently inefficient when trying to communicate in a "one to many" scenario. Situational awareness is key when multiple crews including contractors are involved in circuit operations. A single radio call can inform multiple groups without the need for individual names and phone numbers.

Alternatives Considered. In reviewing the SRP, the Company, in collaboration with Guidehouse, considered continuing using the Company's current fleet of mobile and portable radio communications equipment. However, system support for the current mobile data radio system is ending, and critical spare equipment are limited from manufacturers. Not implementing the Voice and Mobile Data Radio System Refresh Resiliency Measure could result in too few radios and unavailable radio coverage to support operation activities. The Company is in the process of using a competitive request for proposals to select a specific program for this project, though no decisions have been made at this point, beyond the resolution that the Voice and Mobile Data Radio System Refresh Resiliency Measure needs to be implemented.

The Company also considered relying on private LTE communications, but the Company determined that a private LTE communications program could not be adopted in time to meet the Company's short-term, and mid-term needs. Additionally, it is unclear whether private LTE can effectively be used as a replacement for radio. The Company is aware of several utilities that utilize private LTE as a supplement to (and not a replacement of) their radio systems. . Utilization of a Project 25 ("P25") or Digital Mobile Radio ("DMR") system in Land Mobile Radio ("LMR") is possible, but the need from the LMR is still the same, which is portability, and mobile radio coverage and connectivity through a dispatch console system. It was determined this would be the most feasible approach.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Dispatch speed,
- Field tests completed,
- Remoteness of communications, Decrease in maintenance time,
- Annual number of End-of-life equipment replacements to:
    - Maintain continuity,
    - Avoid truck rolls, and
    - Integrate GPS tracking and text messaging

Section 5.7.5. Backhaul Microwave Communication (RM-37)

Description. The Company uses microwave equipment for monitoring and controlling field devices, including substations. Microwave equipment serves as a backup system for field devices that have fiber optic control and as the primary communication system for sites that are not fiber optic compatible. Much of The Company's current microwave equipment is nearing obsolescence and thus support is limited, and it is incompatible with newer platforms. The Backhaul Microwave Communication Resiliency Measure will replace this aging microwave equipment with new equipment that is compatible with the Company's newer microwave equipment, enabling the use of a single network management tool to see issues and remotely troubleshoot.

Relevant Details. The following figure summarizes the Backhaul Microwave Communication Resiliency Measure.

Figure SRP-127
Backhaul Microwave Communication Resiliency Measure (RM-37)

Backhaul Microwave Communication Resiliency Measure (RM-37)	
Estimated capital costs from 2026 - 2028	$12.7 million
Estimated incremental O&M expense from 2026 - 2028	None
Estimated overall project duration	2026 – 2028 (approximately 25% with 165 radios; but extends through 2029)
Net salvage value	None
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Provide visibility, and command and control for substations operations Avoid radio frequency interference Avoid hardware failures Support communication during restoration
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. Implementation will be prioritized by age of the equipment by section. For instance, this effort focuses on the South ring, West ring then the East ring, based on age and risk of failure. The geography has backhaul microwave communications in rings that divide up the service area. The work focuses on one ring at a time.

History of Effectiveness. Redundancy is one of the primary methods for ensuring a resilient electric delivery service. Having a secondary method of communication available during extreme weather or cybersecurity events has helped reduce the risk of critical data loss. Additionally, enhancements to the microwave system directly impact the Company's ability to perform remote operations effectively.

Alternatives Considered. The Company currently uses fiber optic cable as the primary form of communication except for field equipment in remote or difficult to access locations. In reviewing the SRP, the Company, in collaboration with Guidehouse, considered running extensive fiber optic cable to these remote field equipment locations, but determined this approach was not economically feasible. Extensive fiber optic cable runs are costly, installation requires significant lead time and can present easement and permitting issues.

The Company is maintaining the equipment but is now reaching the end of life/aging equipment and vendor support life cycles. Thus, the alternative to continue using the current equipment is not viable because of the Company would lack support for the end-of-life equipment, need to maintain multiple equipment platforms, and eventually need features that currently cannot be used due to technological incompatibilities between the different platforms.

Additionally, the Company also considered whether it was necessary to continue to utilize microwave equipment as a secondary communication source in locations with fiber optic access and determined that the added redundancy justified the cost. For resiliency, it is best practice to have two paths of communication to a site in the event of an outage/unavailability of one communication path. For instance, there could be construction activities that damage optic fiber or a weather event that negatively affects a microwave radio.

Measuring Efficacy. In reviewing the SRP, the Company, in collaboration with Guidehouse, determined the following performance metrics will be tracked:

- Amount of end-of-life equipment replaced by modern vendor-supported systems,
- Decrease in maintenance time, and
- Increased collection of data points.

Section 5.7.6. Emergency Operations Center (RM-38)

Description. In 2025 the Company will be focusing on staging site enhancements and begin building a new Emergency Operations Center, that will ultimately finish in 2026 representing the \$50M total included in this SRP. Staging site enhancements include the identification and evaluation of available properties within the service footprint that will be reviewed for permanent development in preparation to be used as a staging site during an event. Our new Emergency

Operations Center (EOC) will provide a location where the Company will centralize event response efforts and create a central hub for situational awareness across the service footprint. This facility will further improve efficiency amongst ICS branches and enable an effective and efficient restoration effort. The EOC improvements taking place in 2025 were also identified through the Hurricane Beryl After Action Review performed by PA Consulting. The recommendation outlined various activities to further streamline the EOC layout including things such as dedicated work areas for multiple groups throughout the Incident Command Structure (ICS), and improved technology resources. In addition to the above steps being taken to improve event response, the Company will be constructing four new and hardened electric distribution service centers across the service footprint. This will not only provide benefits in everyday restoration scenarios, but most importantly provide a hardened Company owned location that can be utilized in resiliency events that will keep employees safe and allow for the quickest response possible when it is safe to begin restoration.

Relevant Details. The following figure summarizes the Emergency Operations Center Resiliency Measure.

Figure SRP-128
Emergency Operations Center Resiliency Measure (RM-38)

Emergency Operations Center Resiliency Measure (RM-38)	
Estimated capital costs from 2026 - 2028	$50.0 million
Estimated incremental O&M expense from 2026 - 2028	$6.0
Estimated overall project duration	2026 – 2028 (100% completion)
Net salvage value	None
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Centralized event response Central hub for situational awareness across the service footprint Improve efficiency amongst ICS branches
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. Implementation will involve the identification and evaluation of properties across the service footprint that will offer the greatest efficiency and location to successfully withstand a resiliency event. Once a property is identified the Company will build a hardened structure.

History of Effectiveness. Hardened structures the Company has completed construction on in recent years, specifically the Brazoria and Fort Bend electric service centers, withstood resiliency events prior to and throughout 2024. This fact coupled with the centralization of the Company's ICS teams will bring greater efficiency and safety during response to an event.

Alternatives Considered. The company currently uses multiple locations to manage an event response. In reviewing the SRP, the Company, in collaboration with Guidehouse considered the alternative of remaining with what we have today and not taking an opportunity to not only design and build a hardened building to centralize emergency response efforts streamline communications during a resiliency event. To further harden the Company's assets, and considering the PA Consulting recommendation to streamline communications during a resiliency event, the company chose to not follow this alternative.

Measuring Efficacy. Where the Company completes construction on the new Emergency Operations Center, the Company will track and report to the Commission annually on whether or not the structure is damaged during a resiliency event.

Section 5.7.7. Hardened Service Centers (RM-39)

Description. The Company is building four new hardened Service Centers that are capable of withstanding extreme wind speeds up to 162MPH (to aid in withstanding beyond category 4 hurricane windspeeds). Two of the hardened service centers will be completed by end of 2028 and the other two will be completed in 2029. Distribution resources located at the Company's service centers are integral to successfully restore electric service as quickly and safely as possible to our customers within the service footprint. The Service Centers have access to critical systems, materials, and resources to support situational awareness and restoration efforts. Some of the restoration processes the Service Centers support include cut and clear processes, damage assessment, and coordination of field operations and mutual assistance crews.

Relevant Details. The following figure summarizes the Hardened Service Centers Resiliency Measure.

Figure SRP-129
Hardened Service Centers Resiliency Measure (RM-39)

Hardened Service Centers Resiliency Measure (RM-39)	
Estimated capital costs from 2026 - 2028	$107.6 million
Estimated incremental O&M expense from 2026 - 2028	None
Estimated overall project duration	2026 – 2028 (approximately 78% complete, but extends through 2029)
Net salvage value	None
Resiliency Event(s) addressed	All Resiliency Events that may cause outages
Anticipated benefits	Provide a hardened Company owned facility. Use of service centers as possible staging sites.
Other relevant details	Availability of inventory and personnel may impact cost estimates

Prioritization. The four service center locations to be hardened as part of the Resiliency Plan were prioritized based off numerous variables including, but not limited to, infrastructure age, proximity to the coast, service center location, etc. Considering all these variables the four service centers were identified to further harden the Company's assets and keep our employees safe in a resiliency event and everyday normal operations everyday.

History of Effectiveness. Hardened structures the Company has completed construction on in recent years, specifically the Brazoria and Fort Bend electric service centers, withstood resiliency events prior to and throughout 2024. This evidence supports this Resiliency Measure.

Alternatives Considered. The company currently utilizes three existing service centers to operate normal daily operations, as well as respond to resiliency events cross the footprint. In reviewing the SRP, the Company, in collaboration with Guidehouse considered the alternative of keeping our existing three service centers (Baytown, Humble, and Galveston/Sante Fe), and not building the new Channelview service center. This alternative does not present the best path forward for our service footprint or employees as we strive to harden the grid.

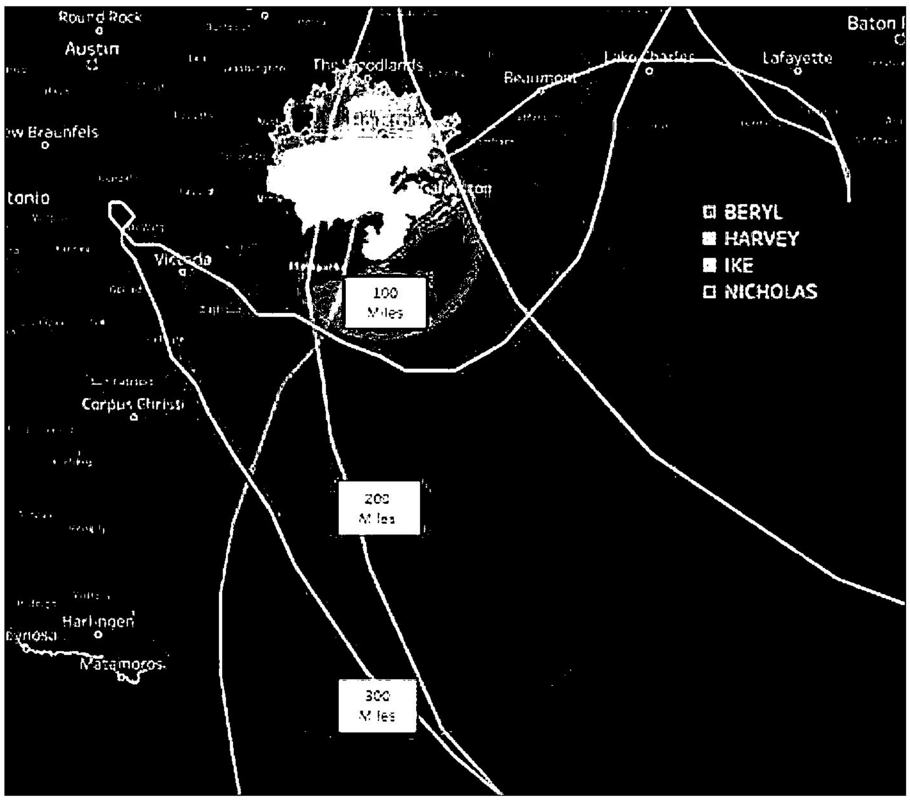
Measuring Efficacy. Where the Company completes construction on the new hardened service centers, the Company will track and report to the Commission annually on whether or not the structures are damaged during a resiliency event.

Appendix A - Extreme Wind Events

Section 1. Overview of the Company's Service Territory

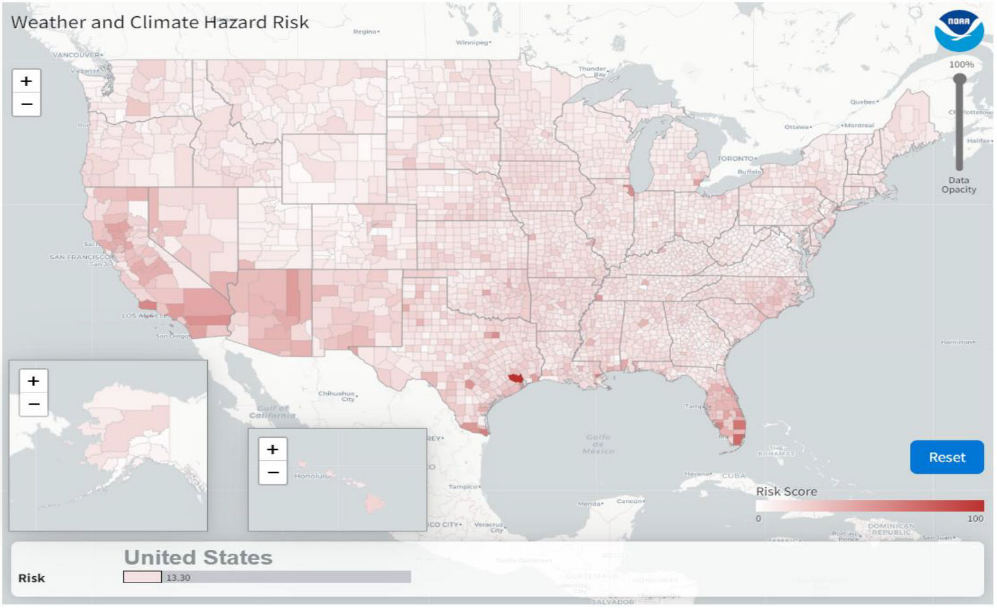
Historically, CenterPoint Energy Houston Electric's ("CEHE" or the "Company") service territory has been subjected to many extreme wind events of varying types including hurricanes, tornadoes, and extreme straight-line winds. Although there are many similarities between these events, they often differ in the percentage of the service territory impacted. Hurricanes have proven to be the highest risk events due to their potential to encompass all CEHE assets given the relatively small service territory compared to the average hurricane size. Typical hurricanes are approximately 300 miles wide with hurricane force winds extending outwards as far as 150 miles from the eye of the storm as shown in the figure below.

Figure AA-1



CEHE's compact service territory has also been analyzed and determined to include the highest population density county of all coastal counties by the National Oceanic and Atmospheric Administration ("NOAA"). When coupling these high winds with vegetation risks, a challenging mix of tree fall and inaccessibility results. To take this point further, according to NOAA, CEHE's service territory includes the county with the highest weather and climate hazard risk score when considering a multitude of climate risks.

Figure AA-2



Data Type	Harris County	Texas	U.S.
Weather and Climate Risk			
Drought Risk	20.36	14.32	11.61
Flooding Risk	100.00	12.97	9.13
Freeze Risk	12.05	13.09	15.72
Severe Storm Risk	94.56	20.58	16.99
Tropical Cyclone Risk	100.00	6.41	4.36
Wildfire Risk	11.81	11.28	6.30
Winter Storm Risk	65.33	15.99	13.71
Flooding, Freeze, Severe Storm, Tropical Cyclone, Wildfire, and Winter Storm Risk	100.00	15.88	12.14

As seen in the figures above, the highest risks in Harris County are associated with Tropical Cyclone and Flooding with the largest difference between state and U.S. risks being related to Tropical Cyclones. NOAA results align with a majority of the Company's System Resiliency Plan being focused on the direct and indirect effects of extreme wind on power system infrastructure, restoration processes and the technologies which aid in optimal mitigation deployment.

Section 1.1. Preparation for Wind Events

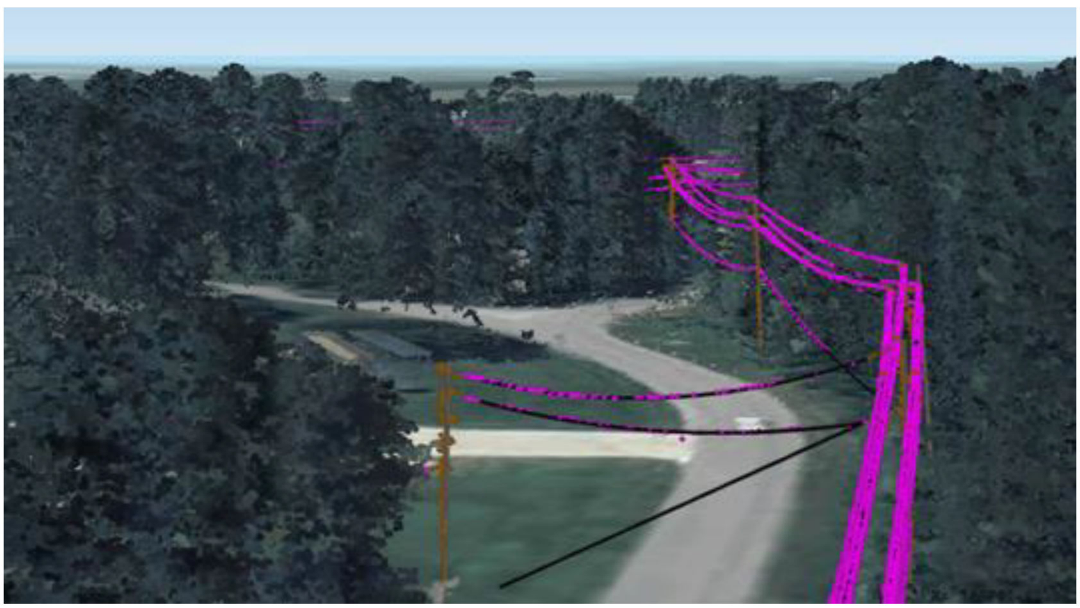
Section 1.1.1. **Modeling.**

Modeling provides insights for future events while simultaneously aiding in the understanding of variables including but not limited to soil moisture, vegetation health, and storm track. Mitigation projects were selected using a 3-tier process including review of historical events, industry best practices benchmarking, and LiDAR based modeling. Recent advancements in modeling have allowed the Company to process volumes of data with previously unattainable levels of efficiency to identify, optimize and plan projects specifically related to extreme wind structural hardening, strategic undergrounding, automation as well as more generally for situational awareness, customer impact modeling, and increased cyber security of critical systems used for restoration.

Section 1.1.2. Structural Hardening.

Structural hardening is utilized to reduce the number of transmission structures and distribution poles experiencing failures during extreme wind events. The Company has more than twenty-five thousand transmission structures; however, this system resiliency plan will focus on replacing all wooden structures, angle tower designs which are subjected to higher loading as well as select legacy towers identified for hardening, all using stronger towers or concrete/steel monopoles. Overhead distribution system hardening analyzed over one million installed poles along numerous circuits and will be improved using stronger more resilient poles and focusing on areas with limited accessibility, critical customers, and higher customer counts. Overhead options are used to provide balance between cost and risk reduction; however, in some cases the more costly option of strategic undergrounding is used particularly where tree fall in risk cannot be mitigated as identified in the 3D model shown in the figure below.

Figure AA-3



Section 1.1.3. Asset Monitoring

When extreme wind events impact a significant portion of the Company's service territory, more than 60% of the 1,800 distribution feeders are exposed to the possibility of being disconnected from their substations. In many cases these outages are caused by trees falling into overhead conductors. In these instances, crews must inspect each circuit, manually identifying and isolating the damaged portions of the feeder before initiation of safe restoration processes. Automation can transform a multi-day manual process into an automated action, greatly speeding restoration based on tree risk models. In addition to asset-based analysis, CEHE also performs system level analysis to identify a broader range of issues which may uncover the need for the addition of new transmission lines or distribution feeders to provide the necessary resiliency for our customers and avoid extended outages. This need for additional coastal transmission facilities was identified during similar system studies due to a potential common contingency failure point. Lastly, prolonged wind patterns can cause an accumulation of salt contamination on coastal assets resulting in flash overs and customer outages. Monitoring of these assets and contamination resistant designs can aid in reducing these possible impacts to our coastal customers. The mitigation programs CEHE selected from a wider range of available alternatives are listed in the figure below.

Figure AA-4

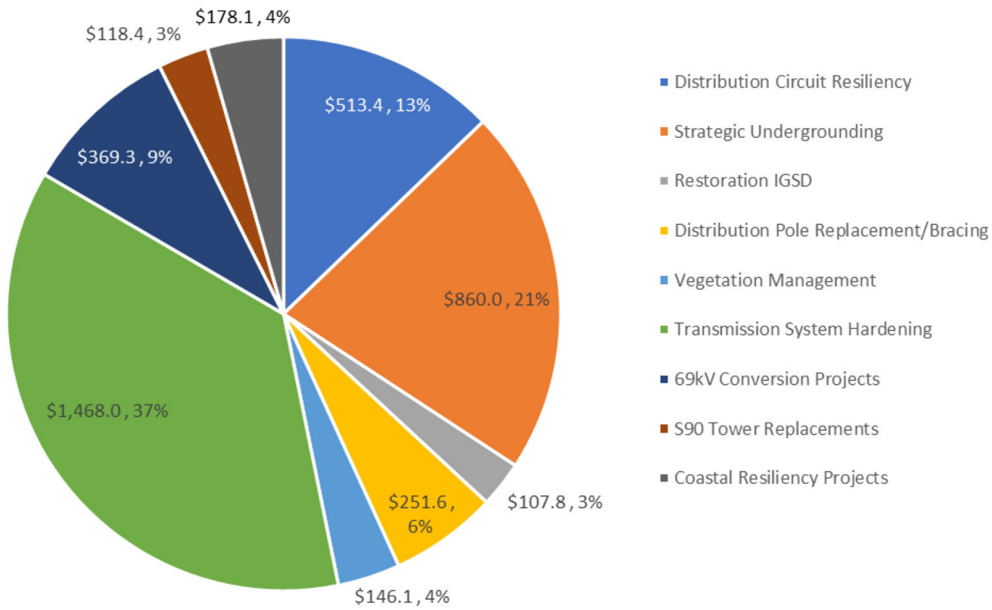
Event Class	Event Type (% assets impacted)	Mitigation Objective
Extreme Wind	Hurricane (100%) Microburst (50%) Derecho (50%) Tornado (25%) High wind (50%)	Replace legacy structures with new towers or monopoles
		Replace 90-degree structures with monopoles
		Replace wooden structures with stronger towers or concrete/steel monopoles
		Replace or brace distribution poles based on condition
		Replace equipment poles and reconfigure cross-arms
		Build additional transmission lines for contingency case
		Underground freeway crossings and low access spans
		Add automation to reduce outages for customers
		Coastal contamination mitigations and response

Section 2. Advanced Modeling Methodology

Section 2.1. Cost Allocation

Based on best practice benchmarking, utilities similarly challenged by extreme wind events tend to bias initial hardening to transmission assets given their higher replacement costs, longer equipment lead times and the operational dependency of distribution investments on the transmission system. As resiliency efforts continue, a predictable shift in cost allocation occurs with transmission system investments decreasing. Distribution investment is focused on improving areas of low accessibility and greatly reduced crew productivity during restoration. This reduction in productivity results from an inability to utilize heavy machinery when accessing back lots or heavily wooded areas. Based on LiDAR modeling, approximately 25% of the Company's overhead distribution system is subject to high or very high vegetation fall-in risk. Transmission and distribution hardening are the two highest investment areas at over 60%, as shown in the figure below, when considering the portfolio of projects to mitigate extreme wind event customer effects.

Figure AA-5



Section 2.2. Characterization of Wind Events

The Company used advanced modeling to quantify benefits based on event characteristics, asset vulnerability, benefits of automation and repair times of predicted damage based on expected crew productivity. Furthermore, the analysis uses climate projections to complete a Benefit Cost Analysis ("BCA") over a longer period which accounts for changes in frequency and intensity of events. The BCA was calculated using the total cost of the extreme wind mitigations and the benefits associated with faster event restoration. The mitigations included in this resiliency plan are expected to reduce customer minutes of interruption by 1,055.7 million CMI. The following pages offer a detailed explanation of the event types, event sequence of events, present susceptibility of assets and historical events, the modeling methodology used to forecast future customer impacts, a review of best practice benchmarks and alternatives, prioritization of mitigations, as well as project selection and locations. The section concludes with additional details on the customer benefits of the mitigation within the context of an extreme wind event.

Section 2.2.1. Risk Characterization by Event Type

Extreme wind events primarily cause customer outages from structural failures of transmission towers and distribution poles as well as from outside causes such as lightning, limbs being blown into overhead conductors and trees falling on conductors. The events differ in the amount of advanced warning, percentage of system impacted, windspeed and direction of wind forces.

Section 2.2.1.1. Hurricane. A hurricane results when the maximum sustained winds reach 74 mph in a tropical cyclone originating in the Atlantic basin. Typically, the risk from a hurricane is known days prior to the storm making landfall. Storm track heavily influences the impact to power system infrastructure as this dictates the percentage of the system experiencing the maximum wind speeds. Winds are multidirectional meaning that the risks of limbs blowing into conductors and tree fall are increased when compared to unidirectional wind events (a.k.a. the winds "hit" the trees and assets from different directions at different timeframes).(What is a hurricane? (noaa.gov))

Section 2.2.1.2. Derecho. A derecho is a widespread, long-lived windstorm that can produce destruction similar to that of a tornado, the damage typically occurs in one direction along a relatively straight path. The criteria typically include wind damage extends at least 400 miles, is at least 60 mile wide, and includes wind gusts of at least 58 mph. The derecho impacts less area than the hurricane with lower wind speed relative to major hurricanes leading to a lower level of predicted damage. (Facts About Derechos - Very Damaging Windstorms (noaa.gov))

Section 2.2.1.3. Microburst. A microburst is a localized column of sinking air (downdraft) within a thunderstorm and is usually less than or equal to 2.5 miles in diameter. Microbursts can cause extensive damage at the surface. Forecasting for microbursts is typically done on a near-term basis, generally within 6-12 hours before convection is expected to develop. The short timeframe and nature of damage makes modeling of microbursts extremely difficult; however, the mitigations associated with other extreme events can help mitigate the impacts from a microburst. (What is a Microburst? (weather.gov)).

Section 2.2.1.4. Tornado. A tornado is a narrow, violently rotating column of air that extends from a thunderstorm to the ground. Tornadoes can be among the most violent phenomena of all atmospheric storms we experience. Wind speeds associated with tornadoes can be significantly higher than the previously described events which increases the potential for damage to transmission structures. The typical damage path is 2 to 3 miles resulting in many similarities with microburst. (Severe Weather 101: Tornado Basics (noaa.gov)).

Section 2.2.1.5. Sustained High Wind. Prevailing winds which blow salt particulate onto power system infrastructure can result in a diminishing of insulation levels and customer outages from flashovers. Prevailing winds are a surface wind that blows predominantly from a particular direction. The dominant winds are the trends in direction of wind with the highest speed over a particular point on the Earth's surface at any given time. A region's prevailing and dominant winds are the result of global patterns of movement in the Earth's atmosphere. The timescale for persistent high wind events to occur is much slower than the previously identified events; however, the impacts can be significant for coastal customers.

Section 2.2.2. Planning and Response

Section 2.2.2.1. Pre-Storm. Prior to the storm a number of activities are completed to prepare for restoration activities. The activities include the use of damage prediction modeling to determine the areas expected to be most impacted, mutual assistance resource levels, staging site location prioritization, coordination of critical customer restoration including the deployment of temporary generation.

Damage Prediction Modeling. Damage Prediction Modeling will be performed when a storm or hurricane has the potential to impact CEHE's service territory. The model consists of 3 components: wind speed estimation by polygon, pole failure calculation, and estimating crew needs by crew type. Damage prediction begins with defining the path of a storm by selecting multiple probable scenarios or utilizing

NOAA's projected path of a storm. The path, expected wind speed based on storm category, storm size, and rate at which the storm moves are used to estimate the maximum potential windspeed that CEHE's distribution assets could experience at a 2 square mile polygon level. This along with pole characteristics, vegetation data from LiDAR and soil moisture is used to estimate pole failure in each polygon. Pole failure generally happens from trees falling onto distribution circuits or from structural failure of poles with the latter being less probable at windspeeds below the design threshold. Empirical data from prior storms, LiDAR surveys, fragility curves, etc. are used to estimate the polynomials and coefficients for computing failure probabilities and crew needs. Since replacement of poles is a time-consuming process, total restoration time for the system following a storm or hurricane is dependent on the number of pole failures that occur. This is further extended if the failed poles are in areas less accessible using trucks or cranes. With a target system wide restoration duration for an expected storm or hurricane, the number of crews needed can be estimated.

Mutual Assistance. Mutual assistance resources are estimated based of the expected level of damage from the impending event. These resources are staged outside areas of the projected storm path for the safety of the individuals and to avoid damage to equipment needed for restoration. Once windspeeds fall below 30 mph conditions are considered safe for restoration activities to begin. Modeling specific to the staging sites and work locations will assist in forecasting what time crews will be able to work in each location to enhance pre-planning activities. Damage models will not only project the number of resources but the types of resources as well. Mutual Assistance crews can provide a number of different skill sets including overhead line skills, underground cable crews, vegetation management, damage assessment, etc. The allocation of the mutual assistance resources by the various skill sets will depend on the storm characteristics and local environmental factors. The continued enhancement of damage prediction models aids in optimizing the resources acquired for mutual assistance.

Staging Sites. Staging Sites are informed by the damage prediction model as well. The ability to optimally select staging sites considers predicted areas with most significant damage, capacity of the staging site and geographic location of the staging site. Staging site assessment is refreshed as additional storm forecast are received up until landfall and one final prediction post landfall to inform site adjustments.

Critical Customer Restoration. The Company maintains a database of priority customer locations in addition to utilizing processes during significant events to prioritize restoration. The damage prediction modeling assist in forecasting when critical customers may be in areas of more significant damage. These predictions can assist in prioritizing restoration crews and/or the deployment of temporary generation as well as supporting the selection of hardening projects.

Section 2.2.2.2. Storm Response. Upon initial impact of the extreme wind event, a combination of temporary and sustained outages will occur on the system.

Distribution Automation and Remote Switching. Temporary events such as tree branches or debris blowing into a conductor can be automatically restored using automation devices such as TripSavers®, IGSDs and breakers. These devices will temporarily de-energize (open) and re-energize (close back) the entire circuit or the portion of the circuit that experienced an outage and if the outage was temporary, service will be restored to the affected customers. In cases where equipment failure has occurred, such as the mechanical failure of a pole or a tree falling on a conductor, the re-energization will be unsuccessful resulting in a permanent outage. In this scenario, the TripSavers®, IGSDs or breakers will remain open in a lock-out state and isolate the permanent fault while the unaffected customers stay energized. TripSavers® are installed in-lieu of fuses that do not have reclosing capability. Fuses will interrupt any temporary fault condition resulting in a permanent outage. Tripsavers® eliminate these sustained outages that results from temporary fault conditions downstream fuse location. IGSDs on the other hand are installed as an additional protective device creating new protection zones along the circuit. This allows fault conditions downstream of an IGSD locations to be interrupted by the IGSDs eliminating the customers upstream of the IGSDs from experiencing sustained outages. These devices are also remote-controlled allowing unaffected customers downstream of a IGSD to be restored through switching to adjacent circuits when the outage is caused by a permanent fault upstream of the IGSD. The contribution from such automated reclosing and remote switching capability can significantly improve customer outcomes; for example, during Hurricane Beryl approximately 430.35 million customer minutes of interruption were saved due mainly to automation.

Automated Sectionalization to Re-energize Substation Breakers. The previously mentioned permanent outages can be a result of all customers being served from the substation circuit breaker and losing service. IGSDs installed closer to substation breakers cannot be configured as fault interrupting devices due to limitations with protection coordination. In such cases IGSDs can be configured as sectionalizing devices. In this type of automation, IGSDs are programmed to open after a set number of breaker reclosing. Once a counter is reached, substation breaker reclosing is delayed for IGSD to open. If the faults was downstream of the IGSD, subsequent reclosing of substation breaker will be successful allowing the portion of circuit from substation to the IGSD to be restored. The successful closing of the circuit breaker is critical for two specific reasons: first the closing of the circuit breaker and successful restoration of customers on the circuit between the sectionalization point and circuit breaker and secondly it speeds the restoration process by automating the cut and clear process through the de-energization of the portion of the circuit with the damage. The current cut and clear process is conducted by crews riding out the distribution circuits starting at the substation, inspecting the de-energized circuits to identify the location of the damage and then manually isolating the damaged section to allow re-energization from the Control Center. For events which impact the entire service area, the cut and clear process can take 24 to 72 hours once conditions are safe to work. Automated sectionalizing could begin significantly faster than manual processes, while also reducing the need for manual intervention from the Control Center. Increasing automation for cut and clear sectionalizing could accelerate the restoration process by 1 to 2 days. For system wide events, customer minutes of interruption can total over 8.1 million minutes per day (as seen in Hurricane Beryl).

Damage Assessment. The damage assessment and cut and clear processes are competed in parallel to identify and plan restoration based on observed damage and ensure safe conditions for the public and restoration crews by isolating damaged circuit sections. Damage prediction modeling aids in directing resources based on the areas of highest damage concentration as well as estimating the number of damage assessment resources needed to complete field inspections. The efficient completion of damage assessment is critical to customer communications, crew work allocation, and material management.

System Restoration. System restoration can vary based on the specifics of the extreme wind event; however, there are fundamentals which hold for all events. Once restoration begins, temporary generation is deployed based on pre-determined locations identified in collaboration with County Offices of Emergency Management. Similarly, the Company maintains a database of critical customers to inform prioritization of restorations. The dynamic nature of these events requires processes which can adjust by responding to unforeseen needs from the public. To address these emergent issues, the Company embeds resources within city and county Emergency Operations Centers, activates its priority desk, and maintains communication with State Officials. Beyond critical customers, the restoration process works to address outage events based on the number of customers impacted, following a restoration of circuit level outages, then lateral, then fuse, and finally single service outages in an effort to gain the most customer restorations as quickly as possible.

Section 2.2.3. System Susceptibility to Extreme Wind Resiliency Events

Section 2.2.3.1. Historical Events 2020 – 2024. The Company is constantly identifying lessons learned and opportunities for enhancement of design and processes for each successive event. One such notable event was hurricane Ike in 2008 which led to changes in our standard designs for overhead equipment with a specific example of new overhead transformer installations. The effects of this change were realized during Hurricane Beryl where pole failures associated with transformer equipment poles were greatly diminished. The figure below summarizes some of the more recent extreme wind Resiliency Events that have occurred in the Company's service area, the total number of customers affected by outages due to the Resiliency Event, and their respective restoration times for the years 2019 through 2024.

Figure AA-6

Year	Resiliency Event	Total Customers Affected	Restoration Time
2020	April 29th: A strong squall and associated cold front produced very strong, gusty winds, frequent lightning, and heavy rain.	256,057	16 hours, 15 minutes
	May 15th-16th: Daytime heating, elevated moisture levels, and instability combined to produce scattered showers and thunderstorms, frequent lightning, strong gusty winds, and heavy rainfall. Subsequently, a strong upper-level disturbance pushed a line of severe thunderstorms with frequent lightning, strong damaging winds gusting up to 60 mph, and heavy downpours.	114,575	28 hours, 5 minutes
	May 27th-29th: An upper-level disturbance combined with daytime heating and an unstable environment produced severe thunderstorms with severe wind gusts, frequent lightning, and heavy rainfall.	423,000	32 hours, 15 minutes
	September 17th-18th: Hurricane Nicholas produced powerful, gusty winds, heavy rain, and flooding.	706,429	120 hours, 5 minutes
	October 28th-29th: High winds sustained at 30-35mph with gusts up to 50mph.	308,585	32 hours, 55 minutes
2021	April 30th: Wind Shear event in West Columbia, Texas	313	11 hours, 40 minutes
	August 15th: Tornado event in Cyrpress, Texas	7,270	11 hours, 55 minutes
2022	January 8th-9th: A warm front brought strong gusty winds, tornados, lightning, and heavy rain.	79,138	27 hours, 20 minutes
	March 22nd:	49,743	5 hours,

Year	Resiliency Event	Total Customers Affected	Restoration Time
	Strong thunderstorms, heavy rain, frequent lightning, and wind gusts nearing 40 mph.		40 minutes
2023	January 24th-26th: A strong disturbance brought severe thunderstorms with frequent lightning, hail, damaging wind gusts, tornadoes, and heavy rain.	207,547	57 hours, 10 minutes
	June 8th-10th: Scattered storms that brought strong wind gusts, small hail, and frequent lightning strikes.	362,363	34 hours
	June 21st-25th: Thunderstorms brought frequent lightning, hail, and damaging winds.	574,582	77 hours, 40 minutes
	September 25th: Microburst event in Humble, Texas	813	24 hours,
2024	January 5th: Fair and dry conditions with increasing wind in the afternoon as an approaching storm system pushed eastward bringing widespread showers, some heavy, and isolated thunderstorms with a few stronger storms including one Tornado	141	5 hours, 52 minutes
	April 10th - 11th: Strong thunderstorms pushed through the area in the early morning of April 10, bringing heavy lightning and high winds, high winds, and confirmed case of tornado damages in the Katy area.	288,203	24 hours, 30 minutes
	May 2nd - 3rd: A series of disturbances brought heavy rain and strong thunderstorms Thursday morning. Wind gusts of 30-40mph as well as frequent lightning and heavy downpours were the results. Additionally, a microburst event was detected in the northern portions of the Greenspoint and Humble Service Areas.	239,411	36 hours, 4 minutes
	May 5th: Microburst event in Pinehurst, Texas	2,951	30 minutes
	May 16th – 24th: A weather event brought widespread severe weather, derecho storm conditions with windspeeds of up to 100 mph, Category 2 Hurricane-like winds, and two tornadoes into the Houston metro area. A derecho is defined by the National Oceanic and Atmospheric Administration as a line of intense, widespread, long-lived and fast-moving straight line wind storms and sometimes thunderstorms that moves across a relatively straight swath and is characterized by damaging winds similar to a tornado. Additionally, two EF1 tornados touched down in the Waller and Harris County portions	1.23 Million	190 hours, 40 minutes

Year	Resiliency Event	Total Customers Affected	Restoration Time
	of CNP' s service area. These events caused widespread devastation to CNP transmission and distribution system including toppling of transmission towers, falling and broken distribution poles, equipment failures, extensive vegetation and debris damages, and prolonged outages.		
	May 28th – May 30th: Severe storms passed through CNP's service area which brought strong wings, locally heavy rainfall, and frequent lightning	508,666	54 hours, 32 minutes
	July 8th - July 19th: Hurricane Beryl made landfall in Texas as a powerful Category 1 hurricane, carrying with it significant sustained winds, storm surges and torrential rain. The storm significantly impacted CenterPoint' s service territory, with damaging winds reaching 97-miles-per-hour in Brazoria County, 89-miles-per-hour in Harris County, and 78-miles-per-hour in Galveston County, according to the Houston-Galveston National Weather Service. The destructive winds caused widespread damage to the electric grid that included uprooted trees, downed branches and other debris affecting its distribution poles, wires, and equipment, resulting in peak outages of approximately 2.11 million customers and approximately 3.47 million non-distinct customers during the storm period.	3.47 Million	278 hours, 20 minutes
	December 28th: Strong storms brought high winds and multiple tornados in Waller, Harris, and Galveston County	26,142	31 hours 46 minutes

Section 2.2.3.2. Benchmark Events. While all significant events provide lessons learned, benchmark events are those which resulted in the highest customer impacts for a given event type. These events include Hurricane Beryl which resulted in outages for 3,466,383 customers, a Derecho which created outages for 1,227,346 customers, as well as a tornado and microburst which resulted in outages for 169,684 and 33,652 customers respectively. Lastly, a period of sustained southeast prevailing wind and resulting effects of salt contamination is reviewed. The detailed review of benchmark events includes discussions with community partners such as County OEMs and third-party reviews from independent experts.

Hurricane Beryl. On July 8, 2024, Beryl made landfall near Matagorda with the east side of the eyewall impacting Brazoria County. It produced wind gusts over 60–70 mph (97–113 km/h) with a peak gust of 97 mph (156 km/h) in Brazoria.[3] In addition to the hurricane, there were 16 tornadoes ranging from EF0 to EF2 in intensity were confirmed in the state; another tornado tracked out of Louisiana and into Texas.[4]

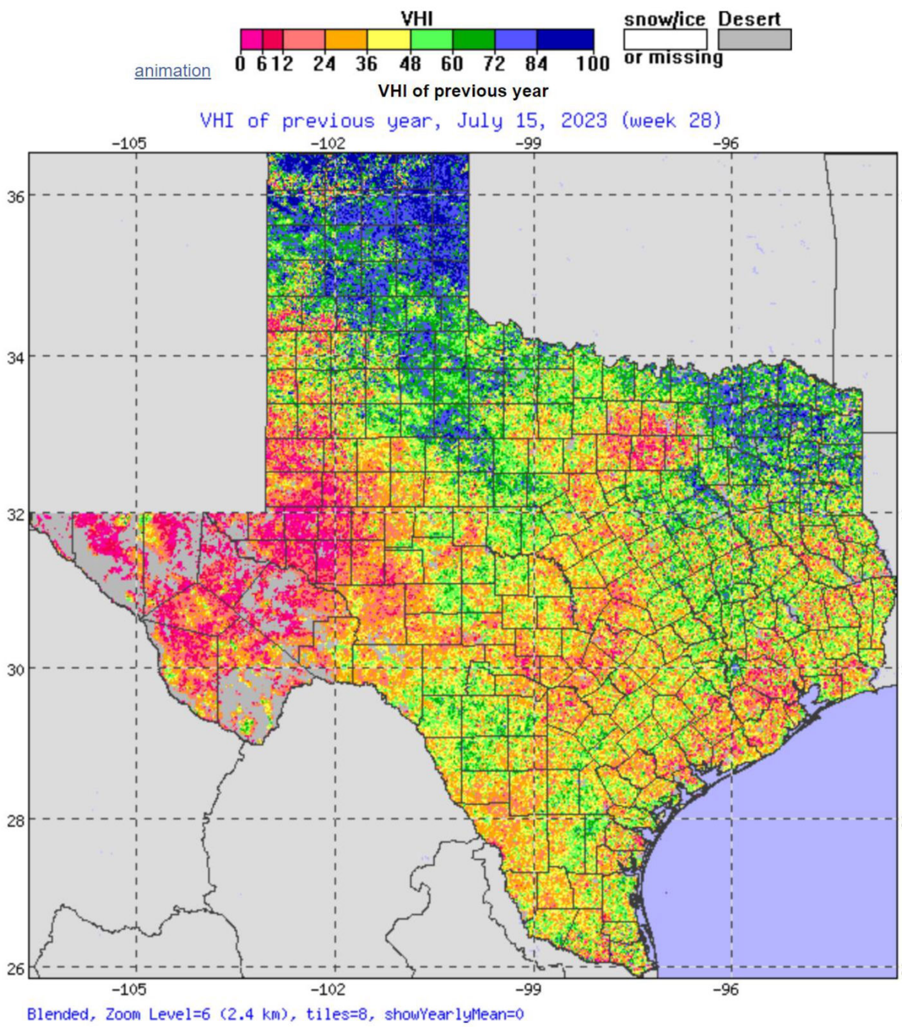
The storm eye-wall tracked west of the most populated potions of the services territory exposing the transmission and distribution system to the worst case wind loading scenario. The destructive winds caused widespread damage to the electric grid that included uprooted trees, downed branches and other debris affecting its distribution poles, wires, and equipment, resulting in peak outages of approximately 2.11 million customers. Systemwide, the storm affected some or all customers on approximately 215 substations and 1,688 feeders. The CEHE service areas that sustained significant damage and outages were in the Baytown, Brazoria, Bellaire, Cypress, Greenspoint, Humble, South Houston, Spring Branch, and Sugarland service areas having the impact of outages for 1,455 feeders served from 183 substations within those service areas. The figure below shows the landfall of hurricane Beryl that encompassed CEHE's entire service area within the dirty side of the hurricane.

Figure AA-7

By National Weather Service Houston/Galveston TX - https://radar.weather.gov/station/KHGX/standard, Public Domain, https://commons.wikimedia.org/w/index.php?curid=150155834

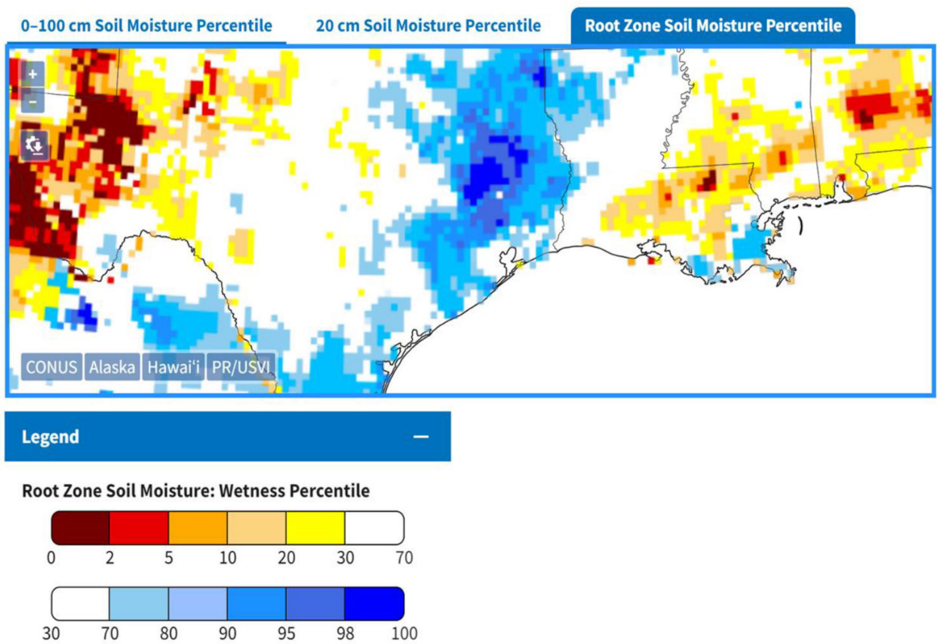
Compounding the effects of the western storm track were highly stressed trees due to recent freeze (2021 winter storm Uri) and heat/drought conditions (2022 and 2023) and soil moisture levels in the 99th percentile compared to values over a 64-year time horizon. As a result, a year preceding both of the aforementioned extreme wind events the Vegetation Health Index (VHI) in the CEHE service territory was below 40 for a significant portion of the greater Houston area. The vegetation health index (VHI) is one of the most popular remote sensing drought monitoring indices. [5],[6],[7],[8] VHI considers local biophysical and climatic conditions and can be used for actual plant drought monitoring in various agrometeorological regions.[9] Global, 4 km, 7-day composite, validated. VHI=α *VCI + (1- α)*TCI, where α is a coefficient determining contribution of the two indices. VHI is a proxy characterizing vegetation health or a combine estimation of moisture and thermal conditions. VH (VHI, VCI, TCI) is used often to estimate crop condition and anticipated yield. If the indices are below 40 indicating different level of vegetation stress, losses of crop and pasture production might be expected; if the indices above 60 (favorable condition) plentiful production might be expected. VH (VHI, VCI, TCI) is very useful for an advanced prediction of crop losses. Vegetation stress is shown in the figure below for Hurricane Beryl.

Figure AA-8



The tree stress caused the root systems of millions of trees to degrade in the greater Houston area, which is reported to have over 600 million trees. Above average soil moisture levels also contributed to the weakening of these root systems ultimately culminating in loosely anchored roots leading to a significant number of trees to toppling over during the high winds in the storm. The GRACE-Based Root Zone Soil Moisture Drought Indicator describes the current wet or dry conditions of the top 1 meter of soil, expressed as a percentile showing the probability of occurrence within the record period from 1948 to 2012. This product is based on terrestrial water storage observations derived from NASA GRACE satellite data and integrated with other observations, using a sophisticated numerical model of land surface water and energy processes. Red and orange hues indicate drier soil moisture conditions, while blue hues indicate wetter conditions.[10] The 30-year climate normal amount of rainfall for the first six months of the year in Houston is around 25.2 inches. The cumulative rainfall last year for that period was 26.99 inches. But this year, total cumulative rainfall for that same period — from Jan. 1 to the first day of July, which was Monday — was 35.96 inches or almost 11 inches more than normal. Houston also recorded an increase of about 9 inches compared to the same period in 2023, despite having the same number of days with measurable precipitation.[12] The figure below shows this unusually high soil moisture at the time of hurricane Beryl.

Figure AA-9



While tree damage is expected during major weather events, Beryl's winds caused more damage to forestry due to the stress Houston's trees have undergone in recent years, Herrin said.[11] Storm events such as in February 2021 and droughts in summer 2022 and 2023 put an unusual amount of stress on the trees, he said. Droughts can kill trees' root systems, though it's difficult for homeowners to detect.[11] The figure below shows an example of tree failures at the root system during hurricane Beryl.

Figure AA-10

A tree in The Woodlands at Woodlands Parkway and Kuykendahl Road was uprooted by Beryl. (Kelly Schafler/Community Impact)

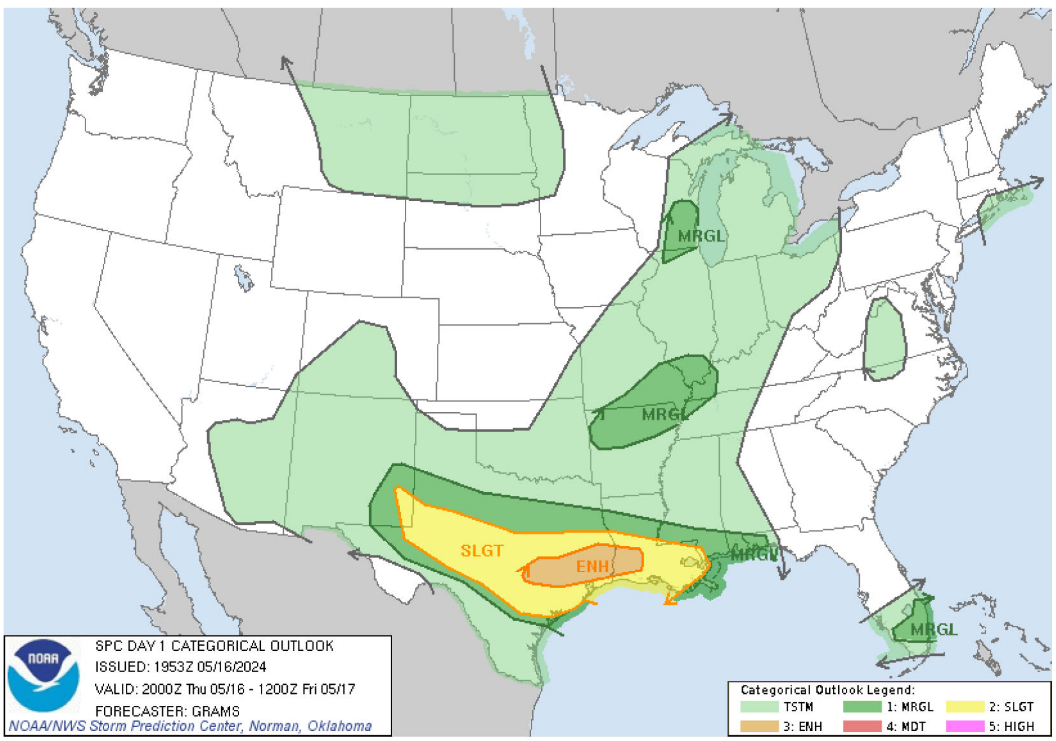
While CEHE had developed and utilized a deterministic model for hurricane damage prediction for Beryl, the effects of the storm highlighted opportunities for enhancement through the inclusion of local environmental factors such as soil moisture, vegetation fall in risk and vegetation health.

Figure AA-11

These environmental factors go beyond the asset-based considerations of wind loading design and assist in representing outside causes such as tree fall in rates affected by eye wall location, vegetation health and soil moisture. Due to the potential for significant differences between extreme events, damage rates can also vary significantly based on expansion of the service territory, vegetation growth over decades and changes to design standards.

Derecho 2024. From the evening of May 16, 2024, to midday May 17, 2024, a derecho struck the Gulf Coast of the United States from Southeast Texas to Florida, causing widespread damage, particularly in the city of Houston and surrounding metropolitan area.[1] The effects on the power system resulting in peak outages to approximately 858,000 electric customers served by CEHE transmission and distribution systems. As the derecho moved through the Greater Houston area, it produced wind gusts of up to 100 mph (161 km/h) in Downtown Houston.[2] Additionally, two EF1 tornados touched down in the Waller and northwest Harris County portions of CEHE's service area. These events caused widespread devastation to CNP transmission and distribution system including toppling of transmission towers, falling and broken distribution poles, equipment failures, extensive vegetation and debris damages, and prolonged outages. Systemwide, the storm affected some or all customers on approximately 210 substations and 1,355 feeders. The CEHE Service Areas that sustained significant outages were in the Bellaire, Spring Branch, Cypress and Greenspoint service areas resulting in substantial damage and outages for 698 feeders served from 90 substations.

<u>Figure AA-12</u>



Public Doman:
https://www.spc.noaa.gov/products/outlook/archive/2024/day1otlk_20240516_2000.html

The figure above from NOAA shows the far-reaching effects of the derecho which covered multiple states. The Company had a few minutes warning of the impending event, much unlike hurricanes which typically provide days to prepare internal and mutual assistance resources. Consistent with the damage patterns identified in the Hurricane Beryl analysis, trees were a major contributing factor in longer duration outages. Likewise, soil moisture and vegetation health resulted in increased tree related customer outages. The geospatial damage outcomes can be seen in the polygon-based map of the figure below.

Figure AA-13

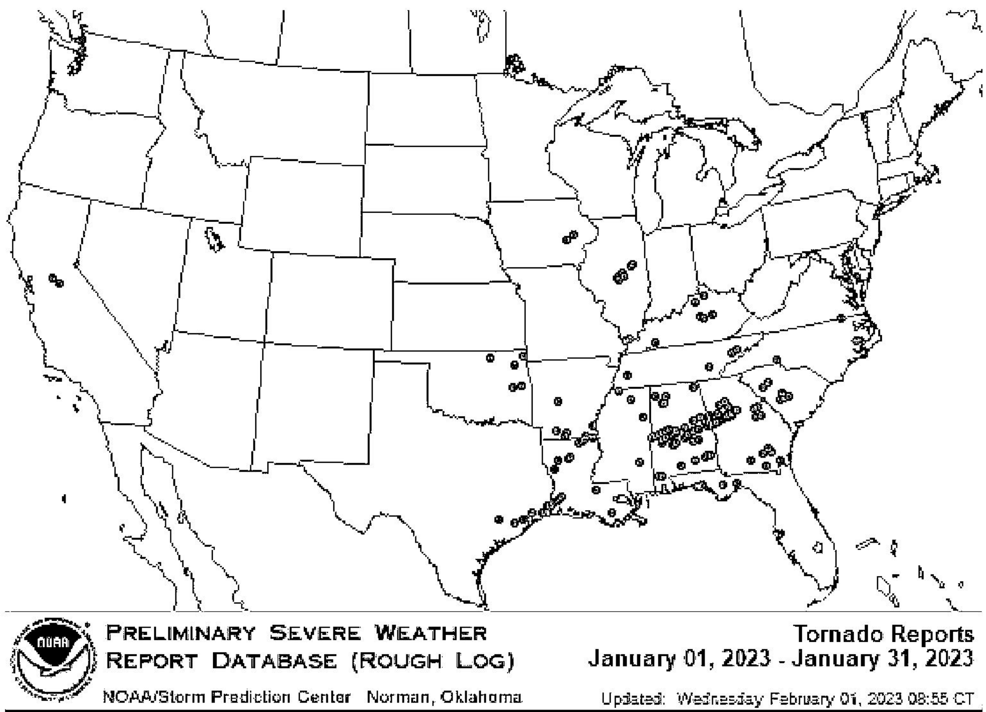
The extreme straight-line winds of the derecho resulted in the failure of 21 transmission structures demonstrating the need to continue enhancing the construction of more resilient structures on both the transmission and distribution system. Tree fall was not a leading cause for transmission damage given differences in the right of way practices between transmission and distribution. The figure below shows damage to transmission structures on the western portion of the Company's service area.

Figure AA-14

The loss of transmission structures can impact system reliability by limiting options to serve customers connected to substations and reduce paths for transmission connected generator output.

Pasadena/Deer Park Tornado. On January 24, 2023 the National Weather Service classified a low-end EF3 tornado in the suburbs of Pasadena and Deer Park although damage ranged from EF0 to high-end EF-2 from the 35-minute event. The associated winds were estimated at 140 miles per hour and was identified as the strongest cold-season tornado in the Houston area since 1992. The path of the tornado was approximately 18 to 24 miles long and at least 0.5 miles wide according to the National Weather Service. The tornado and accompanying storms resulted in 207,547 customer outages, the deployment of two temporary generation units as well as damage to both transmission and distribution system assets. The figure below shows the tornado activity for January 2023 which includes the Pasadena/Deer Park event.

Figure AA-15



The storm was extremely devastating over a reduced portion of the service territory and also resulted in failures of 2 transmission structures due to the extreme wind speeds as shown in the figure below.

Figure AA-16

Extreme wind event modeling showed the more limited geographic impact of the tornado and consistent damage pattern of other more geographically dispersed events. The figure below shows these results for the Pasadena and Deer Park communities.

Figure AA-17

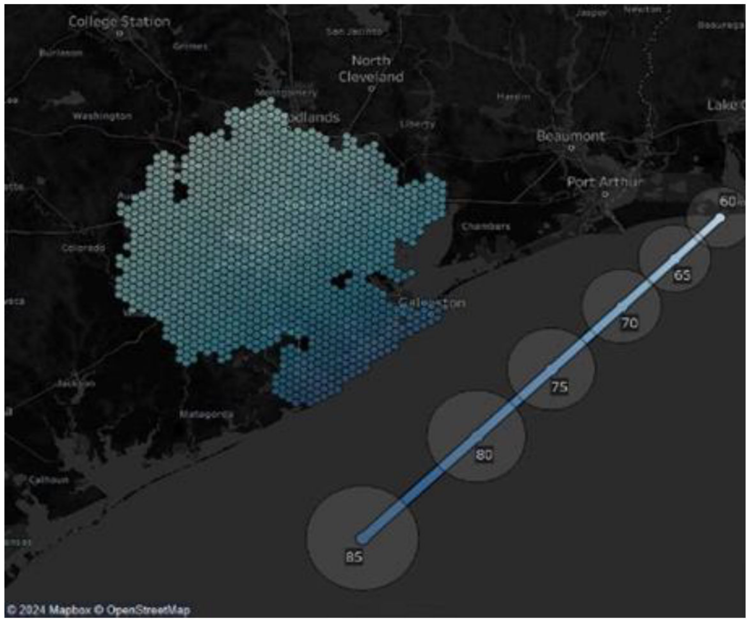
Spring Microburst. Similar to the tornado, the microburst had a significant impact over a smaller geographic area when compared to the hurricane and derecho scenarios. The damage models were consistent with the other extreme wind events as reflected by the model outputs in the figure below.

Figure AA-18

Although the geographic areas vary for each of the event types, commonalities exist for each of the events. These commonalities are informative when considering the mitigations for extreme wind events associated with damaging wind speeds.

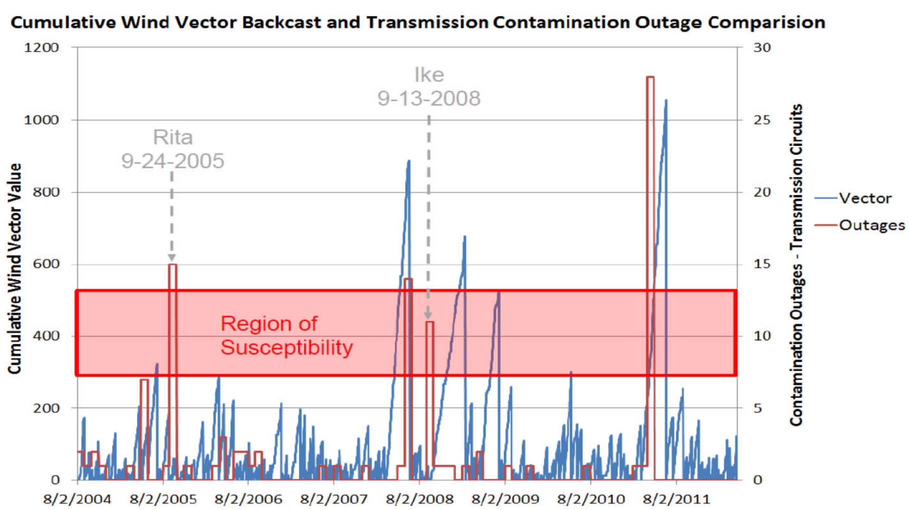
Sustained High Prevailing Winds. While sustained high prevailing winds do not reach speeds capable of damaging power system components these winds can create significant outages by causing flashovers on transmission, distribution and substation insulators. When southeast winds blow on shore, they can deposit salt from gulf waters onto insulators decreasing the insulators' ability to prevent flashovers from occurring. The resulting flashovers on transmission circuits and distribution feeders can result in sustained customer outages and pose a risk of pole fires from dry band arcing. The risk associated with dry band arcing and pole fires will be discussed further in the section associated with wildfire risk. The accumulations are typically mitigated naturally when more than 0.5 inch of daily rain fall occurs. Elevated wind speeds can result in accumulations which occur faster than natural cleansing occurs or in times of drought. Hurricanes which follow a storm track offshore can produce large wind fields without sufficient levels of precipitation to wash salt deposits contributing to coastal insulator flashovers. An example of such a storm track is shown in the figure below.

Figure AA-19



The relationships between wind speed, wind direction and precipitation are used to correlate weather patterns to susceptibility for flashovers. The figure below showing an analysis completed for the most significant event which occurred in 2011 during an extreme drought condition and sustained southeast prevailing winds.

Figure AA-20



The outages spiked in April of 2011 threating transmission service to coastal areas at the boundary of the service territory which would have resulted in an outage to thousands of customers. These outages were mitigated by manual washing of insulators to restore the electrical insulation properties to the system.

Section 2.2.3.3. County-Based Models. A critical phase of the review and modeling benchmark for events is the incorporation of insights from experts responsible for community emergency response. The Company developed county-based models for review with each of the twelve County Offices of Emergency Management (OEM). CEHE hosted meetings with each of these county OEM's that provided valuable feedback to align the model outputs with the County based experiences of each community. The OEM feedback provided confidence regarding the model's ability to predict areas of most significant damage as well as insights to further enhance the model based on local knowledge. Each of the County based models as well as key insights are highlighted below:

Figure AA-21: Austin County

Damage Prediction   Outage Duration

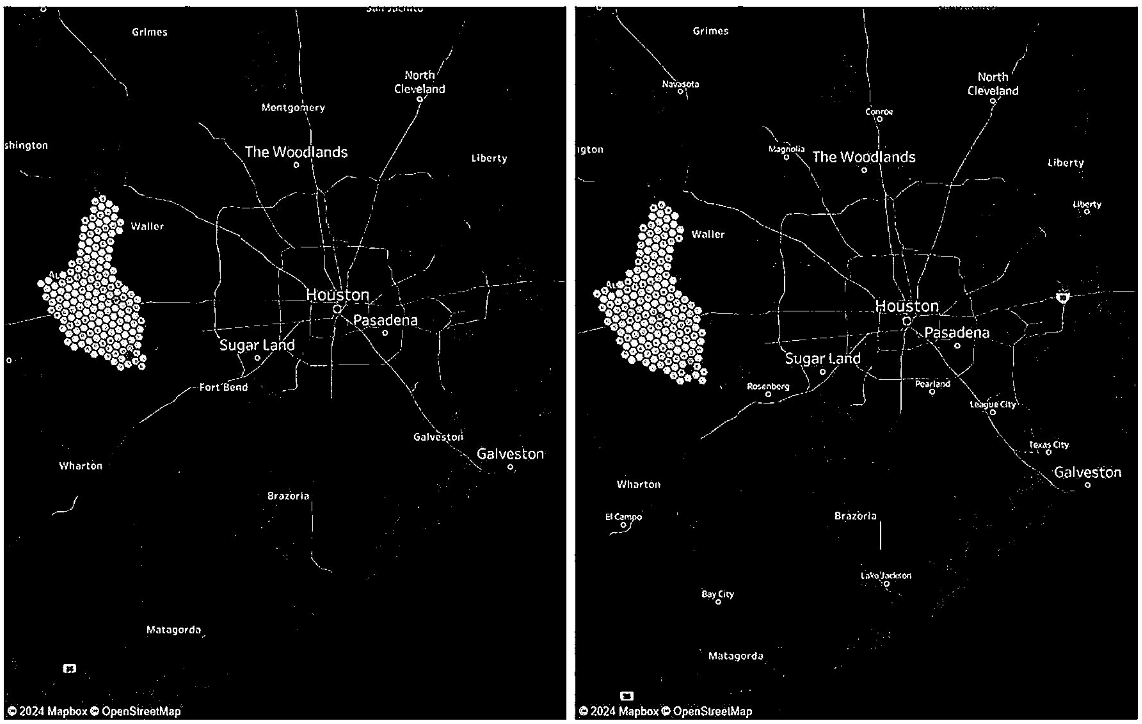


Figure AA-22: Brazoria County

Damage Prediction | Outage Duration

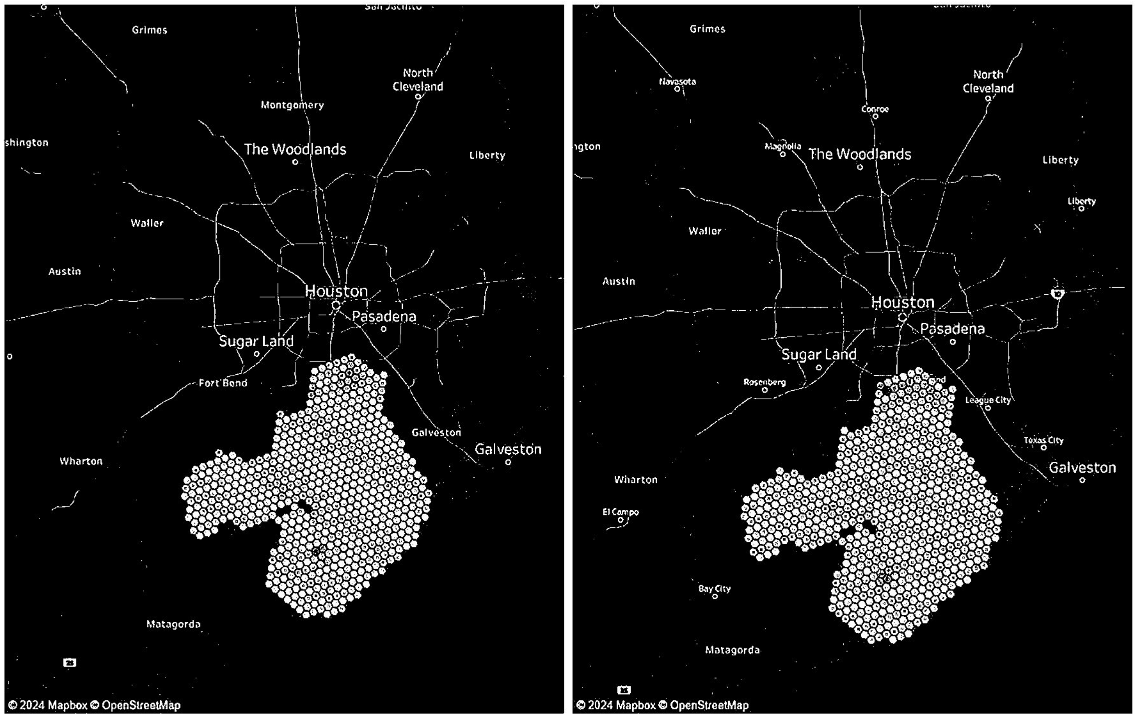


Figure AA-23: Chambers County

Damage Prediction | Outage Duration

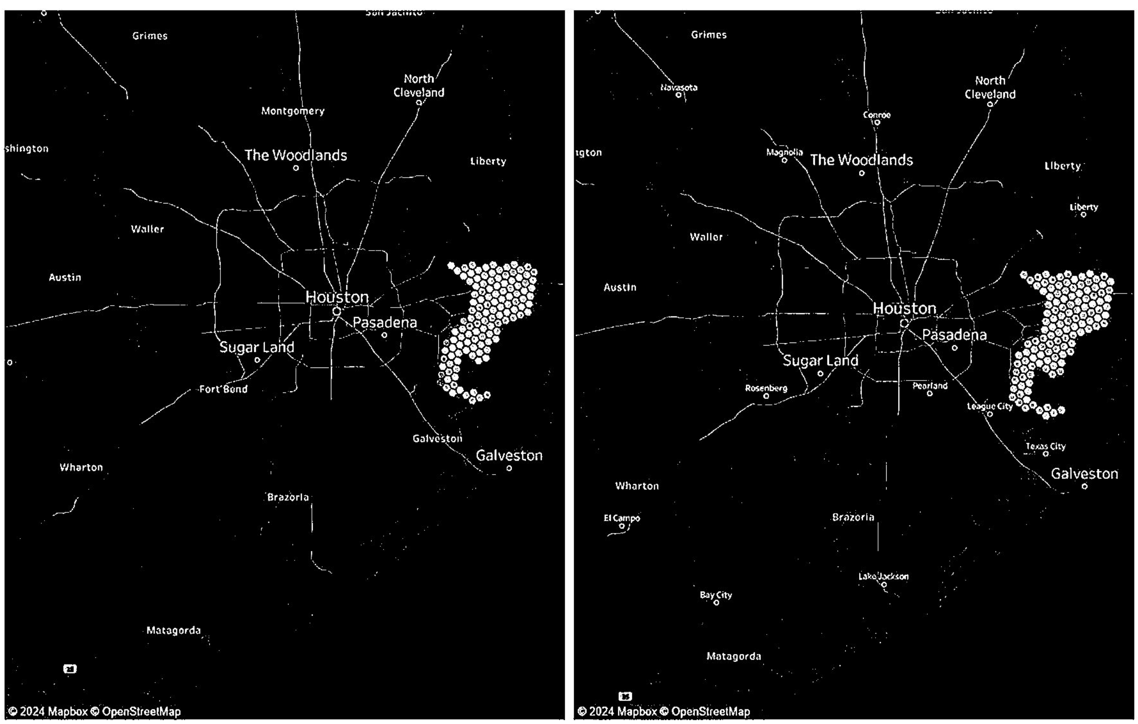
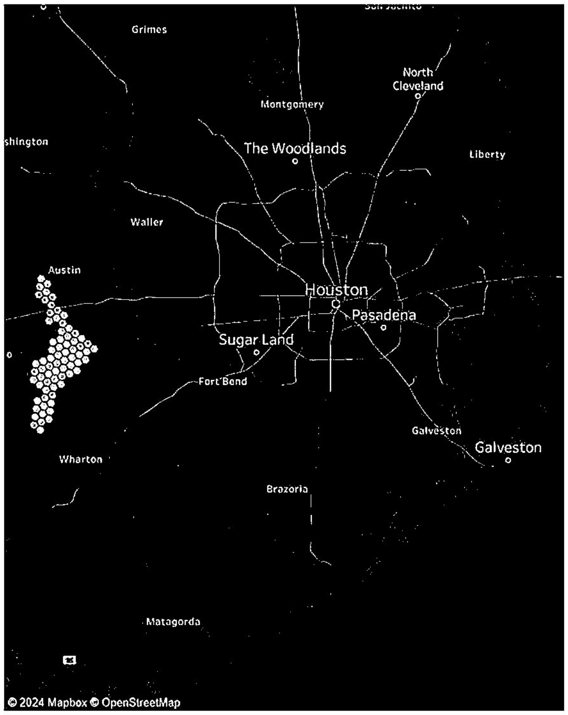


Figure AA-24: Colorado County

Damage Prediction



Outage Duration

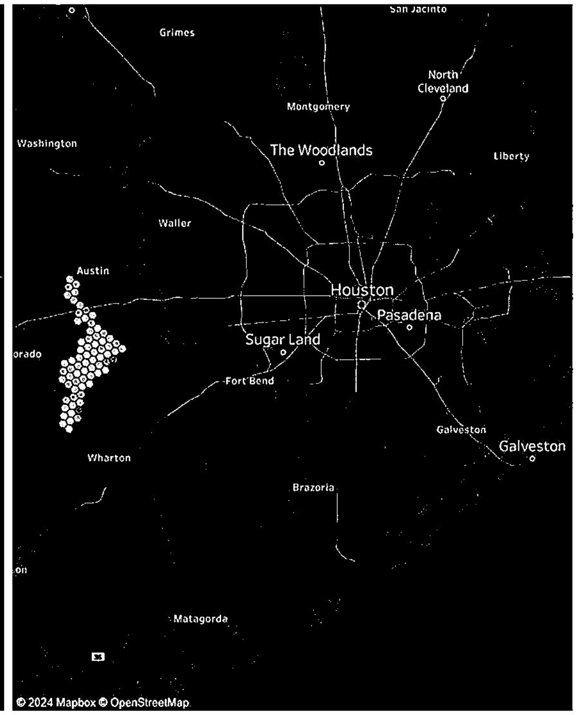
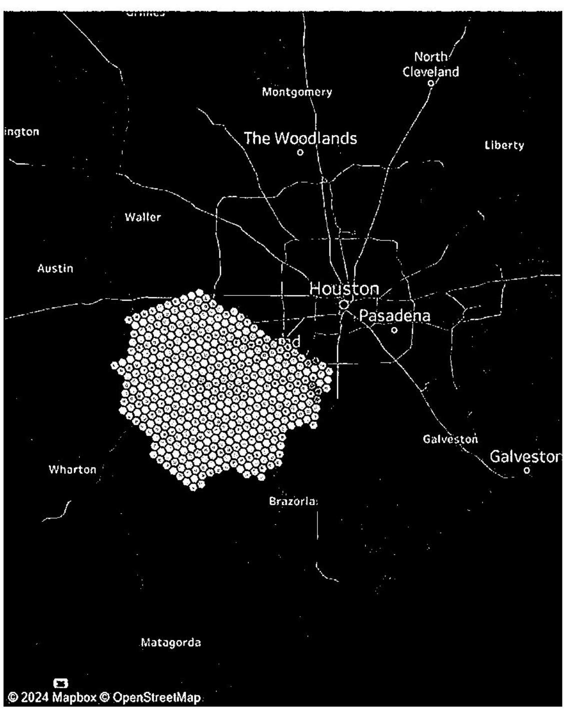


Figure AA-25: Fort Bend County

Damage Prediction



Outage Duration

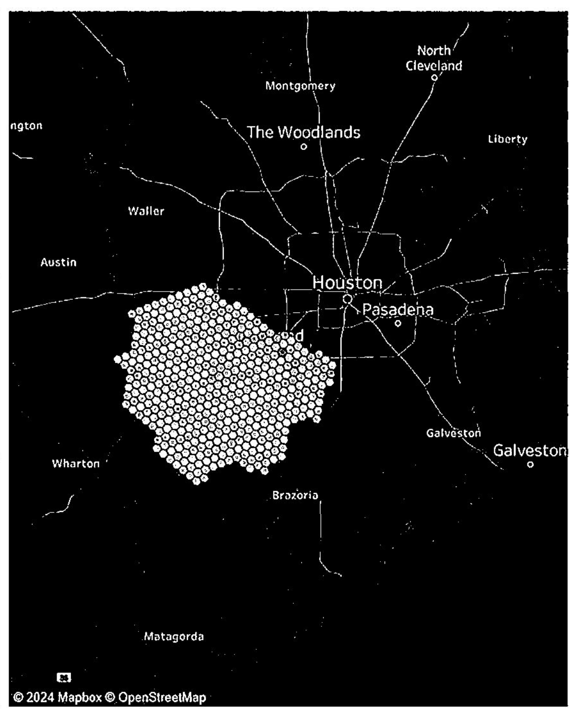


Figure AA-26: Galveston County

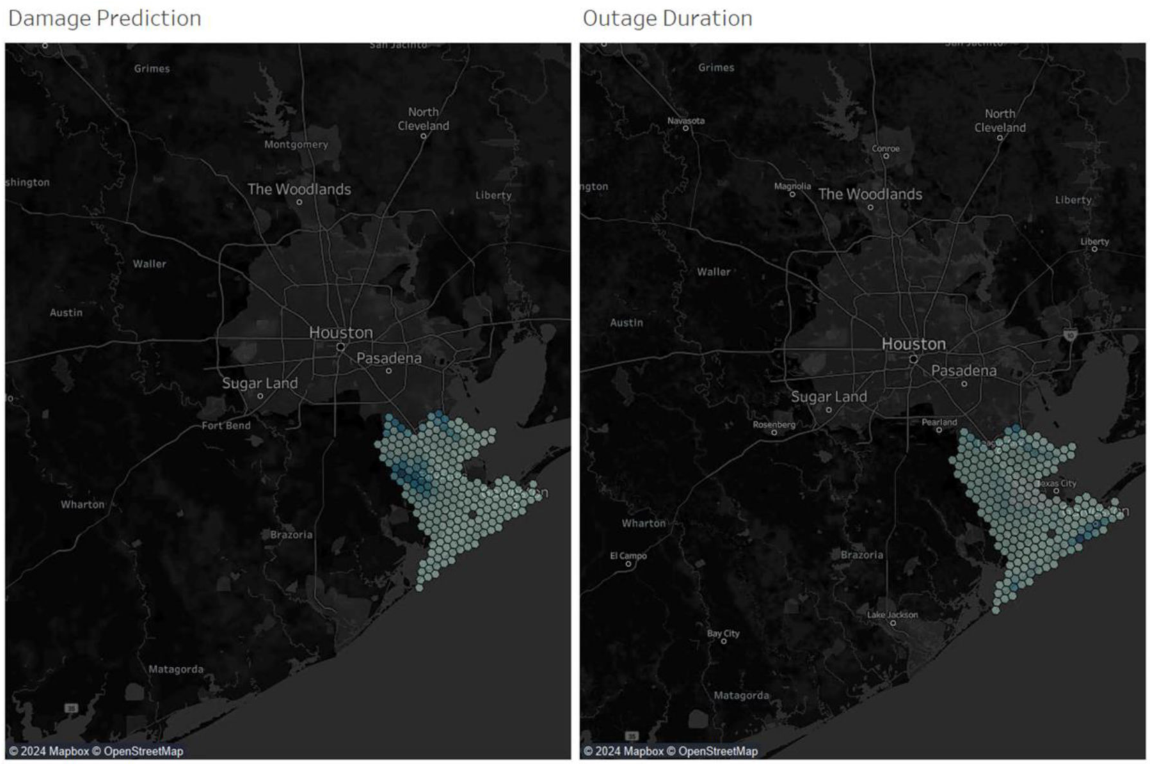


Figure AA-27: Harris County

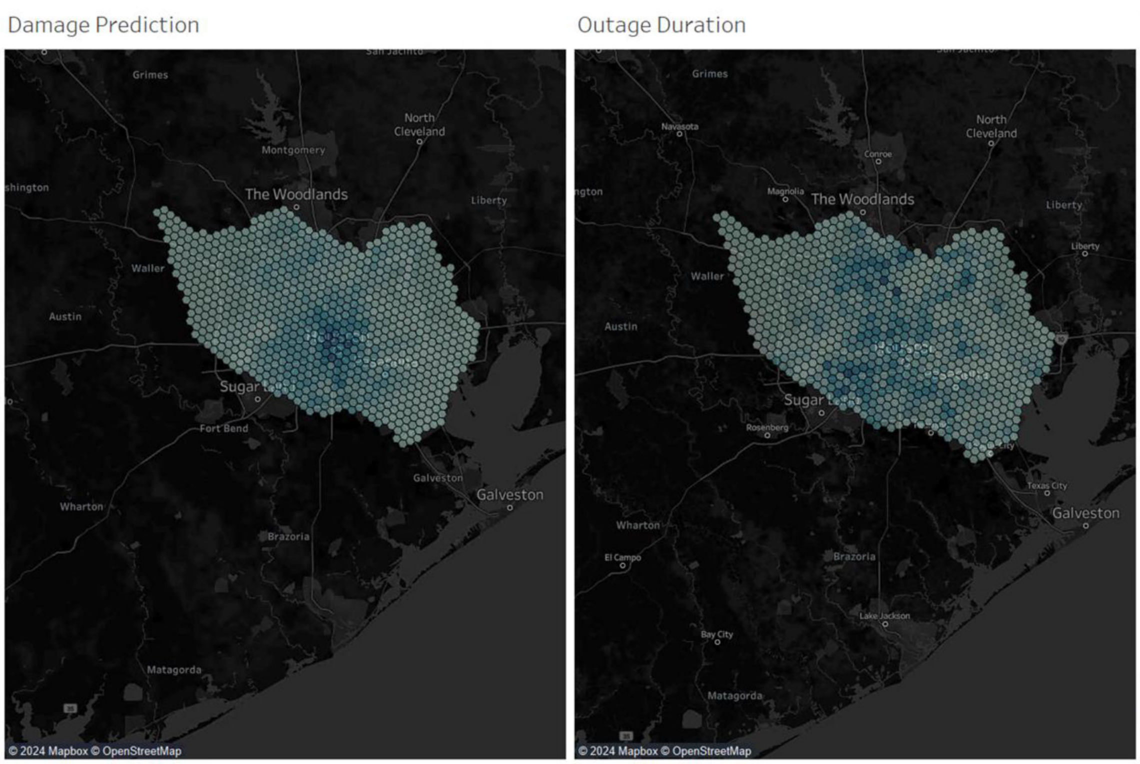


Figure AA-28: Liberty County

Damage Prediction | Outage Duration

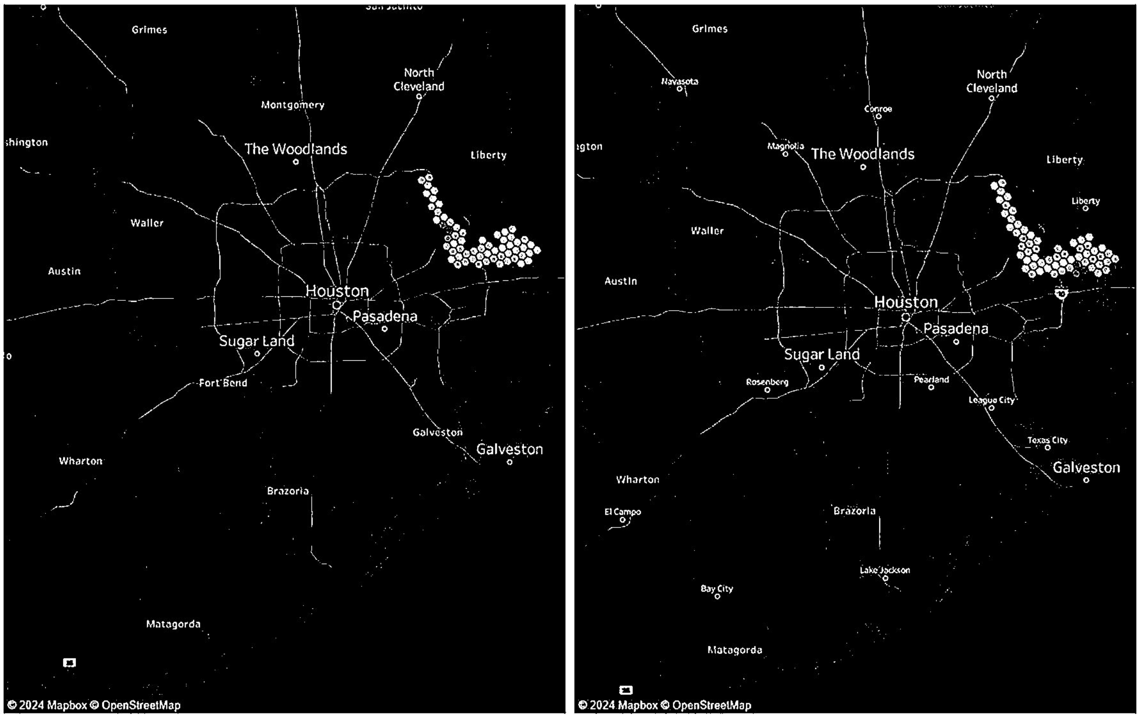


Figure AA-29: Matagorda County

Damage Prediction | Outage Duration

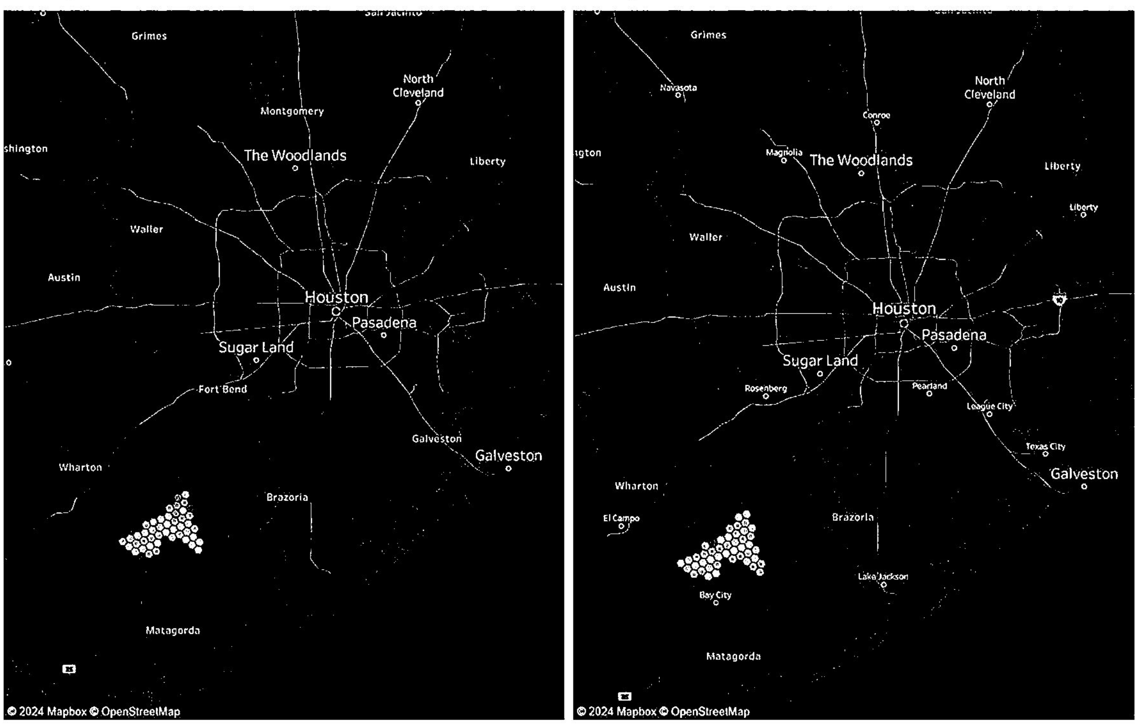


Figure AA-30: Montgomery County

Damage Prediction | Outage Duration

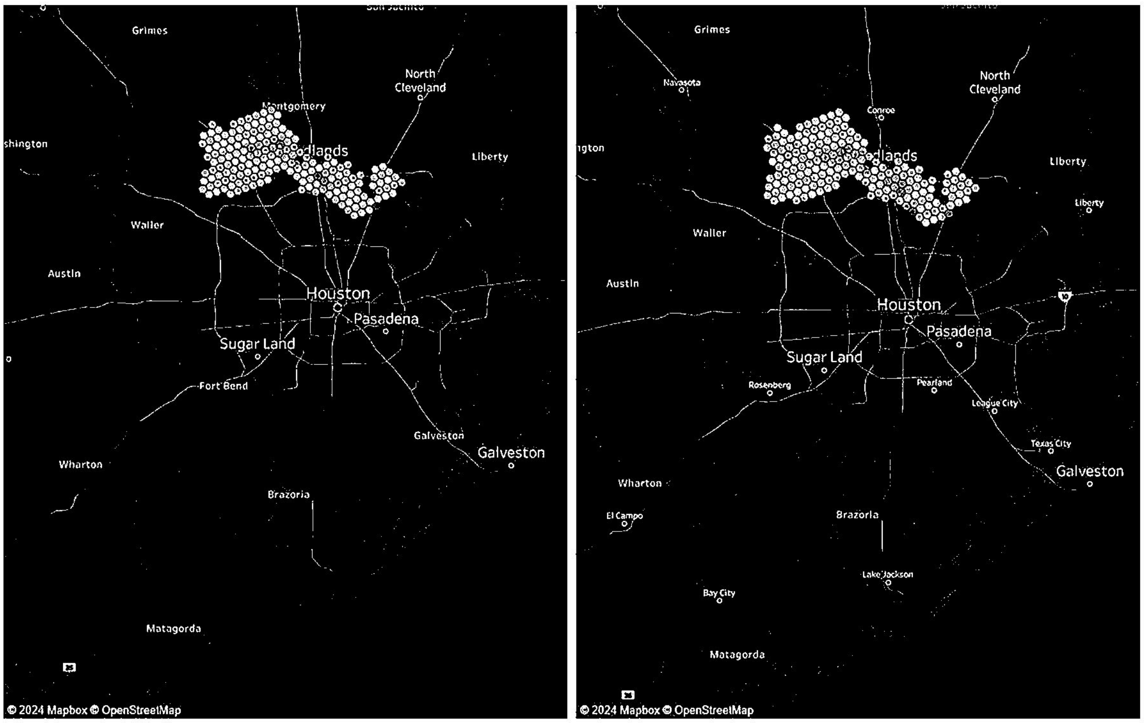


Figure AA-31: Waller County

Damage Prediction | Outage Duration

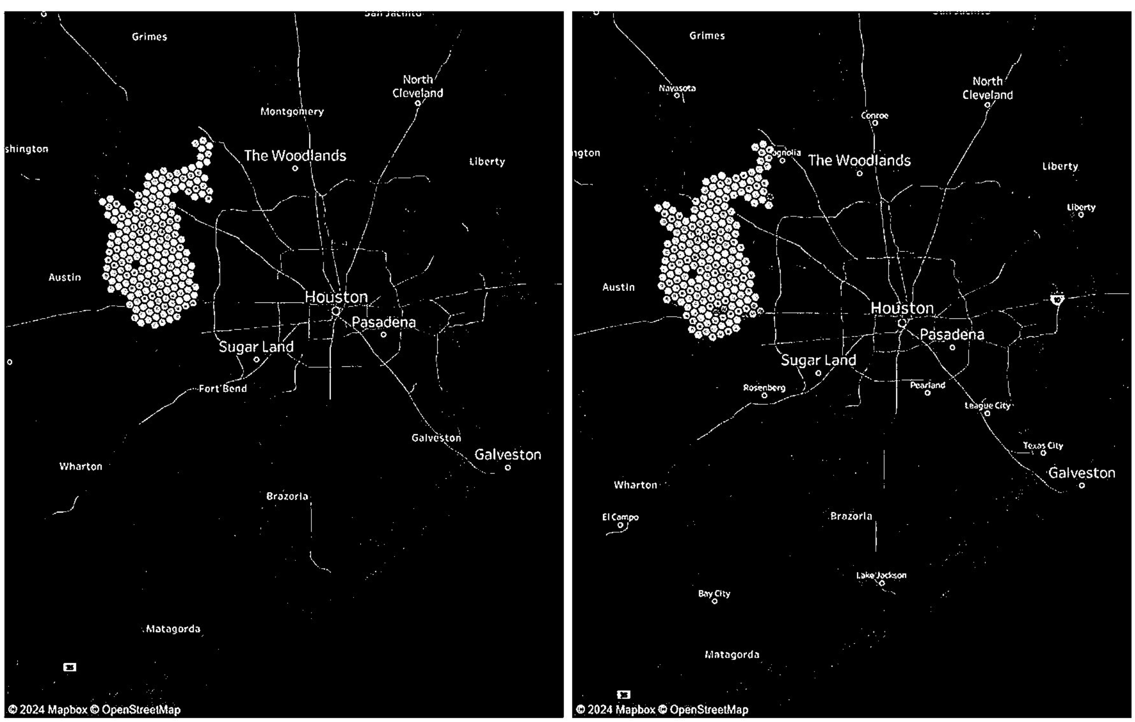
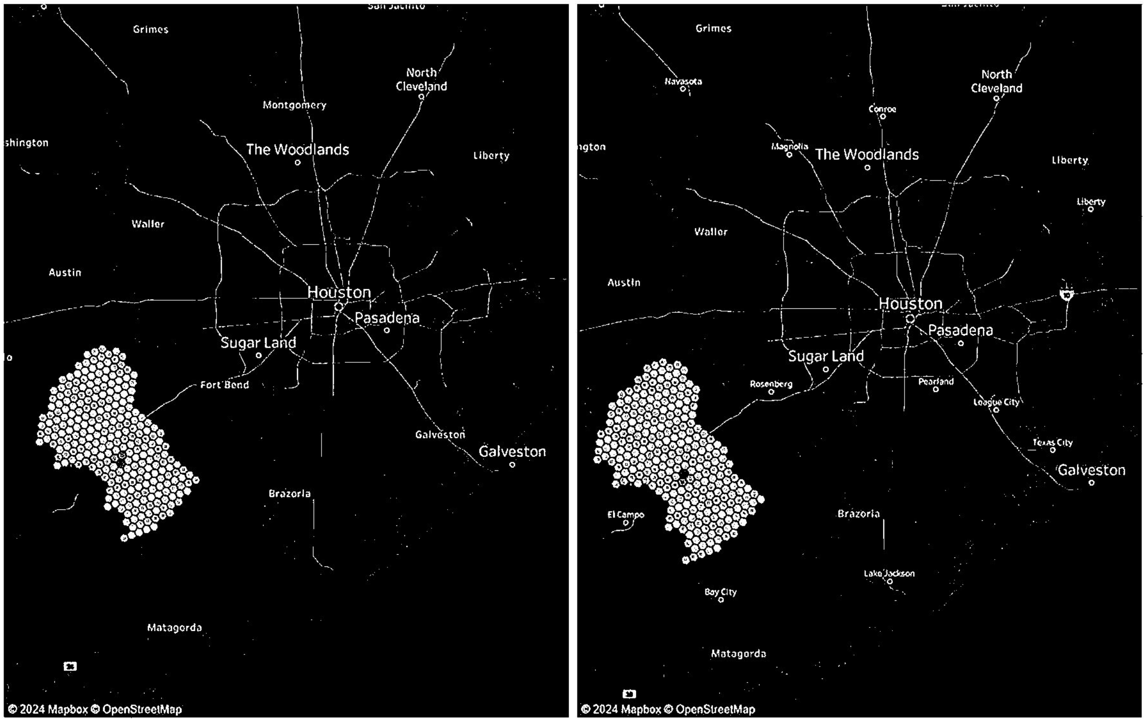


Figure AA-32: Wharton County

Damage Prediction | Outage Duration



Section 2.2.3.4. Guidance from the Public Utility Commission of Texas. Additionally, insights were gained from the recent PUC report.

Figure AA-33

Physical Infrastructure

6. **Utilities should assess poles constructed under prior NESC standards for replacement with poles that meet current extreme wind and ice design standards.**
   - Utilities should target circuits chosen for upgrade according to those that serve critical facilities such as hospitals, water treatment plants, or police stations, and that support mobile generation or serve underserved communities.

7. **Utilities should consider automated grid performance devices, like sectionalizers or automatic circuit reclosers, to reduce unnecessary outage times and help restoration crews locate and resolve faults more quickly.**

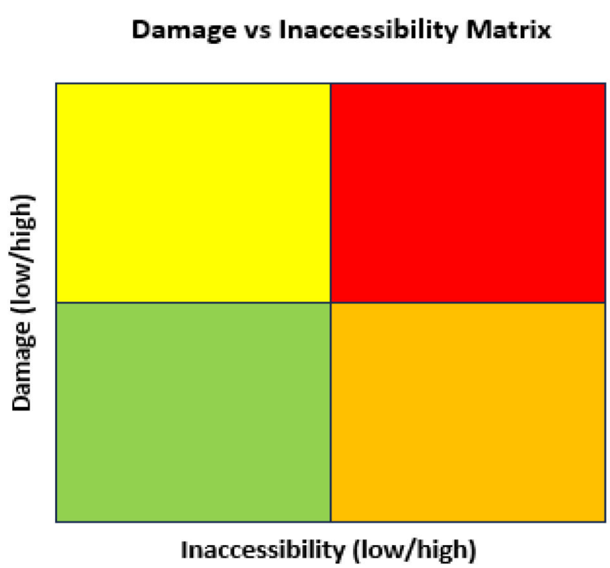
8. **In more densely vegetated areas, utilities should assess whether to replace distribution lines with covered conductor.**
   - The conductor is the wire that carries the electricity. Covered conductors have an insulating outer layer. This replacement may yield better protection against vegetative debris blown-in from outside the right-of-way and decrease overall outage rates.

10. **Utilities should use analytics-based vegetation management strategies to augment, not replace cyclical vegetation management plans.**
    - Vegetation management practices within Texas are not standardized, with some utilities moving away from a cyclical plan to a more analytics-based vegetation management plan. Analytics-based plans can help prioritize sections of a service territory due to heightened vegetation hazard. However, utilities should take precaution to not minimize factors like "time between trims." To ensure all segments in the service territory are addressed, utilities should augment cyclical vegetation management plans with analytics instead of replacing them with a solely analytics-based approach. Alternatively, utilities should ensure that maximum duration between trims serves as a default or failsafe factor within their analytics-based plan. This may require vegetation management budgets to increase slightly to accommodate additional priority segment work.

Section 2.2.4. Damage Prediction Modeling

Following an analysis of potential enhancements, CEHE worked to revise the previous damage prediction model to assist in estimating the number of mutual assistance crews needed to achieve a desired restoration rate, recommend the optimal staging site locations to activate, identify locations for potential temporary generation deployments and areas for augmented field crew resource allocations based on predicted geographic concentrations of longer duration outages relative to other portions of the system. An additional factor is the accessibility which can extend restoration times independent of the level of infrastructure damage. For the present enhancements, assumptions are made regarding accessibility to CEHE assets based on an available sample of LiDAR data and then applying that ratio system-wide. Increased levels of inaccessibility are correlated with lower crew efficiency (i.e. productivity). Ultimately, damage levels and productivity will determine the rate of restoration on a circuit-by-circuit level as shown in the figure below.

Figure AA-34



Section 2.2.4.1. Model Variables. For extreme wind events with wind speeds below the wind speed design basis, the majority of asset failures are expected to be from outside causes including tree fall in from trees outside our ROW. Therefore, local environmental factors must be a significant consideration in the model in addition to wind speeds. Trees have played a significant role in power system outages for extreme wind events in the CEHE service territory historically. The dynamic variables (precipitation and soil moisture) determine how antecedent meteorological conditions either increase or decrease the vulnerability of trees being wind-thrown and leading to outages.[13] The enhanced model is comprised of two sub-models, first to predict the number of mutual assistance crews required and another to predict areas of outage concentration. The prediction of mutual assistance crews is based on the variables in the figure below.

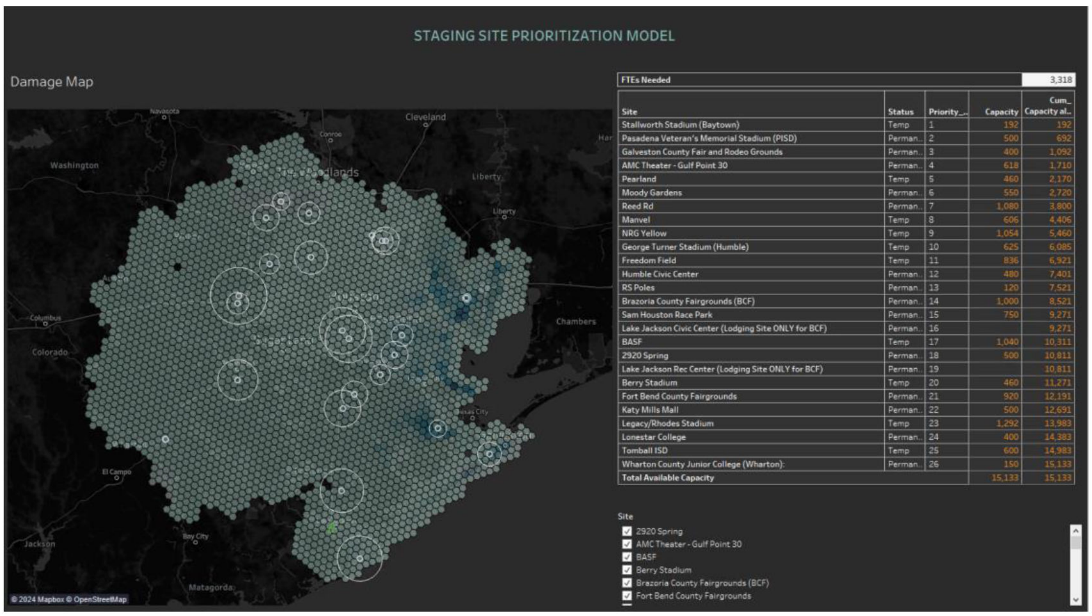
Figure AA-35

Model Variables	
Desired Event Duration (Days)	User entered value for the number of days desired for substantial restoration
Windspeed (Source: StormGeo)	Windspeed
Speed of Storm (Source: StormGeo)	Storm speed along the storm track prior to landfall
Eyewall Location (Source: StormGeo)	Relative location of the eyewall with respect to the CEHE service territory
Effective wind (Calculated)	Windspeed experienced by service territory when accounting for eyewall location
Soil Moisture Intensity (Source: NASA)	High/Medium/Low based on the present intensity percentile (20/80/20)
Vegetation Health (Source: NOAA)	Based on the present Vegetation Health Index (VHI)
Vegetation Density (Source: HGAC)	Vegetation density as calculated from Houston Galveston Aera Council aerial data
Vegetation Proximity (Source: HGAC/GIS)	Calculated based on CEHE GIS data and Houston Galveston Aera Council aerial data
Non-vegetation adjacent poles (Source: HGAC/GIS)	Calculated based on CEHE GIS data and Houston Galveston Aera Council aerial data
Vegetation adjacent poles (Source: HGAC/GIS)	Calculated based on CEHE GIS data and Houston Galveston Aera Council aerial data
Average Pole age (Source: SAP)	Average age of wood poles based on SAP data
Truck accessibility rate (Source: LiDAR)	Calculated based on the LiDAR based sample of 360 distribution circuit miles
Productive Hours per Day	Hours of work accomplished per day
FTEs per OVH Crew	Employees per overhead crew
FTEs per Veg Crew	Employees per vegetation crew
FTEs per URD Crew	Employees per underground crew
Travel Days	Days required for MA crews to travel to system
Logistic Days	Days required for staging sites to stand up
OVH to Veg Ratio*	Ratio of overhead to vegetation crews
OVH to URD Ratio	Ration of overhead to underground crews
Current System OVH FTEs	Number of overhead employees present on system

For the model variables listed in the table, items shown in bold are user defined based on the present operational criteria. All other variables are derived from the data sources listed above. Damage predictions are then calculated based on failure curves for mechanical failures and failures from outside causes. Mechanical failures (solid blue plot) are the result of assets failing from primary causes such as structural wind loading or water inundation. These failures can be caused by asset condition or the exceedance of design standards (i.e. wind speeds greater than the design criteria). Failures from outside causes (dashed orange plot) are failures resulting from indirect asset failures such as trees falling on circuits. While these failures are related to primary factors such as wind speed, proximity to other hazards can increase their rate of occurrence in conditions which do not exceed the design criteria of power system infrastructure. Therefore, the failure curve of outside causes is not primarily based on the asset itself.

Figure AA-36

Screenshot of Mutual Assistance Resource Model Output

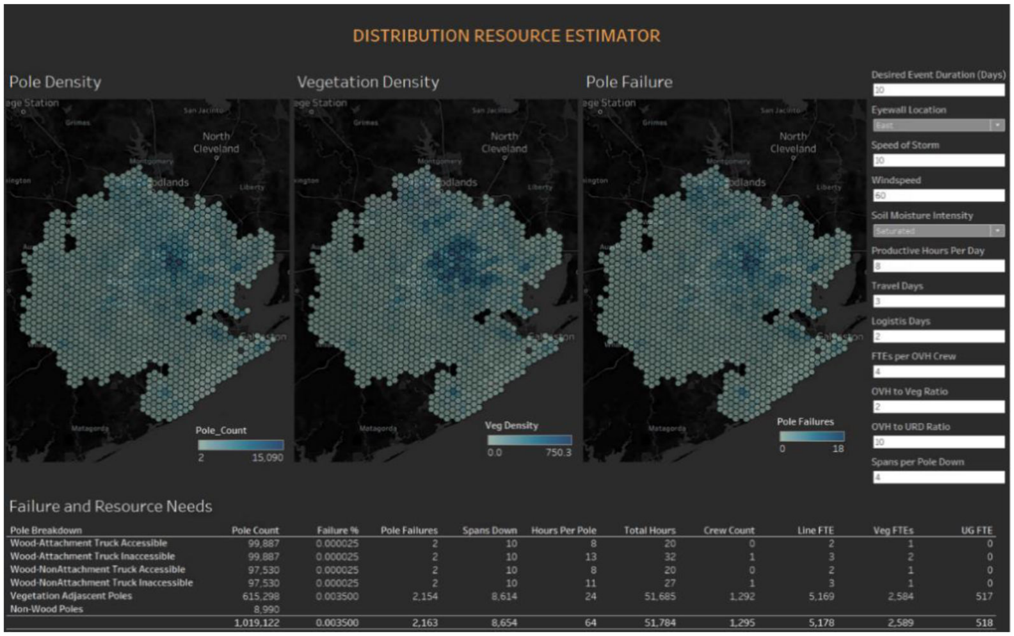


Section 2.2.4.2. Segmentation. When applied at a system-wide level, these calculations provide a generic prediction of the mutual assistance needs required to meet the desired restoration duration; however, these predictions can be improved by segmenting the service territory into more discrete geospatial areas. The model accomplishes this by using 5-mile area polygons and then applying the same computations on a per polygon basis. Each of the data sets is queried at the resolution most equal to the polygon area. In cases where the data resolution is not available, interpolation is used to assign a representative value per polygon. The use of polygon-based calculations results in differing predictions of mutual assistance resources; however, it is expected the higher resolution methodology produces a more accurate result. Following the initial mutual assistance resource prediction an additional buffer of twenty-five percent is added. Additional outages are expected to occur from transient causes such as lightning and tree branches temporarily contacting overhead conductors; however, the model is limited to permanent outage causes which require repair or replacement of power system assets. For the extreme wind scenarios distribution poles are assumed to be the primary cause of protracted outages and more specifically distribution poles with a lack of accessibility by truck as shown in the figure below.

Figure AA-37

The screenshot below shows how each of the relative concentrations of individual variables can be represented geospatially once aggregated within the individual polygons. The ability to visualize these correlations allows efficient validation from model developers, effective use by Operations and concise communication to external stakeholders. The damage prediction and mutual assistance model serves as the basis for staging site location selection, temporary generation locations and expedited deployment of appropriate crews.

Figure AA-38

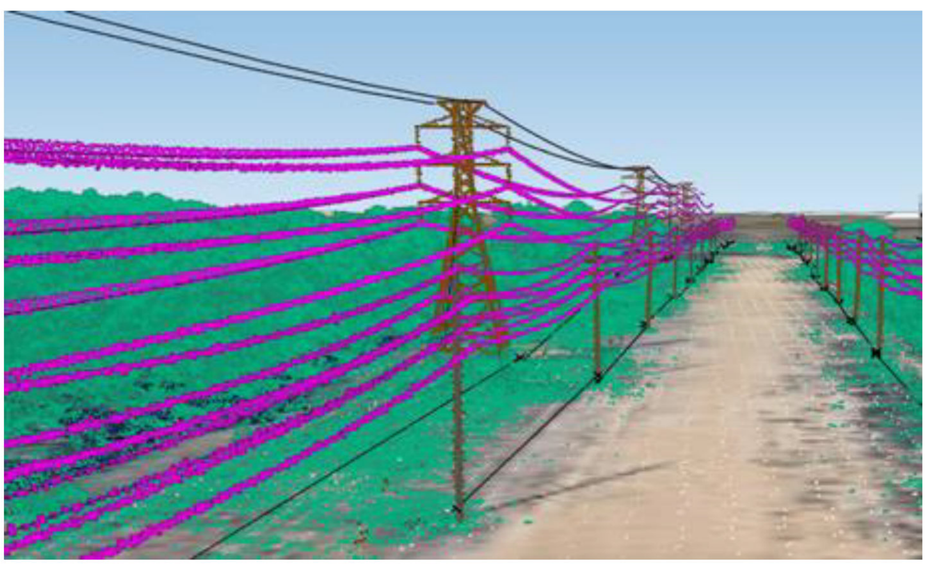


Pole Breakdown	Pole Count	Failure %	Pole Failures	Spans Down	Hours Per Pole	Total Hours	Crew Count	Line FTE	Veg FTEs	UG FTE
Wood-Attachment Truck Accessible	99,887	0.000025	2	10	8	20	0	2	1	0
Wood-Attachment Truck Inaccessible	99,887	0.000025	2	10	13	32	1	3	2	0
Wood-NonAttachment Truck Accessible	97,530	0.000025	2	10	8	20	0	2	1	0
Wood-NonAttachment Truck Inaccessible	97,530	0.000025	2	10	11	27	1	3	1	0
Vegetation Adjacent Poles	615,298	0.003500	2,154	8,614	24	51,685	1,292	5,169	2,584	517
Non-Wood Poles	8,990									
	1,019,122	0.003500	2,163	8,654	64	51,784	1,295	5,178	2,589	518

Section 2.2.4.3. Project Selection and Locations. Projects to mitigate the effects of extreme wind events were evaluated for both the Transmission and Distribution systems. The analysis accounted for the unique challenges faced by each asset type. LiDAR data served as the basis for analysis as well as structural loading calculations related to mechanical effects from wind loading.

Transmission. Transmission assets have a lower risk of tree fall damage due to the wider Rights Of Way (ROW) and taller construction heights. The figure below shows LiDAR data for a typical transmission ROW and transmission structures adjacent to the shorter distribution poles for reference.

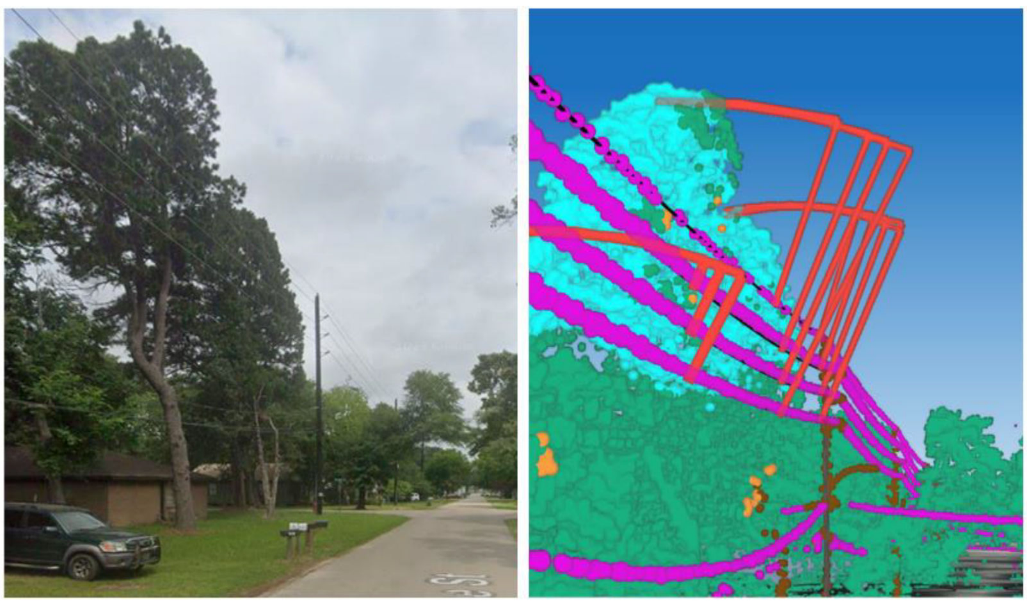
Figure AA-39



The model identified conductor spans with fallin risk which could result in transmission structure failure. Transmission ROW also generally increases accessibility when structural failures occur; however, instances of low accessibility do exist in select portions of the transmission network particularly near water crossings. Challenges in restoration following transmission structure failure are primarily driven by material lead times for specialized structure design. Failures of transmission structures can impair distribution restoration by eliminating sources to substations. Additionally, the transmission structures are substantially more costly to replace when compared to distribution poles increasing the criticality of achieving a hardened transmission system. The transmission extreme wind analysis focused on mechanical stress based on structural design elements to identify priority structural upgrades.

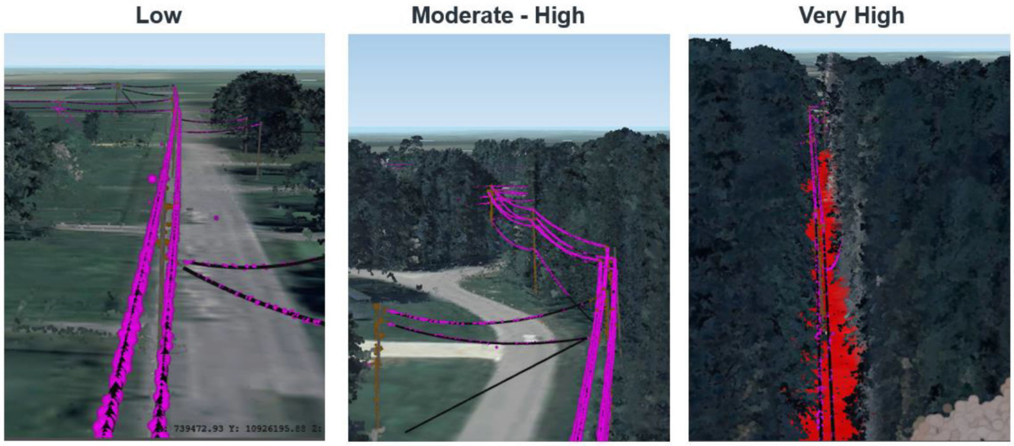
Distribution. Distribution assets have experienced mechanical failure during extreme wind events; however, design changes following Hurricane Ike in 2008 have aided in reduced mechanical failures during extreme wind events. These design changes reduced pole loading by limiting the size of pole mounted transformers which reduces wind loading. Damage from tree fall remains a persistent challenge from trees both inside and outside the distribution ROW. The figure below shows an example of tree fall risk identified using the LiDAR based model.

Figure AA-40



The ability to analyze the entire Company's service area for tree fallin risk provides the ability to optimize project locations based on potential impacts to Customers Minutes of Interruption (CMI). A system-wide analysis of tree fall in risk identified approximately 25% of the Company's overhead distribution system has high to very high fallin risk. The figure below shows the difference in vegetation risk classifications from model screenshots.

Figure AA-41



Areas of high to very high tree fall risk will be prioritized for project locations as not only does the tree fall risk lead to increased outages, it also results in slower restoration times. Areas of increase tree fall risk often correlate with areas of low accessibility forcing restoration to occur without the aid of heavy machinery. In collaboration with Operations employees, the Company's model is able to classify assets as accessible or inaccessible on a system-wide basis as shown in the figure below.

Figure AA-42

Orange = inaccessible, green = accessible

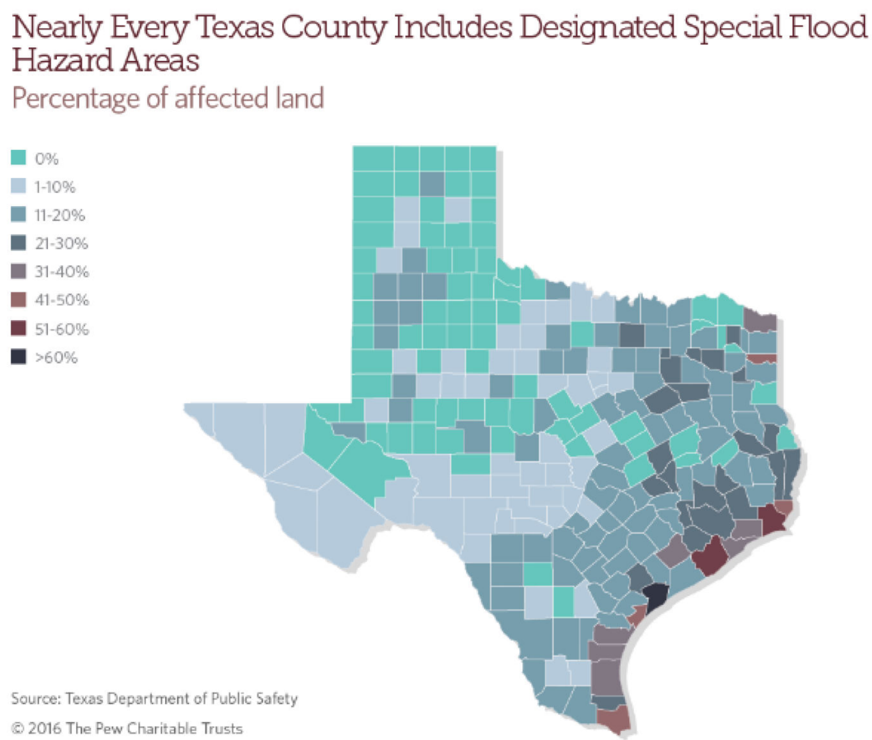
Prioritization. Model based prioritization of project locations used tree fall risk, accessibility and critical customers to identify mitigations for reducing CMI during extreme events. The selected mitigations will also have benefits from a reliability perspective to help improve reliability in addition to resiliency.

Appendix B - Extreme Water Events

Section 1. Overview of the Company's Service Territory

The CenterPoint Energy Houston Electric's ("CEHE" or the "Company") service territory has experienced multiple extreme water events ranging from storm surge events associated with hurricanes to prolonged rainfall and flash floods. This mix of extreme events routinely seen in the Company's service territory results in flood events which can impact both coastal and inland facilities. Adding to the challenges associated with proximity to the coast is the continued and rapid development occurring in the Company's service territory which adds impervious cover causing emerging flood risk inland. Floods and hurricanes are becoming more intense in Texas, with about 400 floods occurring annually.[1] Ninety percent of the state's natural disasters are floods, costing an average of $254 million a year.[2]

Figure AB-1



Based on updated rainfall statistics, which show a sharply increasing risk of heavy precipitation events in the past 20 years, the risk of 1-in-100-year flooding is substantially higher. In addition to the potential for more severe rainfall events, rising sea levels can also contribute to higher flood risk. The resulting FEMA based risk for the Company's service area is shown for riverine and coastal flooding in the figures below, respectively. [National Risk Index for Natural Hazards | FEMA.gov]

[1] Texas Department of Public Safety, State of Texas Mitigation Plan: 2013 Update, http://txdps.state.tx.us/dem/Mitigation/txHazMitPlan.pdf; and U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, "State of Texas Energy Sector Risk Profile," http://www.energy.gov/sites/prod/files/2015/06/f22/TX_Energy Sector%20Risk%20Profile.pdf.

[2] Texas Department of Public Safety, State of Texas Mitigation Plan: 2013 Update.

Figure AB-2
National Risk Index

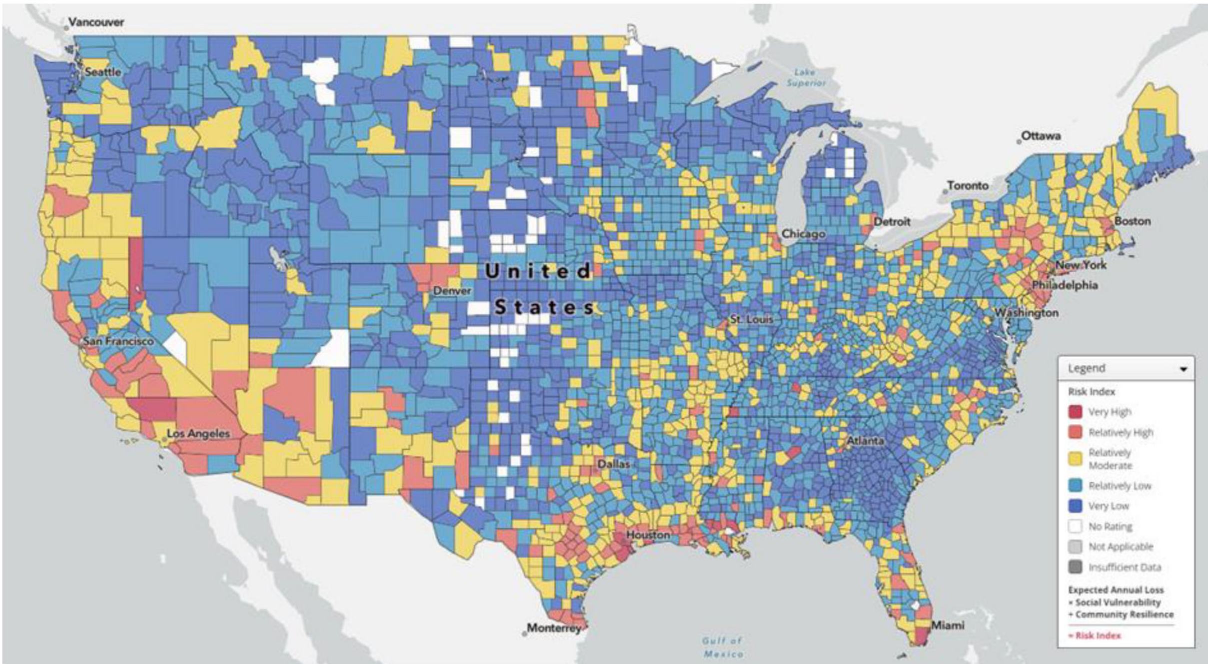
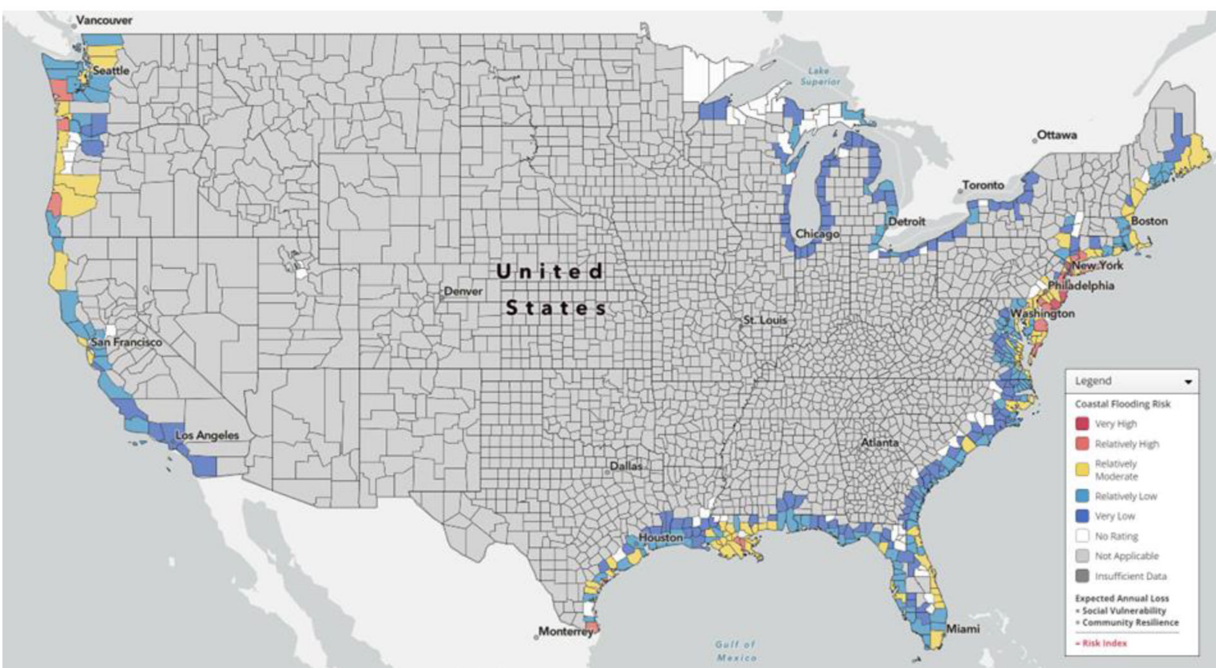


Figure AB-3
Coastal Flooding Risk



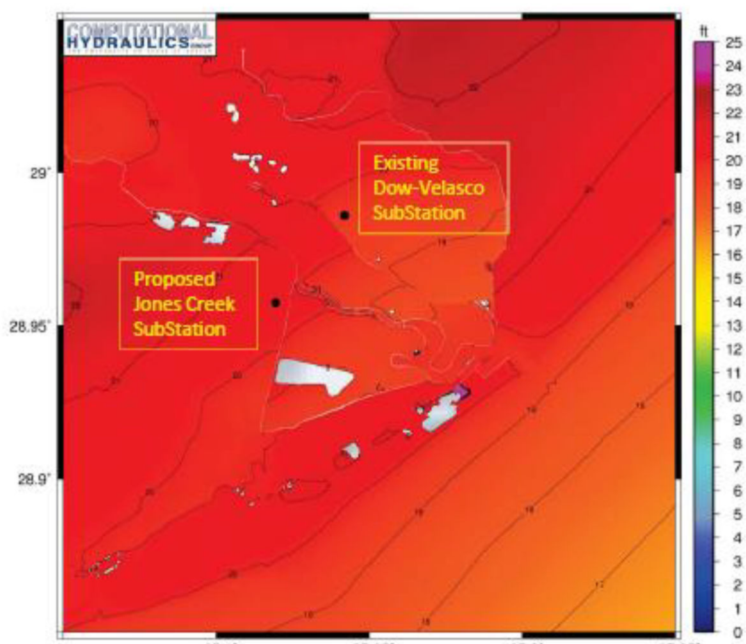
Coupled with the area's flat terrain, relatively limited capacity watercourses, and its proximity to the Gulf of Mexico, Houston is especially prone to severe flooding from tropical storms and hurricanes. There are six major bayou arteries that run through the City of Houston and Harris County from west to east. They are: Greens Bayou, Halls Bayou, White Oak Bayou, Buffalo Bayou, Brays Bayou, and Sims Bayou. These bayous all drain into the Houston Ship Channel and carry the runoff east into Burnett Bay with eventual outfall into Galveston Bay. The flood risk is highest for riverine flooding when compared to coastal flood risk based on FEMA Natural hazard indices. Riverine Flooding can be compounded during hurricane events which can couple storm surge with intense levels of inland rain fall. This combination can result in bayou and stream related flooding. The FEMA results are consistent with the Company's System Resiliency Plan as extreme water projects address both coastal and inland risks.

Section 1.1. Preparation for Water Events

Section 1.1.1. Modeling.

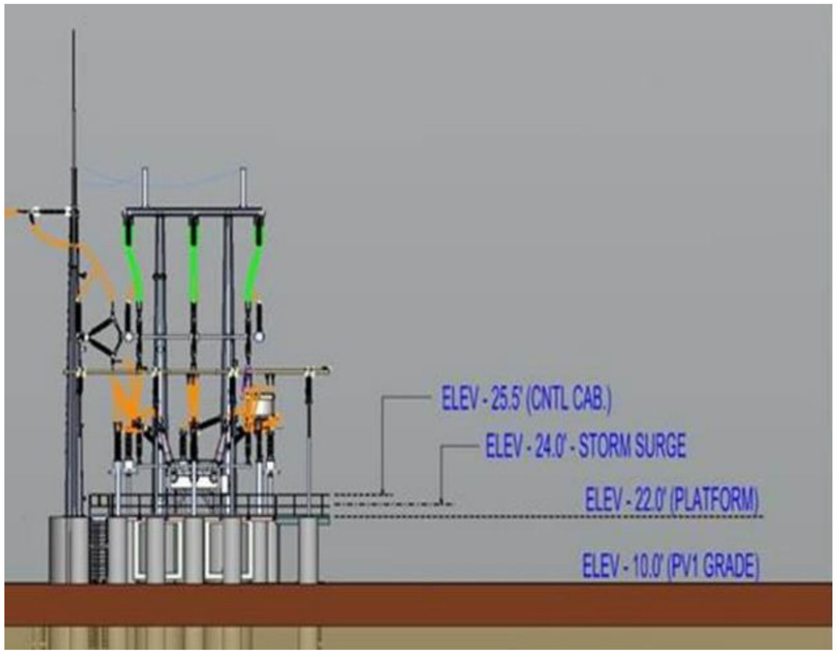
Modeling is particularly important for extreme water events which can be sensitive to local and dynamic topographical features. Mitigation selection used a 3-tier process including review of historical events, industry best practices benchmarking, and storm surge modeling. The need to account for climate patterns associated with frequency of severe precipitation events, changes in sea level, and impervious cover will necessitate frequent updates of the model and review of mitigation projects. Site specific storm surge modeling as shown in the figure below is often completed at the time of costal substation design and will serve to validate the system wide modeling and field observations from previous benchmark events. These models are used to determine the final elevation and design of the substation.

Figure AB-4



The modeling of the figure below was used to complete 3D modeling of the final design which mitigates the flood risk using elevated structures. Highlighting the use cases and application of models for flood mitigation.

Figure AB-5



Section 1.1.2. Structural Hardening.

Substation and underground facilities are more prone to adverse impacts during extreme water events. The company has 309 substations and 802 underground vaults potentially exposed to these adverse conditions. Substations are typically built at ground level which can make electrical components such as terminal boxes, protective relays and control electronics susceptible to flood waters. Salt water is particularly damaging for these components requiring the replacement of any affected equipment when recovering from a flooding event. Underground vaults constructed below ground level can become inundated with water requiring operational actions to ensure safe operation of the customer service and speed restoration once water levels in the vault permit entry by operations personnel. While fewer in number, control centers are vital to safe and efficient restoration following an extreme water event. Based on local factors, control centers can be at risk of inundation and are therefore included in the flood modeling and mitigation project evaluation. Control center failures have the ability to result in system wide impacts for both the distribution and transmission systems increasing the importance of periodic review and timely mitigation. Lastly, mobile transformers can provide operational adaptability for emerging threats where distribution transformer capacity has been compromised.

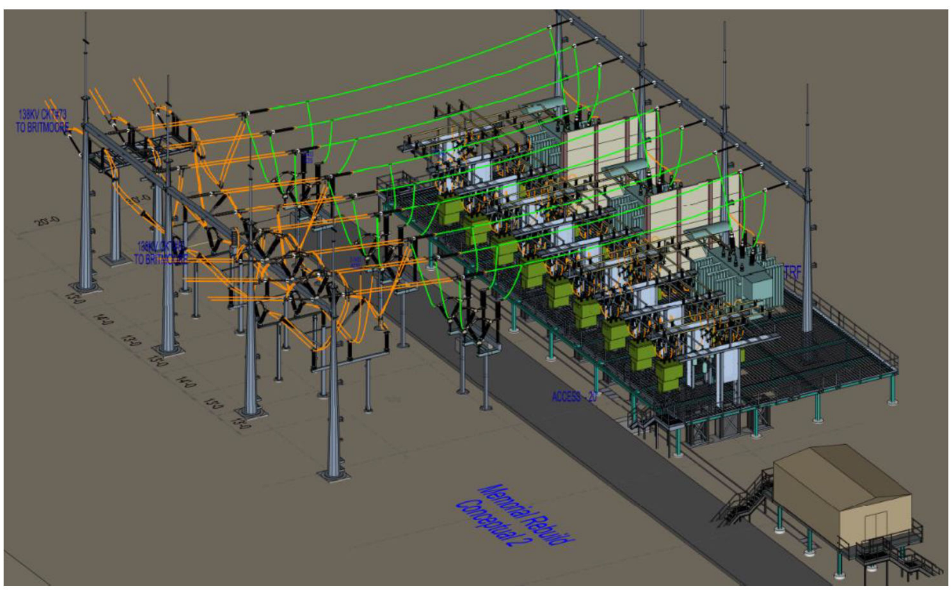
Section 1.1.3. Asset Monitoring

Extreme water events impact subsets of assets in the Company's service territory; however, damage can lead to repairs which require a substantial amount of time to repair. In cases where substations are flooded, the entire control house and a significant amount of the outdoor equipment can require replacement. An example of severe flooding is shown in the figure below from Hurricane Harvey in 2017.

Figure AB-6

Due to water levels in the control house and substation yard, the substation required a complete rebuild utilizing a flood mitigating design. The design utilized an alternative method with steel structures as opposed to the concrete elevation structures.

Figure AB-7



The rebuilding of the substation was completed over a multi-month period, making the use of a mobile transformer essential in providing service to customers in the interim. This flood event provided another example of mobile transformers providing resiliency benefits on a prolonged basis.

Vaults are constructed to have some water ingress. Most equipment will operate normally when a vault is temporarily flooded with low water that does not exceed two feet above its lowest floor. As the water level rises, sensitive electronic devices like protective relays and communications equipment will suffer water damage. Higher water levels could also cause damage to other electrical equipment such as transformers, buss work, and cable connections. The company's protection scheme is designed to de-energize transformers in the presence of high water but permanent water damage to the equipment is still likely. If a protective device fails and is not able to trip due to being flooded in a vault, it could cause circuit wide outages affecting the service of neighboring customers.

Figure AB-8

Figure AB-9

Figure AB-10

The Company utilizes mobile substations which are more efficient to deploy than mobile transformers. The efficiency of mobile substations is due to accompanying breaker and switch trailers as well as incorporated protective relaying. Additionally, multiple voltages allow increased flexibility for restoring customers on both 12kV and 35kV feeders.

Figure AB-11

In summary, the Company is including flood mitigation for substations/control center, monitoring and control for underground vaults and expansion of its mobile substation fleet to enhance resiliency for extreme water events. The figure below lists the objectives of these project types.

Figure AB-12

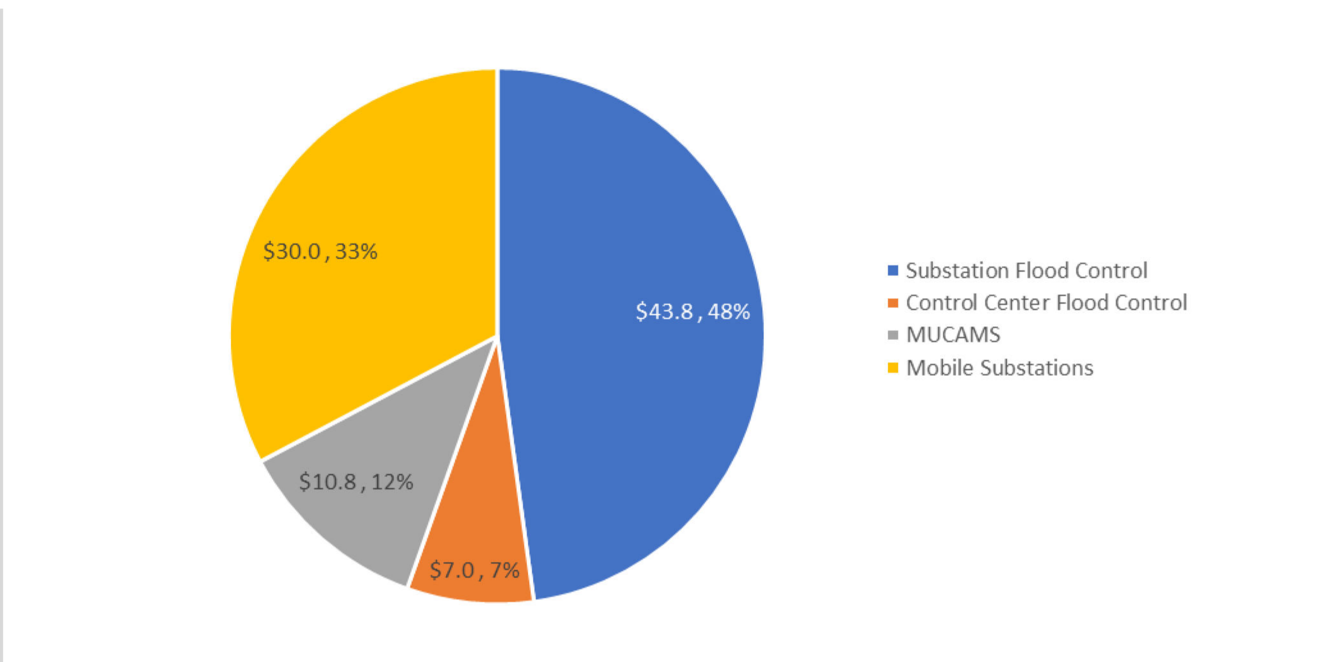
Event Class	Event Type (% assets impacted)	Mitigation Objective
Extreme Water	Hurricane (100%) Flood (80%)	Elevate facilities based on potential flood levels
		Utilize flood mitigation walls to remove flood risk
		Increase monitoring and control in underground vaults
		Increase adaptability using mobile distribution substations

Section 2. Advanced Modeling Methodology

Section 2.1. Cost Allocation

Based on best practice benchmarking, utilities similarly challenged by extreme water events tend to prioritize control center resiliency for extreme events given their criticality to overall system operations. The company has been recognized as an industry leader with respect to elevated substation design and presented several industry papers as well as hosted site visits to elevated substations. Substations are prioritized based on historical events and flood modeling and leverage alternatives such as elevating the substation equipment and control houses or flood mitigation walls to mitigate flood conditions within substations. Mobile substations are used as an industry standard approach in expediting recovery following the loss of a transformer or substation. Mitigation of substation and control center flood risk are the highest investment area at 81%, as shown in the figure below, when considering the portfolio of projects to mitigate extreme water events and customers affected by such events.

Figure AB-13



Section 2.2. Characterization of Water Events

The Company used advanced modeling to characterize extreme water risks, expected operational impacts and associated repair times of predicted damage. Furthermore, the analysis uses climate projections to complete a Benefit Cost Analysis ("BCA") over a longer period which accounts for changes in frequency and intensity of events. The BCA was calculated using the total cost of the extreme wind mitigations and the benefits associated with faster event restoration. The mitigations included in this resiliency plan are expected to reduce customer minutes of interruption by 11.0 million CMI. The following pages offer a detailed explanation of the event types, event sequence of events, present susceptibility of assets and historical events, the modeling methodology used to forecast future customer impacts, a review of best practice benchmarks and alternatives, prioritization of mitigations, as well as project selection and locations. The section concludes with additional details on the customer benefits of the mitigation within the context of an extreme water event.

Section 2.2.1. Risk Characterization by Event Type

Extreme water events primarily cause customer outages from water inundation at substations or underground vaults. When the company is aware of flood related hazards they will de-energize equipment to limit uncontrolled and potentially cascading failures. When substations are de-energized it will result in outages of transmission lines and distribution feeders which causes customer interruptions of service. Outages associated with underground vaults are more localized; however, the events differ in the amount of advanced warning, percentage of system impacted, rainfall and direction of water flow forces.

Section 2.2.1.1. Hurricane (Storm Surge). In addition to the extreme winds produced by hurricanes, storm surge can also pose a significant hazard to the Company's service area, particularly when they coincide with high tide. Storm surge is water from the ocean that is pushed toward the shore by the force of the winds swirling around the hurricane. This advancing surge combines with the normal tides and can increase the water level by 30 feet or more. As a hurricane develops over the open ocean, forecasters at the National Hurricane Center closely monitor its path to evaluate the risk of a coastal strike. They use a computer model called SLOSH to predict storm surge heights. The model depends critically on the hurricane's track, intensity, and size. (Hurricane Storm Surge | Ocean Today)

Section 2.2.1.2. Hurricane/Rain (Surface Water Flood). Surface water floods occur when an urban drainage system is overwhelmed, and water flows out into streets and nearby structures. It occurs gradually, which provides people time to move to safe locations, and the level of water is usually shallow (rarely more than 1 meter deep). It creates no immediate threat to lives but may cause significant socio-economic damage.

Section 2.2.1.3. Hurricane/Rain (Flash Flood). Flash floods are characterized by an intense, high velocity torrent of water. They are triggered by torrential rain falling within a short amount of time within the vicinity or on nearby elevated terrain. Flash floods can also be caused by a sudden release of water from an upstream levee or a dam. They can be very dangerous and destructive, not only because of the force of the water, but also the hurtling debris that is often swept up in the flow.

Section 2.2.2. Planning and Response

Section 2.2.2.1. Pre-Storm. Prior to the storm several activities are completed to mitigate flood impacts and prepare for restoration, including the use of flood inundation models and data from historical events to predict flood risk and potential affects to facilities. Extreme water events can also inform decisions related to staging site activation, resource levels and specialized high-water equipment.

Damage Prediction Modeling. Damage Prediction Modeling is completed during the project identification phase based on updated topographical information. When an extreme flood event is forecasted to occur, the company conducts reoccurring meetings with its meteorologist. These meetings provide information on both the expected storm surge or rainfall total and the timing of the event. Timing is critical for planning when pre-event activities such as closing flood walls should occur and when crews may be able to begin restoration activities.

Mutual Assistance. Mutual assistance resources are estimated based of the expected level of damage from the impending event. Damage to transmission structures and distribution poles from extreme water events is significantly less than those attributed to extreme wind events. As a result, the number of resources and skill sets required changes. Additionally, the need for specialized equipment increases to address access to areas with high water and to pump water away from electrical equipment.

Staging Sites. Staging Sites are informed by flood inundation models to optimize locations based on expected accessibility. Staging site assessment is refreshed as additional storm forecast are received up until landfall and one final prediction post landfall to inform site adjustments.

Critical Customer Restoration. The Company maintains a database of priority customer locations in addition to utilizing processes during significant events to prioritize restoration. The damage prediction models assist in forecasting when critical customers may be in areas that sustain more significant damage. These predictions can assist in prioritizing restoration crews and/or the deployment of temporary generation as well as supporting the selection of hardening projects.

Public Safety Power Shut-off. In some cases, utilities de-energize circuits in the interest of public safety. For extreme flood events, the need to de-energize services when water comes within specified distances of energized lines (dependent on voltage class) or when customer locations (i.e. homes and businesses) are inundated with water and pose a safety risk. When public safety power shut-off is required, utilities attempt to affect the fewest number of customers possible.

Section 2.2.2.2. Storm Response. The conditions experienced during extreme water events can prevent safe crew dispatch requiring preemptive project completion and automation to complete initial response activities. Once water levels recede, restoration crews are dispatched to assess situations, restore service, and reenergize operable equipment when and where safely able.

Substations/Control Center. Most at risk substations and control centers are those near the coast and within close proximity to bayous, other channels, or bodies of water. Water inundation in the substation can damage electronic devices such as protective relays, SCADA sets, breaker control panels, transformer control panels, etc. The water can corrode electronic devices requiring their repair or replacement. These replacements are often conducted in an expedited time frame increasing the restoration cost when compared to preemptive mitigation. Expedited projects can take 9 to 12 months compared to 12 to 15 months for planned projects. During the interim period, mobile substations are used to provide service to distribution customers. Mobile substations do not provide the same load ratings as permanent units; however, they do increase reliability by increasing capacity until permanent restoration can be completed. Extreme flood events can be mitigated by elevating the substation, constructing flood walls or relocating the substation. Substation relocation is not always practical due to operational constraints associated with load and voltage.

Substation Elevation. Substation assets can be elevated using a few methods including extended concrete caps, concrete platforms and steel structures. When elevating substation assets additional considerations for safety must be incorporated into the designs. The company began incorporating elevated designs on storm surge risks; however, as infrastructure additions have changed drainage characteristics and more extreme events have occurred, flooding of inland substations has occurred.

Elevation of the substation is used to raise equipment above highest forecasted flood levels based on storm surge or inundation models. Once elevated event response is limited as the flood risk is mitigated.

Substation/Control Center Flood Walls. In cases where elevating the substation is challenged by space constraints, or other construction related limitations, the construction of flood walls can mitigate flood water. The flood wall height is based on storm surge or inundation models and incorporates additional components such as flood gates and pump systems to ensure the continued operations of the substation throughout the extreme water event. Critical details such as the wall thickness and foundation design are also specific to the expected loading from flood waters.

Substation Flood Monitors. Substation flood monitors can provide situational awareness for substations at risk of inundation. The Company uses publicly available flood data related to bayou and channel water levels in near real-time. Based on the information from the public data sources, field inspections are completed to ensure the substation has not been impacted. The requirement for onsite validation can pose safety risk for personnel in the event flood water rises faster than expected. An additional option for situational awareness is the use of pan-tilt-zoom (PTZ) camera systems. Cameras can offer the ability to monitor water levels; however, their effectiveness can be limited during extreme events where winds can shift the camera position or debris can obstruct viewing angles. Purpose built flood monitoring systems utilize technologies which do not require visual confirmation to determine flood depth and are more robust for extreme weather conditions. These systems can also be integrated into SCADA systems to provide alerts to Control Center personnel.

Underground Vault. Transformer vaults are electrical rooms located near the point of service where the company will install distribution transformers and other electrical equipment necessary for the safe and reliable delivery of electrical service. Transformer vaults are often located inside of a customer's building because of spatial constraints on a property preventing alternate service arrangements. Even though it is often located inside the customer's building, access is restricted to authorized company personnel only.

Transformer vaults are common in high density zones of the city and in dedicated underground areas. Many high-rise buildings and most hospitals in the Texas Medical Center are served from transformer vaults. Historically, the vaults located near bodies of water and installations below grade are prone to flooding. The company requires that all new customer requested transformer vaults be installed at grade.