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January 15, 2025

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Tampa Electric Company's Petition for Approval of 2026-2035 Storm Protection Plan
Dkt. No.: 20250016-EI

Dear Mr. Teitzman:

Attached for filing in the above docket on behalf of Tampa Electric Company, is the Direct Testimony of Kevin E. Palladino and Exhibit No. KEP-1.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

MNM/bml
Attachment
cc: Walt Trierweiler, Office of Public Counsel
TECO Regulatory

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250016-EI

TAMPA ELECTRIC COMPANY'S

2026-2035 STORM PROTECTION PLAN

DIRECT TESTIMONY AND EXHIBIT

OF

KEVIN E. PALLADINO

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KEVIN E. PALLADINO

Q. Please state your name, address, occupation, and employer.

A. My name is Kevin E. Palladino. My business address is 5321 Hartford Street, Tampa, Florida 33619. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Manager Storm Protection Plan Engineering and Customer Outreach.

Q. Please describe your duties and responsibilities in that position.

A. My duties and responsibilities include the governance and oversight of Tampa Electric's Storm Protection Plan ("SPP" or "the Plan") development and implementation. This includes leading the development of the SPP, prioritization of projects within each of the programs, development of project and program costs and overall implementation of the SPP. Organizationally, Tampa

Electric employees responsible for management and implementation of the Vegetation Management, Feeder Hardening, Distribution Lateral Underground programs, as well as the SPP warehouse, report through my organization.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in electrical engineering and a master's degree in electrical engineering from the University of South Florida. I have more than nine years of service with Tampa Electric working in Distribution Design and Engineering.

Q. Have you previously testified before the Florida Public Service ("Commission") or other regulatory authority?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my direct testimony is to present, for Commission review and approval, Tampa Electric's proposed 2026-2035 SPP. I will also describe the process the company followed to develop the proposed 2026-2035 SPP; explain how it will accomplish the goals of Section 366.96 of the Florida Statutes to reduce restoration costs and outage times associated with extreme weather and enhance reliability; and describe how it contains all of the contents required by Rule 25-6.030 of the Florida Administrative Code.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Exhibit No. KEP-1, entitled, "Tampa Electric's 2026-2035 Storm Protection Plan" which was prepared under my direction and supervision. This Exhibit details the company's plans to achieve the goals of Section 366.96 of the Florida Statutes and Rule 25-6.030, Florida Administrative Code.

Q. Will other witnesses submit pre-filed direct testimony in support of Tampa Electric's proposed 2026-2035 SPP?

A. Yes, there are two additional witnesses that will provide pre-filed direct testimony in support of Tampa Electric's proposed 2026-2035 SPP. Witness Jason D. De Stigter's direct testimony explains the methodology used to select and prioritize Storm Protection Projects for Distribution Lateral Undergrounding, Transmission Asset Upgrades, Distribution Overhead Feeder Hardening, and Substation Extreme Weather Programs. Additionally, Witness A. Sloan Lewis provides testimony regarding the estimated annual jurisdictional revenue requirements for the SPP and the estimated rate impacts for each of the first three years of the Plan.

TAMPA ELECTRIC'S SPP ACHIEVEMENTS TO DATE

Q. Is Tampa Electric's proposed 2026-2035 SPP the company's first SPP?

A. No. Tampa Electric previously filed the 2020-2029 SPP in 2020 and the 2022-2031 SPP in 2022. These plans were both approved by the Commission.

Q. Please describe the company's achievements under those two prior SPPs.

A. During the time period covered by the two previous SPPs, Tampa Electric converted nearly 200 distribution overhead lateral miles to underground, converted over 2,000 wood transmission poles to steel, and hardened feeders on over 30 distribution circuits.

Q. Have these activities resulted in any benefits during extreme weather?

A. Yes, our SPP activities have resulted in significant improvement in system performance during and after extreme weather events. The best way to illustrate this improvement is to compare system performance during Hurricane Irma, which predated the 2020-2031 SPP, and Hurricane Ian in September of 2022. During Hurricane Ian, wind speeds remained above 40 miles per hour for 8.5 hours, as compared to only 1.5 hours during Hurricane Irma. Despite these more severe weather conditions, the company saw significantly improved performance in several areas, including:

- A 57 percent reduction in the number of outages on the 18 circuits that were hardened under the Feeder Hardening Program, and zero pole or feeder wire failures on those circuits. There were four pole failures on non-hardened feeders within 1,000 feet of hardened feeders, which indicates that there would have been more pole failures had it not been for the company’s hardening efforts.
- None of the laterals that were undergrounded before Hurricane Ian experienced an outage during Ian. The company examined areas within 1,000 feet of each underground conversion project and identified four pole failures, indicating that weather conditions in those

areas could have caused damage to overhead lateral equipment if it had been present.

- Circuits that received Supplemental Vegetation Management had a 20 percent reduction in the number of outages.
- Circuits that received Mid-Cycle Vegetation Management had a five percent reduction in the number of outages.
- Circuits that received both Supplemental and Mid-Cycle Vegetation Management had a 43 percent reduction in outages.

Q. Did Tampa Electric observe any benefits from SPP projects during the 2024 hurricane season?

A. Yes. As an example, Hurricane Milton, a Category 3 hurricane at the time it affected Tampa Electric’s service area in October 2024, caused significant damage related to windspeeds and rainfall, primarily due to trees falling. Due to continued storm protection work completed under the SPPs, Tampa Electric customers experienced the following benefits:

- None of the upgraded steel poles replaced under the company's SPP Transmission Asset Upgrades program failed during Milton. Of the 28 transmission structures that failed during Milton, 26 were wood transmission poles that have not yet been upgraded. The remaining two poles, a concrete pole and an aluminum H-frame, were not part of the SPP initiative.

- Less than five percent of laterals undergrounded in the company's SPP Distribution Lateral Undergrounding program experienced an outage, whereas 15 percent of the company's overhead laterals experienced an outage.
- Overhead laterals within 500 feet of an SPP undergrounded lateral, experiencing the same storm conditions, experienced outages at a nearly 19 percent rate. This is approximately four times higher than the outage rate for underground laterals.
- Only one of the nine transmission circuits that had an outage was attributed to vegetation.

Q. What metrics does Tampa Electric use to track reliability?

A. The company uses industry standard metrics such as MAIFe (average number of momentary outages/flickers), SAIDI (cumulative interruption minutes), CAIDI (average time to restore power after an outage), and CEMI-5 (percentage of customers who experience five or more sustained outages) to track reliability.

Q. Have these metrics improved during "blue sky" conditions because of Tampa Electric's SPP activities?

A. Yes, the company's Transmission and Distribution reliability has steadily improved since 2021. Our SAIDI improved from a high of 84.5 in 2021 to a low of 57.27 in 2023, and MAIFIe improved from a high of 6.5 in 2021 to a low of 6.44 in 2023. CEMI-5 improved from 9,744 in 2021 to 1,022 in 2023. Tampa Electric attributes these improvements in part to the work performed to implement the company's first two SPPs. To illustrate, circuits that were hardened under the Distribution Overhead Feeder Hardening program have experienced a 33 percent improvement in SAIDI and a 44 percent improvement in MAIFIe in "blue sky" conditions.

PROCESS TO DEVELOP TAMPA ELECTRIC'S PROPOSED 2026-2035 SPP

Q. How did Tampa Electric develop the company's proposed 2026-2035 SPP?

A. Tampa Electric's 2026-2035 proposed SPP builds on the successes of the company's prior two SPPs and incorporates lessons learned from implementation of those two plans. The company's proposed 2026-2035 SPP is largely a continuation of the 2022-2031 SPP and includes seven programs that are carried over from the previous plan with the addition of two new proposed programs, Transmission Switch Hardening and Distribution Storm Surge Hardening. The company’s proposed 2026-2035 SPP programs are:

(1) Distribution Lateral Undergrounding
(2) Vegetation Management
(3) Transmission Asset Upgrades
(4) Substation Extreme Weather Hardening
(5) Distribution Overhead Feeder Hardening
(6) Infrastructure Inspections
(7) Legacy Storm Hardening Initiatives
(8) Transmission Switch Hardening
(9) Distribution Storm Surge Hardening

Q. Please describe the new Transmission Switch Hardening Program.

A. During Hurricane Milton in October 2024, 55 of the company’s transmission circuits experienced a fault causing the circuit to lock-out. When a fault occurs and a circuit is locked out, the company uses a process known as switching to section off portions of the transmission system to perform equipment maintenance or isolate trouble spots to minimize impacts to customers. Of those 55 circuits, 27 had Gang Operated Air Break (“GOAB”) switches. GOAB switches require a technician to go to the site and manually operate the switch.

The Transmission Switch Hardening Program is a four-year initiative to upgrade 250 transmission switch locations with modern switches enabled with Supervisory Control and Data Acquisition ("SCADA") communication and remote-control capabilities. Operating these switches from a control center and avoiding sending technicians to the switch sites will allow for faster isolation of trouble spots on the transmission system and more rapid restoration following line faults, thereby increasing the resiliency of the transmission system. Additional information regarding this Program is provided in Tampa Electric's proposed 2026-2035 Plan.

Q. Please describe the new Distribution Storm Surge Hardening Program.

A. Tampa Electric has approximately 520 pad-mounted live front distribution switchgears and 12,000 pad-mounted transformers located in flood evacuation zones A, B, and C. Distribution switchgears serve as the primary junction point for the underground distribution system, and each switchgear is capable of serving hundreds of homes. During

Hurricanes Helene and Milton, Tampa Electric experienced failure of 13 switchgears and 185 transformers due to storm surge. The Distribution Storm Surge Hardening program will upgrade the live front switchgear in flood zones A through C to a submersible/water-resistant unit and replace the secondary bushings on pad-mounted transformers with an insulated water-resistant unit. This work will make this vital equipment more resistant to water intrusion, which will mitigate the need for complete and more costly replacement of these units which, in turn, will reduce restoration costs and reduce outage time. Additional information regarding this Program is provided in Tampa Electric's proposed 2026-2035 Plan.

Q. How will Tampa Electric prioritize projects for the programs in the proposed 2026-2035 SPP?

A. For the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Distribution Overhead Feeder Hardening, and Substation Extreme Weather Programs, 1898 & Co.'s modeling techniques provided a quantitative analysis of the expected benefits for potential SPP projects, including expected benefits in terms of avoided restoration costs, avoided customer outages, and monetization of avoided customer outages. The evaluated projects are then ranked based on their cost benefit Net Present Value ("NPV") ratios. This process is further described by Mr. De Stigter in his direct testimony. Tampa Electric used the results of the prioritization model as a tool to select projects and set program funding levels.

For the Vegetation Management Program, Tampa Electric worked with Accenture to analyze and compare full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather events, as well as overall service reliability. The Vegetation Management Program is based on this analysis, as described in greater detail in the company's proposed 2026-2035 SPP.

Tampa Electric analyzed and prioritized the two new programs internally. The Transmission Switch Hardening Program grouped projects at the circuit level and prioritized projects based on the system voltage. Prioritization began with the 69kV system due to the volume of targeted switches being at this voltage. The Distribution Storm Surge Hardening program grouped projects at the circuit level and prioritized projects based on evacuation zone, with evacuation zone A given highest priority.

For all of the SPP programs, Tampa Electric considered other factors such as execution constraints, ease of construction, start-up and ramp-up rates, and customer bill impacts to finalize the prioritization.

Q. Did the company incorporate any lessons learned from executing the prior two SPPs into the development of the proposed 2026-2035 SPP?

A. Yes. The most significant lesson learned from executing the prior two SPPs, that is being incorporated in the company's proposed 2026-2035 SPP, is updating the Lateral Undergrounding Program to a circuit-based approach. While reviewing the undergrounding projects completed from 2020 to 2023, the company noticed the larger projects tended to have a lower cost per mile. This was attributed to the reduction of one-time costs such as mobilization and demobilization of resources. By grouping underground projects by circuit, and targeting all laterals on a circuit for undergrounding, the company’s 2026-2035 SPP will be able to deploy resources in a more concentrated area and take advantage of these efficiencies to reduce costs.

Q. You previously mentioned that Tampa Electric’s experiences with recent storms influenced the development of this SPP.

Can you describe the impact of those storms on Tampa Electric's proposed 2026-2035 SPP?

A. Yes. The impacts of Hurricanes Helene and Milton affected the development of the company's proposed 2026-2035 SPP in several ways. First, as I previously explained, the company is proposing two new programs to address issues the company faced during those storms. Second, Tampa Electric modified the Substation Extreme Weather program based on impacts experienced during Hurricanes Helene and Milton. During these hurricanes, several of Tampa Electric's substations sustained damage and saltwater intrusion occurred at facilities such as Port Sutton, Double Branch, and Jackson Road. This intrusion damaged 17 circuit breakers (13kV) at Port Sutton and Jackson Road substations and flooded junction boxes and cabinets at the Double Branch substation. Based on this first-hand experience, the company determined that it should proceed with hardening all 24 substations evaluated as a part of Tampa Electric's proposed 2026-2035 SPP.

Q. Did the company consider any changes to the Vegetation Management programs?

A. Yes, Tampa Electric and Accenture completed an updated analysis of the company’s Vegetation Management Program. Based on this analysis, the company is proposing to modify the expected mileage in both the Supplemental Initiative and the Mid-Cycle Initiative. The updated analysis shows that these changes will result in greater benefits from increased tree removals. Additional information regarding this Program is provided in Tampa Electric’s proposed 2026-2035 Plan.

Q. Did the company consider the potential rate impacts of Tampa Electric’s proposed 2026-2035 SPP during the plan development process?

A. Yes, the company considered the potential rate impacts during the early development phase of the SPP in the summer of 2023.

Q. Based on the estimated rate impacts, did you consider any changes to Tampa Electric’s proposed 2026-2035 SPP?

A. No. While the company does review and consider rate impacts during the development of the SPP, the company believes Tampa Electric’s proposed 2026-2035 SPP programs will continue to deliver storm resilience and “blue-sky” reliability benefits. The company will continue to prioritize projects based in part on their expected costs and benefits and will actively manage costs and continue to look for cost-saving opportunities.

Compliance with Section 366.96 and Rule 25-6.030, F.A.C.

Q. Section 366.96(4)(a) of the Florida Statutes requires the Commission to consider the extent to which a proposed SPP is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability, including whether the plan prioritizes areas of lower reliability performance. Is Tampa Electric’s 2026-2035 proposed SPP designed to accomplish this goal?

A. Yes. The programs selected for inclusion in the company’s proposed 2026-2035 SPP are designed to reduce restoration costs and outage times. The company’s prioritization process, which is described in both my and Mr. De Stigter’s testimony and exhibits, prioritizes areas that are expected to have lower reliability performance in extreme weather conditions.

Q. Section 366.96(4)(b) of the Florida Statutes requires the Commission to consider the extent to which storm protection of transmission and distribution infrastructure is feasible, reasonable, or practical in certain areas of the utility's service territory, including, but not limited to, flood zones and rural areas. Did Tampa Electric carry out this evaluation in preparing its proposed 2026-2035 SPP?

A. Yes. Tampa Electric performed this evaluation and determined that all components of the transmission and distribution system can be hardened to achieve resiliency benefits. Tampa Electric also believes that all customers should benefit from storm protection investments. The company has, however, prioritized hardening those system components that offer the greatest projected benefits for the associated cost.

Q. Section 366.96(4)(c) of the Florida Statutes requires the Commission to consider the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan. Did Tampa Electric present these estimated costs and benefits in Tampa Electric's proposed 2026-2035 SPP?

A. Yes. The company's proposed 2026-2035 SPP and the analysis performed by 1898 & Co. include these estimated costs and benefits.

Q. Section 366.96(4)(d) of the Florida Statutes requires the

Commission to consider the estimated annual rate impact resulting from implementation of the plan during the first three years addressed in the plan. Did Tampa Electric present this information in the proposed 2026-2035 SPP?

A. Yes. The company's proposed 2026-2035 SPP includes the estimated annual rate impact resulting from implementation of the plan during the first three years addressed in the plan. The process for preparing these estimated annual rate impacts is explained further in the direct testimony of A. Sloan Lewis.

Q. Does Tampa Electric's proposed 2026-2035 SPP include all the elements required by Rule 25-6.030(3), F.A.C.?

A. Yes. The table below shows where each category of required information is located within the company's proposed 2026-2035 SPP.

Tampa Electric's 2026-2035 Storm Protection Plan Adherence to Rule 25-6.030 F.A.C.	
Required Contents of Plan	**Section of the Storm Protection Plan**
25-6.030(3)(a)-(b)	Section 2 - SPP Overview
25-6.030(3)(c)	Section 1 - Tampa Electric's Service Area
25-6.030(3)(d)1-4	Section 4 – Storm Protection Programs
25-6.030(3)(d)5	Section 2 – SPP Overview
25-6.030(3)(e)	Section 4 – Storm Protection Programs
25-6.030(3)(f)	Section 4.2 – Vegetation Management
25-6.030(3)(g)	Section 5 – Projected Costs and Benefits
25-6.030(3)(h)	Section 6 – Estimated Rate Impacts
25-6.030(3)(i)	Section 7 – Alternatives and Considerations
25-6.030(3)(j)	N/A (optional)

SUMMARY

Q. Please summarize your direct testimony.

A. My testimony and the direct testimonies of Jason D. De Stigter and A. Sloan Lewis, and the accompanying exhibits, present and support Tampa Electric's proposed 2026-2035 SPP. This SPP was developed in a manner consistent with the requirements of Section 366.96, Florida Statutes, and the implementing Rule 25-6.030, F.A.C., adopted by the

Commission.

Q. Should Tampa Electric’s proposed 2026-2035 SPP be approved?

A. Yes. Tampa Electric’s proposed 2026-2035 SPP should be approved. The Plan contains all of the required contents set out in Rule 25-6.030, F.A.C. The Plan will also build on the achievements under the company’s 2022-2031 SPP and from the prior Storm Hardening Plans and initiatives that were established by this Commission in 2007. Finally, the Plan will continue to forward the company’s existing hardening efforts to achieve the objectives of Section 366.96(3) of the Florida Statutes.

Q. Does this conclude your testimony?

A. Yes.

Tampa Electric's 2026–2035 Storm Protection Plan

Filed: January 15, 2025

Tampa Electric's
2026-2035 Storm Protection Plan Summary

Tampa Electric's 2026-2035 Storm Protection Plan ("SPP") describes the company's comprehensive approach to protect and strengthen its electric utility infrastructure to withstand extreme weather conditions as well as to reduce restoration costs and outage times in a practical and cost-effective manner. Protecting and strengthening Tampa Electric's transmission and distribution electric utility infrastructure against extreme weather conditions can effectively reduce restoration costs and outage times and improve overall service reliability for customers.

Tampa Electric's proposed 2026-2035 SPP will be its third ten-year protection plan filed to comply with Rule 25-6.030, Florida Administrative Code ("F.A.C.") ("the SPP Rule"), which requires utilities to file storm protection plans. This SPP is largely a continuation of the company's first and second Florida Public Service Commission ("Commission") approved SPPs and includes the continuation of seven Storm Protection Programs ("Programs"). In addition, this plan also includes two new programs, Transmission Switch Hardening and Distribution Storm Surge Hardening; and slight modifications to some of the existing Programs to address lessons learned from implementation of the prior two SPPs and from the recent Hurricanes Helene and Milton. This SPP also incorporates the continuation of legacy Storm Hardening Plan Initiatives and wood pole inspections that predate the adoption of the SPP Rule. The proposed 2026-2035 SPP contains all contents and elements required by the SPP Rule.

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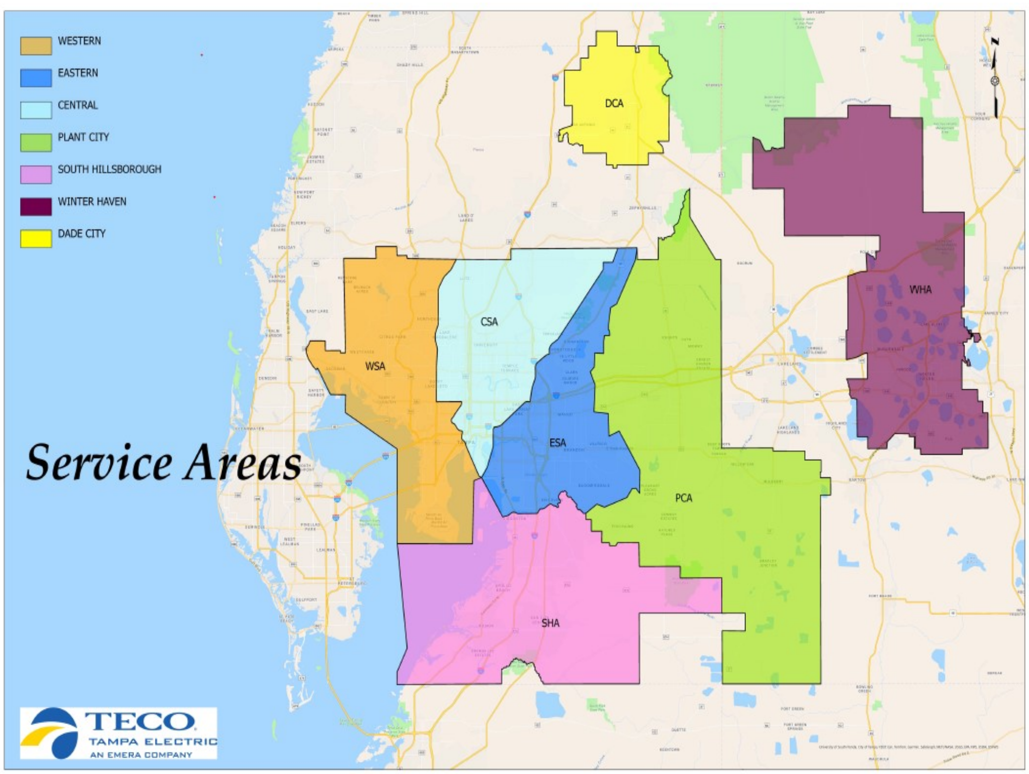
APPENDICES

1. Tampa Electric's Service Area

Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties as shown in the figure below. The company's service area is divided into service areas for operational and administrative purposes. Tampa Electric provides service to 869,995 retail electric customers as of December 31, 2024. The customers served in the seven service areas are as follows.

	Customer Count
Western Service Area "WSA"	219,415
Eastern Service Area "ESA"	136,599
Central Service Area "CSA"	222,973
Plant City Area "PCA"	67,754
South Hillsborough Area "SHA"	114,875
Winter Haven Area "WHA"	90,430
Dade City Area "DCA"	17,949



Tampa Electric's transmission system consists of 1,362 circuit miles of overhead facilities, including 25,198 transmission poles and structures and also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,053 circuit miles of overhead facilities and 427,916 poles. The company currently has approximately 6,805 circuit miles of underground distribution facilities, 218 transmission and distribution substations and approximately 311,464 authorized joint user attachments on the company's transmission and distribution poles.

Tampa Electric developed the proposed 2026-2035 SPP and its supporting Programs and initiatives by examining the company's entire service area for the most cost-effective storm hardening opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities from the storm hardening evaluation due to concerns regarding the feasibility, reasonableness, or practicality of storm hardening.

2. Storm Protection Plan Overview

Tampa Electric's proposed 2026-2035 SPP describes the company's systematic and comprehensive approach to storm protection focused on those Programs and Projects that provide the highest level of reliability and resiliency benefits for the lowest relative cost. The company believes that these activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability," as set out in Section 366.96 of the Florida Statutes, in a cost-efficient manner.

Tampa Electric's proposed 2026-2035 SPP is largely a continuation of the company's prior two Commission-approved SPPs.

To develop this SPP, Tampa Electric engaged 1898 & Co. to perform

Project prioritization and benefits calculations for the following existing SPP Programs.

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening

Tampa Electric and 1898 & Co. use a resilience-based planning approach to identify hardening Projects and prioritize investment in the transmission and distribution ("T&D") system using 1898 & Co's Storm Resilience Model. The Storm Resilience Model simulates the benefits of all potential hardening Projects for an accurate comparison across the system. The resilience-based planning approach calculates the benefits of storm hardening Projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, Program, and Project level. The results of the Storm Resilience Model are:

1. Decrease in storm restoration costs
2. Decrease in the number of customers impacted
3. Decrease in the duration of the overall customer outage, calculated as Customer Minutes of Interruption ("CMI")

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefits of the proposed plan. An overview of the Storm Resilience Model used to calculate the Project benefit and prioritize Projects is included in Tampa Electric's Storm Protection Plan Resilience Benefits Report in Appendix "I."

The Storm Resilience Model starts with the "universe" of major storm events that could impact the company's service area, which is called the "Major Storm Events Database." This database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios. Each storm scenario was then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure ("LOF") was based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone in which the asset is located. The Storm Impact Model also estimated the restoration costs, CMI, and calculated the benefit in decreased restoration costs if that Project is hardened per the company's hardening standards. The CMI benefit was monetized using the DOE's Interruption Cost Estimator ("ICE") for Project prioritization purposes.

The benefits of storm hardening Projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (i.e., Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employed stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types of storm events to impact Tampa Electric's service area over the next 50 years. The probability of each storm scenario was multiplied by the benefits calculated for each Project from the Storm Impact Model to provide a resilience weighted cost benefit for each Project. The resilience benefit calculation for Distribution Overhead Feeder Hardening Projects employs a different methodology due to the data available to calculate benefits. These projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

The Budget Optimization and Project Scheduling model prioritized the Projects based on the highest resilience benefit cost ratio. The model prioritized each Project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the Project cost. The model performed this analysis for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric's technical and operational constraints, such as transmission outages, contractor capacity, permitting, and assets that are not roadway accessible.

This resilience-based prioritization facilitates the identification of the hardening Projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers receive the largest return on investment.

Tampa Electric performed its own in-house analysis of the potential costs and benefits and prioritization of projects that were not evaluated by 1898. These include the legacy program Storm Hardening Plan Initiatives, and the two newly proposed programs included in this SPP, Transmission Switch Hardening and Distribution Storm Surge Hardening.

In addition to these cost-benefit analyses, Tampa Electric considered the practical realities of program implementation, such as growing and sustaining an external workforce to support the SPP, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the 1898 modeling tool to develop the final set of Programs, Program funding and ultimately the individual Project selection.

Finally, the company used the analyses provided by 1898 & Co. as a basis for establishing the spending levels for the programs analyzed by 1898 & Co. in the proposed 2026-2035 SPP. This information was used in conjunction with technical and operational constraints to renew the selection of Storm Protection Programs, Program funding levels and Project selection and prioritization.

Based on this SPP development process and the company's experience with the prior two SPPs, Tampa Electric is confident that the company's proposed 2026-2035 SPP will continue to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission as set out in Section 366.96 of the Florida Statutes.

3. Experience with Major Storm Events

Tampa Electric has significant experience preparing for, responding to, performing restoration, and assisting other utilities in recovery from major storm events. The company's response to major storms that have impacted Tampa Electric's service area and the mutual assistance trips to provide aid to other utilities have given Tampa Electric's restoration team opportunities to gain valuable restoration knowledge and experience in restoring service after a major storm event. This knowledge includes the importance of conducting damage assessment immediately after the storm has passed and providing customers with an accurate Estimated Time of Restoration ("ETR"). In addition to restoration experience, Hurricanes and tropical storms that have affected Tampa Electric's service area have further exposed how vulnerable coastal regions are to the damaging effects of storm surge and the significant effort required to restore a system that has been impacted by coastal flooding. The company discussed, analyzed, and applied these experiences to improve Tampa Electric's storm response plan.

The following table provides the details of named storms affecting Tampa Electric's service area since 1960.

Table 1: Named Storms Affecting Tampa Electric Service Area since 1960		
Year	**Storm Name**	**Size** [1]
1960	Donna	Cat 3
1995	Erin	TS
2004	Charley	Cat 2
2004	Francis	Cat 1
2004	Jeanne	Cat 1
2005	Dennis	TS
2005	Wilma	TS
2006	Alberto	TS
2007	Barry	TS
2012	Debby	TS
2012	Isaac	TS
2013	Andrea	TS
2015	Erika	TS
2016	Colin	TS
2016	Hermine	Cat 1
2016	Matthew	TS
2017	Emily	TS
2017	Irma	Cat 1
2018	Alberto	TS
2019	Nestor	TS
2021	Elsa	TS
2022	Ian	TS
2023	Idalia	TS
2024	Debby	TS
2024	Helene	Cat 3
2024	Milton	Cat 3

Note 1: Maximum category when the storm passed by or through the Tampa Electric service area.

4. Storm Protection Plan Programs

The Programs contained in Tampa Electric's proposed 2026-2035 SPP are designed with the primary objective of enhancing the resiliency and reliability of its transmission and distribution system during extreme weather events. The SPP will also improve overall service reliability for customers in "blue sky" conditions. This SPP will focus on hardening the entire circuit for both feeder hardening and lateral underground programs as needed. Going forward, reliability metrics for these circuits will be readily available for "gray sky" days as well as "blue sky" days offering operational comparisons before and after circuit upgrades. Over the next ten years, Tampa Electric will build upon the success of its prior two SPPs to materially improve resiliency through targeted investments in nine Storm Protection Plan programs: (1)Distribution Lateral Undergrounding; (2)Vegetation Management; (3)Transmission Asset Upgrades; (4)Substation Extreme Weather Hardening; (5)Distribution Overhead Feeder Hardening; (6)Infrastructure Inspections; (7)Legacy Storm Hardening Initiatives, (8) Transmission Switch Hardening; and (9) and Distribution Storm Surge Hardening. These Programs will minimize the impact of severe weather by hardening Tampa Electric's infrastructure and will continue to collectively achieve the goals, objectives, and requirements of the Florida Legislature and the Commission.

4.1 Distribution Lateral Undergrounding

Through the Distribution Lateral Undergrounding Program, Tampa Electric will continue to strategically underground existing overhead lateral primary, lateral secondary, and service lines. The expected benefits from this Program are:

- Reducing the number and severity of customer outages during extreme weather events;
- Reducing the amount of system damage during extreme weather;
- Reducing the material and manpower resources needed to respond to extreme weather events;
- Reducing the number of customer complaints through the reduction in outages during extreme weather events; and
- Reducing restoration costs following extreme weather events.

In addition to the many benefits that should be realized from distribution lateral undergrounding during extreme weather events, it will also provide additional "blue-sky" benefits such as:

- Reducing the number of momentary and prolonged unplanned outages;
- Reducing the number of customer complaints from outages; and
- Improving customer reliability and power quality.

The key metrics for Tampa Electric's Distribution System are:

- Total Circuit Miles: 12,858
- Total Overhead Miles: 6,053 (47%)
- Total Underground Miles: 6,805 (53%)
- Total Overhead Lateral Miles: 4,197
- Total Overhead Feeder Miles: 1,856
- Total Underground Lateral Miles: 6,043
- Total Underground Feeder Miles: 761
- Customers served off Laterals: 95%
- Customers served off Feeders: 5%

Tampa Electric's customers were substantially impacted by Hurricanes Irma (2017), Ian (2022), Helene (2024) and Milton (2024). The following table reflects Tampa Electric's distribution system Overhead versus Underground percentage of outage comparisons across "day-to-day," Major Event Days, and these recent Hurricanes.

Tampa Electric's Distribution System
Overhead versus Underground
Outage Comparison (in Percent)

	Distribution System	Day-to-Day Outages	Major Event Day Outages	Irma Outages	Ian Outages	Helene Outages
Overhead	47	81	96	100	97	89
Underground	53	19	4	0	3	11

Note: Outage data for Hurricane Milton was not available at the time of this filing.

These metrics demonstrate that the underground system is proving to be much stronger and more resilient during extreme weather events, as evidenced by the reduction in outages due to the work of this Program. This Program is also expected to provide similar reliability improvements and restoration benefits (time and costs) during normal day-to-day operations and summer thunderstorm events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years.

Tampa Electric used the 1898 & Co. model output to identify the individual Projects, prioritize these Projects and optimize the 10-year funding levels for Distribution Lateral Undergrounding Program. The model demonstrated that this Program's undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. The table of identified detailed Projects is included in Appendix "C."

One significant component of the SPP that was changed for this proposed SPP is the way laterals are now being grouped for prioritization. In the company's original 2020-2029 SPP, lateral line segments were prioritized between protection devices. In the company's 2022-2031 SPP, the laterals were grouped based upon the entire lateral downstream of the protection device. When reviewing costs for completed projects, the company noted that the cost per mile for the project was lower for the larger projects (of at least one mile). By grouping all the laterals on a feeder circuit, Tampa Electric will take advantage of these economies of scale as well as efficiencies of having operational resources concentrated in an area. Therefore, in this proposed 2026-2035 SPP, the company is moving to a circuit-based approach.

For the proposed 2026-2035 SPP, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The following table shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	131	$124.2
2027	90	$121.9
2028	50	$125.1

The full detail of the supporting Distribution Lateral Undergrounding individual Projects, as required by Rule 25-6.030(3)(d)1-5, is included as Appendix "C".

4.2 Vegetation Management

Tampa Electric's Vegetation Management Program ("VMP") is comprised of five initiatives, including Distribution Vegetation Management Four-Year Cycle, Reactive Vegetation Management, Transmission Vegetation Management, Supplemental Distribution Circuit Vegetation Management, and Mid-Cycle Distribution Vegetation Management. These are the same five VMP initiatives included in the company's prior SPPs, with a modification to the Supplemental Distribution Circuit Vegetation Management and Mid-Cycle Distribution Vegetation Management Initiatives. Tampa Electric partnered with Accenture to analyze various Initiatives. Accenture updated its existing vegetation management ("VM") software to include the company's most recent outage, cost, and trim data, and to add functionality to estimate the value derived from activities that address only part of a circuit at a time. Tampa Electric and Accenture then analyzed and compared full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather events, as well as overall service reliability. Based on this updated analysis, Tampa Electric is proposing to continue the five existing VMP initiatives. The 69 kV VM Reclamation Initiative that was included in the company's previous SPP filings was completed and as a result not included in this proposed 2026-2035

SPP. The updated analysis is included in Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report in Appendix "J."

4.2.1 Vegetation Management Initiatives

Distribution Vegetation Management Four-Year Cycle

Tampa Electric currently trims the company's distribution system on a four-year cycle. This approach was originally approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012, and approved again through the company's prior two SPPs. The four-year cycle is flexible enough to allow the company to change circuit prioritization utilizing the company's reliability-based methodology. Tampa Electric has partnered with a third-party consultant, Accenture, and used their proprietary VM software application. The software is used to analyze multi-year circuit performance data, trim cycles, and corrective and restoration costs to generate a priority list for circuit trimming for the four-year distribution trimming cycle. The software also optimizes circuit selection in terms of both reliability and cost-effectiveness.

Reactive Vegetation Management

The company's Reactive Vegetation Management Initiative provides support for internal and external customer requests. Customer requested work, work orders associated with circuit improvement processes, and outage restoration support are the primary categories of reactive work. Reactive work is managed and tracked via the company's work management software.

Transmission Vegetation Management

The company also adheres to a comprehensive vegetation management strategy for its transmission system. The company operates four categories of transmission lines 230kV, 138kV, 69kV, and 34kV. For circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission ("FERC") standard FAC-003-5.

This standard imposes performance-based, risk-based, and competency-based requirements for vegetation management on these circuits. The company imposes a two-year vegetation management cycle for 138kV circuits, and a three-year cycle for 69kV and 34kV circuits. The company's vegetation management strategy for its transmission system also includes the maintenance of the transmission rights of way ("ROW").

Supplemental Distribution Circuit Vegetation Management

Tampa Electric and Accenture evaluated the costs and benefits of enhancing the four-year distribution VM cycle by trimming additional miles each year to reduce the proximity between vegetation and electrical facilities. The team determined the cost of supplemental trimming would be justified by significant benefits including: (1) decreases in storm restoration costs; (2) decreases in corrective maintenance costs and day-to-day outage restoration costs; (3) improvements in day-to-day reliability; and (4) a reduction in the cost of the baseline four-year trim cycle. Accenture analyzed multiple annual mileage increment scenarios. The analysis showed that each incremental increase in trimming will yield the above-described benefits, but these benefits eventually hit a point of diminishing returns. Accenture ultimately recommended a modification of the currently approved level of 700 supplemental miles to 500 supplemental miles which would provide the greatest benefits for the estimated cost.

Circuit prioritization and selection will be centered around storm resiliency and mitigating outage risk on those circuits most susceptible to storm damage. Accenture's VM software will generate annual circuit trim lists by emphasizing storm resiliency. The Supplemental Circuit VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed in the following table.

Supplemental Distribution Circuit VM by Service Area						
	2026		2027		2028	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	53	12,162	109	17,007	111	21,523
Dade City	7	784	97	2,547	88	3,027
Eastern	95	20,532	56	6,126	77	14,464
Plant City	150	4,617	24	2,335	74	6,676
South Hillsborough	13	3,142	14	3,602	44	12,579
Western	22	4,437	21	4,361	89	18,527
Winter Haven	158	11,754	178	3,306	18	2,453
Total	498	57,428	499	39,284	501	79,249

The total Supplemental Distribution Circuit VM initiative costs for the proposed 2026-2035 SPP are detailed in the following table.

Supplemental Distribution Circuit VM Costs (in thousands)	
2026	$5,000
2027	$4,500
2028	$6,400
2029	$5,800
2030	$6,600
2031	$5,700
2032	$8,200
2033	$6,000
2034	$6,400
2035	$6,800

Mid-Cycle Distribution Vegetation Management

Tampa Electric’s experience has been that vegetation cannot be effectively maintained within the four-year distribution VM cycle due to its rapid growth rate. For instance, the company projects that up to 25% of trees exhibit growth rates that necessitate additional trimming before the next scheduled maintenance cycle. Additionally, some trees develop into a threat to distribution facilities due to an evident defect or have a high risk of potential failure, known as hazard trees. Furthermore, fall-in trees were determined to be a major damage factor in recent storms. The current four-year cycle has limited tree removal potential due to customer permission and permitting constraints.

The Mid-Cycle Distribution VM initiative is inspection-based and designed to identify and selectively mitigate fast-growing vegetation and hazard trees. Tampa Electric and Accenture's analysis showed that this initiative will lead to reductions in both extreme weather outages and restoration costs as well as day-to-day outage costs. Accenture ultimately recommended a modification of the currently approved level of 1,000 mid-cycle miles to 1,200 mid-cycle miles as it would provide the greatest benefits for the estimated cost. The Mid-Cycle VM initiative schedule by Tampa Electric's Service Area, by affected miles and customers is detailed in the following table.

Mid-Cycle Distribution VM by Service Area						
	2026		2027		2028	
Service Area	**Miles**	**Customers**	**Miles**	**Customers**	**Miles**	**Customers**
Central	285	60,034	254	43,977	88	15,824
Dade City	0	0	81	2,243	189	6,934
Eastern	308	46,321	247	45,991	101	18,355
Plant City	118	5,962	73	5,901	277	12,137
South Hillsborough	191	21,785	50	13,263	137	29,417
Western	148	39,014	147	24,686	92	24,003
Winter Haven	352	20,523	266	36,507	175	12,365
Total	1,402	193,639	1,118	172,568	1,059	119,035

The total Mid-Cycle Distribution VM initiative costs for the proposed 2026-2035 SPP are detailed in the following table.

Mid-Cycle Distribution VM Costs (in thousands)	
2026	$6,800
2027	$7,600
2028	$4,200
2029	$4,800
2030	$4,700
2031	$7,100
2032	$6,600
2033	$8,100
2034	$7,800
2035	$8,300

4.2.2 Estimated Costs – Vegetation Management Programs

Tampa Electric and Accenture estimated that, in total, approximately 270 VM contract trimmers and six contract forestry inspectors were needed for all distribution VM initiatives and an additional 40 VM contract trimmers were needed for the transmission VM initiative.

The following table provides the 2026 through 2028 annual VMP costs.

	Tampa Electric's Vegetation Management Program Projected Costs (in thousands)		
	2026	2027	2028
Distribution VM Four-Year Cycle	$13,300	$14,200	$15,600
Reactive VM	$900	$1,000	$1,000
Transmission VM	$4,000	$4,200	$4,500
Supplemental Distribution Circuit VM	$5,000	$4,500	$6,400
Mid-Cycle Distribution VM	$6,800	$7,600	$4,200
Total	$30,000	$31,500	$31,700

4.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program will systematically and proactively replace all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of the proposed 2026-2035 SPP. Tampa Electric has approximately 25,000 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 9.7% are supported with wood poles. From 2020 through 2024, the company replaced over 2,000 wood transmission structures with non-wood material as a part of the 2022-2031 SPP.

The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. To illustrate, out of the 28 transmission poles replaced due to Hurricane Milton in 2024, 26 were wood poles; one concrete pole and one aluminum H-frame were not a part of the SPP initiative.

Tampa Electric used 1898 & Co.'s resilience-based modeling to develop the prioritization of Projects. This prioritization is based on the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. The prioritization and scheduling for the Transmission Asset Upgrades is a continuation of the 2022-2031 SPP, with the addition of internal review for feasibility due to technical and operational constraints, such as access and the long lead time for permits.

The following table shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	11	$18.0
2027	14	$17.4
2028	10	$17.4

Project = Circuit

The full detail of the supporting Transmission Asset Upgrades Projects, as required by Rule 25-6.030(3)(d)1-5, is included as Appendix "D."

4.4 Transmission Switch Hardening

During Hurricane Milton in October 2024, 55 of the company's transmission circuits experienced a lock-out. Of those 55 circuits, 27 had Gang Operated Air Break ("GOAB") switches which require a technician to go to the site and manually operate the switch. This necessary activity is known as switching. Switching is used to section portions of the transmission system to perform equipment maintenance, reroute power from substation to substation or isolate trouble spots to minimize impacts to customers.

Tampa Electric has approximately 250 GOAB switches on its transmission system. Based on the company's experience with Hurricane Milton, Tampa Electric is proposing the replacement of the GOAB switches with automated, remotely controlled switches that will greatly improve isolation and restoration times following extreme weather events. The Transmission Switch Hardening Program is a four-year initiative that aims to upgrade 250 switch locations with modern switches enabled with Supervisory Control and Data Acquisition("SCADA") communication and remote-control capabilities. This upgrade will allow for switches to be operated from a control center and avoid sending a technician to a site to operate the switch. This will allow for faster isolation of trouble spots on the transmission system and more rapid restoration following line faults, thereby increasing the resiliency of the transmission system.

The following table shows the Transmission Switch Hardening Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Transmission Switch Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	0	$0.0
2027	0	$0.0
2028	18	$0.3

Project = Circuit

4.5 Substation Extreme Weather Hardening

Tampa Electric's Substation Extreme Weather Hardening Program is designed to harden existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events. Hardening Projects within this Program may involve the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications, or relocation of substation equipment; modification to the designs of the company's substations; or other approaches identified to protect against extreme weather damage in or around the company's substations.

Tampa Electric selected and prioritized the list of substation projects by first identifying 24 substations located on or near the coast of Tampa Bay. These substations are in low-elevation areas and are a mix of both transmission and distribution stations. The greatest risk to these substations is from water intrusion due to storm surge into the substation control houses and equipment. As a part of the development of Tampa Electric's 2022-2031 SPP, the company commissioned an engineering study for these 24 substations that produced the company's initial prioritization.

During Hurricanes Helene and Milton, several of Tampa Electric's substations sustained damage. Saltwater intrusion occurred at facilities such as Port Sutton, Double Branch, and Jackson Road. This intrusion damaged 17 circuit breakers (13kV) at Port Sutton and Jackson Road substations and flooded junction boxes and cabinets at the Double Branch substation. Based on this experience, the company determined that it should proceed with hardening all 24 substations evaluated as a part of the proposed 2026-2035 SPP.

The images below depict the flooding at the Port Sutton and Double Branch Substations.

The following table shows the Substation Extreme Weather Hardening Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	5	$7.9
2027	2	$7.2
2028	1	$2.7

Project = Substation

The full detail of the supporting Substation Extreme Weather Hardening individual Projects, as required by Rule 25-6.030(3)(d)1-5, is included as Appendix "F".

4.6 Distribution Overhead Feeder Hardening

Tampa Electric's Distribution Overhead Feeder Hardening Program will strengthen the company’s distribution system to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events. This Program will allow the company to reconfigure the electrical system to minimize the number of customers experiencing prolonged outages that may occur because of un-forecasted system conditions and unplanned circuit outages. The Distribution Overhead Feeder Hardening Program will focus on increasing the resiliency and sectionalizing capabilities of the distribution electrical system to better withstand extreme weather and minimize outages, outage durations and affected customer counts through two primary enhancements: Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

4.6.1 Distribution Feeder Strengthening

These enhancements will incorporate changes to the company’s distribution design standards to focus on the physical strength of Tampa Electric’s distribution infrastructure. The company is hardening selected feeders to meet NESC construction Grade B criteria with the Rule 250C (Extreme Wind) loading and strength criteria applied. This will involve the evaluation of the feeder, including a thorough review of the poles, conductor, and equipment to determine the upgrades necessary to ensure the feeder meets new hardened design and construction standards. While overhead hardening remains the primary standard, there are rare instances where engineering and design constraints require the company to convert limited feeder sections to underground. These include areas with dense vegetation, limited clearance to buildings, limited access, and/or where public safety makes replacing overhead facilities not feasible.

4.6.2 Distribution Feeder Sectionalizing and Automation

These enhancements involve increasing the installation of automation equipment, reclosers, trip savers and other supporting sectionalizing infrastructure on existing distribution circuits. These devices provide many benefits that will improve the performance of the distribution system during extreme weather events such as:

- Allowing for the automatic transfer of load to neighboring feeders in the event of unplanned outages that can occur during both normal and extreme weather events;
- Allowing for the network to be re-configured automatically to minimize the number of customers experiencing prolonged outages during both normal and extreme weather events; and
- Reducing restoration time by isolating only those parts of the electrical system that contain faults that require assessment, investigation, follow-up, and repair.

Upgrading the conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgrading additional transformer capacity at strategic substations will ensure maximum load restoration capacity. Combined, these design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Tampa Electric has approximately 800 distribution circuits, which were prioritized based on the 1898 & Co. model. Prioritized circuits are evaluated individually to identify improvements on each circuit that would result in increased sectionalizing of the system with the following measures:

- Target a 200-500 maximum customer range on each segment;
- Limit segment distance to two to three miles; and
- Limit serving between two to three MW of load on each segment.

In Tampa Electric's 2022-2031 SPP the company proposed to add three applications to the Overhead Feeder Hardening Program that would allow the company to use the data coming from the company's advanced metering infrastructure system ("AMI") to prevent outages during extreme weather events, reduce the length of outages during extreme weather events, and reduce the amount spent on extreme weather restoration. The three applications include:

Locational Awareness: determines the electrical connectivity above the meter within the distribution grid and provides the ability to accurately assess the connectivity of the system, from the meter to the transformer, transformer to the feeder, and the phase connectivity which will increase the opportunity for quicker restoration during extreme weather events.

Vegetation Contact Detection: identifies feeder sections that have repeated vegetation contact, indicating that vegetation management should be prioritized to those areas to minimize customer interruptions, and the likelihood of damage caused by vegetation during extreme weather events.

Storm Mode: is a mechanism for maximizing outage and restoration reporting performance during widescale outages by minimizing and prioritizing outage and restoration messages. Storm mode provides a faster and more accurate indication of feeder and feeder section energization state during widescale outages.

Tampa Electric has had success with the initial phase of the Locational Awareness application. The company successfully tested the meter to transformer detection, meter to phase detection and transformer to feeder or substation detection features. Tampa Electric has now moved to the next phase of implementation, which is to integrate this data into Tampa Electric’s systems to facilitate the full functionality of the application.

Tampa Electric has not begun implementation of the Vegetation Contact Detection and Storm Mode applications. Before work could begin, the vendors required a commitment to license the application prior to development and which required next generation meters to enable the application to function. Tampa Electric has decided not to move forward with Vegetation Contact Detection or Storm Mode application and therefore has not included any costs in the proposed 2026-2035 SPP for these applications. Tampa Electric will continue to evaluate other technologies that could provide "vegetation contact detection" to identify and prioritize areas prone to contact.

The following table shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	94	$26.3
2027	90	$29.2
2028	76	$30.6

Project = Circuit

The full detail of the supporting Distribution Overhead Feeder Hardening individual Projects, as required by Rule 25-6.030(3)(d)1-5, is included as Appendix "G".

4.7 Distribution Storm Surge Hardening

Tampa Electric has approximately 520 pad-mounted live front Distribution switchgears and 12,000 pad-mounted transformers located in flood evacuation zones A, B, and C. Distribution switchgears serve as the primary junction point for the underground distribution system, where each switchgear can serve nearly 700 customers. Distribution transformers provide the last step in power service to customers' homes. Each transformer could serve as many as six to ten homes.

During Hurricanes Helene and Milton, Tampa Electric experienced the failure of 13 switchgears and 185 transformers due to storm surge. Based on this experience, Tampa Electric is proposing a new Distribution Storm Surge Hardening Program which will upgrade the live front switchgears to submersible/water-resistant units and replace the secondary bushings on pad-mounted transformers with an insulated water-resistant unit. This work will make this vital equipment more resistant to water intrusion, which will mitigate the need for complete and more costly replacement of these units which, in turn, will reduce restoration costs and reduce outage time.

Since this Program is a recent development based on lessons learned from Hurricanes Helene and Milton, it was not modeled in 1898 & Co.'s Resiliency Model. Tampa Electric did, however, perform an internal evaluation of the estimated costs and benefits of the program. The company prioritized this work based on evacuation zones, meaning the assets located in the highest-risk evacuation zones will be hardened first. The company estimated costs based on the historical, actual time and costs required to replace the equipment on a "blue-sky" day under ideal and pre-planned conditions. The company also factored in higher labor costs during storm restoration and monetized customer outage times as part of the benefits assessment.

The image below depicts secondary bushings on a single-phase pad-mounted transformer experiencing corrosion from storm surge during Hurricane Helene.

The following table shows the Distribution Storm Surge Hardening Program's Projects by year and projected costs for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Distribution Storm Surge Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2026	1	$0.2
2027	2	$15.5
2028	2	$17.4

The full detail of the supporting Distribution Storm Surge Hardening individual Projects, as required by Rule 25-6.030(3)(d)1-5, is included as Appendix "H".

4.8 Infrastructure Inspections

Tampa Electric's Infrastructure Inspection Program continues the comprehensive inspection Program which includes Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company originally developed the wood pole inspection initiative in 2006 to comply with Order No. PSC-06-0144-PAA-EI, which requires each investor-owned electric utility to implement an inspection Program for its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. The company developed the transmission structure inspection and joint-use attachment audit initiatives to comply with Commission Order No. PSC-06-0351-PAA-EI.

Tampa Electric has not historically attempted to quantify the benefits of these inspection activities because they were required by Commission Order. In those Orders, the Commission found that these activities offered significant storm resiliency benefits. For instance, in Order No. PSC-06-0144-PAA-EI the Commission found that wood pole inspections and corrective maintenance "can reduce the impact of hurricanes and tropical storms upon utilities' transmission and distribution systems." The Commission also found that wood pole inspections reduce restoration times because, in the named storms in Florida in 2004 and 2005, "the number of failed poles resulting from a storm [were] correlated with the number of days required to restore service to customers." In Order No. PSC-06-0351-PAA-EI, the Commission later found that a transmission structure inspection program would offer similar benefits. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because "utility poles that are overloaded or approaching overloading are subject to failure in extreme weather." Tampa Electric believes that infrastructure inspection activities still offer these benefits.

Tampa Electric also believes that the costs of these activities are outweighed by their benefits. In Order No. PSC-06-0144-PAA-EI, the Commission analyzed the potential costs of a mandatory wooden pole inspection program and concluded: "The cost of conducting these inspections, while not insignificant, must be compared to the storm restoration costs incurred in 2004 and 2005." Tampa Electric agrees with this assessment and concludes that the costs of these continued infrastructure inspections are outweighed by the associated reduction in restoration costs and outage times identified by the Commission.

4.8.1 Wood Pole Inspections

Tampa Electric's Wood Pole Inspection Initiative is part of a comprehensive program initiated by the FPSC for Florida investor-owned electric utilities to harden the electric system against severe weather.

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair, reinforcement, or replacement to meet strength requirements of the NESC.

The wood pole inspections will be conducted on a feeder circuit basis with a goal of inspecting the entire wood pole population every eight years. An average of 36,000 wood distribution poles will be inspected annually with each pole receiving a visual inspection, a sound & bore procedure, and a groundline/excavation inspection (except for chromated copper arsenate "CCA" poles less than 16 years of age.)

Tampa Electric's wood pole inspection strategy takes a balanced approach and has produced excellent results in a cost-effective manner. The future inspections coupled with the company's pole replacement activities will ultimately harden Tampa Electric's distribution system.

Tampa Electric estimates that this initiative will cost approximately $1.5 million to $2.0 million annually over the ten-years of this proposed SPP.

4.8.2 Transmission Inspections

Tampa Electric will continue to conduct the multi-pronged inspection approach the company has historically applied to the system which has led to the transmission system having a history of strong reliability performance. This approach includes the eight-year ground line wood inspection cycle, annual ground patrol, annual aerial infrared patrol, annual substation inspection cycle and the pre-climb inspection requirement. Tampa Electric will continue these inspections and will also continue the company's ongoing efforts to monitor and evaluate the appropriateness of its transmission structure inspection program to ensure that any cost-effective storm hardening or reliability opportunities found are taken advantage of. Tampa Electric believes this continued cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

Tampa Electric estimates the annual cost of this initiative is approximately $1.8 million annually over the ten-years of this proposed SPP.

4.8.2.1 Groundline Inspections

Tampa Electric conducts groundline inspections in compliance with the Commission's order requiring groundline inspection of wooden transmission structures. A groundline inspection includes excavation, sounding and boring wood poles. Excavation requires removing earth at the base of the pole around the entire circumference to a minimum depth of 18 inches below groundline. All poles passing the excavation inspection will then be sounded with a hammer. If sounding provides evidence of possible interior voids or rot, at least one boring shall be made where the void is indicated. If rot or voids are detected, enough boring shall be made so that the extent can be determined. Poles set in concrete, or otherwise inaccessible below groundline, shall be bored at least twice at groundline at a 45-degree downward direction. All bored holes shall be plugged with treated dowels. Groundline inspections are performed over an eight-year cycle. Each year approximately 12.5% of all wooden transmission structures are scheduled for inspection. For 2026 through 2028, the company plans to perform approximately 1,300 groundline.

Tampa Electric estimates the annual cost of this initiative is approximately $40,000 annually from 2026-2028.

4.8.2.2 Ground Patrol

The ground patrol is a visual inspection for deficiencies including poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware, and encroachment. The ground patrol will include identification of vegetation encroachment as well as all circuit deficiencies. All transmission circuits are patrolled by ground at least once each year.

Tampa Electric estimates the annual cost of this initiative is approximately $220,000 annually over the ten-years of this proposed SPP.

4.8.2.3 Aerial Infrared Patrol

The aerial infrared patrol is planned annually on the entire transmission system. It is performed by helicopter with a contractor specializing in thermographic power line inspections and a company employee serving as navigator and observer. This inspection identifies areas of concern that are not readily identifiable by normal visual methods as well as splices and other connections that are heating abnormally and may result in premature failure of the component. This inspection also identifies obvious system deficiencies such as broken cross arms and visibly damaged poles. Since many of these structures are on limited access ROW, this aerial inspection provides a frequent review of the entire transmission system and helps identify potential reliability issues in a timely manner.

Tampa Electric estimates the annual cost of this initiative is approximately $135,000 annually over the ten-years of this proposed SPP.

4.8.3 Substation Inspections

Tampa Electric performs inspections of distribution substations annually and inspections of transmission substations quarterly. The substation inspections include visual inspection of the substation fence, equipment, structures, control buildings and the integrity of grounding system for all equipment and structures.

Tampa Electric estimates that the annual cost of these inspections is approximately $230,000 annually over the ten-years of the proposed 2026-2035 SPP.

4.8.4 Pre-Climb Inspections

Tampa Electric crews are required to inspect wooden transmission and distribution poles prior to climbing. As part of these inspections, the employee is required to visually inspect each pole prior to climbing and sound each pole with a hammer if deemed necessary. These pre-climbing inspections serve to provide an additional safety-oriented integrity check of poles prior to the employee ascending the pole and may also result in the identification of any structural deterioration issues.

Tampa Electric estimates that there are no costs associated with this activity since it occurs only when an employee is climbing a pole for another purpose.

4.8.5 Joint Use Pole Attachments Audit

Tampa Electric will continue to conduct comprehensive loading analyses to ensure the company’s poles with joint use attachments are not overloaded and meet the NESC or Tampa Electric Standards, whichever is more stringent. These loading analyses are a direct effort to lessen storm related issues on poles with joint use attachments. All current joint use agreements require attaching entities to apply for and gain permission to make attachments to Tampa Electric's poles. Once the application is received, an engineering assessment of every pole where attachments are being proposed will have a comprehensive loading analysis performed. If the loading analysis determines that additional support is necessary, all upgrades will be made prior to notifying the joint use attacher that their construction is ready for attachments.

Tampa Electric's audit of joint use attachments is an important step in documenting all pole attachments. A critical component of the audit is finding pole attachments that the company is not aware of. If an unauthorized attachment is found, the company can perform a comprehensive pole loading analysis to ensure the pole is not overloaded and ensure that all safety, reliability, capacity and engineering requirements are met.

The necessity for the audit arises due to the significant wind loading and stress that pole attachments can have on a pole and the fact that some attachments are made without notice or prior engineering.

There is no incremental cost of this initiative as each audit is ultimately paid for by the joint attacher. This audit is performed at least every five years, and the audit should not exceed a timeframe of 8 years between audits.

4.8.6 Infrastructure Inspections Summary

The infrastructure inspection activities are either part of an ongoing cycle, such as wood pole and transmission structure inspections, or only occur when triggered by a specific event, such as pre-climb and joint use inspections. Given the nature of this Program, Tampa Electric concluded that it was not practical or feasible to identify specific Projects under this Program and it has no estimated completion date as the inspection activities are continuous and ongoing. The following table shows the number of infrastructure inspections the company is projecting for the first three years of the proposed 2026-2035 SPP.

Projected Number of Infrastructure Inspections			
	2026	**2027**	**2028**
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	35,625	35,625	35,625
Transmission			
Wood Pole/Groundline Inspections	505	455	346
Aerial Infrared Patrols	Annually	Annually	Annually
Ground Patrols	Annually	Annually	Annually
Substation Inspections	Annually	Annually	Annually

Note 1: Tampa Electric completed its most recent Joint Use Pole Attachment Audit in the first quarter of 2020 and projects the next Joint Use Pole Attachment Audit to occur in 2025.

The following table provides the annual O&M expenses for each of the inspection programs for the first three years of the proposed 2026-2035 SPP.

Projected Costs of Infrastructure Inspections (in thousands)			
	2026	**2027**	**2028**
Distribution			
Wood Pole Inspections	$1,505	$1,549	$1,595
Transmission			
Wood Pole/Groundline Inspections	$43	$44	$44
Aerial Infrared Patrols	$124	$126	$129
Ground Patrols	$204	$208	$212
Substation Inspections	$213	$217	$224

4.9 Legacy Storm Hardening Plan Initiatives

The final category of storm protection activities consists of the legacy Storm Hardening Plan Initiatives that are well-established, in a steady state, and for which the company does not propose any specific Projects at this time. Tampa Electric will continue these activities as they offer the storm resiliency benefits identified by the Commission in Order No. PSC-06-0351-PAA-EI. There is no estimated completion date for this Program and the company has not performed a formal cost benefit analysis for these activities, as the initiatives are mandated by the Commission and are all integrated into the company's ongoing operations. Instead, the company evaluated projects under these initiatives based upon potential negative impacts on public safety and health, magnitude of impact on customers likely affected by an outage, environmental impacts, and access constraints that may exist following a potential major storm. Once the company selects a storm hardening project, Tampa Electric performs an internal formal cost analysis prior to initiating the project. In this internal analysis, the company projects the costs and estimates the benefits that should be realized.

4.9.1 Geographic Information System

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission and distribution facilities. Tampa Electric continues to develop and improve the GIS. All new computing technology requests and new initiatives are evaluated with a goal to eliminate redundant, exclusive, and difficult to update databases as well as to place emphasis on full integration with Tampa Electric's business processes. Tampa Electric does not propose any GIS Projects in this proposed SPP. The company will, however, continue ongoing activities to improve the functionality and ease of use of the GIS for the company's GIS users.

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is zero dollars as the company's GIS system is an integral system used by the company to maintain its transmission and distribution asset information. Tampa Electric will continue to update and make improvements/enhancements to its GIS as needed.

4.9.2 Post-Storm Data Collection

Tampa Electric has implemented a formal process to randomly sample system damage following a major weather event in a statistically significant manner. This information will be used to perform forensic analysis to categorize the root cause of equipment failure. From these reports, recommendations and possible changes will be made regarding engineering, equipment and construction standards and specifications. A third party of data collection specialists will patrol a representative sample of the damaged areas of the electric system following a major storm event and perform the data collection process. At a minimum, the following types of information will be collected.

- Pole/Structure – type of damage, size and type of pole, and likely cause of damage;
- Conductor – type of damage, conductor type and size, and likely cause of damage;

- Equipment – type of damage, overhead or underground, size, and likely cause of damage; and
- Hardware – type of damage, size, and likely cause of damage.

Third party engineering personnel will perform the forensic analysis of a representative sample of the data obtained to evaluate the root cause of failure and assess future preventive measures where possible and practical. This may include evaluating the type of material used, the type of construction and the environment where the damage occurred including existing vegetation and elevations. Changes may be recommended and implemented if more effective solutions are identified by the analysis team.

The company does not propose any specific post-storm data collection Projects under this Program because there will only be post-storm data collection activity if a major weather event occurs, and the company cannot predict when or if those events will occur during the proposed 2026-2035 SPP.

The incremental cost of this initiative is estimated to be approximately $175,000 per storm and will depend on the severity of the storm and extent of system damage.

4.9.3 Outage Data - Overhead and Underground Systems

Tampa Electric tracks and stores the company's outage data for overhead and underground systems in a single database called the Distribution Outage Database ("DOD"). The DOD is linked to and receives outage data from the company's Electric Management System ("EMS") and Advanced Distribution Management System ("ADMS"). The DOD tracks outage records according to cause and equipment type and can support the following functionality:

- Centralized capture of outage related data;
- Analysis and clean-up of outage-related data;
- Maintenance and adjustment to distribution outage database data;
- Automatic Generation and distribution of standard reliability

reports; and

- Generating ad hoc operational and managerial reports.

The DOD is further programmed to distinguish between overhead and underground systems and is specifically designed to generate distribution service reliability reports that comply with Rule 25-6.0455, F.A.C.

In addition to the DOD and supporting processes, the company's overhead and underground systems are analyzed for accurate performance. The company also has established processes in place for collecting post-storm data and performing forensic analysis to ensure the performance of Tampa Electric's overhead and underground systems are correctly assessed.

The company is not proposing any specific DOD Projects because there will only be DOD activity when there are storm related outages, and the company cannot predict when storm-related outages will occur during the proposed 2026-2035 SPP. The cost of this initiative is estimated to be approximately $100,000 per storm.

4.9.4 Increase Coordination with Local Governments

Tampa Electric representatives will continue to focus on maintaining existing vital governmental contacts and participating in disaster recovery committees to collaborate in planning, protection, response, recovery, and mitigation efforts. In addition, Tampa Electric representatives will continue to communicate and coordinate with local governments on vegetation management, search and rescue operations, debris clearing, and identification of critical community facilities. Tampa Electric will participate with local and municipal government agencies within its service area in planning and facilitating joint storm exercises. In addition, Tampa Electric will continue to be involved in improving emergency response to vulnerable populations and post-disaster redevelopment planning ("PDRP").

The company is not proposing any specific local government coordination Projects because these activities occur intermittently and often on an unplanned basis before, during, and after severe weather events. There are no incremental costs associated with this activity.

4.9.5 Collaborative Research

Tampa Electric will continue the company’s participation in collaborative research effort with Florida’s other investor-owned electric utilities, several municipals, and cooperatives to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers.

This collaborative research is facilitated by the Public Utility Research Center (“PURC”) at the University of Florida. A steering committee comprised of one member from each of the participating utilities provides the direction for research initiatives. Tampa Electric signed an extension of the memorandum of understanding with PURC in December 2018, effective January 1, 2019, for two years. The memorandum of understanding will automatically extend for successive two-year terms on an evergreen basis until the utilities and PURC agree to terminate the agreement.

The company does not propose any specific collaborative research Projects over the proposed 2026-2035 SPP and does not estimate that there will be any collaborative research costs.

4.9.6 Disaster Preparedness and Recovery Plan

A key element in minimizing storm-caused outages is having a natural disaster preparedness and recovery plan. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities, and post-storm recovery. The Commission’s Order No. PSC-06-0351-PAA-E1, issued on April 25, 2006, within Docket No. 20060198-E1 required each investor-owned electric utility to develop a formal disaster preparedness and recovery plan that outlines its disaster recovery procedures and maintain a current copy of its utility disaster plan with the Commission.

Tampa Electric will continue to be active in many ongoing activities to support the restoration of the system before, during and after storm activation. The company will continue to lead or support disaster preparedness and recovery plan activities such as planning, training, and working with other electric utilities and local government to continually refine and improve the company’s ability to respond quickly and efficiently in any restoration situation.

Tampa Electric’s Emergency Management plans address all hazards, including extreme weather events and are reviewed annually. Tampa Electric follows the policy for Emergency Management and Business Continuity which delineates responsibilities at the employee, company, and community levels.

Tampa Electric will also continue to plan, participate in, and conduct internal and external preparedness exercises, collaborating with government emergency management agencies, at the local, state, and federal levels. Internal company exercises focus on testing lessons learned from prior exercises/activations, new procedures, and educating new team members on roles and responsibilities in the areas of incident command, operations, logistics, planning, and finance. The scope and type of internal exercises vary from year to year based on exercise objectives defined by a cross-functional exercise design team, following the Homeland Security Exercise and Evaluation Program (“HSEEP”). External preparedness exercises are coordinated by local, state, and federal governmental emergency management agencies. Tampa Electric personnel participate in these exercises to test the company’s internal emergency response plans, including coordination with Emergency Support Functions (“ESF”) to maintain key business relationships at local Emergency Operations Centers ("EOCs"). Like Tampa Electric, the exercise type (tabletop, functional or full-scale) and scope varies from year to year, and depending upon the emergency management agencies' exercise objectives, Tampa Electric participants may not be included.

Tampa Electric participates in the State of Florida's hurricane exercises with the Commission when planned, which often coincides with exercises conducted by Hillsborough, Pasco, Pinellas, and Polk counties. In addition, municipalities within Tampa Electric's service area (Oldsmar, Plant City, Tampa, and Temple Terrace) may also host exercises and/or pre-storm season briefings.

The total cost to support all Emergency Management activities and initiatives is estimated to be $800,000 annually. This amount includes labor (fringe and payroll taxes included), employee expenses (training, conference, travel, professional dues, subscriptions), outside services (weather, mass notification, resilience management), other operational costs, and materials and supplies to support exercises, activities, and initiatives.

4.9.7 Distribution Pole Replacements

Tampa Electric's distribution pole replacement initiative starts with the company's wood pole inspections and includes designing, utilizing conductors and/or supporting structures, and constructing distribution facilities that meet or exceed the company's current design criteria for the distribution system. The company will continue to appropriately address all poles identified through its Infrastructure Inspection Program.

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Projects in the proposed 2026-2035 SPP. Tampa Electric estimates the annual capital and O&M costs of this initiative to be approximately $10 million annually.

4.9.8 Legacy Storm Hardening Plan Initiatives Costs

The following table shows the projected costs for the Legacy Storm Hardening Plan Initiatives for the first three years of the proposed 2026-2035 SPP.

	Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)	
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2026	$0.8	$10.3
2027	$0.8	$10.5
2028	$0.8	$10.7

5. Storm Protection Plan Projected Costs and Benefits

Tampa Electric developed the projected 2026-2035 SPP costs by examining the time, the scope of work, and reasonably expected costs for each of the SPP Programs. To develop the company's estimations of costs, Tampa Electric relied upon the following key underlying assumptions.

1. The company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This was determined to be approximately $200 million on an annual basis, based upon work constraints.
2. Recognizing the sustained amount of work it takes for external resource companies to physically build or obtain a work force that can support several ongoing Storm Protection Programs.
3. Recognizing that there is some competition for resources between utilities which can push costs upward.

4. Identification of the range of work necessary for each Program and the feasibility of success with external resources.
5. The costs that make up the capital and O&M costs for each of the proposed Programs and their associated Projects.
6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2026-2035 spend at approximately $2 billion over the ten-years of this proposed SPP.
7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be $200 million.
8. Actual historical costs are used where the company has a significant history and/or recent experience in developing the cost for each type of Project. Costs are also analyzed for impacts for potential competition and future contractor capacity impacts.
9. Costs are validated for reasonableness and range by a variety of means; either in discussions amongst internal team members with relative experience, with outside consultants such as 1898 & Co. or HDR Engineering and with neighboring utilities.
10. Costs are used to complete Programs within the designated proposed timeline, such as described in the Transmission Asset Upgrade Program.
11. Costs are projected based upon modeling, project equipment, permits, testing and commissioning costs and team members' experience for projects identified within the Substation Extreme Weather Hardening Program.
12. The company will continue the components of the Commission's legacy Storm Hardening Plan and will seek recovery of the costs associated with these activities through the Storm Protection Plan Cost Recovery Clause ("SPPCRC"), with the exception of the Geographical Information System, Post-Storm Data Collection, Increased

Coordination with Local Governments, Disaster Preparedness and Recovery Plan, Distribution Pole Replacements, and unplanned (reactive) vegetation management.

13. The company will calculate the total costs and total revenue requirements for the proposed 2026-2035 SPP.

5.1 Storm Protection Plan Projected Costs

The following table provides Tampa Electric's projected 2026-2035 SPP total costs (capital and O&M) by Program.

Tampa Electric's 2026-2035 Storm Protection Plan Total Costs by Program (in Millions)

Capital	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Distribution Lateral Undergrounding	$123.84	$121.57	$124.81	$122.54	$125.00	$120.77	$123.60	$124.86	$120.33	$120.54	$1,227.86
Transmission Asset Upgrades	$17.34	$16.77	$16.74	$9.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$60.46
Distribution - Substation Extreme Weather Protection	$7.32	$7.21	$0.00	$0.00	$4.14	$12.39	$3.34	$2.03	$4.06	$0.00	$40.51
Transmission - Substation Extreme Weather Protection	$0.61	$0.00	$2.66	$6.50	$0.88	$0.80	$0.00	$0.00	$0.00	$0.00	$11.45
Distribution Overhead Feeder Hardening	$25.33	$28.21	$30.25	$27.96	$28.45	$28.18	$28.30	$28.08	$28.48	$27.79	$281.03
Transmission Switch Hardening	$0.00	$0.00	$0.27	$3.89	$3.80	$3.81	$0.00	$0.00	$0.00	$0.00	$11.77
Distribtuion Storm Surge Hardening	$0.17	$15.48	$17.39	$16.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$49.09
Distribution Pole Replacements	$10.03	$10.23	$10.43	$10.64	$10.86	$11.07	$11.29	$11.52	$11.75	$11.99	$109.81
Total Capital	$184.65	$199.47	$202.54	$197.20	$173.13	$177.03	$166.53	$166.49	$164.63	$160.32	$1,791.99
O&M	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Distribution Lateral Undergrounding	$0.34	$0.34	$0.32	$0.31	$0.31	$0.46	$0.77	$0.78	$0.79	$0.79	$5.22
Distribution Vegetation Management - planned	$25.10	$26.31	$26.23	$28.92	$30.33	$31.82	$33.39	$35.02	$36.74	$38.89	$312.75
Distribution Vegetation Management - unplanned	$0.91	$0.96	$1.01	$1.06	$1.11	$1.17	$1.22	$1.29	$1.35	$1.42	$11.50
Transmission Vegetation Management - planned	$3.97	$4.21	$4.45	$4.71	$4.99	$5.28	$5.59	$5.92	$6.27	$6.64	$52.03
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.69	$0.67	$0.67	$0.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.42
Distribution - Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission - Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Distribution Overhead Feeder Hardening	$0.99	$1.02	$0.30	$0.28	$0.29	$0.28	$0.28	$0.28	$0.29	$0.28	$4.29
Transmission Switch Hardening	$0.00	$0.00	$0.01	$0.16	$0.15	$0.15	$0.00	$0.00	$0.00	$0.00	$0.47
Distribtuion Storm Surge Hardening	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Distribution Infrastructure Inspections	$1.50	$1.55	$1.60	$1.69	$1.74	$1.79	$1.84	$1.90	$2.01	$2.07	$17.69
Transmission Infrastructure Inspections	$0.58	$0.60	$0.61	$0.58	$0.59	$0.60	$0.62	$0.63	$0.64	$0.66	$6.11
SPP Planning & Common	$1.10	$1.31	$1.98	$1.24	$1.21	$1.43	$2.10	$1.37	$1.35	$1.56	$14.66
Other Legacy Storm Hardening Plan Items	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$8.00
Distribution Pole Replacements	$0.30	$0.31	$0.31	$0.32	$0.32	$0.33	$0.34	$0.34	$0.35	$0.36	$3.28
Total O&M	$36.30	$38.07	$38.29	$40.46	$41.85	$44.13	$46.95	$48.34	$50.59	$53.47	$438.43
Total Capital and O&M	$220.95	$237.53	$240.84	$237.66	$214.98	$221.16	$213.48	$214.82	$215.22	$213.78	$2,230.41

5.2 Storm Protection Plan Projected Benefits

Tampa Electric developed the 2026-2035 SPP projected costs and benefits for each of the proposed Programs through the thorough and comprehensive analysis the company performed with 1898 & Co. Tampa Electric, and 1898 & Co. modeled Programs during extreme weather and evaluated the 10-year benefits of these Programs against a status quo scenario. Due to the timing of the two newly proposed Programs, internal evaluations were completed to estimate the costs and benefits for the Transmission Switch Hardening and Distribution Storm Surge Hardening Programs.

The following table illustrates that both the reduction in restoration costs and the reduction in CMI show improvement during major event days when compared to the status quo.

Tampa Electric - Proposed 2026-2035 Storm Protection Plan Projected Costs versus Benefits

Storm Protection Program	Projected Costs (in Millions)		Projected Reduction in Restoration Costs (in Percent)	Projected Reduction in Customer Minutes of Interruption (in Percent)	Program Start Date	Program End Date
	Capital	O&M				
Distribution Lateral Undergrounding	$1,227.9	$5.2	23	29	Q2 2020	After 2035
Vegetation Management	$0.0	$376.3	22	12	Q2 2020	After 2035
Transmission Asset Upgrades	$60.5	$2.4	87 to 100	8 to 16	Q2 2020	2029
Substation Extreme Weather Hardening	$52.0	$0.0	10 to 17	3 to 31	Q1 2021	After 2035
Distribution Overhead Feeder Hardening	$281.0	$4.3	42	31	Q2 2020	After 2035
Transmission Switch Hardening	$11.8	$0.5	Note 1		Q1 2028	Q4 2031
Distribution Storm Surge Hardening	$49.1	$0.0	48	38	Q1 2026	Q4 2029

Note 1- As a result of Hurricane Milton, Tampa Electric realized it could obtain additional storm resiliency benefits by adding SCADA-controlled remote operating switches to the company’s transmission system. The company expects that the benefits of this program will include faster isolation of trouble spots on the transmission system, fewer truck rolls and less technician time in the field, and more rapid restoration following line faults. While the company has not developed a quantitative estimate of these benefits at this time, the company is confident that adding remote-operating capabilities will result in these benefits.

5.3 Storm Protection Plan Projected Revenue Requirements

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2026-2035 SPP Programs plus depreciation and return on investment, as outlined in the Storm Rule. The estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures using the depreciation rates from Tampa Electric’s most current depreciation study established by the Commission in the company’s most recent base rate proceeding. See Vote Sheet, DN 10091-2024, filed December 3, 2024, in Docket No. 20240026-EI. In addition, the depreciation expense has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the construction of SPP capital Projects. Lastly, in accordance with the FPSC Order No. PSC-2021-0423-S-EI, from the company’s 2021 Stipulation and Settlement Agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity based on the company’s most recent base rate proceeding. See Vote Sheet, DN 10091-2024, filed December 3, 2024, in Docket No. 20240026-EI.

The following table provides Tampa Electric's projected 2026-2035 SPP total revenue requirements (capital and O&M) by Program.

Tampa Electric's 2026-2035 Storm Protection Plan Total Revenue Requirements by Program (in Millions)											
Capital	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
Distribution Lateral Undergrounding	$74.14	$91.11	$104.38	$114.08	$127.06	$140.48	$153.37	$166.29	$178.76	$190.74	$1,340.40
Transmission Asset Upgrades	$10.98	$13.65	$15.13	$16.08	$16.68	$16.56	$16.18	$15.79	$15.41	$15.03	$151.49
Distribution - Substation Extreme Weather Protection	$0.95	$1.81	$2.38	$2.33	$2.45	$3.16	$4.05	$4.58	$4.86	$5.04	$31.60
Transmission - Substation Extreme Weather Protection	$0.03	$0.07	$0.17	$0.56	$1.00	$1.21	$1.26	$1.25	$1.23	$1.21	$7.99
Distribution Overhead Feeder Hardening	$15.22	$18.40	$22.09	$24.69	$28.14	$31.38	$34.50	$37.48	$40.33	$43.05	$295.30
Transmission Switch Hardening	$0.00	$0.00	$0.01	$0.17	$0.53	$0.98	$1.27	$1.34	$1.32	$1.29	$6.91
Distribution Storm Surge Hardening	$0.01	$0.68	$2.28	$4.37	$5.69	$6.02	$5.89	$5.77	$5.64	$5.52	$41.87
Distribution Pole Replacements	$4.98	$6.31	$7.61	$8.90	$10.17	$11.42	$12.65	$13.87	$15.06	$16.23	$107.20
Total Capital	$106.31	$132.03	$154.05	$171.19	$191.71	$211.20	$229.17	$246.37	$262.61	$278.11	$1,982.76
O&M	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
Distribution Lateral Undergrounding	$0.34	$0.34	$0.32	$0.31	$0.31	$0.46	$0.77	$0.78	$0.79	$0.79	$5.22
Distribution Vegetation Management - planned	$25.10	$26.31	$26.23	$28.92	$30.33	$31.82	$33.39	$35.02	$36.74	$38.89	$312.75
Distribution Vegetation Management - unplanned	$0.91	$0.96	$1.01	$1.06	$1.11	$1.17	$1.22	$1.29	$1.35	$1.42	$11.50
Transmission Vegetation Management - planned	$3.72	$3.93	$4.16	$4.41	$4.66	$4.94	$5.23	$5.54	$5.86	$6.21	$48.66
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.65	$0.63	$0.63	$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.26
Distribution - Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission - Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Distribution Overhead Feeder Hardening	$0.99	$1.02	$0.30	$0.28	$0.29	$0.28	$0.28	$0.28	$0.29	$0.28	$4.29
Transmission Switch Hardening	$0.00	$0.00	$0.01	$0.15	$0.14	$0.14	$0.00	$0.00	$0.00	$0.00	$0.44
Distribution Storm Surge Hardening	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Distribution Infrastructure Inspections	$1.50	$1.55	$1.60	$1.69	$1.74	$1.79	$1.84	$1.90	$2.01	$2.07	$17.69
Transmission Infrastructure Inspections	$0.55	$0.56	$0.57	$0.54	$0.55	$0.56	$0.58	$0.59	$0.60	$0.61	$5.71
SPP Planning & Common	$1.10	$1.31	$1.98	$1.24	$1.21	$1.43	$2.10	$1.37	$1.35	$1.56	$14.66
Other Legacy Storm Hardening Plan Items	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$8.00
Distribution Pole Replacements	$0.30	$0.31	$0.31	$0.32	$0.32	$0.33	$0.34	$0.34	$0.35	$0.36	$3.28
Total O&M	$35.96	$37.71	$37.92	$40.08	$41.48	$43.74	$46.55	$47.91	$50.14	$52.99	$434.48
Total Capital and O&M	$142.27	$169.74	$191.97	$211.27	$233.19	$254.94	$275.72	$294.28	$312.75	$331.11	$2,417.23

5.4 Storm Protection Plan Program Budget Levels

Based on the experience from the two previous SPPs, Tampa Electric is able to provide more consistent annual targets for the SPP which results in a more consistent overall budget. For example:

- Distribution Lateral Undergrounding targets are between 65 to 85 miles converted annually
- Distribution Overhead Feeder Hardening targets are between 20 to 30 circuits completed
- Transmission Asset Upgrade circuits range from 10 to 15
- Vegetation Management targets are also consistent with the four-year goal of around 1,500 distribution miles.
  - 500 – 700 miles of Supplemental Distribution
  - 700 – 1,000 miles of Mid-Cycle Distribution
  - Around 500 miles of annual Transmission

As such, Tampa Electric strives to obtain these targets each year to harden our electric system in a focused, structured, and prudent manner.

6. Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts for 2026, 2027, and 2028 of the proposed SPP.

Each year's costs derive from the Programs described in this SPP. For each Program, the capital-related costs, depreciation and return, and O&M costs are combined into a revenue requirement. For each year, the SPP Programs were itemized and identified as to whether they are substation, transmission, or distribution costs.

Tampa Electric applied the methodology that was established by the Commission in the company's most recent base rate proceeding to allocate the revenue requirements to the appropriate rate classes. See Vote Sheet, DN 10091-2024, filed December 3, 2024, in Docket No. 20240026-EI.

The company then applied the appropriate Revenue Tax Factor to determine the revenue requirements. The 2025 billing determinants were then applied to each of the revenue requirements amounts to determine the SPP factors by rate class.

For Residential customers, the charge is a kWh charge. For both Commercial and Industrial customers, the charge is a kW charge. These costs were then applied to the billing determinants associated with typical bills for those groups to calculate the impact on those bills. This was done for 2026, 2027, and 2028.

This same process is used to derive the actual SPPCRC charges in the clause cost recovery docket with the exception that only recoverable SPP costs are included in the SPPCRC docket.

The following table shows the full rate impact of the SPP on typical bills.

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts					
	Customer Class					
	Residential 1,000 kWh		Commercial 1 MW 60 percent Load Factor		Industrial 10 MW 60 percent Load Factor	
	$	%	$	%	$	%
2026	8.48	5.82	2.44	3.72	1.65	3.37
2027	10.12	6.95	2.91	4.44	1.97	4.02
2028	11.45	7.87	3.29	5.02	2.23	4.55

The rate impacts presented above reflect the total cost of the

SPP, even though some of the costs are currently being recovered through the SPPCRC, therefore the incremental cost of the SPP to customers will be less than shown above.

The total costs for the proposed 2026-2035 SPP and the Programs therein were considered for reasonableness and rate impact throughout the development of the SPP, which began in July 2023. Extensive time and effort was expended to ensure the best possible outcome. This included monthly touchpoint meetings and working sessions with multiple departments and contractors to discuss and analyze all aspects of the SPP to make informed decisions about which Programs and Projects to include that would provide the most benefit to the customer with the cost-effective spending levels.

7. Storm Protection Plan Alternatives and Considerations

Tampa Electric considered several "implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the plan" as required by Rule 25-6.030(3)(i).

The company started the development of the proposed SPP by briefly considering a "do nothing" scenario that would have resulted in no incremental investments in the transmission and distribution systems. This initial discussion was based upon the company's historical performance and the current ongoing Storm Hardening and SPP activities. This alternative was good for level setting in that it identified the analyses that would be needed to examine the entire service area for opportunities to enhance storm hardening activities. The company quickly dismissed this alternative since the statute clearly requires all Florida investor-owned utilities to submit a storm plan with the express purpose of hardening the system to reduce outage restoration costs and outage times. The statute emphasizes vegetation management, overhead hardening, and the undergrounding of overhead distribution lines, so the company began its planning with these three activities at the forefront.

As discussed previously, the company engaged Accenture to evaluate the VMP initiatives in the company's current SPP to enhance the existing initiatives and overall performance of the Program. As part of this analysis, several increments of activity and spending were evaluated. The company is proposing to continue with the option that yielded the most customer benefits, with modifications described in Section 4.2.

Tampa Electric and 1898 & Co. used the resilience-based planning approach to establish an overall capital budget level and to identify and prioritize resilience investment in the company's T&D system. The budget optimization analysis was performed in $250 million increments up to $2.5 billion. The analysis showed significantly increasing levels of net benefit from the $250 million to $1.25 billion budget scenarios with the benefit level flattening from $1.25 billion to $1.75 billion and decreasing from $1.75 billion to $2.5 billion. The company's overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's SPP has an appropriate level of investment over the 2026-2035 ten-year period capturing the Projects that provide the most value to customers.

In addition to the Programs included in the proposed 2026-2035 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in this SPP. Examples of things considered, but not included in the SPP are as follows:

- Upgrading wood distribution poles to non-wood materials. The company will continue to evaluate this option as manufacturing capabilities improve. At this time, the upgraded wood materials provide the best cost-benefit ratio for customers.
- Raising existing pad mounted transformers to 36 inches above grade to mitigate surge impact. The solutions proposed in our Distribution Storm Surge Hardening program present a more cost-effective approach.

- Tampa Electric has 209 Lattice Towers that support portions of nineteen (19) 230 kV Circuits. Preliminary analysis suggests that the strength of these Towers can be increased by upgrading, bracing existing structural elements, or total replacement. Further analysis is needed to determine the operational and financial impact and scope.

Tampa Electric will continue to examine and analyze the processes and procedures used to implement the company's proposed 2026-2035 SPP Programs for continuous improvement opportunities. This examination will assist in mitigating the resulting rate impact and ensure the benefits from the proposed SPP are realized.

Tampa Electric's

2026–2035

Storm Protection Plan

Appendices

Appendix A

References

References:

The following resources are referenced in Appendix B, "Construction Standards, Policies, Practices and Procedures."

a) 2023 National Electrical Safety Code
b) National Hurricane Center Database
c) Florida State Building Code
d) Tampa Electric's prior Storm Implementation Plans
e) Tampa Electric's Distribution Engineering Technical Manual
f) Tampa Electric's Standard Electrical Service Requirements
g) Tampa Electric's General Rules and Specifications-Overhead
h) Tampa Electric's General Rules and Specifications-Underground
i) Tampa Electric's Approved Materials Catalog
j) Hillsborough County Flood Hazard Maps

Appendix B

Construction Standards, Policies, Practices and Procedures

Index

Construction Standards, Policies, Practices and Procedures

Tampa Electric’s existing construction standards, policies, practices, and procedures were developed over time to promote the ability of the company to provide safe and reliable electric service at reasonable rates. The company has included these standards, policies, practices, and procedures in each of the three-year Storm Hardening Plans filed with and approved by the FPSC and is including these in this SPP as important background and context for the Program elements of its SPP. The company will continue to evaluate and enhance its standards, policies, practices, and procedures to incorporate new storm hardening and resiliency techniques.

1. National Electrical Safety Code Compliance

Tampa Electric’s construction standards and policies meet or exceed all minimum National Electric Safety Code (“NESC”) Rule requirements.

2. Wind Loading Standards

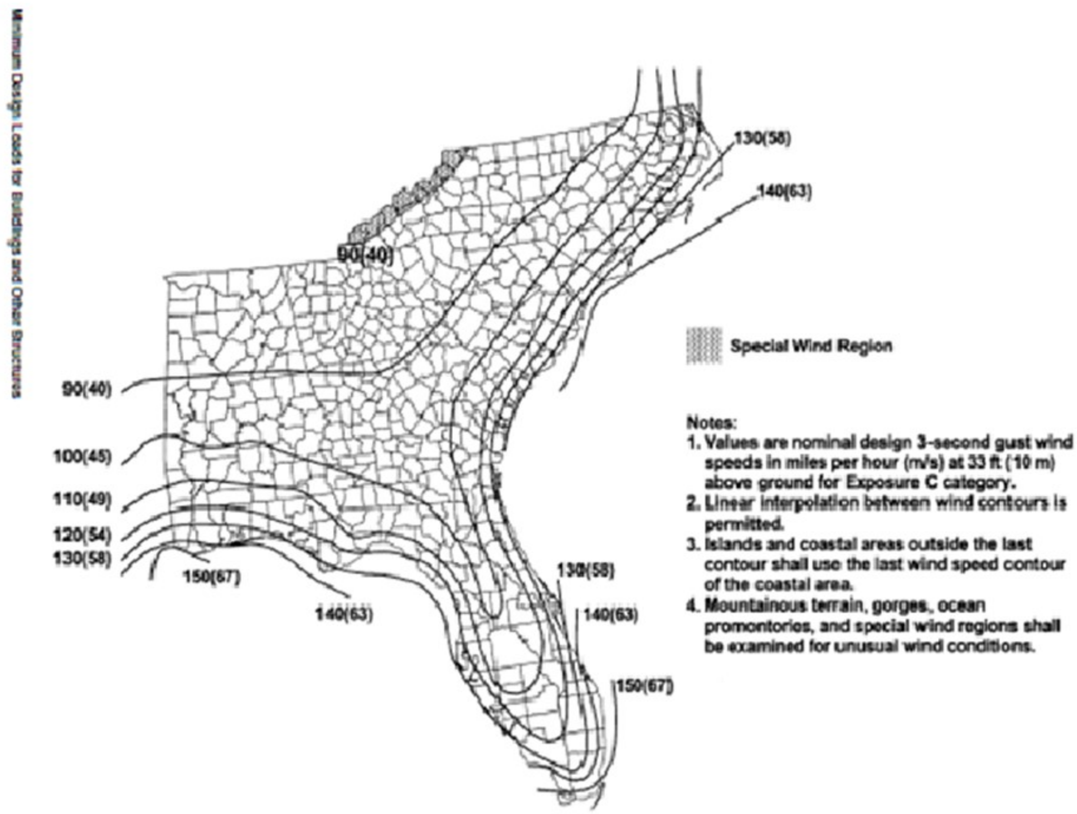
NESC Rule 250, which addresses pole loading requirements in the United States, is divided into three loading districts; Heavy, Medium, and Light (see Figure 2 below). Tampa Electric’s service area is in the Light loading district, which assumes no ice buildup and a wind pressure rating of nine pounds per square foot. The nine-pound wind corresponds to wind speeds of approximately 60 mph. The Light loading district wind speed corresponds to a wind pressure of more than twice that in the Heavy or Medium districts due to the strong (non-linear) dependence of the wind force on wind speed (i.e., the wind pressure is proportional to the square of the wind speed). Another part of the NESC Rule 250 requires safety loading factors to be applied to the calculated wind forces to provide a conservative margin of safety when selecting appropriate pole sizes. A safety loading factor of 2.06:1 is applied to Grade C construction and 3.85:1 is applied to Grade B construction. The effective wind speed of Grade B new construction is approximately 116 mph. According to the NESC, Grade B wind loading criteria must be applied when constructing facilities less than 60 feet in height when crossing railroads, bridges, and highways.

Figure 2: NESC General loading map of United States with respect to loading of overhead lines.

2.1 Extreme Wind Loading Criteria

The NESC also specifies an extreme wind pole loading criterion for all facilities constructed that are 60 feet in height or greater. The NESC provides a wind loading map that indicates the wind speed criteria for each area of the country. These same criteria and regional boundaries, developed by the American Society of Civil Engineers ("ASCE"), are used by the state of Florida and Hillsborough County for building code requirements. Tampa Electric's service territory is divided into two wind regions (see Figure 3 below). The western half is in the 120-mph zone and the eastern half is in the 110-mph zone.

Figure 3: ASCE 74-10 Eastern Gulf of Mexico and Southeastern U.S. Hurricane Coastline



3. Distribution

This section of the Plan builds upon the design philosophy discussed above and provides an overview of the design criteria, construction standards and practices applicable to all new distribution facilities. This section also presents a broad discussion of the distribution materials and structure types the company uses.

Tampa Electric has developed and maintains a Distribution Engineering Technical Manual ("DETM") which provides corporate and field personnel the policies, procedures and technical data related to the design of distribution facilities owned and operated by the company. Information contained in this manual along with the Standard Electrical Service Requirements ("SERS"), General Rules and Specification – Overhead ("GR&S-

OH"), General Rules and Specification – Underground ("GR&S-UG") and the Approved Material Catalog ("AMC") provide guidelines for designing, constructing and maintaining Tampa Electric's distribution system.

3.1 Design Philosophy

The basis of Tampa Electric's construction standards, policies, practices, and procedures has been the NESC Grade B-Light since the 1980's. All new overhead main feeder lines will be constructed to meet the NESC Extreme Wind loading criteria for our area. All new lateral lines will be constructed underground if doing so will reduce storm restoration costs and outage times. From this foundation, it supports the company's philosophy of providing safe, reliable, and cost-effective service to its customers.

3.2 Overhead System

3.2.1 Voltage

Tampa Electric's primary distribution system operates at a uniform 13.2 kilovolts ("kV") at three-phase. Secondary voltage is provided in conjunction with the primary distribution system.

3.2.2 Clearances

Primary voltage conductors are in the power space on the pole that is the upper most portion of the pole as defined by the NESC. Secondary and service conductors along with the neutral are located approximately six feet lower than the primary conductors. Joint use attachers are in the communication space on the pole which is at a minimum 40 inches below the neutral cable or Tampa Electric's communication cable.

3.2.4 Pole Loading

The company's design and construction standard for all new construction, major planned work, expansions, rebuilds and relocations on the overhead distribution system will follow the

NESC construction Grade B criteria with the NESC Extreme Wind loading criteria applied to all Feeder main lines. As described above, the safety factors considered in the NESC construction Grade B criteria provide for a system that is 87% stronger than the NESC construction Grade C criteria which results in a more robust design. The company's experience has shown that this design provides a safe, reliable, and cost-effective service. This standard exceeds the minimum requirement of the NESC, which requires distribution poles to be designed to construction Grade C. While the NESC requirements related to extreme wind conditions apply to only structures over 60 feet in height and rarely apply to distribution structures, they will be used as a new design and construction standard for all new feeder construction and priority feeder hardening.

3.2.5 Materials

There are several types of poles that are used for distribution structures. Tampa Electric's distribution system uses wood, concrete, steel, ductile iron, and fiberglass poles. The standard for all new distribution construction is Chromated Copper Arsenate ("CCA") treated wood poles as these CCA poles meet the strength requirements for most of the company's distribution line construction, have excellent life expectancy in Tampa Electric's service area (30+ years), are readily available, and cost effective.

The company's standard conductor for circuit feeders is 336 kcmil Aluminum Conductor, Steel Reinforced ("ACSR") with a 2/0 All Aluminum Alloy Conductor ("AAAC") neutral. Conductor sizes used for distribution laterals (overhead takeoffs from feeders) may either be #2, 2/0 or 4/0 AAAC with some older existing facilities containing #6 copper conductor.

3.2.6 Construction Types

Proper configuration selection is important for safety, maintenance, and economics. The company typically maintains the existing line configuration for multi-phase line extensions. Customer requests for alternative distribution pole and construction types will be considered and if agreed upon, the customer(s) requesting would incur the incremental expense from standard service.

Triangular line configuration using fiberglass brackets is the preferred construction standard. It is the most economical to install and is particularly suited to situations involving restrictive ROW, easements, and clearances. Because of its narrow profile, it is also preferred for locations with numerous trees. Other construction types that may be used include vertical, modified vertical and wood, or fiberglass cross arms.

3.2.7 Pole Loading Compliance

Tampa Electric uses "PoleForeman," a pole loading software program to assure that Tampa Electric is following all NESC loading requirements and company construction standards. The program uses the company's construction standards with templates to model each pole and assist company distribution design technicians and distribution design engineers. The technician or engineer inputs the appropriate template, conductor, pole size and class, which the program uses to determine all loads on the pole. The program applies the loads to the structure and calculates the resulting stresses as a percent utilization of the pole.

3.3 Underground Facilities

3.3.1 Standard Design

Tampa Electric's standard underground distribution system consists of normally looped circuits operating at 13.2kV three-phase or 7.6kV single-phase primary voltages. The standard cable is 15kV strand-filled jacketed tree-retardant cross-linked polyethylene insulated aluminum cable with a copper concentric neutral. Tampa Electric's standard is to place all underground distribution cables in a conduit system buried at depths of 24 to 36 inches from the ground surface to the top of the conduit.

3.3.2 Network Service

Tampa Electric has several types of underground services with associated facilities. One is a standard underground service that is used in residential subdivisions and commercial areas, which are described above. Another is network service, which provides a higher level of reliability and operating flexibility.

Tampa Electric employs two types of network service. The first type is an integrated secondary grid network that serves the high-density load area in downtown Tampa. The second type is spot network systems that also serves certain high-density loads in the downtown Tampa network area.

The network systems provide redundant circuit feeds from a two-transformer substation and thus are designed to maintain service during a first contingency outage. The network systems are also designed to resist water intrusion, and the equipment is in vaults, some of which are below-grade. However, the customer-owned electrical panels are not necessarily waterproof and will likely be severely impacted by saltwater intrusion. This will possibly delay power restoration to network customers in the event of a major storm with storm surge into the network areas.

3.4 Construction Standards in Coastal Areas

Tampa Electric's service area is partially bounded by Tampa Bay and has approximately 60 square miles of land in the Flood Zone 1 designated area as defined in Hillsborough County's Hazard Flood Maps and approximately 2.5 square miles of land in the

Oldsmar area in the Flood Zone 1 designated area as defined in Pinellas County's Hazard Flood Maps. There is an increased risk of storm surge, flooding, and saltwater contamination along these coastal areas. Since 2008, the company's standard is that new underground distribution facilities (pad mounted transformers, switchgear, and load break cabinets) shall be of stainless steel or aluminum construction and bolted to a concrete pad. Upgrading the material from mild steel to stainless steel or aluminum makes it more durable and typically extends equipment life after saltwater contamination. While using stainless steel or aluminum has significant benefits to storm hardening, the equipment is not waterproof and may require cleaning prior to re-energizing after a flooding event. In addition, Tampa Electric has begun using submersible switchgear for customers in locations prone to flooding or where the switchgear can be subjected to harsh conditions. Since 2004, all primary switchgear has been specified using 100% stainless steel enclosures, and since 2008 all pad mounted transformers have been specified using 100% stainless steel enclosures to reduce the corrosive effects from salt spray, effluent irrigation spray and to help harden the equipment against the corrosive effects of a saltwater storm surge.

In 2015, Tampa Electric began using submersible pad mount switchgear to harden the underground system in certain applications. This switchgear is designed to withstand intrusion from water, including salt-water, while remaining in service. This gear will be specifically used for those critical customers in areas where storm surge is expected to have a significant impact or those low-lying areas where the environment has caused non-submersible switchgear to fail.

3.5 Location of Facilities

Tampa Electric's policy as stated in the DETM is to ensure that the route for new lines is located within the Public ROW or an electric utility easement. New residential lines shall be front lot construction and truck accessible. Commercial lines may be rear lot construction, but they must be truck accessible. This approach facilitates efficient access during installation and maintenance of the facilities. Prior to 1970 when this policy was instituted, some distribution facilities were constructed in rear lot easements. Communities or homeowner associations occasionally make inquiries regarding the relocation of overhead facilities from rear lot locations to the front of customer's properties. Tampa Electric evaluates each inquiry on a case-by-case basis for feasibility, practicality, and cost-effectiveness.

3.6 Critical Infrastructure

Tampa Electric, in conjunction with local government emergency management, has identified the company's critical facilities and associated circuits feeding loads which are deemed necessary for business continuity and continuity of government. As such, critical community facilities are identified based on being most critical to the overall health of the community, including public health, safety or the national or global economy. Such facilities include hospitals, emergency shelters, master pumping stations, wastewater plants, major communications facilities, flood control structures, electric and gas utilities, Emergency Operation Centers ("EOC"), as well as main police and fire stations, and others. The circuits serving these facilities have the highest restoration priority level. Tampa Electric has hardened several circuits which feed some of the most critical customers on the company's system to extreme wind criteria.

4. Transmission

This section of the SPP provides an overview of design considerations and references when performing a transmission structure analysis for new and existing facilities. This section is a broad discussion of transmission structure types, foundation design and design criteria.

4.1 Design Criteria

There are two types of methodologies used to analyze pole strength. Tampa Electric uses the ultimate strength analysis for all wood and non-wood structures. However, it is acceptable and often recommended to use the working stress method for wood poles.

Tampa Electric designs and specifies all transmission facilities in accordance with the latest version of the NESC. All designs address NESC extreme wind and Grade B construction at a minimum. The extreme wind loads are applied to all attachments on the transmission structure regardless of attachment height.

Tampa Electric's service area is largely within the 100 mph to 120 mph extreme wind contours referenced in the NESC. For design consistency, the 120-mph wind standard is applied on all 69kV structures throughout the service area. In addition, a 133-mph wind standard is applied to all 138kV and 230kV structures throughout Tampa Electric's service area. The 133-mph wind standard exceeds the NESC requirements for extreme wind loading. This standard was adopted when Tampa Electric commissioned the first 230kV line in the company's service area. Tampa Electric continues to support the 133-mph wind standard as the best practice for 138kV and 230kV line construction.

Since the inception of the NESC extreme wind standard, it has been applied to Tampa Electric transmission facilities. Tampa Electric historically has applied the 133-mph wind standard to 230kV facilities and in some cases an even higher wind speed has been applied when the company determined that the circuit would be very difficult to restore. An example of this higher wind standard is when the company replaced the transmission structures crossing the Alafia River. For these structures, a 150-mph wind standard was used.

4.2 Transmission Structures

4.2.1 Voltage levels

Tampa Electric's transmission system consists of circuits operating at 230kV, 138kV and 69kV. These circuits consist of a minimum of three phase conductors and (usually) a static wire (ground). Additional facilities may exist or be incorporated in the design of a transmission structure, including additional transmission conductors, optical ground wire, communication conductors, distribution conductors and an assortment of wire attachments by joint users.

4.2.2 Material types

Tampa Electric's transmission system consists of wood, concrete, aluminum, steel, and composite supporting structures. Since 1991, Tampa Electric has used a standard that all new construction, line relocations and maintenance replacements will use pre-stressed spun concrete, steel, or composite pole structures. Past practices included wood pole, aluminum, and lattice steel structure design. Pre-stressed spun concrete, tubular steel and composite poles are now the preferred structure material types of Tampa Electric installs when replacing or upgrading structures.

4.2.3 Configuration Types

Tampa Electric uses multiple transmission structure configurations. Pre-stressed spun concrete poles and tubular steel poles are used in single or multiple pole configurations. The advent of pre-stressed spun concrete and tubular steel poles has permitted a more cost-effective, lower maintenance and higher strength option.

The configurations will vary widely when considering the many variables associated with transmission facilities. Some of these variables are:

1. Number of circuits
2. Conductor size
3. Structure strength
4. Span length
5. Soil conditions
6. ROW width
7. Potential permitting requirements
8. Utilization of adjacent land
9. Environmental impacts
10. Electric and magnetic field criteria
11. Aesthetics
12. Economics and cost-effectiveness
13. Community input

Single pre-stressed spun concrete or tubular steel structure configurations have proven to be the most economical and maintainable choice given the work environment and constraints encountered while engineering and constructing transmission facilities. Prior to pre-stressed spun concrete and tubular steel technology, typical structure configurations commonly consisted of single wood pole or multiple wood pole structures, lattice aluminum H-frames and lattice steel towers.

4.3 Foundations

Direct embedment is the preferred foundation type used for pre-stressed spun concrete, tubular steel, or composite structures. A direct embedded foundation typically has a specified depth and diameter. The direct embedded foundation also requires a segment of the superstructure to be embedded below ground, acting as part of the foundation, along with natural soil, crushed rock or concrete backfill.

When a structure location requires it, Tampa Electric uses an industry accepted program for foundation design. Soil borings are collected, or standard penetration tests are conducted to compile the appropriate soil data for foundation analysis.

5. Substation

Tampa Electric has developed and maintains a Substation Engineering Technical Manual ("SETM") which provides the company's personnel with the policies, procedures, and technical data to the design of substation facilities owned and operated by the company. Information contained in the SETM along with the Standard Electrical Service Requirements ("SESR"), GR&S-OH, GR&S-UG and AMC, provide guidelines for designing, constructing, and maintaining Tampa Electric's substation facilities.

Tampa Electric designs, constructs and maintains transmission and distribution substations and switchyards ranging from 13.2kV to 230kV. This includes performing siting studies, physical design, grading and drainage, foundation design, layout and design of control buildings, structure design and analysis, protection and control systems, and preparation of complete specifications for material, equipment, and construction. The company currently has 234 substations.

5.1 Design Philosophy

5.1.1 Wind Strength Requirements

Tampa Electric designs the company's substations in accordance with the latest approved version of the NESC. Currently, all distribution substation structures are designed to withstand a wind load of 120 mph. All current design standards for 230kV generation facilities and 230kV transmission stations call for terminal line structures to withstand 133 mph wind loading along with the line tension of the transmission circuit.

The design standards summarized above meet the NESC loading criteria for extreme wind, Grade B construction. As previously stated, Tampa Electric's service area is within the 100 mph to 120 mph extreme wind contours referenced in the NESC.

5.1.2 Equipment Elevations

The company carefully evaluates equipment elevations when building on existing sites or when selecting future sites in the Flood Zone 1 designated area. Information on past flooding in localized areas and potential future storm surge levels are evaluated. Most equipment is built on steel supports and is above expected flood levels. Some equipment such as transformers can be submerged up to the point of attached cabinets and controls. Therefore, the major focus is on the elevation and water resistance of the control cabinets and related equipment. The sites and/or equipment are elevated based on the overall site permitting that must be done with the governmental and environmental agencies while taking into consideration the surrounding area.

5.1.3 Protection

Animal protection covers are installed on all new 13kV bushings, lightning arrestors, switches and leads. This helps prevent outages caused by animals and will also reduce damage from debris that may get inside the substation during a major storm event. Tampa Electric uses circuit switchers or circuit breakers instead of fuses or ground switches on new and upgraded transformer installations. This design will clear a fault faster which minimizes damage and greatly reduces restoration time.

5.1.4 Flood Zones

The company carefully evaluates flood zones when building on existing sites or when selecting future sites. The company will continue to review existing sites in the Flood Zone 1 designated area. The major focus will be on the elevation and water resistance of control cabinets and related equipment. Prudent modifications will be made. Consideration will be given to whether there will be load to be served in the area of the substation immediately after a storm and if any load can be served from adjacent substations that are outside the flooded area.

5.1.5 Other

When transformers are added to an existing substation or a transformer is upgraded, if needed, existing fences are removed, and new fences are installed to meet or exceed current NESC wind and height standards. At the same time, animal protection covers are installed on all 13kV bushings, lightning arrestors, switches and leads. This helps prevent damage from debris that gets inside the substation.

5.2 Construction Standards

Tampa Electric uses galvanized tubular steel structures in new distribution substations. The tallest structure is approximately 24 feet above grade, with most of the structures and equipment being below 17 feet. Distribution feeder circuits are designed to exit the substation via underground cables installed inside a six-inch conduit.

In 230kV substations and 69kV switching stations, control buildings are used to house protection relays, communication equipment, Remote Terminal Unit (“RTU”) monitoring equipment and substation battery systems. Previous construction methods used concrete block construction with poured concrete columns and concrete roof panels, which are designed to withstand winds of 120 mph without any damage to the building or the equipment housed inside. Control buildings currently being installed are prefabricated metal buildings designed for 150 mph wind loading. Tampa Electric installs eight-foot-tall perimeter chain link fences designed to 120 mph or walls designed to 125 mph. This provides additional protection from wind-blown debris. Tampa Electric has determined that this fencing standard is most effective in blocking debris and exceeds county codes.

6. Deployment Strategy

Tampa Electric’s proposed 2026-2035 SPP’s deployment strategy will reduce storm restoration costs and customer outage duration following major storm events and enhance system reliability through the continuation of several core components of the company’s Storm Hardening Plans. The deployment strategy includes the continuation of the existing SPP Programs and the legacy Storm Hardening Plan Initiatives.

Appendix C

Project Detail

Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding - Year 2026 Details										
Project ID	Circuit No.	Specific Project Detail	Customers				Project Start Qtr	Construction		Project Cost in 2026
		OH to UG Length Converted (miles)	Residential	Small C&I	Large C&I	Total		Start Qtr	End Qtr	
LUG ESA 13454.90429155	13454	1.53	122	11	3	136	Q1 - 2026	Q1 - 2027	Q2 - 2027	$2,071,790
LUG CSA 14012.91573736	14012	1.31	199	27	0	226	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,597,114
LUG ESA 13433.10466911	13433	0.71	14	4	0	18	Q1 - 2026	Q1 - 2027	Q2 - 2027	$952,670
LUG WSA 13754.90097474	13754	0.62	186	14	2	202	Q1 - 2026	Q1 - 2027	Q2 - 2027	$756,400
LUG ESA 13911.90130568	13911	1.26	95	15	0	110	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,702,074
LUG WSA 13873.60311122	13873	1.40	37	5	3	45	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,824,383
LUG WSA 13078.10127958	13078	2.18	464	4	1	469	Q1 - 2026	Q1 - 2027	Q2 - 2027	$2,836,280
LUG CSA 13036.91479826	13036	0.51	242	8	1	251	Q1 - 2026	Q1 - 2027	Q2 - 2027	$528,269
LUG CSA 13045.10165356	13045	0.87	74	13	4	91	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,403,324
LUG WSA 13522.10392882	13522	2.55	137	10	3	150	Q1 - 2026	Q1 - 2027	Q2 - 2027	$3,312,715
LUG WSA 13638.91177941	13638	1.18	80	11	1	92	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,534,000
LUG WSA 13068.90098746	13090	0.99	92	17	0	109	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,287,000
LUG ESA 13230.92180224	13230	0.61	11	34	3	48	Q1 - 2026	Q1 - 2027	Q2 - 2027	$826,619
LUG WSA 13141.92630916	13141	0.44	20	17	4	41	Q1 - 2026	Q1 - 2027	Q2 - 2027	$574,524
LUG CSA 13046.91016874	13046	0.38	59	4	3	66	Q1 - 2026	Q1 - 2027	Q2 - 2027	$494,000
LUG ESA 14355.60258173	14355	0.16	96	6	1	103	Q1 - 2026	Q1 - 2027	Q2 - 2027	$212,983
LUG WSA 13199.10050730	13199	0.54	235	17	0	252	Q1 - 2026	Q1 - 2027	Q2 - 2027	$656,637
LUG CSA 13091.60029925	13091	0.98	108	14	0	122	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,274,000
LUG CSA 13224.92856634	13224	0.43	30	18	1	49	Q1 - 2026	Q1 - 2027	Q2 - 2027	$559,000
LUG WSA 13065.91354294	13065	0.22	40	6	0	46	Q1 - 2026	Q1 - 2027	Q2 - 2027	$286,000
LUG CSA 13045.10165381	13045	3.26	39	15	3	57	Q1 - 2026	Q1 - 2027	Q2 - 2027	$3,772,946
LUG WSA 13533.91060899	13533	0.67	79	5	2	86	Q1 - 2026	Q1 - 2027	Q2 - 2027	$871,000
LUG WSA 13165.91910924	13165	0.21	75	6	5	86	Q1 - 2026	Q1 - 2027	Q2 - 2027	$289,023
LUG CSA 13103.91232937	13103	1.16	134	4	1	139	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,508,000
LUG WSA 13191.60474882	13191	0.34	11	19	4	34	Q1 - 2026	Q1 - 2027	Q2 - 2027	$442,000
LUG ESA 13509.92890860	13509	0.33	6	1	1	8	Q1 - 2026	Q1 - 2027	Q2 - 2027	$452,045
LUG WSA 13586.92298267	13586	0.82	7	2	0	9	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,068,600
LUG CSA 13837.91563454	13837	0.39	64	2	0	66	Q1 - 2026	Q1 - 2027	Q2 - 2027	$480,259
LUG WSA 13756.10589595	13756	0.27	96	7	0	103	Q1 - 2026	Q1 - 2027	Q2 - 2027	$346,241
LUG WSA 13140.92408051	13140	1.07	1	4	2	7	Q1 - 2026	Q1 - 2027	Q2 - 2027	$1,391,000
LUG WSA 13218.60124027	13218	0.64	69	6	0	75	Q1 - 2026	Q1 - 2027	Q2 - 2027	$831,705
LUG SHA 13645.92207754	13645	0.73	3	1	4	8	Q1 - 2026	Q1 - 2027	Q2 - 2027	$988,977
LUG WSA 13754.90630567	13754	0.39	63	4	1	68	Q1 - 2026	Q1 - 2027	Q2 - 2027	$475,800
LUG WSA 13219.92005809	13219	0.42	43	13	1	57	Q2 - 2026	Q2 - 2027	Q3 - 2027	$540,917
LUG CSA 13419.90399851	13419	1.13	135	1	1	137	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,378,600
LUG PCA 13011.10625698	13011	1.23	74	3	1	78	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,504,260
LUG ESA 13133.10802850	13133	1.86	27	21	1	49	Q2 - 2026	Q2 - 2027	Q3 - 2027	$2,264,117
LUG CSA 13837.91812632	13837	0.41	112	4	0	116	Q2 - 2026	Q2 - 2027	Q3 - 2027	$501,425
LUG WSA 13082.60073788	13082	0.85	45	6	1	52	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,100,883

Tampa Electric's Distribution Lateral Undergrounding - Year 2026 Details										
Project ID	Circuit No.	Specific Project Detail	Customers				Project Start Qtr	Construction		Project Cost in 2026
		OH to UG Length Converted (miles)	Residential	Small C&I	Large C&I	Total		Start Qtr	End Qtr	
LUG CSA 13093.60029776	13093	0.46	67	4	1	72	Q2 - 2026	Q2 - 2027	Q3 - 2027	$593,778
LUG WSA 13754.90847913	13754	0.34	64	4	1	69	Q2 - 2026	Q2 - 2027	Q3 - 2027	$408,728
LUG WSA 13078.10127937	13078	1.60	59	6	0	65	Q2 - 2026	Q2 - 2027	Q3 - 2027	$2,078,209
LUG ESA 13127.90334707	13127	0.36	0	0	0	0	Q2 - 2026	Q2 - 2027	Q3 - 2027	$486,818
LUG WSA 13072.10165789	13072	0.48	21	10	3	34	Q2 - 2026	Q2 - 2027	Q3 - 2027	$624,000
LUG WSA 13217.92097014	13217	0.63	16	1	3	20	Q2 - 2026	Q2 - 2027	Q3 - 2027	$820,263
LUG WSA 13611.10092875	13611	0.67	49	2	0	51	Q2 - 2026	Q2 - 2027	Q3 - 2027	$872,016
LUG ESA 13906.92282884	13906	0.10	31	2	1	34	Q2 - 2026	Q2 - 2027	Q3 - 2027	$128,864
LUG CSA 13748.60111391	13748	0.73	77	3	1	81	Q2 - 2026	Q2 - 2027	Q3 - 2027	$891,363
LUG DCA 13330.92197131	13330	1.17	72	2	1	75	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,521,000
LUG WSA 13510.10218987	13510	0.15	0	7	1	8	Q2 - 2026	Q2 - 2027	Q3 - 2027	$195,000
LUG WSA 13191.10173522	13191	0.50	4	28	8	40	Q2 - 2026	Q2 - 2027	Q3 - 2027	$650,553
LUG WSA 13063.10124545	13063	0.51	49	3	1	53	Q2 - 2026	Q2 - 2027	Q3 - 2027	$693,497
LUG CSA 13218.60318065	13218	0.50	48	2	0	50	Q2 - 2026	Q2 - 2027	Q3 - 2027	$614,067
LUG WSA 13740.60614298	13740	1.01	18	14	0	32	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,308,221
LUG ESA 13509.10501141	13509	0.16	12	0	2	14	Q2 - 2026	Q2 - 2027	Q3 - 2027	$220,909
LUG CSA 13091.10163224	13091	0.76	62	4	0	66	Q2 - 2026	Q2 - 2027	Q3 - 2027	$931,180
LUG PCA 13390.92605381	13390	0.34	50	2	0	52	Q2 - 2026	Q2 - 2027	Q3 - 2027	$444,600
LUG PCA 13805.10916743	13805	0.48	6	2	1	9	Q2 - 2026	Q2 - 2027	Q3 - 2027	$625,300
LUG WSA 13112.92890357	13112	1.23	51	6	1	58	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,594,716
LUG CSA 13043.10093646	13043	0.56	63	1	1	65	Q2 - 2026	Q2 - 2027	Q3 - 2027	$678,264
LUG WSA 13206.10167762	13206	0.55	29	3	1	33	Q2 - 2026	Q2 - 2027	Q3 - 2027	$720,318
LUG SHA 13780.10723993	13780	0.27	0	2	0	2	Q2 - 2026	Q2 - 2027	Q3 - 2027	$364,602
LUG ESA 13326.10477228	13326	2.48	8	13	4	25	Q2 - 2026	Q2 - 2027	Q3 - 2027	$3,226,600
LUG WSA 13219.60518342	13219	0.47	4	3	1	8	Q2 - 2026	Q2 - 2027	Q3 - 2027	$611,010
LUG ESA 13793.92685255	13793	0.19	6	3	2	11	Q2 - 2026	Q2 - 2027	Q3 - 2027	$256,449
LUG CSA 13093.60031511	13093	0.80	31	1	1	33	Q2 - 2026	Q2 - 2027	Q3 - 2027	$1,040,000
LUG WSA 13483.60393455	13483	2.87	20	3	0	23	Q3 - 2026	Q3 - 2027	Q4 - 2027	$3,727,623
LUG WSA 13865.60305740	13865	0.14	6	3	1	10	Q3 - 2026	Q3 - 2027	Q4 - 2027	$181,951
LUG ESA 13502.10497396	13502	0.30	24	2	0	26	Q3 - 2026	Q3 - 2027	Q4 - 2027	$398,864
LUG WSA 13162.94434120	13162	0.60	68	2	0	70	Q3 - 2026	Q3 - 2027	Q4 - 2027	$780,000
LUG CSA 13175.60060554	13175	1.23	16	5	0	21	Q3 - 2026	Q3 - 2027	Q4 - 2027	$1,599,000
LUG WSA 13112.92874488	13112	0.35	54	1	1	56	Q3 - 2026	Q3 - 2027	Q4 - 2027	$478,534
LUG ESA 13878.10105726	13878	0.54	38	0	0	38	Q3 - 2026	Q3 - 2027	Q4 - 2027	$729,205
LUG CSA 14012.92299193	14012	0.62	26	16	5	47	Q3 - 2026	Q3 - 2027	Q4 - 2027	$756,677
LUG ESA 13231.10868121	13231	0.27	24	2	0	26	Q3 - 2026	Q3 - 2027	Q4 - 2027	$368,693
LUG CSA 13829.10425054	13829	0.24	35	4	0	39	Q3 - 2026	Q3 - 2027	Q4 - 2027	$245,791
LUG WSA 13624.10274748	13624	0.28	7	0	0	7	Q3 - 2026	Q3 - 2027	Q4 - 2027	$363,409
LUG WSA 13167.92398222	13167	0.37	17	0	2	19	Q3 - 2026	Q3 - 2027	Q4 - 2027	$481,000
LUG ESA 13039.92496615	13039	1.45	22	1	0	23	Q3 - 2026	Q3 - 2027	Q4 - 2027	$1,882,400
LUG PCA 13723.60422059	13723	0.91	1	3	1	5	Q3 - 2026	Q3 - 2027	Q4 - 2027	$1,110,200
LUG WSA 13738.90267141	13738	0.22	0	0	0	0	Q3 - 2026	Q3 - 2027	Q4 - 2027	$286,000
LUG WSA 13082.60073803	13082	0.22	40	2	0	42	Q3 - 2026	Q3 - 2027	Q4 - 2027	$286,000

Tampa Electric's Distribution Lateral Undergrounding - Year 2026 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Project Start Qtr	Construction		Project Cost in 2026
		OH to UG Length Converted (miles)	Residential	Small C&I	Large C&I	Total		Start Qtr	End Qtr	
LUG SHA 13899.60005952	13899	0.91	76	2	0	78	Q3 - 2026	Q3 - 2027	Q4 - 2027	$1,184,300
LUG CSA 13036.10143568	13036	0.66	26	1	0	27	Q3 - 2026	Q3 - 2027	Q4 - 2027	$809,428
LUG WSA 13072.10165803	13072	0.52	10	1	2	13	Q3 - 2026	Q3 - 2027	Q4 - 2027	$639,863
LUG ESA 13795.90398961	13795	0.51	1	1	2	4	Q3 - 2026	Q3 - 2027	Q4 - 2027	$664,300
LUG WSA 13198.10051863	13198	0.42	6	1	0	7	Q3 - 2026	Q3 - 2027	Q4 - 2027	$567,000
LUG SHA 13900.91863298	13900	0.27	0	0	0	0	Q3 - 2026	Q3 - 2027	Q4 - 2027	$359,744
LUG WSA 13217.10247858	13217	0.83	34	1	0	35	Q3 - 2026	Q3 - 2027	Q4 - 2027	$1,078,313
LUG WSA 13219.92527637	13219	1.58	39	2	0	41	Q3 - 2026	Q3 - 2027	Q4 - 2027	$2,054,000
LUG CSA 13832.91532289	13832	0.74	13	8	0	21	Q3 - 2026	Q3 - 2027	Q4 - 2027	$962,000
LUG WSA 13068.10688316	13068	0.62	9	7	0	16	Q3 - 2026	Q3 - 2027	Q4 - 2027	$806,000
LUG WSA 13060.92907479	13060	0.46	0	0	0	0	Q3 - 2026	Q3 - 2027	Q4 - 2027	$598,000
LUG WSA 13167.10160212	13167	0.24	69	4	0	73	Q3 - 2026	Q3 - 2027	Q4 - 2027	$311,723
LUG WSA 13081.60008652	13081	0.08	26	4	0	30	Q3 - 2026	Q3 - 2027	Q4 - 2027	$111,477
LUG WSA 13164.10158932	13164	1.62	13	1	1	15	Q3 - 2026	Q3 - 2027	Q4 - 2027	$2,106,000
LUG WSA 13201.91868130	13201	0.59	18	0	0	18	Q3 - 2026	Q3 - 2027	Q4 - 2027	$771,440
LUG WSA 13016.92132257	13016	0.19	22	2	0	24	Q3 - 2026	Q3 - 2027	Q4 - 2027	$240,530
LUG WSA 13756.10589590	13756	0.59	30	1	0	31	Q3 - 2026	Q3 - 2027	Q4 - 2027	$767,000
LUG WSA 13622.60048809	13622	0.73	3	3	0	6	Q4 - 2026	Q4 - 2027	Q4 - 2027	$985,500
LUG WSA 13219.90098743	13218	0.77	35	0	0	35	Q4 - 2026	Q4 - 2027	Q4 - 2027	$939,400
LUG WSA 13621.91418404	13621	0.42	5	1	0	6	Q4 - 2026	Q4 - 2027	Q4 - 2027	$546,000
LUG WSA 13740.90487798	13740	2.09	10	6	0	16	Q4 - 2026	Q4 - 2027	Q4 - 2027	$2,717,000
LUG CSA 13034.10142238	13034	0.64	17	1	0	18	Q4 - 2026	Q4 - 2027	Q4 - 2027	$840,708
LUG WSA 13065.92238609	13065	0.45	29	1	0	30	Q4 - 2026	Q4 - 2027	Q4 - 2027	$611,987
LUG WSA 13078.90444684	13078	1.26	45	0	0	45	Q4 - 2026	Q4 - 2027	Q4 - 2027	$1,638,000
LUG WSA 13194.10286125	13194	1.68	34	0	0	34	Q4 - 2026	Q4 - 2027	Q4 - 2027	$2,266,112
LUG CSA 13417.92035203	13417	0.60	16	2	0	18	Q4 - 2026	Q4 - 2027	Q4 - 2027	$732,000
LUG WSA 13737.10007252	13737	0.46	10	1	0	11	Q4 - 2026	Q4 - 2027	Q4 - 2027	$598,000
LUG ESA 13878.10105728	13878	0.23	0	0	0	0	Q4 - 2026	Q4 - 2027	Q4 - 2027	$313,210
LUG WSA 13754.90423524	13754	0.54	0	0	0	0	Q4 - 2026	Q4 - 2027	Q4 - 2027	$657,007
LUG CSA 14012.91181114	14012	0.65	22	0	0	22	Q4 - 2026	Q4 - 2027	Q4 - 2027	$787,963
LUG WSA 13198.94019819	13198	0.23	13	0	0	13	Q4 - 2026	Q4 - 2027	Q4 - 2027	$299,000
LUG CSA 13036.10143504	13036	0.75	3	4	0	7	Q4 - 2026	Q4 - 2027	Q4 - 2027	$918,443
LUG WSA 13754.90915815	13754	0.91	6	0	0	6	Q4 - 2026	Q4 - 2027	Q4 - 2027	$1,110,200
LUG WSA 13208.90152415	13208	0.17	0	1	0	1	Q4 - 2026	Q4 - 2027	Q4 - 2027	$229,500
LUG ESA 13686.93697046	13686	0.40	0	1	0	1	Q4 - 2026	Q4 - 2027	Q4 - 2027	$544,347
LUG WSA 13080	13080	7.25	1091	43	7	1,141	Q4 - 2026	Q4 - 2027	Q4 - 2027	$2,614,095
LUG WHA 13371	13371	6.79	417	33	5	455	Q4 - 2026	Q4 - 2027	Q4 - 2027	$2,426,907
LUG WSA 13162	13162	2.71	213	128	33	374	Q4 - 2026	Q4 - 2027	Q4 - 2027	$1,004,493
LUG PCA 13125	13125	3.83	404	24	12	440	Q4 - 2026	Q4 - 2027	Q4 - 2027	$827,292
LUG CSA 13051	13051	0.88	69	30	5	104	Q4 - 2026	Q4 - 2027	Q4 - 2027	$328,788
LUG CSA 13093	13093	3.17	629	39	1	669	Q4 - 2026	Q4 - 2027	Q4 - 2027	$1,150,150
LUG ESA 13228	13228	2.79	103	98	31	232	Q4 - 2026	Q4 - 2027	Q4 - 2027	$1,014,796
LUG WSA 13140	13140	1.86	202	51	13	266	Q4 - 2026	Q4 - 2027	Q4 - 2027	$688,416

Tampa Electric's Distribution Lateral Undergrounding - Year 2026 Details										
Project ID	Circuit No.	Specific Project Detail	Customers				Project Start Qtr	Construction		Project Cost in 2026
		OH to UG Length Converted (miles)	Residential	Small C&I	Large C&I	Total		Start Qtr	End Qtr	
LUG WSA 13165	13165	0.54	53	27	10	90	Q4 - 2026	Q4 - 2027	Q4 - 2027	$193,578
LUG WSA 13164	13164	1.77	273	7	0	280	Q4 - 2026	Q4 - 2027	Q4 - 2027	$646,555
LUG WHA 13288	13288	0.54	41	29	10	80	Q4 - 2026	Q4 - 2027	Q4 - 2027	$197,491
LUG WSA 13638	13638	0.98	44	19	5	68	Q4 - 2026	Q4 - 2027	Q4 - 2027	$306,430
LUG WSA 13738	13738	0.60	32	8	7	47	Q4 - 2026	Q4 - 2027	Q4 - 2027	$224,055
LUG WSA 13141	13141	0.74	227	17	3	247	Q4 - 2026	Q4 - 2027	Q4 - 2027	$281,797

Appendix D

Project Detail

Transmission Asset Upgrades

Tampa Electric's Transmission Asset Upgrades - Year 2026 Details						
Project ID	Circuit No.	Pole Count	Project Start Month	Construction		Project Cost in 2026
				Start Month	End Month	
Transmission Upgrades-69 kV-66833	66833	145	Jan-26	Jan-26	Dec-26	$5,787,530
Transmission Upgrades-138/230 kV-230037	230037	1	Jan-26	Jan-26	Dec-26	$57,210
Transmission Upgrades-69 kV-66653	66653	93	Jan-26	Jan-26	Dec-26	$3,712,002
Transmission Upgrades-69 kV-66004	66004	66	Jan-26	Jan-26	Dec-26	$2,634,324
Transmission Upgrades-69 kV-66655	66655	73	Jan-26	Jan-26	Dec-26	$2,913,722
Transmission Upgrades-69 kV-66831	66831	1	Jan-26	Jan-26	Dec-26	$39,914
Transmission Upgrades-69 kV-66651	66651	30	Jan-26	Jan-26	Dec-26	$1,197,420
Transmission Upgrades-69 kV-66058	66058	7	Jan-26	Jan-26	Dec-26	$279,398
Transmission Upgrades-69 kV-66012	66012	15	Jan-26	Jan-26	Dec-26	$598,710
Transmission Upgrades-138/230 kV-138005	138005	2	Jan-26	Jan-26	Dec-26	$79,828
Transmission Upgrades-69 kV-66835	66835	1	Jan-26	Jan-26	Dec-26	$39,914

The North American Electric Reliability Corporation ("NERC") defines the transmission system as lines operated at relatively high voltages varying from 69kV up to 765kV and capable of delivery large quantities of electricity. Tampa Electric's transmission system is made up of 69kV, 138kV and 230kV voltages and is designed to transmit power to the end-user 13.2kV distribution substations. As such, Tampa Electric does not attribute customer counts directly to individual transmission lines. It should be noted, that without Tampa Electric's transmission network in place, power could not be delivered to the distribution network which would result in automatic load loss.

Appendix E

Project Detail

Transmission Switch Hardening

No Transmission Switch Hardening

Projects Planned for 2026

Reserved for Future Use

Appendix F

Project Detail

Substation Extreme Weather Hardening

Tampa Electric's Substation Extreme Weather Hardening - Year 2026 Details				
Project	Project Start Month	Construction		Project Cost in 2026
		Start Month	End Month	
First Street	Jan-26	Jun-26	Oct-26	$1,800,450
Skyway	Jan-26	Jun-26	Oct-26	$1,990,026
Lake Agnes	Jan-26	Jun-26	Aug-26	$609,336
Trout Creek	Jan-26	Apr-26	Jul-26	$2,727,432
Estuary	Jan-26	Jun-26	Aug-26	$806,940
Project = Substation				

Appendix G

Project Detail

Distribution Overhead Feeder Hardening

Tampa Electric's Distribution Overhead Feeder Hardening - Year 2026 Details

Project ID	Circuit No.	Pole Count	Customers				Project	Construction		Project Cost in 2026
			Residential	Small C&I	Large C&I	Total	Start Month	Start Month	End Month	
SPP FH - Mulberry 13010	13010	102	998	314	72	1384	Jan-26	Jan-27	Dec-27	$236,598
SPP FH - Bloomingdale 13040	13040	13	6	9	3	18	Jan-26	Jan-27	Dec-27	$124,045
SPP FH - Fern Street 13045	13045	108	2244	180	52	2476	Jan-26	Jan-27	Dec-27	$189,907
SPP FH - Forty Sixth Street 13051	13051	47	164	142	54	360	Jan-26	Jan-27	Dec-27	$455,753
SPP FH - Mckinley 13057	13057	39	1	8	5	14	Jan-26	Jan-27	Dec-27	$380,815
SPP FH - Ivy Street 13068	13068	125	840	104	25	969	Jan-26	Jan-27	Dec-27	$144,219
SPP FH - Lois Avenue 13072	13072	73	640	117	34	791	Jan-26	Jan-27	Dec-27	$83,635
SPP FH - Baycourt 13080	13080	73	2564	130	34	2728	Jan-26	Jan-27	Dec-27	$1,855,381
SPP FH - Plymouth Street 13088	13088	74	466	41	7	514	Jan-26	Jan-27	Dec-27	$86,685
SPP FH - Plymouth Street 13090	13090	78	606	113	19	738	Jan-26	Jan-27	Dec-27	$93,371
SPP FH - Plymouth Street 13091	13091	180	1523	228	30	1781	Jan-26	Jan-27	Dec-27	$205,625
SPP FH - Plymouth Street 13093	13093	100	935	103	13	1051	Jan-26	Jan-27	Dec-27	$960,068
SPP FH - Alexander Road 13119	13119	77	12	28	22	62	Jan-26	Jan-27	Dec-27	$95,891
SPP FH - Alexander Road 13123	13123	123	786	224	38	1048	Jan-26	Jan-27	Dec-27	$199,285
SPP FH - Plant City 13125	13125	77	527	48	17	592	Jan-26	Jan-27	Dec-27	$753,557
SPP FH - Habana Avenue 13137	13137	29	252	22	0	274	Jan-26	Jan-27	Dec-27	$34,394
SPP FH - Hyde Park 13140	13140	55	386	86	22	494	Jan-26	Jan-27	Dec-27	$509,983
SPP FH - Hyde Park 13141	13141	35	1334	168	28	1530	Jan-26	Jan-27	Dec-27	$325,955
SPP FH - Matanzas 13162	13162	87	589	188	56	833	Jan-26	Jan-27	Dec-27	$882,399
SPP FH - Matanzas 13164	13164	39	823	27	3	853	Jan-26	Jan-27	Dec-27	$375,607
SPP FH - Matanzas 13165	13165	33	251	64	28	343	Jan-26	Jan-27	Dec-27	$318,489
SPP FH - Matanzas 13167	13167	136	1262	279	60	1601	Jan-26	Jan-27	Dec-27	$152,792
SPP FH - Madison 13170	13170	51	15	10	3	28	Jan-26	Jan-27	Dec-27	$587,741
SPP FH - Double Branch 13193	13193	23	9	7	2	18	Jan-26	Jan-27	Dec-27	$33,866
SPP FH - Brandon 13228	13228	87	138	226	59	423	Jan-26	Jan-27	Dec-27	$1,302,315
SPP FH - Caloosa 13233	13233	37	87	16	9	112	Jan-26	Jan-27	Dec-27	$364,311
SPP FH - Caloosa 13235	13235	27	9	5	0	14	Jan-26	Jan-27	Dec-27	$31,781
SPP FH - Caloosa 13236	13236	40	37	18	0	55	Jan-26	Jan-27	Dec-27	$387,632
SPP FH - Lake Silver 13288	13288	38	53	66	18	137	Jan-26	Jan-27	Dec-27	$410,438
SPP FH - Lake Silver 13289	13289	53	294	68	20	382	Jan-26	Jan-27	Dec-27	$75,116
SPP FH - Lake Silver 13292	13292	67	456	16	3	475	Jan-26	Jan-27	Dec-27	$114,928
SPP FH - Sun City 13304	13304	52	34	12	8	54	Jan-26	Jan-27	Dec-27	$551,236
SPP FH - Skyway 13317	13317	7	110	6	4	120	Jan-26	Jan-27	Dec-27	$7,823
SPP FH - Dade City 13329	13329	111	1578	618	120	2316	Jan-26	Jan-27	Dec-27	$130,031
SPP FH - Twenty Seventh Street 13348	13348	104	1666	312	64	2042	Jan-26	Jan-27	Dec-27	$120,541
SPP FH - Twenty Seventh Street 13349	13349	16	4	9	4	17	Jan-26	Jan-27	Dec-27	$18,833
SPP FH - Hyde Park 13360	13360	9	5	6	0	11	Jan-26	Jan-27	Dec-27	$88,281
SPP FH - Dairy Road 13371	13371	60	970	72	14	1056	Jan-26	Jan-27	Dec-27	$1,916,247
SPP FH - Cypress Street 13451	13451	30	2	14	11	27	Jan-26	Jan-27	Dec-27	$294,208
SPP FH - Lakewood 13454	13454	48	215	64	11	290	Jan-26	Jan-27	Dec-27	$576,920
SPP FH - Lakewood 13455	13455	56	158	107	28	293	Jan-26	Jan-27	Dec-27	$120,069
SPP FH - Alexander Road 13463	13463	63	236	83	9	328	Jan-26	Jan-27	Dec-27	$74,472
SPP FH - Alexander Road 13464	13464	82	503	86	11	600	Jan-26	Jan-27	Dec-27	$94,437
SPP FH - Woodlands 13484	13484	91	34	30	13	77	Jan-26	Jan-27	Dec-27	$961,437
SPP FH - Del Webb 13494	13494	38	0	7	2	9	Jan-26	Jan-27	Dec-27	$377,888
SPP FH - Forty Sixth Street 13499	13499	30	0	8	10	18	Jan-26	Jan-27	Dec-27	$359,432
SPP FH - State Road 574 13509	13509	89	280	72	20	372	Jan-26	Jan-27	Dec-27	$107,840
SPP FH - Stadium 13518	13518	29	65	18	7	90	Jan-26	Jan-27	Dec-27	$284,461
SPP FH - Carrollwood Village 13538	13538	28	21	26	25	72	Jan-26	Jan-27	Dec-27	$31,708
SPP FH - Dale Mabry 13584	13584	42	0	6	3	9	Jan-26	Jan-27	Dec-27	$69,256
SPP FH - Macdill 13606	13606	58	110	7	3	120	Jan-26	Jan-27	Dec-27	$71,351
SPP FH - Tampa Bay Blvd 13635	13635	6	3	11	4	18	Jan-26	Jan-27	Dec-27	$7,062
SPP FH - Tampa Bay Blvd 13637	13637	80	62	28	2	92	Jan-26	Jan-27	Dec-27	$757,300
SPP FH - Tampa Bay Blvd 13638	13638	25	179	67	11	257	Jan-26	Jan-27	Dec-27	$245,225
SPP FH - Rhodine Road 13652	13652	12	209	3	0	212	Jan-26	Jan-27	Dec-27	$14,125
SPP FH - Hampton 13655	13655	65	435	60	13	508	Jan-26	Jan-27	Dec-27	$614,241
SPP FH - Meadow Park 13670	13670	8	18	2	2	22	Jan-26	Jan-27	Dec-27	$10,034
SPP FH - Meadow Park 13671	13671	27	15	12	5	32	Jan-26	Jan-27	Dec-27	$264,843
SPP FH - Meadow Park 13673	13673	1	0	11	1	12	Jan-26	Jan-27	Dec-27	$9,809
SPP FH - Tampa Palms 13718	13718	15	5	1	0	6	Jan-26	Jan-27	Dec-27	$25,684
SPP FH - Tampa Palms 13719	13719	33	50	19	6	75	Jan-26	Jan-27	Dec-27	$354,573
SPP FH - Clearview 13738	13738	55	188	50	23	261	Jan-26	Jan-27	Dec-27	$539,495
SPP FH - Casey Road 13748	13748	102	702	216	74	992	Jan-26	Jan-27	Dec-27	$120,032
SPP FH - Granada 13756	13756	65	866	126	17	1009	Jan-26	Jan-27	Dec-27	$74,959
SPP FH - Boyscout 13761	13761	33	13	28	5	46	Jan-26	Jan-27	Dec-27	$339,135
SPP FH - Mckinley 13844	13844	54	18	25	10	53	Jan-26	Jan-27	Dec-27	$609,030
SPP FH - Imperial Lakes 13850	13850	2	0	3	0	3	Jan-26	Jan-27	Dec-27	$3,589
SPP FH - Patterson Road 13860	13860	46	25	33	4	62	Jan-26	Jan-27	Dec-27	$432,118
SPP FH - Henderson Road 13872	13872	4	0	2	0	2	Jan-26	Jan-27	Dec-27	$37,500
SPP FH - Henderson Road 13873	13873	38	70	25	11	106	Jan-26	Jan-27	Dec-27	$384,646
SPP FH - Providence Road 13878	13878	39	88	50	13	151	Jan-26	Jan-27	Dec-27	$45,073
SPP FH - Providence Road 13879	13879	6	96	28	2	126	Jan-26	Jan-27	Dec-27	$6,646
SPP FH - Providence Road 13884	13884	5	169	22	9	200	Jan-26	Jan-27	Dec-27	$18,824
SPP FH - Providence Road 13885	13885	7	154	16	0	170	Jan-26	Jan-27	Dec-27	$8,240
SPP FH - First Street 13899	13899	75	462	146	42	650	Jan-26	Jan-27	Dec-27	$85,422
SPP FH - First Street 13900	13900	90	48	54	16	118	Jan-26	Jan-27	Dec-27	$106,131
SPP FH - Peach Avenue 13906	13906	107	1018	150	42	1210	Jan-26	Jan-27	Dec-27	$123,699
SPP FH - Lake Ruby 13920	13920	49	52	22	9	83	Jan-26	Jan-27	Dec-27	$57,469
SPP FH - Lake Magdalene 13934	13934	49	31	23	6	60	Jan-26	Jan-27	Dec-27	$482,315
SPP FH - Terrace 13961	13961	1	103	6	1	110	Jan-26	Jan-27	Dec-27	$1,177
SPP FH - Trout Creek 13986	13986	10	3	6	2	11	Jan-26	Jan-27	Dec-27	$11,771
SPP FH - Trout Creek 13990	13990	5	8	2	0	10	Jan-26	Jan-27	Dec-27	$49,045
SPP FH - Riverview 14022	14022	4	12	19	5	36	Jan-26	Jan-27	Dec-27	$17,647
SPP FH - Sunlake 14070	14070	67	99	23	8	130	Jan-26	Jan-27	Dec-27	$78,864
SPP FH - Pebble Creek 14090	14090	5	2	11	4	17	Jan-26	Jan-27	Dec-27	$49,045
SPP FH - Pebble Creek 14091	14091	1	0	2	0	2	Jan-26	Jan-27	Dec-27	$9,809
SPP FH - Lakewood 14117	14117	6	12	99	15	126	Jan-26	Jan-27	Dec-27	$7,062
SPP FH - Fishhawk 14121	14121	14	254	62	12	328	Jan-26	Jan-27	Dec-27	$549,279
SPP FH - Sun City 14145	14145	4	3	5	1	9	Jan-26	Jan-27	Dec-27	$4,708
SPP FH - Massaro 14199	14199	34	1	38	18	57	Jan-26	Jan-27	Dec-27	$343,798
SPP FH - Wilderness 14218	14218	34	3	0	0	3	Jan-26	Jan-27	Dec-27	$333,506
SPP FH - Washington Street 14226	14226	11	5	29	2	36	Jan-26	Jan-27	Dec-27	$107,899
SPP FH - Wolfbranch 14317	14317	1	180	12	2	194	Jan-26	Jan-27	Dec-27	$1,177
SPP FH - Tucker Jones 14396	14396	25	290	40	11	341	Jan-26	Jan-27	Dec-27	$29,276

Appendix H

Project Detail

Distribution Storm Surge Hardening

Tampa Electric's Distribution Storm Surge Hardening - Year 2026 Details						
Project ID	Circuit No.	Structure Count	Project Start Month	Construction Start Month	Construction End Month	Project Cost in 2026
SSH-TBD300	Multiple	174	Jan-26	Jan-27	Dec-27	$174,000

Appendix I

1898 & Co, Tampa Electric's Storm Protection Plan Resilience Benefits Report

1898 & CO
PART OF BURNS & McDONNELL

2026-2035 STORM PROTECTION PLAN RESILIENCE BENEFITS REPORT

TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC COMPANY RESILIENCE PLAN

PROJECT NO. 162728

January 9, 2025

CONTENTS

FIGURES

TABLES

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
LOF	Likelihood of Failure
MED	Major Event Day
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
POF	Probability of Failure
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

1.0 Executive Summary

Tampa Electric Company (TEC) engaged the services of 1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, to assist with the development of the 2026 to 2035, 10-year Storm Protection Plan (SPP) required by Florida Statute 366.96, also known as Senate Bill 796. In collaboration, TEC and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the Transmission and Distribution (T&D) system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model are:

1. Calculate the customer benefit of hardening projects due to reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish a long-term SPP that optimizes cost, maximizes customers' benefit, and does not exceed TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's SPP. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of both reduced restoration costs and reduced Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit in several ways. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customer interruptions (CI), and others decrease the duration of storm-related outages. This report provides only the reduction in CMI, which reflects both reduced interruptions and decreased durations. Of note, there is a strong relationship between reduction in CMI and reduction in CI.

Resilience-based prioritization identifies the hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening

Other programs within TEC's SPP are not evaluated or included in this report. The benefits and prioritization of those programs are described in other parts of TEC's SPP.

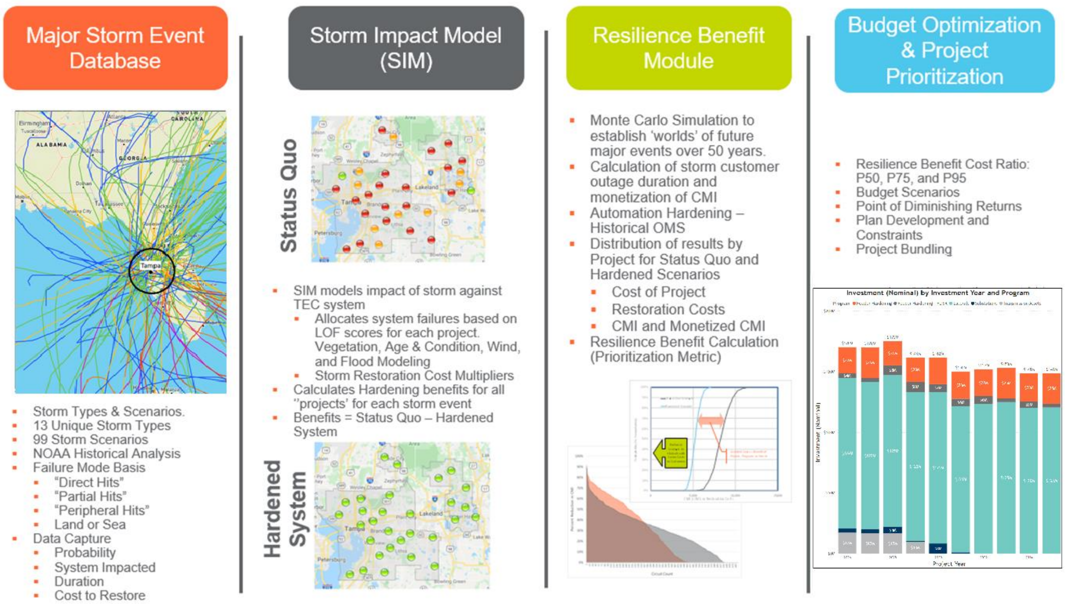
Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs, CI, and CMI. Each of the different components are reviewed in further detail in Sections 3.0, 4.0, 5.0, and 6.0.

The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios. The storm scenarios range from a Category 3 or greater direct hit from the Gulf of Mexico to a Category 1 or 2 partial hit over Florida[1], to a tropical storm. Section 3.0 provides additional details on the 99 different storm scenarios.

[1] "Over Florida" or "Florida Side" in this report refers to weather events that approach TECO's territory generally from the east, where it travels over land before striking the territory.

Figure 1-1: Storm Resilience Model Overview



Each storm scenario is modeled within the Storm Impact Model to identify those parts of the system most likely to fail during the storm scenario. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the applicable wind zone for the asset's location. The Resilience Model is comprehensive in that it evaluates nearly all of TEC's T&D system. Table 1-1 provides an overview of the potential project count for each of the programs.

Table 1-1: Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	847
Transmission Asset Upgrades	46
Substation Extreme Weather Hardening	6
Distribution Overhead Feeder Hardening	689
Total	1,588

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1, during each storm scenario. In this report, the term “project” refers to a collection of assets. Assets are typically organized from a customer-impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit received, in decreased restoration costs and CMI, by hardening each project, per TEC’s hardening standards. The CMI benefit is monetized using the U.S. Department of Energy (DOE)’s Interruption Cost Estimator (ICE) to enable project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to produce 1,000 different, future storm worlds. Each of these storm worlds includes a randomly selected quantity for each of the 13 unique storm types, based upon that storm type’s probability. These 1,000 future storm worlds provide an expected range of benefit values, based on the impacts to the TEC system of the probabilistically determined storm types. Calculating a scenario-probability weighted sum of each project’s benefits (from the Storm Impact Model) provides a resilience-weighted benefit for each project, in dollars. Distribution Overhead Feeder Hardening projects are evaluated based on both the historical outages and the expected decrease in historical outages if automation had been in place.

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

The optimization model prioritizes each project based on the sum of the restoration-cost benefit and the monetized CMI benefit, divided by the project cost, which is to say, the project’s resilience benefit cost ratio. The model also incorporates TEC’s technical and operational constraints in scheduling the projects such as contractor capacity and scheduling planned transmission outages. Using the Resilience Benefit Calculation and Project Scheduling and Budget Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

1.1 Key Updates to Storm Resilience Model from 2022 to 2031 SPP to 2026 to 2035 SPP

The following are the key updates from the 2022-2031 to the 2026-2035 Storm Resilience Model:

1. General – These updates include shifting of the time horizon, adding additional years of storms to the historical analysis, and accounting for previously completed projects.

2. Capital Cost Assumptions – Based on actual completed projects and communicated increases in commodity prices, the cost assumptions for all project types were adjusted.

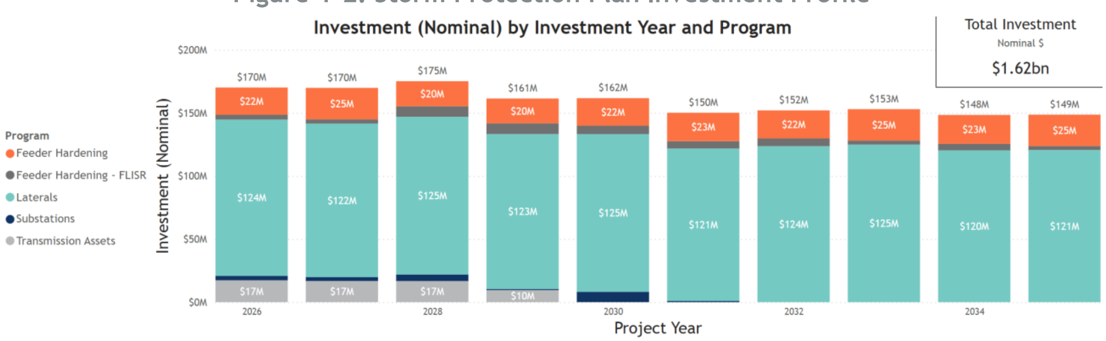
3. Site Access Project Development – This program is not currently part of TEC's SPP.

4. Lateral Undergrounding Circuit Project Approach – Based on continued lessons learned from the lateral undergrounding program, TEC has refined its lateral undergrounding project approach for this SPP. TEC has determined that the analysis should assume all laterals on a circuit will be undergrounded as part of the 1898 & Co. analysis. This change will enhance the ability for TEC to contract out work and deliver benefits to all TEC customers on a circuit. Although the model assumes each lateral on a circuit will be undergrounded, during detailed distribution planning and engineering review, TEC may determine some lateral sections that need not be undergrounded (e.g., feeds abandoned meter, crosses waterway, crosses railroad). By undergrounding all the electrically connected protection zones off a circuit feeder / mainline, TEC will be better able to anticipate costs and to design work that minimizes the number of new underground miles. It should be noted that TEC still has lateral undergrounding projects being designed and constructed as part of its previous SPP. The analysis assumes these segments will be completed as planned to avoid duplicating costs or benefits.

1.2 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to establish budget levels by program and to identify and prioritize resilience investment in the T&D system. Figure 1-2 shows the SPP investment profile. The figure includes the buildup by program to the total. The investment capital costs are in nominal dollars, that is, the dollars of that day. The overall plan investment level is approximately $1.62 billion. Lateral undergrounding makes up most of the total, accounting for approximately 77.7 percent of the total investment. Distribution Overhead Feeder Hardening is the second-largest program, at 17.2 percent. Transmission upgrades make up approximately 3.7 percent of the total, while substations making up 1.4 percent.

Figure 1-2: Storm Protection Plan Investment Profile

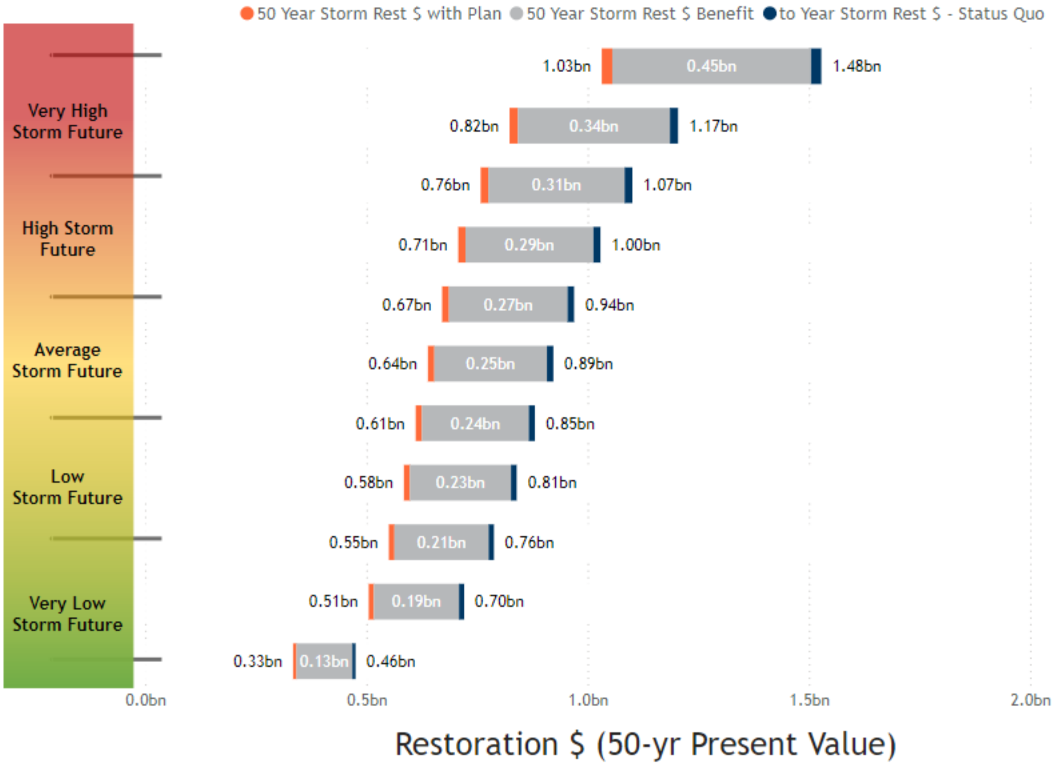


Customer benefits are calculated in terms of the:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 1-3 shows the range in restoration cost reduction at various levels of storm-future severity. An average storm future is one in which storm frequencies and impacts range from approximately the 50th percentile (P50) to the 65th percentile (P65) of all storm futures. Similarly, high storm futures and very-high storm futures have P70-to-P85 and P90-to-P95 levels, respectively.

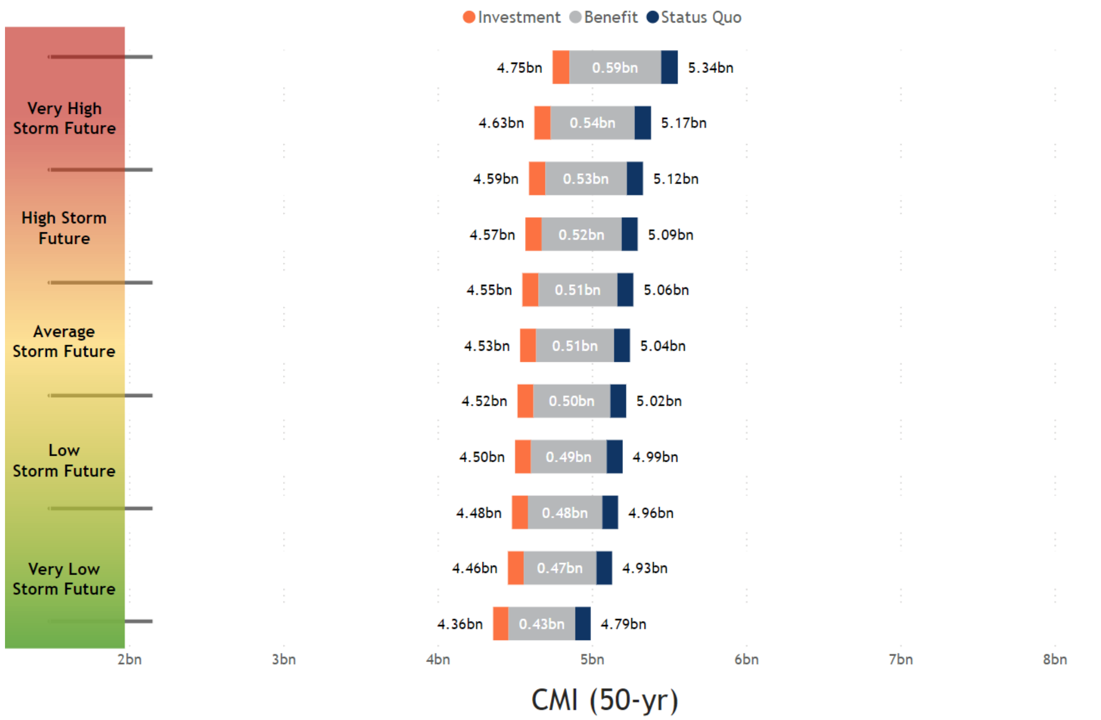
Figure 1-3: Storm Protection Plan Restoration Cost Benefit



The figure shows that the 50-year NPV of future storm restoration costs, in the Status Quo case, ranges from $460 million to $1,480 million. With the SPP, those restoration costs decrease by approximately 28 to 30 percent, a reduction of approximately $130 to $450 million. In NPV terms, the restoration-cost reduction is approximately 8 to 28 percent of the SPP Investment Level. In other words, reduced restoration costs pay for 8 to 28 percent of the total invested capital costs.

Figure 1-4 shows the range in CMI reduction at various levels of storm-future severity. The figure shows relative consistency in CMI benefit level across the storm futures, with storm CMI decreasing by approximately 10 percent over the next 50 years.

Figure 1-4: Storm Protection Plan Customer Benefit



Evaluating TEC's SPP with the Storm Resilience Model provides the following conclusions:

- The overall investment level of $1.62 billion for TEC's SPP is reasonable and provides customers with maximum benefits.
- TEC's SPP reduces storm restoration costs by approximately 28 to 30 percent. In relation to the plan's capital investment, the restoration costs savings range from 8 to 28 percent depending on future storm frequency and impacts.
- The storm CMI decreases by approximately 10 percent over the next 50 years. This decrease comes from eliminating certain outages all together, reducing the number of customers interrupted during outages, and decreasing the length of those outage times.
- The cost associated with purchasing the reduction in storm CMI (that is, the total Investment less the Restoration-Cost Benefits) is in the range of $1.98 to $3.46 per minute. This entire range is less than the outage costs derived from the DOE ICE Calculator and less than typical 'willingness to pay' found with customer surveys.

- TEC's mix of hardening investment strikes a balance between investing in substations and the transmission system to, primarily, increase resilience for high impact / low probability events and investing in the distribution system, to increase resilience for all event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored in this report.

2.0 Introduction

Hurricanes have inflicted significant damage to Florida in recent years and parts of the state face years of recovery. In 2024 alone, TEC experienced Debby (category 1), Helene (category 4), and Milton (category 3). One of the most important things Florida can do to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. Florida businesses and families save money because they can get back on their feet more quickly[2]. Florida Statute 366.96 allows for the comprehensive planning and front-end investment necessary to protect Florida's power supply. It also allows utilities to design integrated programs to address all phases of resilience which, in turn, will reduce storm-related restoration costs and outage times.

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and reduced impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system

The resilience-based approach is an integrated data driven decision-making strategy comparing various storm hardening projects on a normalized and consistent basis. This approach takes an integrated asset management perspective, a bottom-up approach starting at the asset level. Each asset is evaluated for its LOF in a storm event. Additionally, the consequence of failure is also evaluated at the asset level in terms of the restoration costs and CMI. Assets are rolled up to hardening projects and hardening projects are then rolled up to programs. Each project only hardens the assets that provide the most benefit to customers and that align with TEC's design standards.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades

[2] State Rep. Randy Fine and State Sen. Joe Gruters, Sun Sentinel, May 2019

- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening

Other programs within TEC's SPP are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's SPP.

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- The topic of resilience
- Resilience as the project assessment approach
- TEC asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

Resilience has many faces. It looks different to different people and organizations depending on their challenges and focus. Is it more important to avoid an event from disrupting your business or is it more important to recover quickly? Both are important and TEC's approach considers both of these questions and more.

Resilience has been defined differently by many organizations. In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) paraphrased its own definition of resilience in a manner that is simple and easy to understand.

"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and includes elements used in many other definitions. It states that resilience is

"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description. The difference is that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time, the precursors are normally detectable.
- Respond (During)
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

Hardening of the overhead transmission system is targeted at the "prepare" phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stress on the grid by monitoring it. Responding to an event as it is impacting the grid depends on the ability to make informed decisions, to deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and good planning.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, site access, feeder, and lateral). Section 2.3 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of TEC's T&D system. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**743**
Feeder Poles	[count]	61,805
Lateral Poles	[count]	120,005
Feeder OH Primary	[miles]	2,386
Lateral OH Primary	[miles]	3,737
Transmission Circuits	**[count]**	**229**
Wood Poles	[count]	3,087
Steel / Concrete / Lattice Structures	[count]	21,832
Conductor	[miles]	882
Substations	**[count]**	**9**

All of the assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, a trip saver, or a fuse. For lateral undergrounding projects, each lateral on a circuit was grouped together as a single project, except for projects already slated to be completed under SPP2. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all weak links in the circuit and for capturing the full benefit for customers.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. Since the main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e., bigger and stronger poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '1' were also included in these projects. The combination of physical hardening and automation hardening provides significant resilience benefits for feeders. Physical hardening addresses the weakened-infrastructure storm failure component. While the vegetation outside the trim zone is still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than the corresponding densities for laterals. Further, the fault location isolation and service restoration (FLISR) projects within Distribution Overhead Feeder Hardening allow for automated switching to perform 'self-healing' functions that mitigate vegetation outside trim zone and other types of outages. The combination of physical hardening and FLISR provides a balanced resilience strategy for feeders. It should be noted that this balanced strategy with FLISR is not available for laterals. As such, undergrounding is the preferred approach for lateral hardening and overhead physical hardening combined with FLISR is the preferred approach for feeders.

At the transmission-circuit level, wood poles were identified for hardening by replacing with non-wood materials like steel, spun concrete, and composites. These materials have consistent external shell strength while wood poles can vary widely and are more likely to fail. Transmission wood poles were grouped at the circuit level into projects.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category. Based on TEC's more detailed assessment, 6 substations remaining for this SPP[3] that included flooding risk to the level that could justify investment.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. The following sections outline the approach to selecting the

[3] The previous SPP had 9 substations evaluated. Starting with this SPP in 2026, there will be 6 remaining

hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2: Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	847
Transmission Asset Upgrades	46
Substation Extreme Weather Hardening	6
Distribution Overhead Feeder Hardening	689
Total	1,588

2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

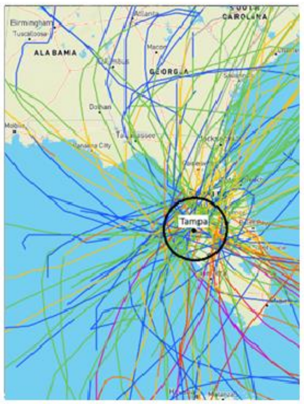
Figure 2-1 provides an overview of the resilience planning approach to calculate the customer benefit, restoration cost reduction and CMI reduction of hardening projects and prioritization of the projects.

2.3.1 Major Storm Event Database

Since the magnitudes of the restoration-cost decrease and the CMI decrease are dependent on the frequency and magnitude of future major storm events, the Storm Resilience Model starts with the ‘universe’ of major storm events that could impact TEC’s service territory, the Major Storm Event Database.

Figure 2-1: Resilience Planning Approach Overview

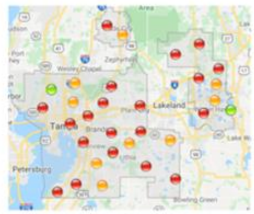
Major Storm Event Database



- Storm Types & Scenarios.
- 13 Unique Storm Types
- 99 Storm Scenarios
- NOAA Historical Analysis
- Failure Mode Basis
  - "Direct Hits"
  - "Partial Hits"
  - "Peripheral Hits"
  - Land or Sea
- Data Capture
  - Probability
  - System Impacted
  - Duration
  - Cost to Restore

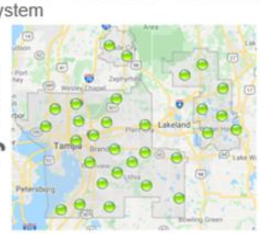
Storm Impact Model (SIM)

Status Quo



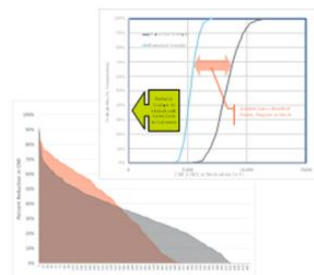
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all "projects' for each storm event
- Benefits = Status Quo – Hardened System

Hardened System



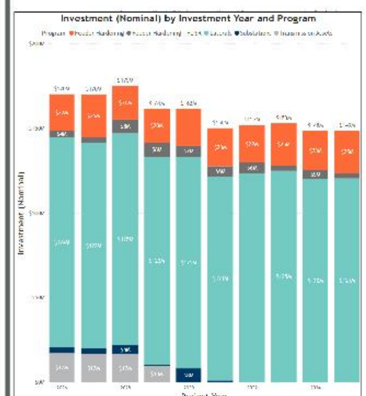
Resilience Benefit Module

- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration Costs
  - CMI and Monetized CMI
- Resilience Benefit Calculation (Prioritization Metric)



Budget Optimization & Project Prioritization

- Resilience Benefit Cost Ratio: P50, P75, and P95
- Budget Scenarios
- Point of Diminishing Returns
- Plan Development and Constraints
- Project Bundling



The Major Storm Event Database describes the stressors that cause system failure. The database also provides a high-level impact to the system of the storm stressors. The database includes the following:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The Major Storm Event Database has 13 unique storm types. The storm types include the various hurricane categories and direction they come from (hurricane impacts from the Gulf side are much different than from the Florida side). Each storm type has a range of probabilities and impacts. With the various combinations (high probability with lower consequence and low probability with high consequence, etc.) the Major Storms Event Database includes 99 different storm scenarios. Section 3.0 provides additional details on the Major Storm Event Database.

2.3.2 Storm Impact Model

Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact Model calculates the restoration costs and customers impacted by system failures for both the Status Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the TEC asset base.

For circuits, the main cause of failure is wind blowing vegetation onto a conductor, causing a conductor or structures to fail. If structures (i.e., wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilize expected remaining life curves with the asset’s ‘effective’ age, determined using condition data. The wind zone rating is based on the wind zone in which the asset is located. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank projects against each other to identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood-modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types.

Once the Storm Impact model identifies the portions of the system that are damaged and cause an outage for a specific storm, it then calculates the restoration costs to rebuild the system and restore service. The restoration costs are based on multipliers that convert planned-replacement costs into storm-replacement costs. The restoration cost multipliers are based on historical storm events and reflect the expected higher costs of both outside labor and expedited material charges during a storm restoration, when compared to the typical costs for TEC labor and routinely procured materials.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes.

Finally, the Storm Impact Model then calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 99 storms in both the Status Quo and Hardened scenarios.

2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to produce 1,000 different, future storm worlds. Each of these storm worlds includes a randomly selected quantity for each of the 13 unique storm types, based upon that storm type's probability. These 1,000 future storm worlds provide an expected range of benefit values, based on the impacts to the TEC system of the probabilistically determined storm types. Calculating a scenario-probability weighted sum of each project's benefits (from the Storm Impact Model) provides a resilience-weighted benefit for each project, in dollars. Distribution Overhead Feeder Hardening projects are evaluated based on both the historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4 Project Scheduling and Budget Optimization

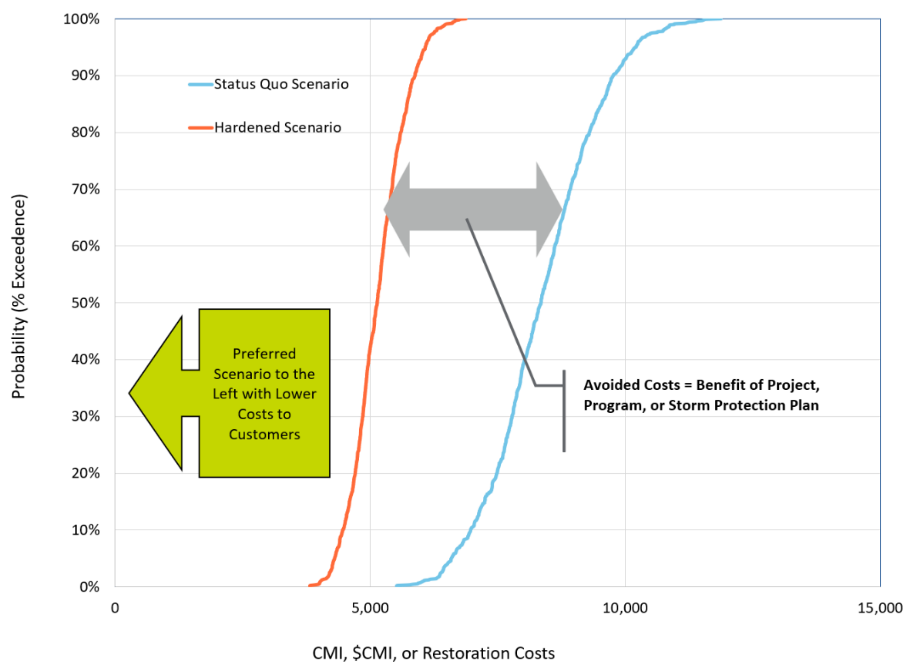
The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

The optimization model prioritizes each project based on the sum of the restoration-cost benefit and the monetized CMI benefit, divided by the project cost, which is to say, the project's resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling planned transmission outages. Using the Resilience Benefit Calculation and Project Scheduling and Budget Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

2.4 S-Curves and Resilience Benefit

The results from the 1,000 storm futures, or iterations, are graphed in a cumulative density function, also known as an 'S-Curve'. In simple terms, the results from the thousand futures are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-2 shows an illustrative example of 1,000 iteration results for the Status Quo and Hardened Scenarios.

Figure 2-2: Status Quo and Hardened Results Distribution Example

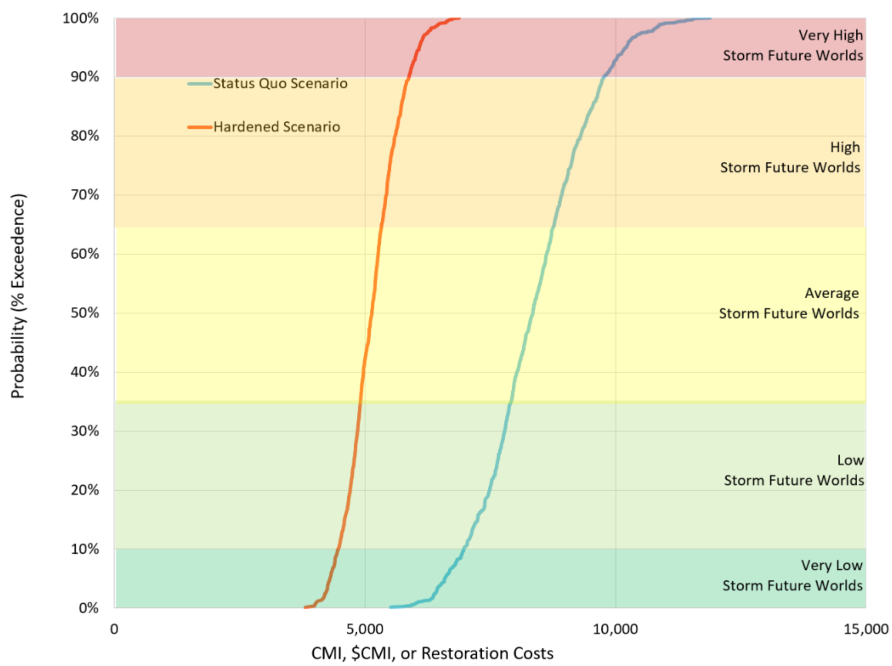


The horizontal axis shows the storm cost in terms of CMI, monetized CMI ($CMI), or restoration costs. (The values in the figure are illustrative.) The vertical axis shows the percent exceedance values, that is, the likelihood that the particular cost will be no greater than the value on the horizontal axis. For example, in the Hardened Scenario (the orange line), the chart shows that there is a 40 percent probability that the cost will be no greater than 5,000. Each of these probability levels can be referred to as a P-value. In this case the P40 (40th percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left, i.e., the scenario with lower costs. The gap or delta between the two curves is the overall benefit.

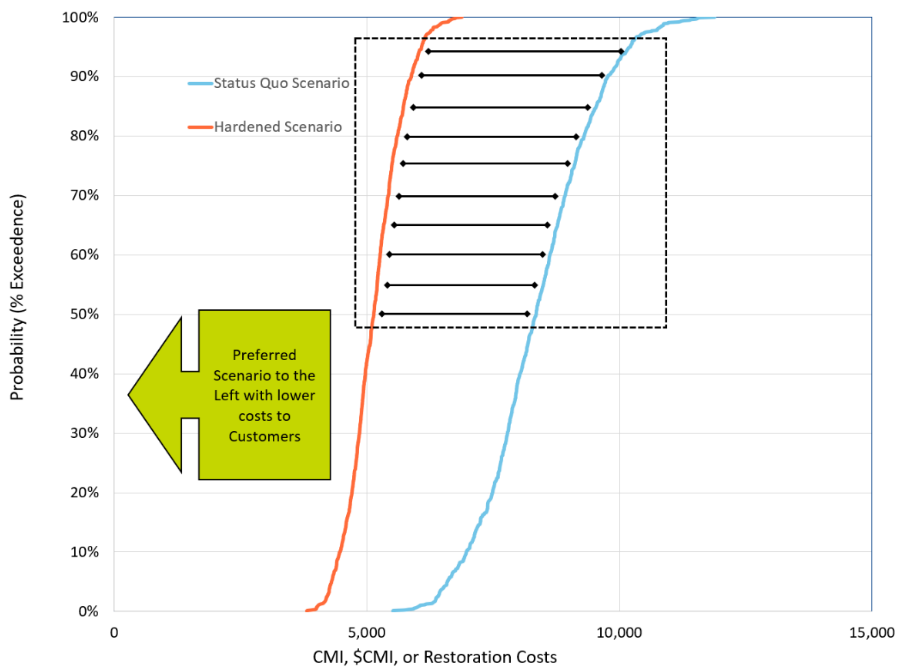
The S-Curves typically have a near-vertical slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e., vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-3 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

Figure 2-3: S-Curves and Future Storms



For the storm-resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Figure 2-4 illustrates this concept of looking at the top part of the S-curves and showing the P-values.

Figure 2-4: S-Curves and Resilience Focus



3.0 Major Storm Event Database

The first main component of the Storm Resilience Model is the Major Storm Event Database. The database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for a range of storm stressors. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range of storm types that could impact TEC's service territory. The impact of major storm events on the TEC system is dependent on the following:

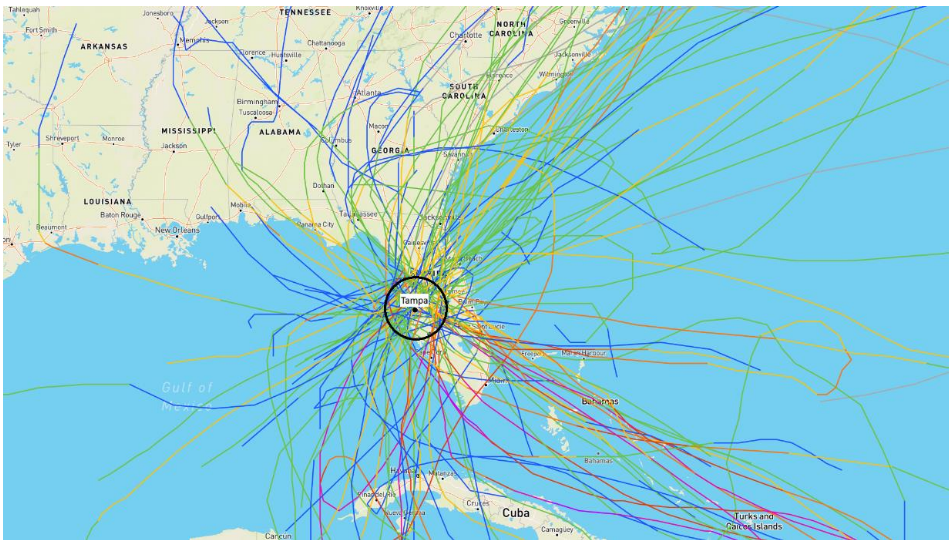
- Wind speeds of the storm (i.e., category of storm). Higher wind speeds mean more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- Direction that it comes from (Gulf or Florida). Gulf storms, i.e., those entering TEC's service territory directly from the Gulf of Mexico, could bring storm surge and associated flooding. Florida storms, that is, those entering TEC's service territory from over land, do not present these added storm-surge risks. Additionally, the counter-clockwise storm band rotation provides different levels of energy (i.e., wind speed) depending on whether they have been over land for a period of time.
- Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, perhaps only a few storm bands will the TEC service territory.

The major storm event database includes the range of storm stressors that would cause an outage(s) to the TEC system based on the three main contributing factors above. The database includes both the probability of the storm stressor, impact in terms of restoration costs and duration, and impact with respect to which parts of the TEC system fail. The following sections provide additional analysis and commentary on how these assumptions were developed for the storm event database.

3.1 Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 172 years, beginning in 1851. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

Figure 3-1: NOAA Example Output – 50 Mile Radius



Source: https://coast.noaa.gov/hurricanes/

This database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

- 'Direct Hits' – 50 Mile Radius from the Gulf and Florida directions. The max wind speeds hit all or significant portions of TEC service territory twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.

- 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, reducing damage relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' from a small storm.
- 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1851.

Table 3-1: Historical Storm Summary[4]

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	3
Cat 3	0	1	1	5	4	11
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	46
Tropical Storm	11	20	31	30	30	122
Tropical Depression	9	8	17	17	NA	51
Total	30	37	67	68	51	248

[4] Table includes information as of November 2023 to align with the basis of the analysis.

Table 3-1 shows 248 storms hitting the Tampa area since 1851. Of these, 67 were direct hits within 50 miles, 68 were partial hits between 51 and 100 miles, and 51 were peripheral hits between 101 and 150 miles. The table indicates zero category 5 storms and very few category 4 storms: 3 out of 248, with one ‘Direct Hit’. While there have been 11 Category 3 storms, only 1 was a ‘Direct Hit’. We see that nearly 20 percent of the events were Category 1 Hurricanes, while almost 70 percent of the events were Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 45 percent of events come from the Gulf of Mexico while the other 55 percent come over Florida. The direction of the storm has significant impact on the overall damage to TEC’s system. Based on these results and the various quantities by event type, the following 13 unique storm types serve as the foundation for the Major Storms Event Database:

1. Category 3 and Above ‘Direct Hit’ from the Gulf
2. Category 1 & 2 ‘Direct Hit’ over Florida
3. Category 1 & 2 ‘Direct Hit’ from the Gulf
4. Tropical Storm ‘Direct Hit’
5. Tropical Depression ‘Direct Hit’
6. Localized Event ‘Direct Hit’
7. Category 3 and Above ‘Partial Hit’
8. Category 1 & 2 ‘Partial Hit’
9. Tropical Storm ‘Partial Hit’
10. Tropical Depression ‘Partial Hit’
11. Category 3 and Above ‘Peripheral Hit’
12. Category 1 & 2 ‘Peripheral Hit’
13. Tropical Storm ‘Peripheral Hit’

Each of these storm types serve as a stressor on the system that may cause outages and damage. The next three subsections provide a historical analysis of storm events that impacted TEC’s Service Territory to provide information on the probability of each of the 13 storm types.

3.1.1 Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1851 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

Figure 3-2: "Direct Hits" (50 Miles) Over Time[5]

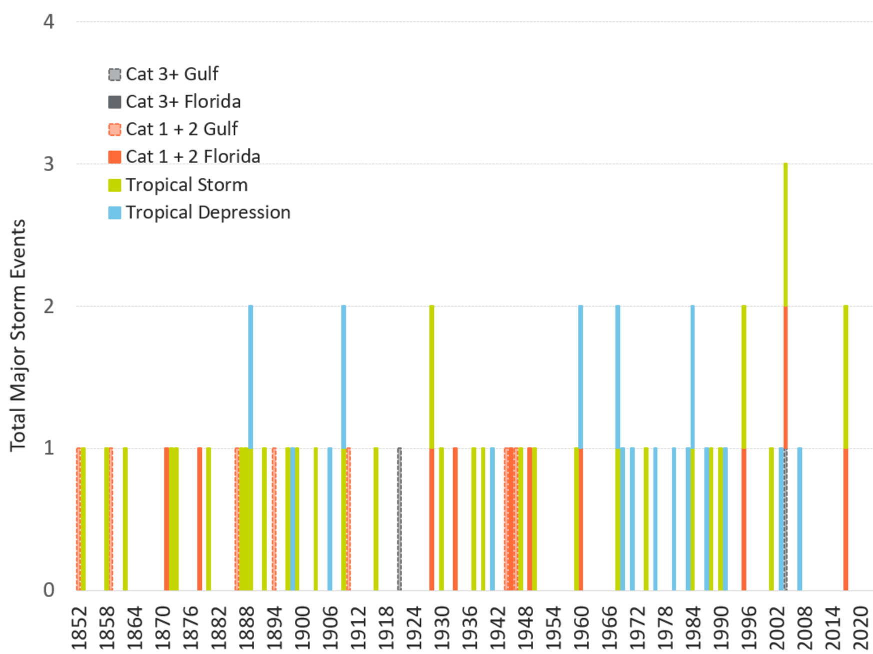
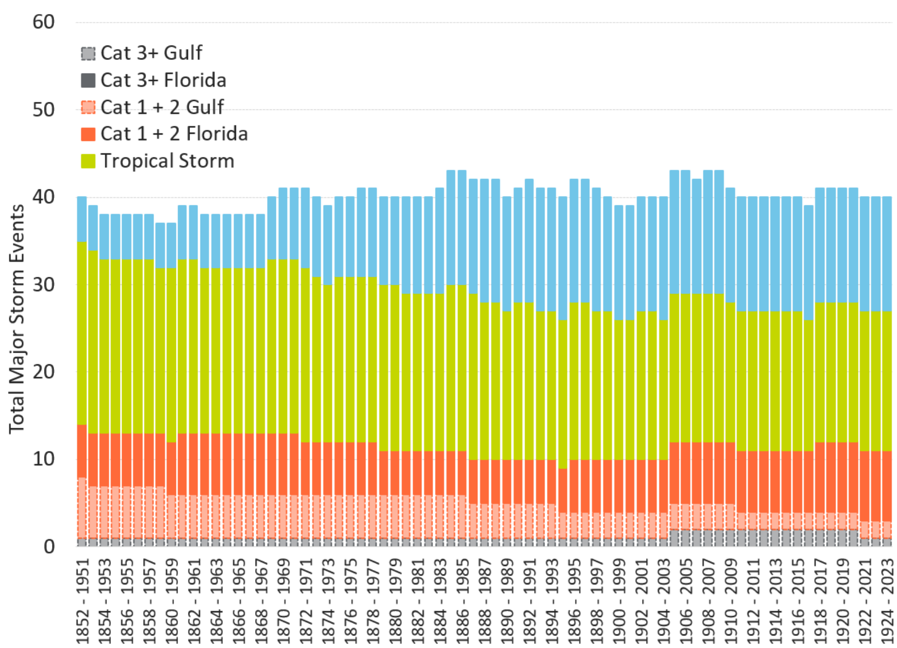


Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from, ending 1951 to 2023. The rolling 100-year average results show a stable number of 'Direct Hits' over the time horizon. The figure shows relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100. (Note that lines in Figure 3-4 are not stacked.)

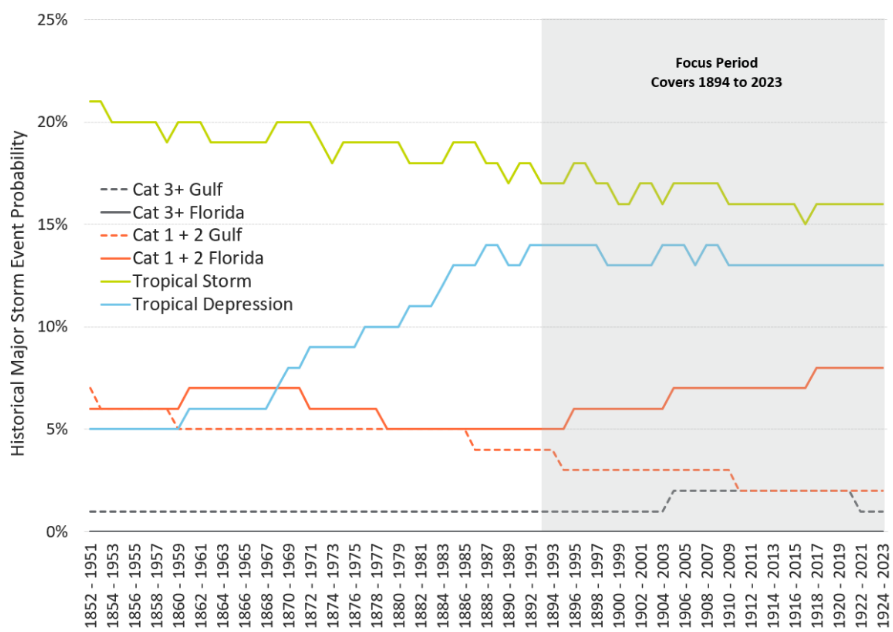
[5] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 3-3: "Direct Hits" (50 Miles) 100 Year Rolling Average[6]



[6] See Footnote 5

Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[6]



The figure shows a low historical probability of 1 to 3 percent for Category 3 and above events from the Gulf. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Depression until 1993 and stabilizes thereafter. As the figure shows, the probabilities of failure show relative stability for the 100-year rolling average probabilities from 1993 to 2023, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.2 Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 172 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory. The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1851 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

Figure 3-5: "Partial Hits" (51 to 100 Miles)[7]

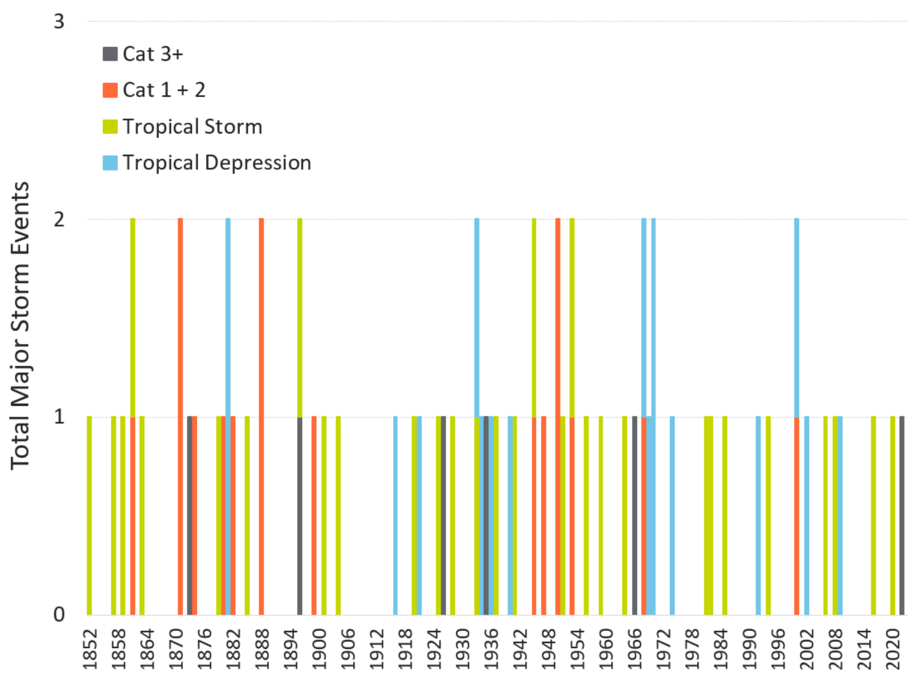
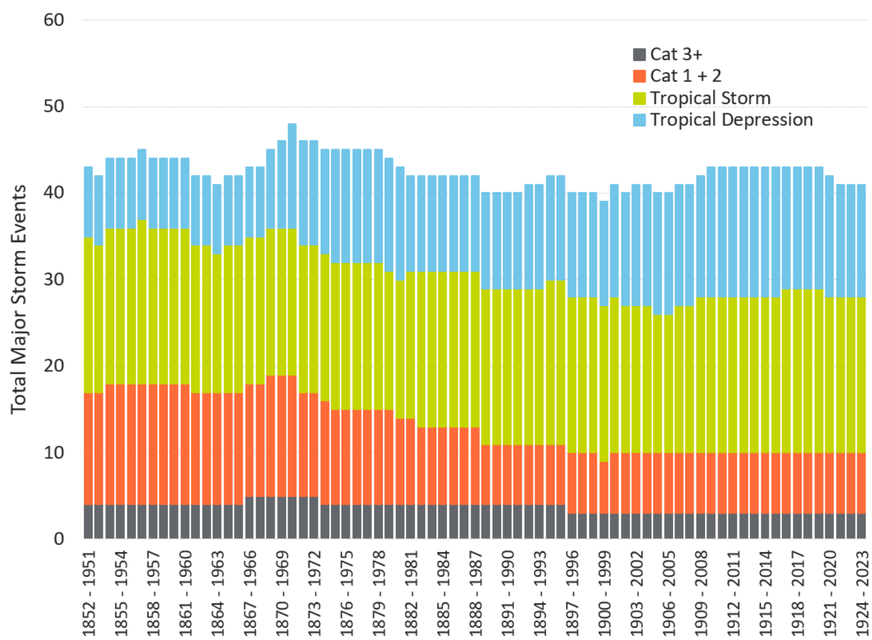


Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2023. The rolling 100-year average results show a stable number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

Figure 3-7 converts the totals for each 100-year period in Figure 3-6 to probabilities by dividing by 100. This figure further illustrates the change in storm type distributions as Category 1 and 2 storms gave way to tropical depressions. The reason for the shift is unknown, but it is possible that this change is due to increases in data accuracy or recording procedures over time.

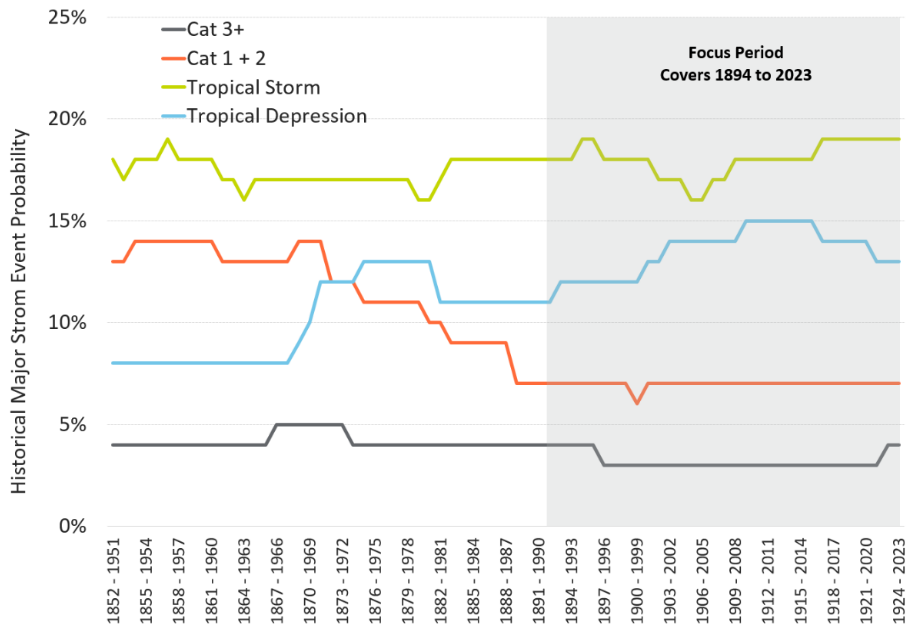
[7] See Footnote 5

Figure 3-6: "Partial Hits" (51 to 100 Miles) 100 Year Rolling Average[8]



[8] See Footnote 5

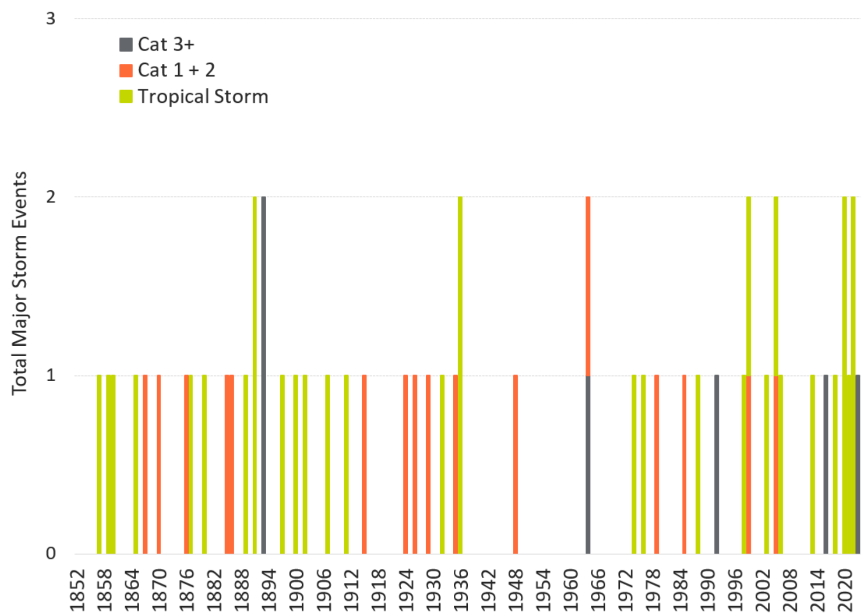
Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[8]



3.1.3 Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 172 years. A storm is classified as a peripheral hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1853 to 1952.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[9]



The 100-year rolling average of storm events for peripheral hits shows a slight decline from 30 to 25 storms, mostly driven by a decline in Tropical Storms.

Figure 3-10 converts the totals for each 100-year period in Figure 3-9 by dividing by 100. This figure further illustrates the decline in probability of Tropical Storms over the analysis period.

[9] See Footnote 5

Figure 3-9: "Peripheral Hits" (101 to 150 Miles) 100 Yr. Rolling Avg.[10]

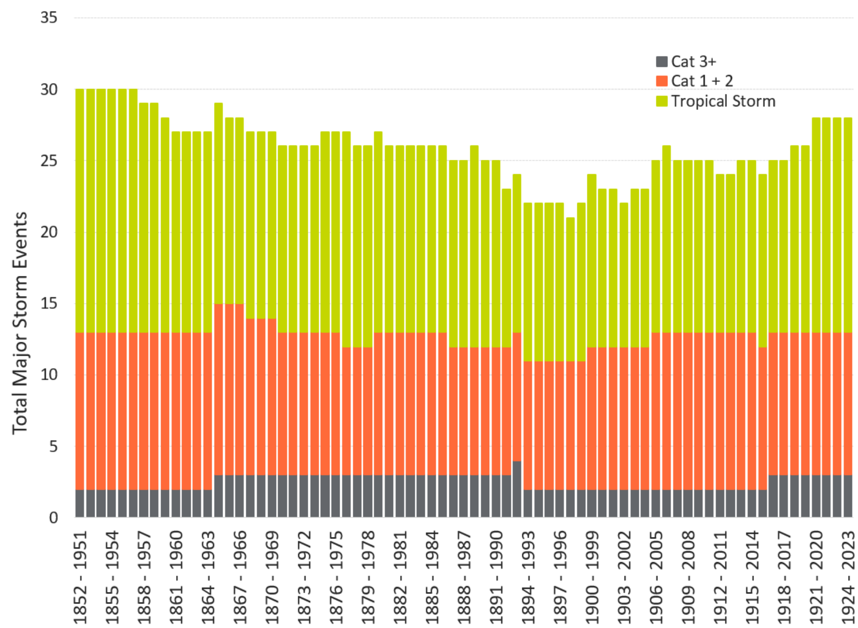
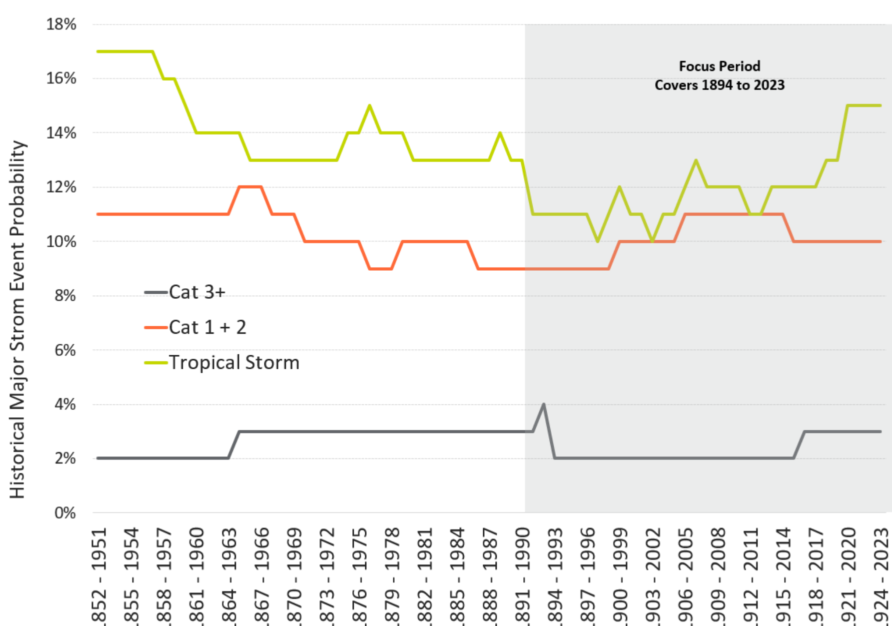


Figure 3-10: "Peripheral Hits" (101 to 150 Miles) 100 Yr. Rolling Probability[10]



[10] See Footnote 5

3.2 Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 172 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

> "Though there is evidence both for and against the existence of a detectable anthropogenic signal in the tropical cyclone climate record to date, no firm conclusion can be made on this point. However, research shows that there is evidence that the magnitude of the events are and will continue to increase."

Given this research, the Major Storm Event Database utilizes the historical probabilities for future storm probability. The impact of the events is discussed in the next section.

3.3 Major Storms Impact

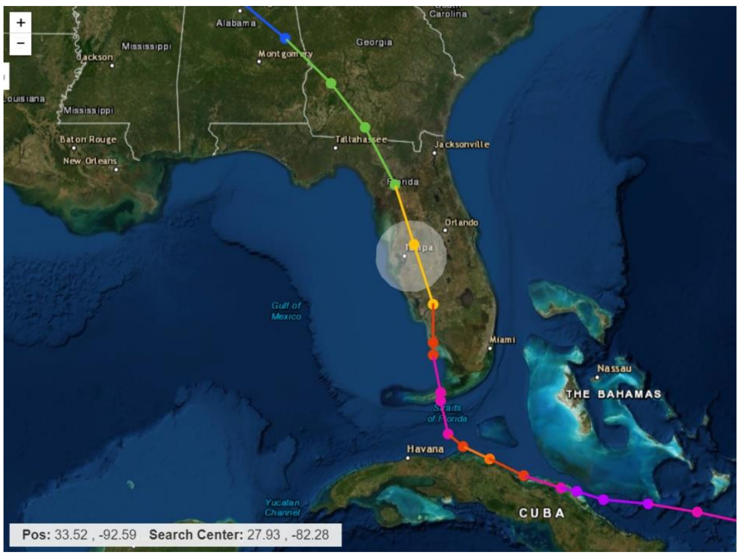
Table 3-2 shows the damages cost of recent major storms to hit the Southeast United States. The table shows that the costs of these major events are significant.

Table 3-2: Recent Major Event Damages Cost

Storm Name	Category	Year	Damages (2024 $Billions)
Milton	3	2024	>$85(estimate)
Helene	4	2024	>$88(estimate)
Idalia	3	2023	$4
Ian	4	2022	$113
Sally	2	2020	$7
Michael	5	2018	$32
Irma	1	2017	$65
Matthew	2	2016	$13
Wilma	3	2005	$13
Dennis	3	2005	$4
Jeanne	3	2004	$11
Ivan	3	2004	$24
Frances	2	2004	$15
Charley	4	2004	$24

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 through Figure 3-17 provide a summary of the recent storms that have impacted TEC in the last several years. Table 3-3 provides a summary of other recent TEC storms.

Figure 3-11: Hurricane Irma Impact to TEC Service Territory[11]



Storm Name: Irma
Year: 2017
TECO Cost: ~$102 million
Category: 1 over Florida
Radius: 50 miles

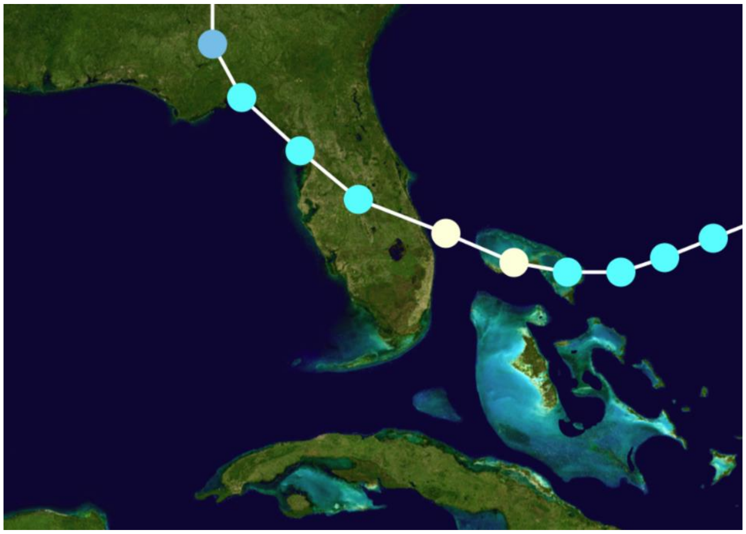
[11] See Footnote 5

Figure 3-12: Hurricane Ian Impact to TEC Service Territory[12]

Storm Name: Ian
Year: 2022
TECO Cost: ~$131 million
Category: 4 from Gulf
Radius: 50 miles

[12] See Footnote 5

Figure 3-13: Hurricane Nicole Impact to TEC Service Territory[13]



Storm Name: Nicole
Year: 2022
TECO Cost: ~$2 million
Category: 1 over Florida
Radius: 50 miles

[13] See Footnote 5

Figure 3-14: Hurricane Idalia Impact to TEC Service Territory[14]

Storm Name: Idalia

Year: 2023

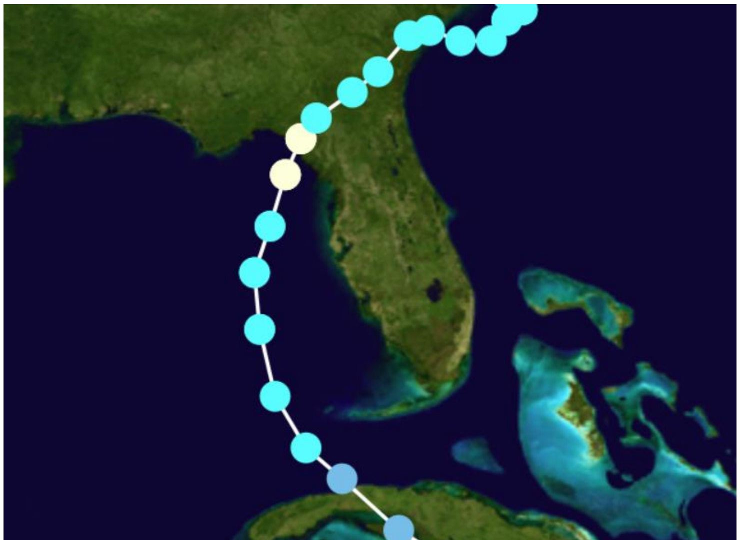
TECO Cost: ~$35 million

Category: 3 from Gulf

Radius: 50 miles

[14] See Footnote 5

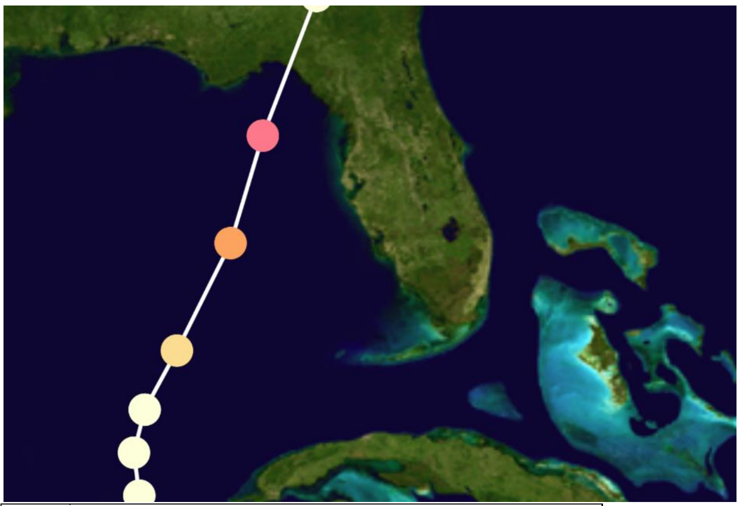
Figure 3-15: Hurricane Debby Impact to TEC Service Territory[15]



Storm Name: Debby
Year: 2024
TECO Cost: ~$7 million
Category: 1 from Gulf
Radius: 50 miles

[15] See Footnote 5

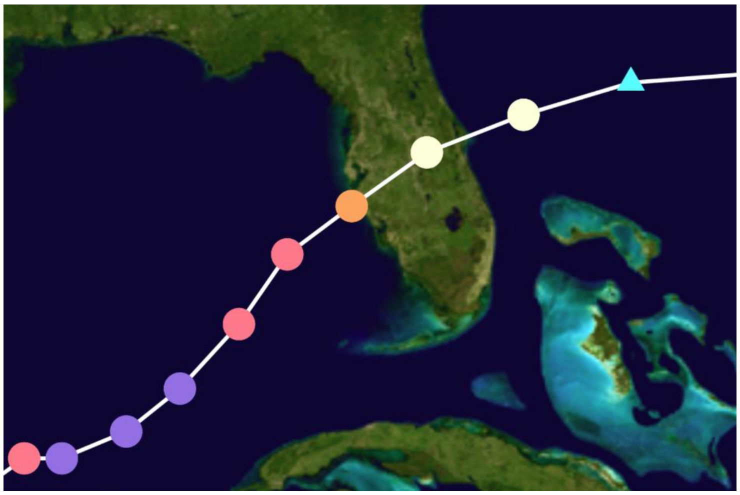
Figure 3-16: Hurricane Helene Impact to TEC Service Territory[16]



Storm Name: Helene
Year: 2024
TECO Cost: ~$53 million (estimated)
Category: 4 from Gulf
Radius: 50 miles

[16] See Footnote 5

Figure 3-17: Hurricane Milton Impact to TEC Service Territory[17]



Storm Name: Milton
Year: 2024
TECO Cost: ~$357 million (estimated)
Category: 3 from Gulf
Radius: 50 miles

[17] See Footnote 5

Table 3-3: Storm Report Summary

Storm Name	Category	Year	Damages ($Millions)
Milton	3	2024	~$357[1]
Helene	4	2024	~$53[1]
Debby	1	2024	$7
Idalia	3	2023	$35
Nicole	1	2022	$2
Ian	4	2022	$131
Irma	1	2017	$102
Matthew	2	2016	$1

[1] Damage costs for Milton and Helene are estimated.

Major Storm Event Database

TEC and 1898 & Co collaborated in developing the Major Storm Event Database. The database utilizes the results of the NOAA analysis to identify 13 unique storm types. Given the range of storm probabilities, the range in costs for each unique storm type, and the range in system impacts, the analysis further decomposes the 13 unique storm types into 99 different storm events, or scenarios. Table 3-4 provides a summary of the Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration. Each of the 99 storm events are then modeled within the Storm Impact Model described more in the next section.

Table 3-4 Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$306 - $1,224	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit - Florida	5.0% - 8.0%	$76.5 - $153	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit - Gulf	2.0% - 7.0%	$153 - $306	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25.5 - $76.5	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	13.3%	$5.1 - $15.3	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.102 - $1.53	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3.0% - 5.0%	$91.8 - $184	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15.3 - $91.8	8.5% - 28%	1.9 - 6.9
9	TS Partial Hit	16% - 19%	$11.5 - $30.6	8% - 15%	2.0 - 3.6
10	TD Partial Hit	8% - 15%	$0.4 - $3.1	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2.0% - 3.0%	$0.8 - $ 21.8	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.8	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.9	0.7% - 3.4%	0.9 - 1.3

4.0 Storm Impact Model

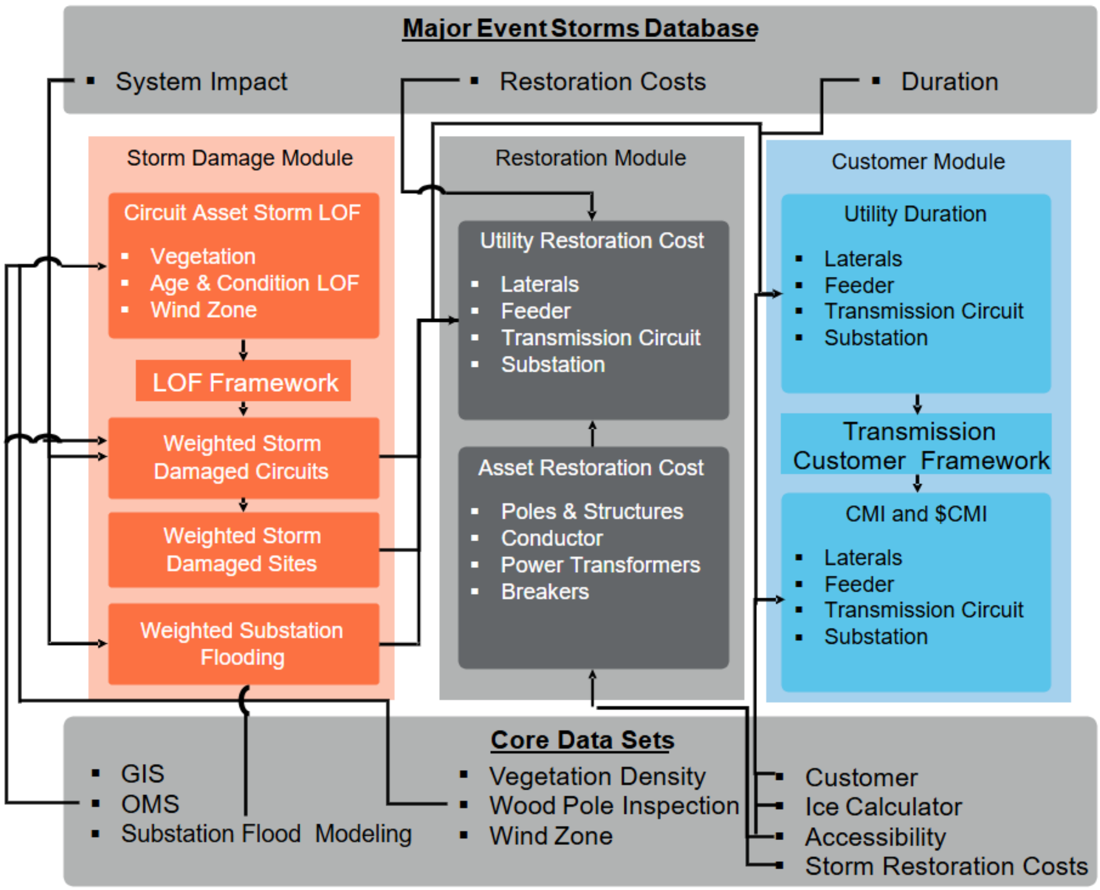
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storm Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the TEC T&D system for each storm stressor scenario.

The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened scenario. The Hardened scenario assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and reduced CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. This section of the report outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model. It outlines a very granular level of analysis of the TEC System. This granular level of data and analysis allows for the Storm Resilience Model to accurately calculate the ratio of resilience benefit to cost resulting in more efficient hardening investment. This also provides confidence that investments are targeted at the portions of the system that provide the most value for customers.

Figure 4-1 provides an overview of the Storm Impact Model architecture. The following sections describe each of the core modules in more detail.

Figure 4-1: Storm Impact Model Overview



4.1 Core Data Sets and Algorithms

As discussed above, the resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Impact Model. TEC's data systems include a connectivity model that allows for the linkage of the three foundational data sets used in the Storm Impact Model – the Geographic Information System (GIS), the Outage Management System (OMS), and Customer Information.

4.1.1 Geographical Information System

GIS serves as the first of three foundational data sets for the Storm Impact Model. GIS provides a list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management, bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the SPP.

In alignment with this methodology, TEC utilized the connectivity in their GIS model to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, TEC and 1898 & Co. were able to use the asset level information from Table 4-1 and convert it to the project level summaries in Table 4-2. It is important to note that each asset in Table 4-1 is tied to one of the projects listed in Table 4-2, which provides a bottom-up analysis.

Table 4-1: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**743**
Feeder Poles	[count]	61,805
Lateral Poles	[count]	120,005
Feeder OH Primary	[miles]	2,386
Lateral OH Primary	[miles]	3,737
Transmission Circuits	**[count]**	**229**
Wood Poles	[count]	3,087
Steel / Concrete / Lattice Structures	[count]	21,832
Conductor	[miles]	882
Substations	[count]	**9**

Table 4-2: Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	847
Transmission Asset Upgrades	46
Substation Extreme Weather Hardening	6
Distribution Overhead Feeder Hardening	689
Total	1,588

4.1.2 Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 20 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightning, and storm-based outages. The OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3 Customer Type Data

TEC provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Impact Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing a specified number of customers to be without service. The model also knows what type of customers are served by each asset; residential, small or large commercial, small or large industrial, and priority customers. This customer information is included for every distribution asset in the TEC system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected multiplied by outage duration) for each storm for each lateral or feeder project. Table 4-3 below shows the count of customers by class from TEC's service territory that have been linked to assets in the Storm Impact Model.

Table 4-3: Customer Counts by Type

Customer Type	Customer Count
Residential	778,266
Small Commercial and Industrial	75,565
Large Commercial and Industrial	18,703
Total	872,534

4.1.4 Vegetation Density Algorithm

The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet grids across the entire TEC system. The 100-feet square grid size is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 240,000) a vegetation density is assigned based on the grid the conductor goes through. This information is used within the LOF framework to identify the portions of the system most likely to have an outage for each type of storm.

Figure 4-2 and Figure 4-3 show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 30 to 35 percent of the conductor spans (not weighted by length) for OH Primary and Transmission Conductor have near zero tree canopy coverage, while the remaining 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 4-2: Vegetation Density on TEC Primary Conductor

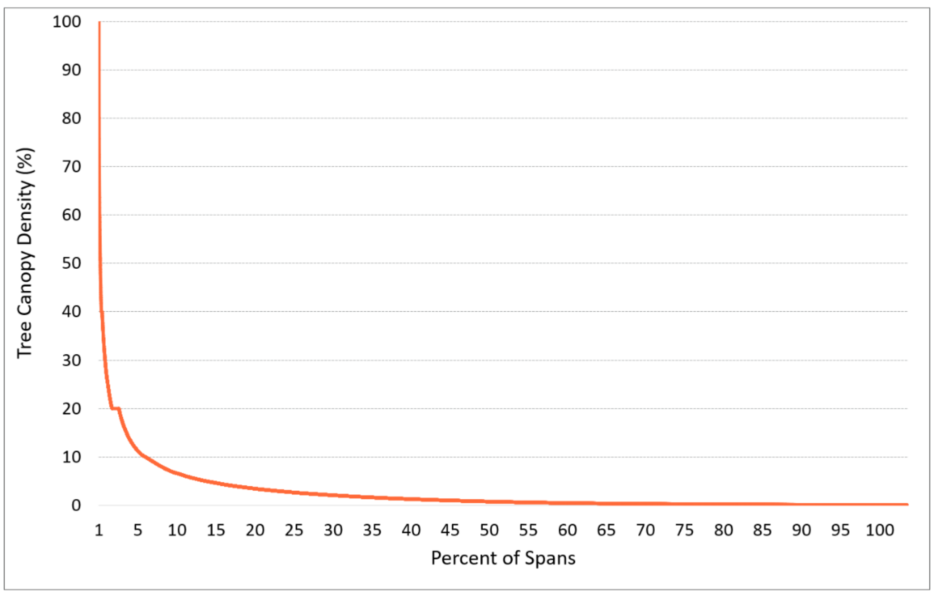
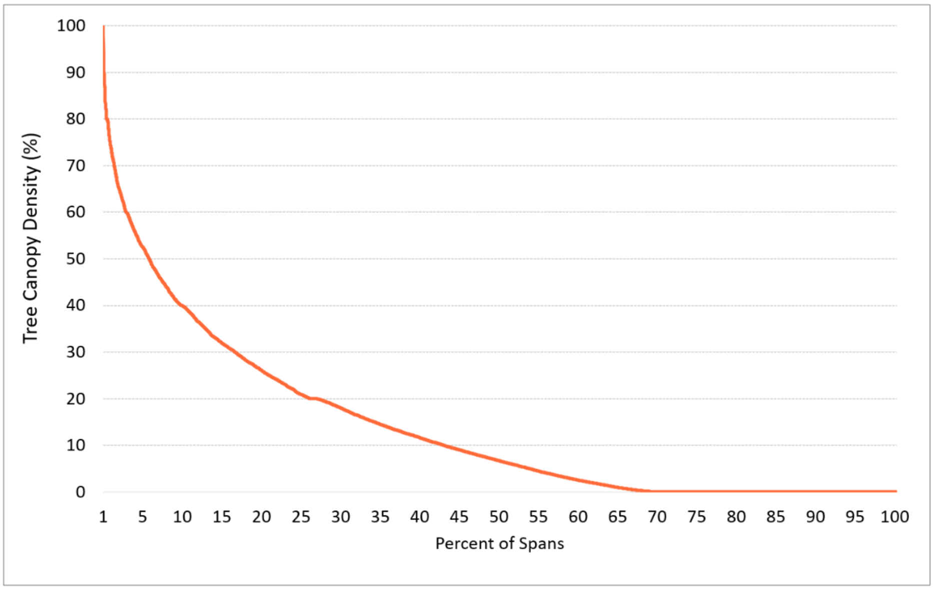


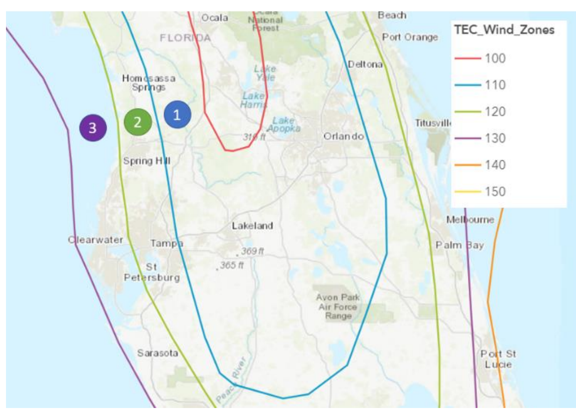
Figure 4-3: Vegetation Density on TEC Transmission Conductor



4.1.5 Wood Pole Inspection Data

A compromised, or semi-compromised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within the 1898 & Co. asset health algorithm to calculate an Asset Health Index and ‘effective’ age for each pole. Section 4.2.2 outlines the approach for using the ‘effective’ age for assets to calculate the age and condition-based LOF.

4.1.6 Wind Zone



A third driver of storm-based failure is the asset’s location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-7 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

4.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storm Event Database. The module is grounded in the primary failure mode of the asset base; storm surge and associated flooding for substations and wind, asset condition, and vegetation for circuit assets.

4.2.1 Substation Storm Likelihood of Failure

The main driver of substation failures during major storm events is flooding. The Major Storm Event Database designates the number of substations expected to have minor and major flooding for each of the 99 storm scenarios. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary conditions to produce storm surge that would cause substation flooding.

To identify which substations would be the most likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.5.3. This model provides the estimated feet of flooding above site elevation, assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme, worst-case scenario, the results are not reflective of a typical hurricane category that would hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

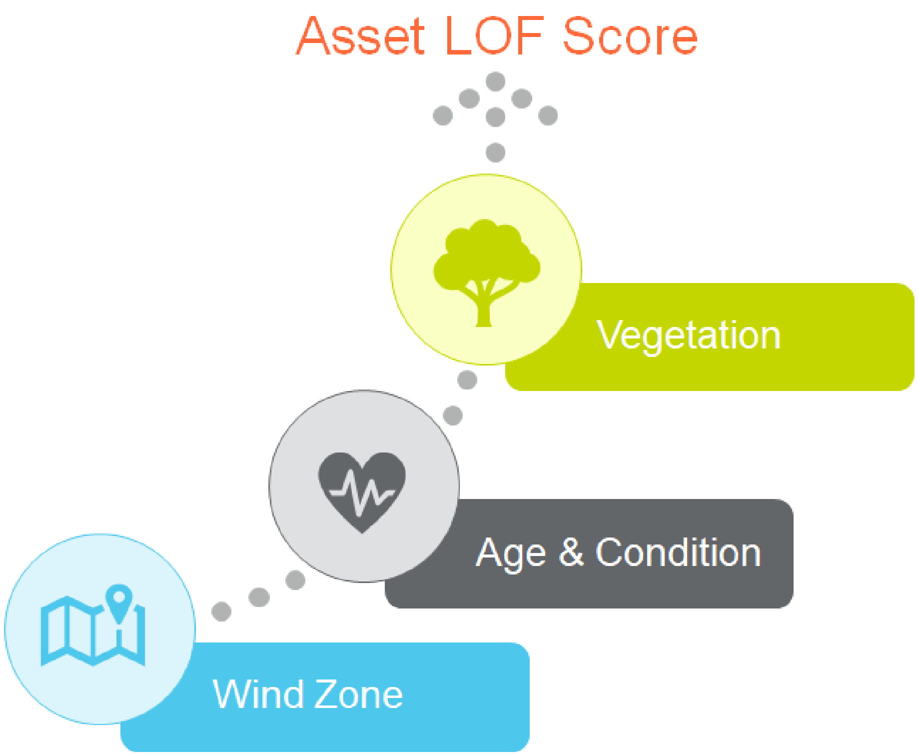
4.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into conductor. The conductor is weighed down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate, however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age and condition of the asset, and the applicable wind zone (coastal zones see higher wind speeds).

Figure 4-4 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density, normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

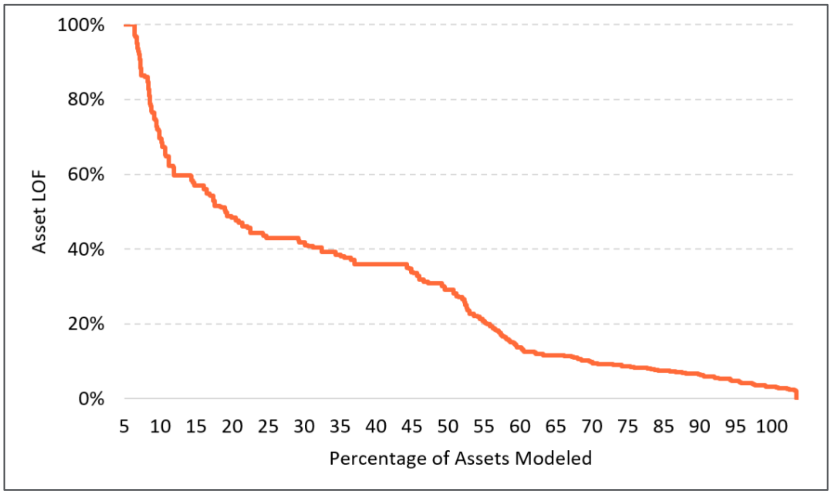
Figure 4-4: Storm LOF Framework for Circuit Assets



The Storm Impact Model utilizes 1898 & Co.'s Aging Infrastructure Model to estimate the age and condition-based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. The model uses industry standard survivor curves with an asset class expected average service life and the asset's 'effective' age (or calendar age if condition data is not available) to estimate the age and condition-based LOF over the next 10 years. Condition data for wood poles was used to factor in any rot or impacts to the pole's ground-line circumference. Section 4.1.5 outlines the wood pole inspection data used in the 'effective' age calculations.

Figure 4-5 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition-based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute, on average, 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-5: Age & Condition LOF Distribution



The wind zone criteria use the wind zone designation data from Section 4.1.6 inside the asset LOF framework to develop the LOF scores. Overall, the wind zone contributes, on average, 5 to 10 percent of system LOF depending on the storm scenario.

The Storm Impact Model uses the sum of the three criteria (vegetation, age & condition, and wind zone) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project POF for each storm event in the Major Storms Event Database.

4.3 Project & Asset Reactive Storm Restoration

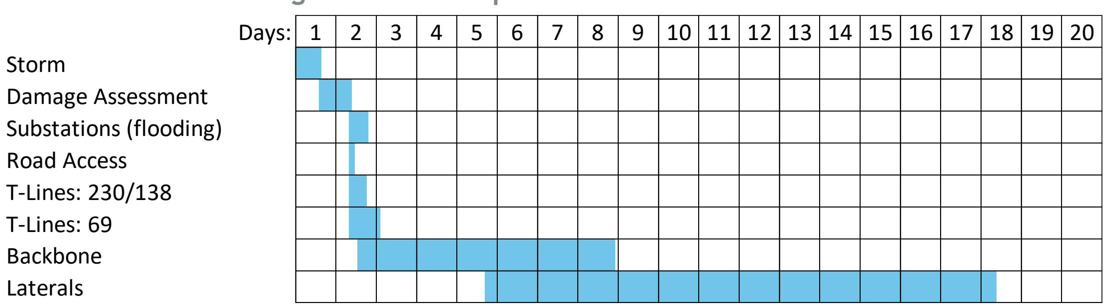
The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were developed using storm-restoration-cost multipliers that reflect the relatively higher costs for storm replacements compared to planned replacements. These multipliers, in the range of 1.4 to 4.0, were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced.

For each storm event, the restoration costs at the asset level are aggregated up the project level and then weighted based on the project LOF (Section 4.2) and the overall restoration costs for the storm event outlined in the Major Storm Event Database.

4.4 Duration and Customer Impact

The Storm Impact Model calculates the outage duration, i.e., the time required to restore each project, in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Storm Event Database. Figure 4-6 provides an example duration profile for the Category 3 and above storm event.

Figure 4-6: Example Storm Duration Profile



The project-specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those TEC uses to prioritize storm restoration activity, such as priority customers. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e. customer count is high with more critical customers). That lateral would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 350, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

Some of the storm scenarios include significant outages to the transmission system. The percentage of the system impacted is so high that the designed resilience (looping) of the system is lost for a short period of time, which in turn causes mass customer outages across the system from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the TEC transmission system based on transmission system operating capacity and overall importance to the Bulk Electric System (BES).

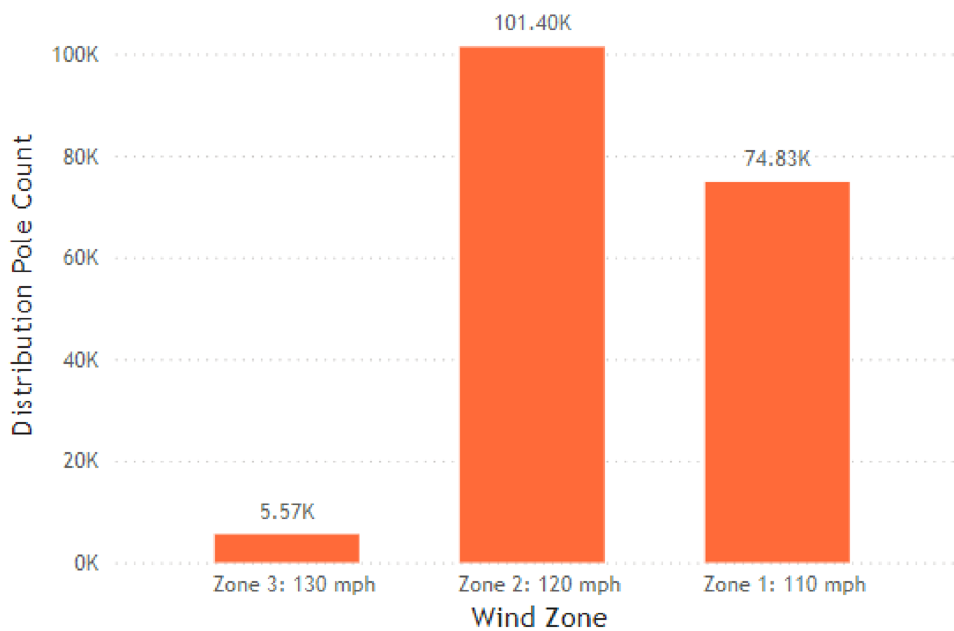
Finally, the CMI for each project, for each storm event, is monetized using the ICE Calculator. Section 4.5.2 provides additional details on the ICE Calculator. Monetization is performed for each type of customer; residential, small commercial and industrial (C&I), large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5 Status Quo and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the Status Quo and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project-by-project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the Status Quo and Hardened Scenarios for all 99 major storm scenarios. The following section describes the methodology utilized to model all 99 major storms and calculate the resilience benefit of each project.

Figure 4-7: Distribution Pole Wind Zone Distribution



4.5.1 Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way. This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 35 percent of the T&D system has some kind of road access while the remainder, approximately 65 percent, is in the deep right-of-way.

4.5.2 ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE.

The Storm Impact Model includes the estimated storm interruption costs for residential, small C&I, and large C&I customers. The calculator was extrapolated for the longer outage durations from storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level. The avoided monetized CMI and restoration cost benefit are used for prioritization of projects.

4.5.3 Substation Flood Modeling

TEC performed detailed storm surge modeling using the SLOSH model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, Tampa in this case, incorporating the unique bay and river configurations, water depths, bridges, roads, levees, and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of TEC's 216 substations to estimate the height of above the ground elevation for storm surge. The SLOSH model identified 59 substations with flooding risk depending on the hurricane category. Based on TEC's more detailed assessment and timing of this SPP, 6 substations were identified for this SPP that included flooding risk to the level that could justify investment.

5.0 Resilience Net Benefit Calculation Module

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes Monte Carlo simulation to randomly select a thousand future worlds of major storm events to calculate the range of both Status Quo and Hardened restoration costs and CMI. The benefit calculation is performed over a 50-year time horizon, matching the expected life of hardening projects.

The Distribution Overhead Feeder Hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The OMS includes 20 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

5.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2 percent
- Discount Rate: 6 percent

5.2 Project Cost

Project costs were estimated for the more than 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were developed using the data within the Storm Resilience Model to estimate scope (asset counts and lengths), which was then multiplied by unit-cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

5.2.1 Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.5.1) were leveraged to estimate the miles of overhead conductor for 1, 2, and 3 phase laterals to be undergrounded

These values create the scope for each of the projects. TEC provided unit-cost estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit-cost estimates are based on supplier information and previous undergrounding projects.

5.2.2 Transmission Asset Upgrades Project Costs

The Transmission Asset Upgrades program project costs are based on the number of wood poles by class, type (H-Frame vs monopole), and circuit voltage. TEC provided unit cost estimates for each type of pole to be replaced. The project costs equal the number wood poles on the circuit multiplied by the unit replacement costs.

5.2.3 Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program were provided by TEC.

5.2.4 Distribution Overhead Feeder Hardening Project Costs

The distribution overhead feeder hardening project costs are based on the number of wood poles that do not meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the average cost to add automation to each circuit.

5.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g., Category 1 from the Gulf) has a range of potential probabilities and consequences.

In the context of the Storm Resilience Model, for each future storm world, the Monte Carlo simulator selects from the Major Storm Event Database (Section 3.0) those major storm events that will impact the TEC service territory over the next 50 years. Recall that the database outlines the 'universe' of storm event types that could impact the TEC service territory and includes 13 unique storm types with 99 different storm events, that collectively encompass the full range of storm probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 172 years.

Table 5-1 shows the selection of storm events, by storm type, for the first 7 and the final of 1,000 total iterations. Within each iteration, the selected quantities for each of the 13 storm types combine to provide one possible future world of storms that could impact the TEC service territory over the next 50 years. Each storm has a different frequency and impact on the TEC system.

Each project's CMI, monetized CMI, and restoration costs are calculated for each of the 13 storm events, during each of the 1,000 iterations, for both the Status Quo and Hardened Scenarios, all over a 50-year time horizon. The difference between the Status Quo and Hardened Scenario values is the benefit of the project for the particular storm event. The sum of the benefits over all 13 storm types equals the total benefits for the project. The CMI, monetized CMI, and restoration costs are then weighted by the probability of the storm event to calculate the storm resilience-weighted life-cycle benefit.

Table 5-1: Monte Carlo Simulation Storm Event Selection

Storm Type No	Scenario Name	Storm Event - Iteration								
		1	2	3	4	5	6	7	...	1000
1	Cat 3+ Direct Hit - Gulf	5	6	5	2	3	6	1	...	3
2	Cat 1 & 2 Direct Hit - Florida	13	16	11	11	8	17	12	...	17
3	Cat 1 & 2 Direct Hit - Gulf	20	24	20	19	19	20	23	...	20
4	TS Direct Hit	28	29	29	30	29	29	30	...	29
5	TD Direct Hit	31	32	31	32	33	31	33	...	31
6	Localized Event Direct Hit	36	35	34	35	36	34	35	...	34
7	Cat 3+ Partial Hit	39	39	39	39	40	37	37	...	41
8	Cat 1 & 2 Partial Hit	43	45	46	43	43	48	45	...	43
9	TS Partial Hit	50	52	52	52	50	54	52	...	50
10	TD Partial Hit	62	61	56	58	61	59	59	...	62
11	Cat 3+ Peripheral Hit	74	72	72	72	71	70	72	...	70
12	Cat 1 & 2 Peripheral Hit	82	87	87	76	79	84	81	...	82
13	TS Peripheral Hit	99	92	98	90	92	93	95	...	88

Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the Status Quo and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost are the NPV of the 50-year storm probability adjusted cash flows. The delta between the Status Quo and Hardened scenarios is the benefit of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms.

This calculation is repeated for all 1,000 iterations for the more than 1,500 projects in the Storm Resilience Model.

Table 5-2: Project CMI and Restoration Cost Example - Iteration 1

Storm Type No	Scenario Name	Status Quo			Hardened		
		CMI	$CMI	Rest$	CMI	$CMI	Rest$
1	Cat 3+ Direct Hit - Gulf	64,910	$606,664	$132,303	41,947	$392,045	$0
2	Cat 1 & 2 Direct Hit - Florida	26,001	$377,198	$38,694	16,803	$243,757	$0
3	Cat 1 & 2 Direct Hit - Gulf	22,228	$305,395	$38,078	14,364	$197,356	$0
4	TS Direct Hit	26,587	$471,815	$53,821	17,072	$302,952	$43,127
5	TD Direct Hit	9,612	$150,651	$9,619	6,172	$96,733	$7,708
6	Localized Event Direct Hit	1,282	$27,601	$4,858	823	$17,723	$3,893
7	Cat 3+ Partial Hit	5,975	$86,440	$12,779	3,862	$55,860	$0
8	Cat 1 & 2 Partial Hit	3,575	$58,056	$14,771	2,310	$37,517	$0
9	TS Partial Hit	1,077	$27,788	$6,303	691	$17,843	$5,051
10	TD Partial Hit	$0	$0	$0	$0	$0	$0
11	Cat 3+ Peripheral Hit	$0	$0	$0	$0	$0	$0
12	Cat 1 & 2 Peripheral Hit	$0	$0	$0	$0	$0	$0
13	TS Peripheral Hit	$0	$0	$0	$0	$0	$0
	Total	161,246	$2,111,610	$311,225	104,043	$1,361,786	$59,779

5.4 Feeder Automation Benefits Calculation

As part of the SPP's Distribution Overhead Feeder Hardening program, TEC intends to include feeder automation, or FLISR, to allow for automatic switching during storm events. The design standard will limit outages to impact a maximum of 400 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event.

The resilience benefit for feeder automation was estimated using historical MED outage data from the OMS (see Section 4.1.2). TEC has outage records going back 20 years. The analysis assumes that future MED outages for the next 50 years will be similar to those from the last 20 years.

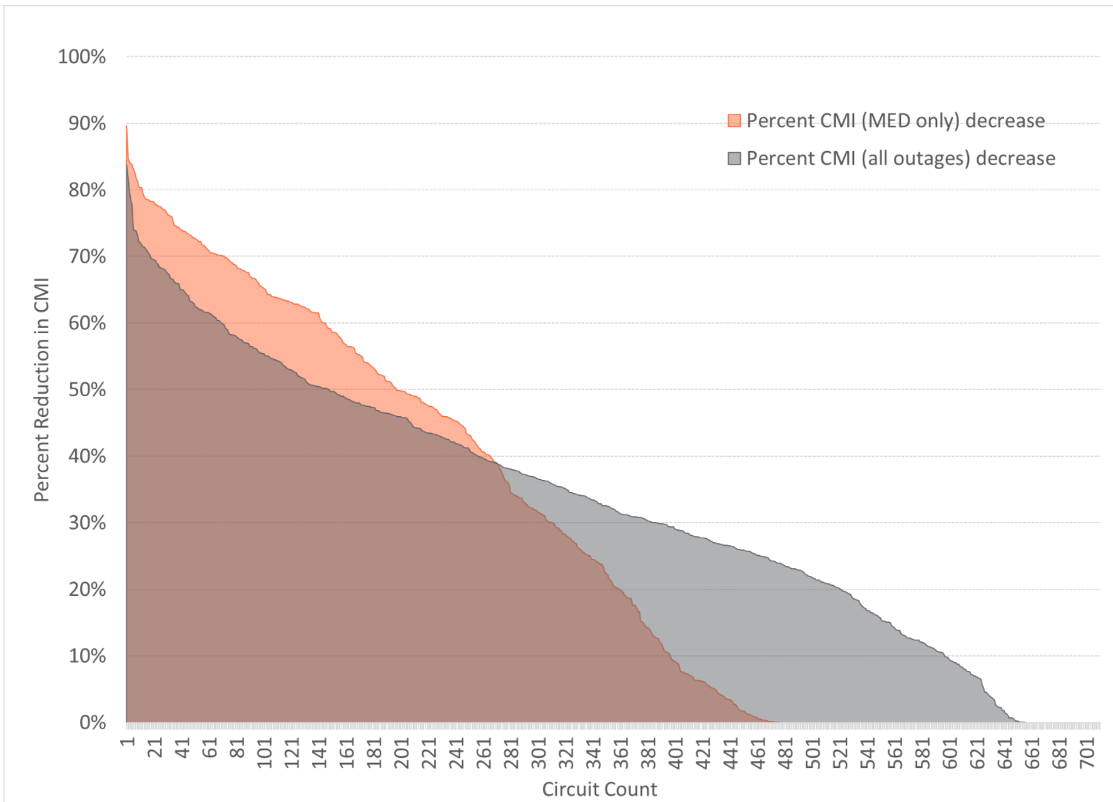
The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the benefit calculations to 50 years, matching the time horizon of the other projects.

The feeder automation projects include a range of investment types including reclosers, poles, re-conductoring, tie-line additions, and substation upgrades to handle the load transfer.

Figure 5-1 shows the percent decrease in CMI using this approach for all circuits. The figure shows circuits ranked from highest to lowest percent reduction in CMI, from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits providing a 40 percent or greater reduction in MED CMI. Additionally, the figure shows that approximately two thirds of the circuits would decrease MED CMI by some amount. This figure indicates that there is an opportunity for outage reductions via FLISR beyond those proposed in this SPP and that TEC should continue to evaluate the benefits and costs of FLISR throughout its system.

Figure 5-1: Automation Hardening Percent CMI Decrease



6.0 Budget Optimization and Project Selection

The Storm Resilience Model consistently models the benefits of all potential hardening projects to produce an 'apples to apples' comparison between projects. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the evaluated projects. Resilience benefits include:

- CMI 50-year Benefit
- Restoration Cost 50-year NPV Benefit
- Life-cycle 50 year NPV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Life-cycle 50 year NPV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding, and in alignment with the resilience base strategy, the approach focuses on the P50 and above values, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

The following sections discuss the prioritization metric, budget optimization, and approach to developing the SPP.

6.1 Prioritization Metric - Benefit Cost Ratio

With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50-year NPV gross benefit value listed above. The ranking is performed for each of the P-values listed above (P50, P75, and P95) as well as a weighted value.

Performing prioritization for each of the four benefit-cost ratios (i.e., CMI, Restoration Cost, Gross Benefit, Net Benefit) is important since each project has a different rate of benefit change between the average storm future (P50) and the extreme storm future (P95) For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. In contrast, many of the transmission asset hardening projects are only marginally beneficial at P50, have significant benefits at P75, and have even greater benefits at P95. TEC and 1898 & Co. chose to weight the three benefit values in the base prioritization metric. However, investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2 Storm Protection Plan Project Selection and Prioritization

In developing TEC's SPP, TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each program. It is important to note that the Storm Resilience Model is only a tool to enable more informed decision making. While the Storm Resilience Model employs a data-driven decision-making approach with a robust set of algorithms at a granular asset and project level, it is limited by the need for and the quality of assumptions. In developing the TEC SPP project identification and schedule, the TEC and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (e.g., project A before project B, project Y at the same time as project Z).
- Remaining transmission structures left to be converted from wood to non-wood (Transmission Asset Upgrades Program)
- Remaining substations (6) identified for extreme weather protetion measures

7.0 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D system. This section presents the costs and benefits of TEC's SPP. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

7.1 Storm Protection Plan

This section includes the program capital investment and resilience benefit results for TEC's SPP.

7.1.1 Investment Profile

Table 7-1 shows the SPP investment profile. The table includes the build up by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.62 billion, although this table omits a small amount of cost that extends into 2036. Lateral undergrounding makes up most of the total, accounting for approximately 77.7 percent of the total investment. Feeder Hardening is second, accounting for 17.2 percent. Transmission upgrades make up approximately 3.7 percent of the total, with substations making up 1.4 percent.

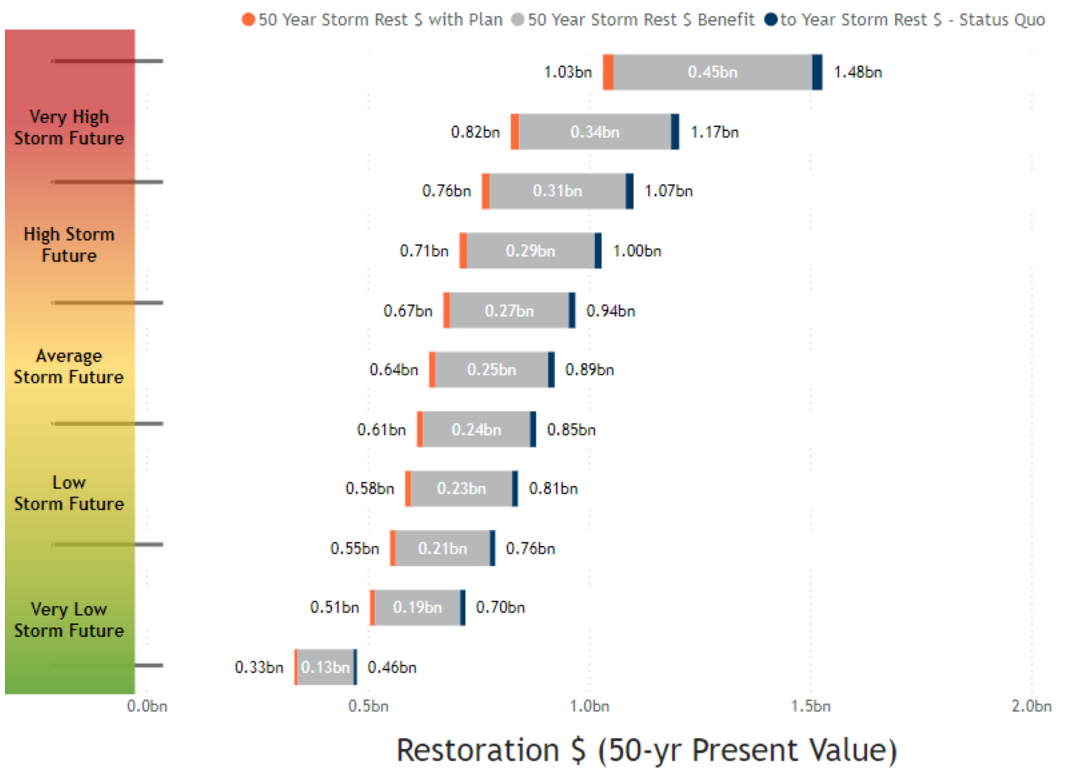
Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Total
2026	$123,800	$17,300	$3,500	$22,400	$167,000
2027	$121,600	$16,800	$3,200	$28,300	$169,900
2028	$125,000	$16,700	$5,200	$28,100	$175,000
2029	$123,000	$9,600	$800	$28,100	$161,500
2030	$125,000	$-	$8,200	$28,400	$161,600
2031	$120,800	$-	$1,000	$28,300	$150,100
2032	$123,600	$-	$-	$28,300	$151,900
2033	$124,900	$-	$-	$28,100	$153,000
2034	$120,300	$-	$-	$28,000	$148,300
2035	$120,500	$-	$-	$28,100	$148,600
Total	$1,228,500	$60,400	$21,900	$276,100	$1,586,900

7.1.2 Restoration Cost Reduction

Figure 7-1 shows the range in restoration cost reduction at various levels of storm-future severity. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent and intense, i.e., high, and the P90 and P95 levels represent a future world where storm frequency and impact are all elevated, i.e., very high.

Figure 7-1: Storm Protection Plan Restoration Cost Benefit

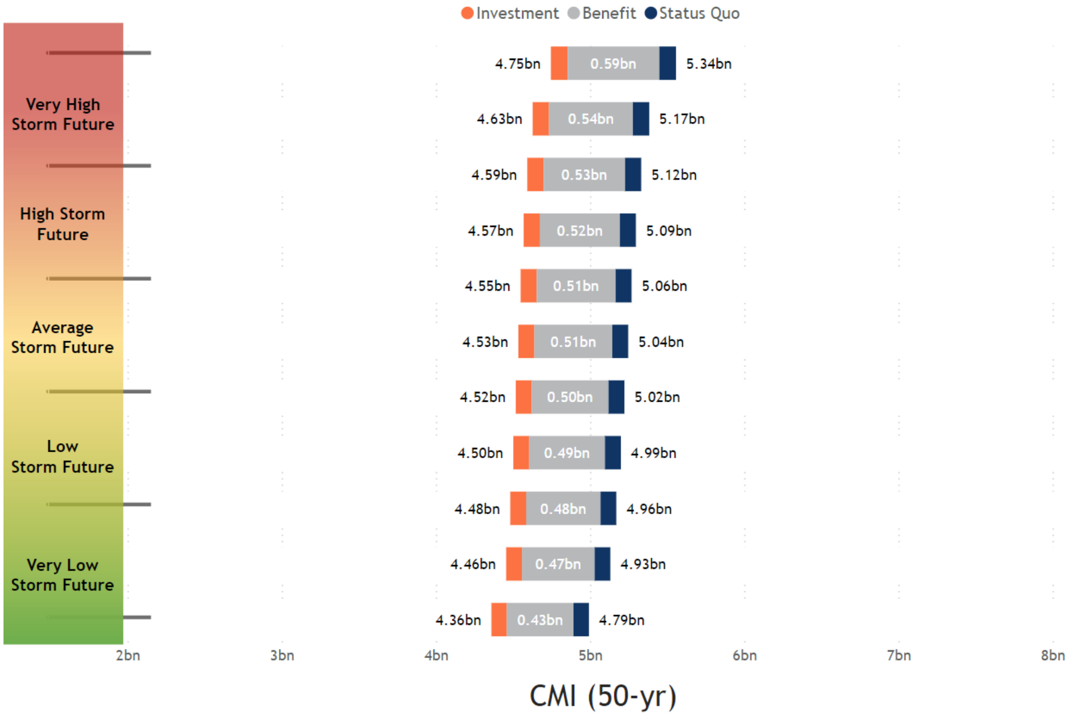


The figure shows that the 50-year NPV of future storm restoration costs, in the Status Quo case, ranges from $460 million to $1,480 million. With the SPP, those restoration costs decrease by approximately 28 to 30 percent, a reduction of approximately $130 to $450 million. In NPV terms, the restoration-cost reduction is approximately 8 to 28 percent of the SPP Investment Level. In other words, reduced restoration costs pay for 8 to 28 percent of the total invested capital costs.

7.1.3 Customer Benefit

Figure 7-2 shows the range in CMI reduction at various levels of storm-future severity. The figure shows relative consistency in CMI benefit level across the storm futures, with storm CMI decreasing by approximately 10 percent over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit



7.2 Program Investment Profile Details

Table 7-2, Table 7-3, Table 7-4, and

Table 7-5 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the project counts associated with each investment level. Table 7-3 shows the total count of transmission circuits being worked on during each year; several circuits are worked on over multiple years. The plan includes upgrading assets on 97 different transmission circuits.

Table 7-2: Distribution Lateral Undergrounding Investment Profile

Year	Circuit Count	Miles	Nominal Cost ($000)
2026	87	87	124
2027	57	79	122
2028	26	77	125
2029	24	86	123
2030	24	74	125
2031	22	81	121
2032	29	71	124
2033	32	81	125
2034	27	67	120
2035	31	82	121
Total	359	805	1,130

Table 7-3: Transmission Asset Upgrades Investment Profile

Year	Circuits Worked On	Nominal Cost ($000)
2026	11	17
2027	14	17
2028	10	17
2029	11	10
2030	-	-
2031	-	-
2032	-	-
2033	-	-
2034	-	-
2035	-	-
Total	46	61

Table 7-4: Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2026	1	4
2027	1	3
2028	1	5
2029	1	1
2030	1	8
2031	1	1
2032	-	-
2033	-	-
2034	-	-
2035	-	-
Total	6	22

Table 7-5: Distribution Overhead Feeder Hardening Investment Profile

Year	Circuit Count	Nominal Cost ($000)
2026	44	22
2027	50	25
2028	25	20
2029	32	20
2030	32	22
2031	32	23
2032	34	22
2033	31	25
2034	34	23
2035	55	25
Total	369	227

7.3 Program Benefits

Table 7-6 shows the restoration cost and CMI benefit for each of the programs

Table 7-6: Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Lateral Hardening	~23%	~29%
Transmission Asset Upgrades	~90%	~11%
Substation Extreme Weather Protection	10%-17%	16%-31%
Distribution Feeder Hardening	~43%	~31%
FLISR	~10%	~8%

Table 7-6 shows

- The Distribution Lateral Undergrounding program decreases the storm related restoration and CMI costs for the asset base by approximately 23 and 29 percent, respectively. Additionally, the program accounts for approximately 77.7 percent of the total plan's invested capital, approximately 49 percent of the plan's restoration benefit, and approximately 48 percent of the plan's CMI benefit. The low CMI reduction of the lateral program, relative to the total plan's reduction, is due to the high CMI reduction provided by the Feeder Hardening program, specifically feeder automation.
- While Transmission Asset, Substation, and Access programs each reduce a fairly high percentage of their respective CMI, their total contribution to CMI reduction for the plan is relatively low (less than 1 percent).
- Substation Hardening accounts for over 4.1 percent of the restoration benefit of the plan while consuming only approximately 1.4 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4 Conclusions

The following include the conclusions of TEC's SPP evaluated within the Storm Resilience Model:

- The overall investment level of $1.62 billion for TEC's SPP is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is just below the point of diminishing returns.
- TEC's SPP results in a reduction in storm restoration costs of approximately 28 to 30 percent. In relation to the plan's capital investment, the restoration costs savings range from 8 to 28 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 10 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted by individual outages, and decreasing the length of the outage time.
- The cost associated with purchasing the reduction in storm CMI (that is, the total Investment less the Restoration-Cost Benefits) is in the range of $1.98 to $3.46 per minute. This entire range is less than the outage costs derived from the DOE ICE Calculator and less than typical 'willingness to pay' found with customer surveys.
- TEC's mix of hardening investment strikes a balance between investing in substations and the transmission system to, primarily, increase resilience for high impact / low probability events and investing in the distribution system, to increase resilience for all event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

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Appendix J

Accenture, Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report

2024
VEGETATION MANAGEMENT
STORM PROTECTION PROGRAM
ANALYTIC SUPPORT REPORT

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1 Executive Summary

In 2019, the Florida Legislature passed a law mandating that each investor-owned electric utility (utility) submit a Transmission and Distribution Storm Protection Plan (SPP) to the Florida Public Service Commission ("FPSC"). This plan must outline the utility's strategies for the immediate ten-year planning period and must be updated at least every three years. Part of the requirement involves utilities detailing their proposed vegetation management (VM) activities for the first three years of the SPP, including:

A. The projected frequency (trim cycle)
B. The projected miles of affected transmission and distribution overhead facilities
C. The estimated annual labor and equipment costs for both utility and contractor personnel
D. How these activities will reduce outage times and restoration costs in extreme weather conditions

To validate and continuously refine TECO's SPP, TECO collaborated with Accenture to refine circuit and trimming assumptions using the most recent data available. As a result of the analysis conducted, the following VM initiatives are proposed going forward:

1. Continuation of the four-year distribution VM cycle.
2. Modify initiative to augment annual distribution VM by targeting 500 supplemental miles each year, a 200-mile modification from the previous analysis.
3. Modify initiative for mid-cycle distribution circuit inspections and the resulting prescribed VM, entailing an average of 1,200 miles of inspections per year, a 200-mile modification from the previous analysis.

The associated Full-Time Equivalent (FTE) Resource requirement and inflation adjusted budget are outlined in **Table 1-1** below:

Table 1-1: Recommended Approach: Program 2-500

Year	Distribution VM Four-Year Cycle [Miles]	Supplemental Distribution VM [Miles]	Mid-Cycle Distribution VM Inspection [Miles]	Estimated FTE Resource Requirement[1]	VM Budget[2]
2025	1,534	500	1,180	261	$23.6M
2026	1,534	500	1,400	261	$24.8M
2027	1,534	500	1,124	261	$26.0M
2028	1,534	500	850	261	$27.3M
2029	1,534	500	924	261	$28.7M
2030	1,534	500	917	261	$30.1M
2031	1,534	500	847	261	$31.6M
2032	1,534	500	1,159	261	$33.2M
2033	1,534	500	1,540	261	$34.9M
2034	1,534	500	1,161	261	$36.6M

[1] 261 represents the projected headcount TECO's VM workforce. The annual scope for the mid-cycle initiative is throttled based on the anticipated four-year cycle and supplemental VM scope to maintain a stable headcount.

[2] Budget reflects anticipated vegetation management program costs for 1) the distribution VM four-year cycle, 2) supplemental distribution VM, 3) mid-cycle distribution VM, and 4) corrective maintenance. Excluded are the anticipated company-wide restoration costs associated with day-to-day outages and major storm events.

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2 Overview

TECO runs its distribution VM via a four-year cycle, systematically addressing approximately one-quarter of its overhead distribution system mileage annually.

As part of the SPP's implementation in 2020, TECO also performs supplemental distribution VM and mid-cycle distribution VM to further enhance both day-to-day operations and system resilience during extreme weather conditions.

Continuously refining its VM strategy, TECO leverages industry leading analytical tools, including the Vegetation Management Optimization Tool (VMOT). Since the initial implementation of the model in 2006, TECO has diligently enhanced its program and adapted the tool's configuration using an expanding repository of historical spending and reliability performance data.

The VMOT conducts a thorough analysis of day-to-day outages attributable to vegetation, alongside a sampling of outages with unknown or weather-related causes that could potentially be linked to vegetation. It assesses these outages relative to the elapsed time since the last circuit trimming. During the configuration phase of the VMOT modeling, circuits are categorized according to similarities in outage escalation and VM cost, resulting in a matrix of reliability and cost groupings. This data-driven approach guides a ten-year prioritization strategy aimed at optimizing day-to-day performance per dollar spent on VM activities.

In times of extreme weather, the proximity of tree limbs to lines and the cross-sectional area of vegetation exposed to winds (referred to as the 'sail area') significantly impact the severity of damage inflicted on the electrical system during vegetation-caused outages. The correlation between years since last trim, wind speed, and damage extent has been thoroughly analyzed and incorporated into VMOT's Storm Report. By utilizing VMOT's trim list outputs and a range of probable windspeeds specific to TECO's service territory, the Storm Report forecasts damage levels and associated restoration costs for typical weather events, while also forecasting the potential impact of storms of specified magnitudes.

Both VMOT and the Storm Report assess the outcomes of targeted circuit VM initiatives and estimate the value derived from these interventions in terms of reliability improvement, which aids TECO in implementing cost-effective VM workplans to further minimize the impact of vegetation on blue and gray sky reliability.

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3 Vegetation Management Program Initiatives

TECO and Accenture analyzed the initiatives described in **Table 3-1** to determine an optimal blend of VM activity to reduce vegetation-related outages during extreme weather events while continuing to minimize day-to-day vegetation-related outages.

Table 3-1: Vegetation Management Initiatives

Initiative	Name	Description	Modeling Methodology
Initiative 1	**Distribution VM Four-Year Cycle**	Trim an equivalent of 25% of TECO's overhead lines (~1,534 miles) annually.	Target 25% of the miles in each of TECO's 7 service areas annually. Due to the nature of the algorithm and available targeting data, targeting is based on SAIDI performance in regular weather (i.e., blue sky).
Initiative 2	**Supplemental Distribution VM**	Trim an additional 400 – 700 targeted miles annually with a view to mitigating outage risk on those circuits most susceptible to storm damage	Six different approaches were evaluated – 400, 450, 500, 550, 600, and 700 miles. Targeting criteria is identical to Initiative 1.
Initiative 3	**Mid-Cycle Distribution VM**	Perform mid-cycle inspections on circuits, prescribing additional VM as needed. Periodicity is based on the following criteria: - Circuits with a trim periodicity of every 4 or more years: two years after trim - Circuits with a trim periodicity of every 3 years: two years after trim, skipping every other mid-cycle - Circuits with a trim periodicity of every 2 years: one year after trim, skipping every other mid-cycle	- The VMOT analysis assumes that a percentage of circuit's adjacent trees will be prescribed for trimming or removal (percentage varies based on circuit cycle periodicity; see **section 8.3.3** for details on criteria). - As VMOT works with miles of circuit rather than individual trees, this is modeled as a percentage of the circuit's miles re-setting to trimmed in that year, while the remainder of the circuit continues to age. Within the model, the costs associated with day-to-day restoration, major event restoration, and corrective maintenance costs are re-calculated to reflect the new trim-age profile of the circuit.

Initiative 2 (Supplemental Distribution VM) seeks to reduce tree-caused outages by reducing the proximity between tree limbs and lines, as well as reducing trees' sail area which would otherwise cause them to sway or break as wind speed increases.

Initiative 3 (Mid-Cycle Distribution VM) focuses on the same proximity and sail area reduction efforts as Initiative 2 but is primarily intended to address hazard trees and fast-growing tree species which may encroach on lines despite prudent recurring VM activity.

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4 Cost Considerations

In addition to considering the costs of the three VM initiatives described in the prior section, TECO and Accenture also considered the financial implications for relevant budget categories to capture the most comprehensive impact of each VM program. The budget categories are shown in **Table 4-1**, along with indicators as to whether the cost component is part of the VM budget and whether the costs are associated uniquely with VM resources or, as in the case of outage restorations, extend further into the organization:

Table 4-1: Cost Categories for VMOT Analysis

Cost Category	Type of Cost	Applies to what resources?	Part of VM Budget?
Distribution VM Four-Year Cycle *(Initiative 1)*	Program	Vegetation	Yes
Supplemental Distribution VM *(Initiative 2)*	Program	Vegetation	Yes
Mid-Cycle Distribution VM *(Initiative 3)*	Program	Vegetation	Yes
Corrective Costs	Program	Vegetation	Yes
FTE Resource Premiums	Program	Vegetation	Yes
Day-to-Day Restoration Costs	Restoration	Line & Vegetation	No
Major Event Restoration Costs	Restoration	Line & Vegetation	No

Program costs are classified as those which apply exclusively to TECO's VM workforce, and restoration costs are the estimated indirect costs incurred through restoration of vegetation-triggered outages. Note that the anticipated spending levels for the two categories of restoration costs are driven by VM decisions but are not part of the VM budget. They are considered and presented within this analysis because the investments in enhancing VM for the Storm Protection Plan should be offset by reductions in cost due to outage response.

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5 VM Activity Distribution Across Service Areas

For Initiative 1 (Distribution VM Four-Year Cycle), each service area is allotted one-quarter of its mileage every year, amounting to 1,534 miles across TECO's entire service territory. Central, for example, accounts for roughly 16.5% of TECO's overhead miles, and is allotted 16.5% of the annual 1,534-mile target as depicted in **Table 5-1.**

Table 5-1: Four-Year Cycle Mileage Targets

Service Area	Annual Mileage Target	Percentage
Central	253	16.5%
Dade City	92	6.0%
Eastern	209	13.6%
Plant City	306	20.0%
South Hillsborough	179	11.6%
Western	265	17.3%
Winter Haven	229	14.9%
TECO (Overall)	**1,534**	**100.0%**

For the mileage addressed via Initiative 2 (Supplemental Distribution VM), one quarter of the prescribed supplemental miles are allocated across the service areas in the same proportions as Initiative 1. The remainder of the miles are directed where they will deliver the greatest benefit in terms of reliability improvement per dollar spent, as determined by VMOT. To describe this in practical terms, for a strategy in which 400 miles of supplemental distribution VM are prescribed, 100 miles would be assigned across the service areas in accordance with the percentages outlined in the above table, with the remaining 300 miles directed to the areas where it would deliver the greatest benefit.

As covered in the **Vegetation Management Program Initiatives** section, Initiative 3 (Mid-Cycle Distribution VM) focuses on the same proximity and sail area reduction efforts as Initiative 2 but is primarily intended to address hazard trees and fast-growing tree species which may encroach on lines despite prudent recurring VM activity. **Table 3-1** shows how the annual inspection mileage for Initiative 3 is estimated on an annual basis.

6 VM Program Evaluation

TECO utilized VMOT to compare the projected impact of several SPP approaches by evaluating vegetation-related blue and gray sky reliability against relevant costs. TECO examined the resource implications of each approach and the relative reliability improvements for the additional dollars spent to determine the best strategy moving forward. To ensure that all model outputs were based on the most recent data available, TECO engaged Accenture to refresh the VMOT configuration and the various assumptions built into the VMOT Storm Report. The configuration refresh process and associated

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assumptions are outlined in the **Vegetation Management Optimization Tool & Report Configuration** section.

6.1 Specific Programs Considered

The programs outlined in this report consist of the following combinations of VM initiatives:

Table 6-1: Program Nomenclature and Initiative Components

Program Name	Initiative 1 Component	Initiative 2 Component	Initiative 3 Component
Program 1	Distribution VM Four-Year Cycle	n/a	n/a
Program 2 – 400	Distribution VM Four-Year Cycle	Supplemental Distribution VM (400 Miles)	Mid-Cycle Distribution VM (1,200 miles of annual inspections on average)
Program 2 – 450	Distribution VM Four-Year Cycle	Supplemental Distribution VM (450 Miles)	Mid-Cycle Distribution VM (1,240 miles of annual inspections on average)
Program 2 – 500	Distribution VM Four-Year Cycle	Supplemental Distribution VM (500 Miles)	Mid-Cycle Distribution VM (1,260 miles of annual inspections on average)
Program 2 – 550	Distribution VM Four-Year Cycle	Supplemental Distribution VM (550 Miles)	Mid-Cycle Distribution VM (1,260 miles of annual inspections on average)
Program 2 – 600	Distribution VM Four-Year Cycle	Supplemental Distribution VM (600 Miles)	Mid-Cycle Distribution VM (1,270 miles of annual inspections on average)
Program 2 – 700	Distribution VM Four-Year Cycle	Supplemental Distribution VM (700 Miles)	Mid-Cycle Distribution VM (1,300 miles of annual inspections on average)

Note that all versions of Program 2 incorporate variations of initiatives 2 & 3. Program 1 was modeled purely for illustrative purposes.

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6.2 Program Projections Comparison

The ten-year average annual projections for the costs described in **Section 4 (Cost Considerations)** versus the projected blue sky SAIDI is shown in the below figure and accompanying table for each of the evaluated programs:

Figure 6-1: Ten-Year Projections Comparison of Evaluated Programs (Average Annual Program & Restoration Costs versus Blue Sky Vegetation-related SAIDI)

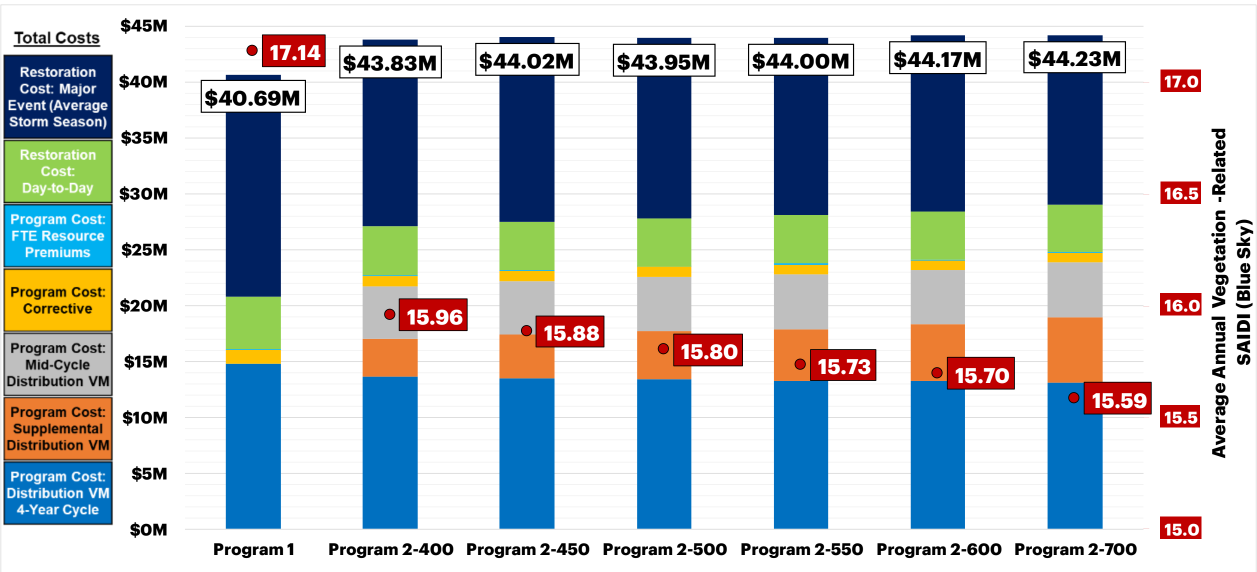

Table 6-2: Ten-Year Projections Comparison of Evaluated Programs (Average Annual Costs & Blue Sky SAIDI)

Parameter: *(colors match the above chart)*	Program 1	Program 2-400	Program 2-450	Program 2-500	Program 2-550	Program 2-600	Program 2-700
Restoration Cost: Major Event *(Average Storm Season)*	$19.87M	$16.72M	$16.53M	$16.12M	$15.90M	$15.77M	$15.15M
Restoration Cost: Day-to-Day	$4.71M	$4.34M	$4.32M	$4.30M	$4.28M	$4.27M	$4.24M
Program Cost: FTE Resource Premiums	$0.09M	$0.08M	$0.09M	$0.05M	$0.16M	$0.09M	$0.13M
Program Cost: Corrective	$1.23M	$0.92M	$0.87M	$0.87M	$0.87M	$0.87M	$0.83M
Program Cost: Mid-Cycle Distribution VM	$0.00M	$4.71M	$4.82M	$4.90M	$4.89M	$4.84M	$4.89M
Program Cost: Supplemental Distribution VM	$0.00M	$3.38M	$3.90M	$4.29M	$4.61M	$5.06M	$5.87M
Program Cost: Distribution VM 4-Year Cycle	$14.78M	$13.68M	$13.49M	$13.42M	$13.29M	$13.26M	$13.12M
Total Costs (Program + Restoration)	**$40.69M**	**$43.83M**	**$44.02M**	**$43.95M**	**$44.00M**	**$44.17M**	**$44.23M**
Vegetation-Related SAIDI [Blue Sky]	17.14	15.96	15.88	15.80	15.73	15.70	15.59

The average annual VM budget, without inflation, for these options ranges from $16.1M for Program 1 to $24.8M for the Program 2-700. Meanwhile the annual total restoration costs, which include all line work and VM costs for blue sky and major event restoration, trend in the opposite direction from

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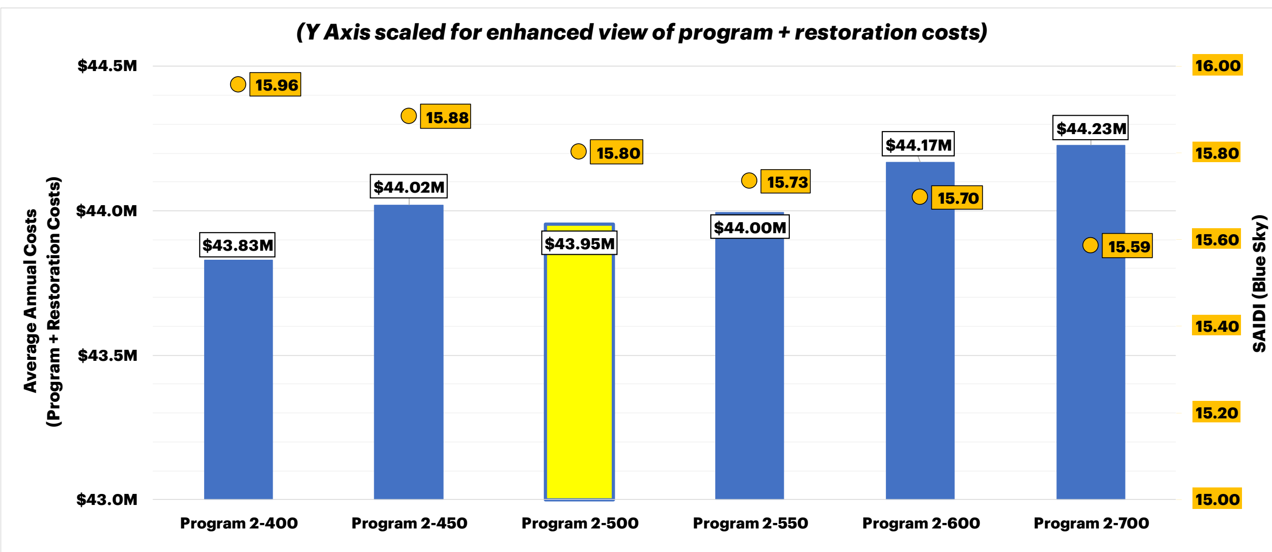
$24.6M for Program 1 to $19.4M for the Program 2-700. The total anticipated cost of the VM budget and restoration combined sits in a narrower range, at $40.7M for the Program 1 and $44.2M for the Program 2-700.

The side-by-side comparison of scenarios yields several insights:

- The introduction of Initiative 2 (Supplemental Distribution VM) drives down the cost to execute Initiative 1 (Distribution VM Four-Year Cycle).
- Each supplemental mileage increase in Program 2 yields an improvement in blue sky SAIFI and SAIDI, although the incremental improvements diminish beyond the 500-mile threshold.
- Although difficult to see in Figure 6-1, Program 2-500 yields an optimization point (i.e., comprehensive program costs projecting lower than the preceding mileage tier, while still yielding an incremental improvement in blue sky reliability) which, due to diminishing returns, begins to trend back upwards for higher supplemental mileage approaches. See **Figure 6-2** for a scaled view focused on average annual total cost (all program & restoration costs) for each of the Program 2 approaches.

Figure 6-2: Program 2 Comparison with Focus on Average Annual Total Costs (Program & Restoration Costs)



When comparing the prospective impact of Program 2-500 to an approach without any of the SPP initiatives (Program 1), it yields an 8% improvement in day-to-day restoration costs, and a 19% improvement in major event restoration costs.

Table 6-3: 10-year Average Annual Restoration Cost Savings for Program 2-500 Relative to Program 1

Cost Element	Program 1 Average 2025-2034	Program 2-500 Average 2025-2034	Improvement for Program 2-500
Day-to-Day Restoration	$4.71 M	$4.30 M	**8%**
Major Event Restoration	$19.87 M	$16.12 M	**19%**

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6.3 Developing a Modified Strategy to Accommodate FTE Constraints

Once Program 2-500 was identified as the optimal approach, full-time equivalent (FTE) resource impact was the final element considered. The prior sections of this chapter showed the projections of non-FTE constrained approaches, meaning that annual fluctuations in VM program scope were also met with fluctuations in FTE needs, thereby introducing added costs (e.g., overtime and/or bonuses), classified in the model as resource premiums. As of 2024, TECO employs 256 FTEs to carry out its three VM initiatives. Comparatively, the ten-year average requirement for the Program 2-500 approach described in the prior section is 261 FTEs, a modest increase from TECO's existing FTE count and achievable within a single year.

To maintain a stable FTE workforce and avoid fluctuations in resource demands, an FTE-leveled approach for Program 2-500 was developed. This strategy constrains the annual work scope over the ten-year projection to a consistent level that can be managed by a steady headcount of 261 FTEs. By capping the annual mid-cycle scope, the average annual mid-cycle inspection mileage was effectively reduced from 1,260 (as shown in **Table 6-1**) to 1,200. The projections of this FTE-leveled approach are detailed in the next section.

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7 Recommendation

The recommended VM Storm Protection approach (Program 2-500) consists of the following initiatives:

1) **Initiative 1 (Distribution VM Four-Year Cycle):** Perform VM on one-quarter of system mileage annually.
2) **Initiative 2 (Supplemental Distribution VM):** Perform VM on an additional 500 miles annually.
3) **Initiative 3 (Mid-Cycle Distribution VM):** Inspections and prescribed VM for entire circuit. Expand the program to include circuits which are on a two-year trim cycle. On average across the ten-year projection, TECO will perform 1,200 miles of inspections annually.

Relevant program and restoration costs versus blue sky reliability projections are shown in the below figure and corresponding table. As described in the prior section, resource premium costs are eliminated as a result of leveling the annual work scope for a stable FTE count of 261.

Figure 7-1: Inflation-Adjusted Annual Program & Restoration Costs versus Reliability Projections of Recommended VM Program

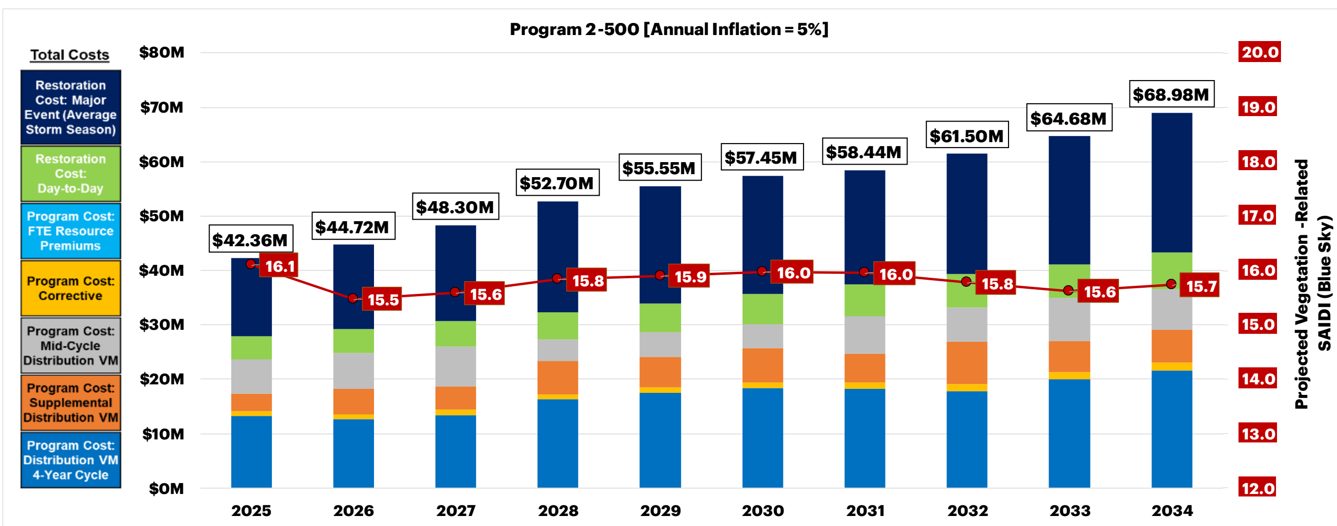

Table 7-1: Inflation-Adjusted Annual Program & Restoration Costs vs. SAIDI Projections of Recommended VM Program

Parameter: *(colors match the above chart)*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Restoration Cost: Major Event *(Average Storm Season)*	$14.38M	$15.50M	$17.60M	$20.35M	$21.58M	$21.76M	$21.00M	$22.21M	$23.52M	$25.69M
Restoration Cost: Day-to-Day	$4.36M	$4.42M	$4.67M	$5.01M	$5.27M	$5.55M	$5.79M	$6.06M	$6.27M	$6.66M
Program Cost: Corrective	$0.87M	$0.91M	$0.96M	$1.01M	$1.06M	$1.11M	$1.17M	$1.22M	$1.29M	$1.35M
Program Cost: Mid-Cycle Distribution VM	$6.27M	$6.62M	$7.41M	$4.01M	$4.63M	$4.44M	$6.92M	$6.34M	$7.90M	$7.56M
Program Cost: Supplemental Distribution VM	$3.16M	$4.66M	$4.21M	$6.06M	$5.51M	$6.24M	$5.32M	$7.81M	$5.67M	$6.07M
Program Cost: Distribution VM 4-Year Cycle	$13.31M	$12.61M	$13.46M	$16.26M	$17.50M	$18.34M	$18.24M	$17.86M	$20.04M	$21.66M
Total Costs (Program + Restoration)	**$42.36M**	**$44.72M**	**$48.30M**	**$52.70M**	**$55.55M**	**$57.45M**	**$58.44M**	**$61.50M**	**$64.68M**	**$68.98M**
Vegetation-related SAIDI [Blue Sky]	16.11	15.48	15.59	15.84	15.90	15.98	15.95	15.78	15.63	15.74

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From a benefits perspective, two measures are worth exploring because each program takes a few years for the impact in terms of reliability improvement to be realized: the overall ten-year average performance, and the future steady-state value taken in this case by considering the average of the last five years in the analysis, which are shown in the next table. For the 10-year and 5-year future steady-state averages, all years and cost elements are priced at 2024 rates, with no inflation applied.

Table 7-2: VM Storm Protection Program 2-500 Performance Characteristics Comparison: Blue Sky Reliability

	HISTORICAL	PROJECTED			
	Averages over 2021 - 2023[3]	*Average Across all Ten Years*		*Future Steady-State* *(Average of Final Five Years of Projection)*	
		Program 1	Program 2-500	Program 1	Program 2-500
SAIFI *(Blue Sky)*	0.231	0.225	0.206	0.233	0.206
SAIDI *(Blue Sky)*	17.84	17.14	15.80	17.61	15.84

Table 7-3: VM Storm Protection Program 2-500 Performance Characteristics Comparison: Major Event Restoration Costs (not adjusted for inflation)

	PROJECTED			
	Average Across all Ten Years		*Future Steady-State* *(Average of Final Five Years of Projection)*	
	Program 1	Program 2-500	Program 1	Program 2-500
Major Event Restoration Costs *(Average Storm Season)*	$19.9M	$16.1M	$20.9M	$16.2M

In the above tables, the projected average blue sky reliability and major event restoration costs for the FTE-leveled Program 2-500 are compared against that of the standalone Distribution VM Four-Year Cycle (Program 1).

The proposed Program 2-500 has a projected SAIFI that is 8% lower relative to Program 1 across ten years, or 12% in the future steady-state. SAIDI improvement is 8% across ten years, or 10% in the future steady-state. Major event restoration costs improves by 19% across ten years, or 22% in the future steady-state.

[3] 2021 – 2023 averages were estimated using the following total TECO customer count assumptions: 800,065 [2021], 812,113 [2022], and 824,160 [2023]

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8 Vegetation Management Optimization Tool & Report Configuration

The Vegetation Management Optimization Tool requires periodic updates wherein the latest circuit configuration, trimming and outage history are employed to ensure the model is using the latest information available when targeting circuits for trimming. In addition, the storm report requires updates to a variety of cost and workforce assumptions to perform its functions correctly.

8.1 VMOT Inputs and Assumptions

VMOT requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count and overhead mileage
- The outage database
- A history of VM activity for each circuit spanning multiple cycles, including start and completion dates, and all relevant costs

8.1.1 Circuit List

A comprehensive list of circuits was obtained from TECO, which contained a total of 837 circuits, consisting of 749 overhead circuits and 88 fully underground circuits.

Not all circuits and mileage were of interest, as VMOT is only relevant to the overhead portion of circuits for which VM is a regular concern. Ultimately, the 749 "trimmable" circuits were included in the analysis, representing some 6,137 miles of overhead circuit length. Because SAIFI and SAIDI projections are dependent upon a comprehensive customer count, the fully underground circuits are also incorporated into the VMOT circuit import, though the overhead mileage for each is zero so they do not impact the annual VM cost estimates.

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8.1.2 Performance Data

Circuit reliability performance data was gathered from TECO's Distribution Outage Database (DOD). The analysis included outages from January 1, 2019 through December 31, 2023, thus accommodating 5 full years of data. Of interest were outages with the tree-related cause codes found in **Table 8-1** below. The table indicates the number of events associated with each cause code, as well as the total customer interruptions (CI) and customer minutes of interruption (CMI).

Table 8-1: Blue Sky Vegetation-Related Cause Code Statistics (January 1, 2019 - December 31, 2023)[4]

Group Name – Cause Name	Events	CI	CMI
Tree - Blew into Line	2	1,891	60,035
Tree - Grew into Line	4	1,358	117,424
Tree - Non Prev.	2,159	131,016	12,814,198
Tree - Prev.	1,631	162,231	10,949,506
Tree - Vines	856	13,814	1,552,709
Tree - Trees	69	2,972	219,945
Vegetation - Blew/Fell into Line	2,292	312,684	23,649,328
Vegetation - Grew into Line	1,011	56,931	4,051,517
Vegetation – Other	35	548	58,199
Vegetation – Pole	20	2,184	496,395
Vegetation – Vines	1,050	16,557	1,434,558
Incorporated Weather (25% of total)	1,834	139,660	14,650,731
Incorporated Unknown (25% of total)	1,437	144,443	5,810,241
Grand Total	**12,400**	**986,288**	**75,864,786**

TECO also incorporated a portion of CIs and CMIs from outages with "Unknown" and "Weather" cause codes. Accenture has found from past work with other utilities that a significant portion of outage events tagged to "Unknown" and "Weather" causes were, in fact, tree related. Historically, TECO has used 25% of the CI and CMI from those cause codes as a reasonable proportion, and that same assumption was applied for the 2024 analysis.

[4] The totals from major storm exclusion periods are omitted irrespective of cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

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8.1.3 Trim Data

TECO records and maintains trim history that includes the following types of data:

- Circuit number
- Trim start date
- Trim completion date
- Miles trimmed
- Cost to trim the entire circuit

Similar to the performance data, the analysis included full circuit trim records with a logged start date on or after January 1, 2019, and a completion date of no later than December 31, 2023. During that time span, the majority of TECO's circuits have undergone at least one full trim, with nearly half of the 749 circuits (361 total) having two or more documented full trims. For the circuits which were added in recent years but have not yet undergone a full trim by of the end of 2023, the year the circuit was established was used as the proxy for last trim year. The trim data was pared down to the outage data with the circuit number being the link between the two data sources. For analysis purposes, the circuit number, trim completion dates (year and month of trim), and trim cost of each trim were incorporated in the analysis.

Though the scope for the refreshed circuit trim cost analysis was limited to pre-2024 trims due to data availability, the "Last Trim Year" field of the VMOT circuit import was refreshed to account for TECO's 2024 VM work plan. Incorporating planned 2024 trims into the VMOT circuit import was necessary to ensure accurate scenario projections with the next calendar year (2025) set as the start year.

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8.2 Reliability Performance Curve Development

8.2.1 Creating Circuit Performance Groups

Circuits were ordered according to historical reliability performance, using the relevant outage data described in **Section 8.1.2**. Circuits were assigned to one of seven groupings, each for Customer Interruptions (CI) and Customer Minutes Interrupted (CMI), based on average annual performance across 2019 – 2023. The results are depicted in the below tables.

Table 8-2: CI Grouping Characteristics

Circuit CI Group	Annual Customer Interruptions (CI) per Mile	Circuits	Miles
01	Greater than 47	176	1,286
02	Between 34 and 47	70	691
03	Between 20 and 34	114	1,218
04	Between 14 and 20	56	634
05	Between 8 and 14	70	743
06	Between 0.02 and 8	221	1,517
07	Less than 0.02	42	48

Table 8-3: CMI Grouping Characteristics

Circuit CMI Group	Annual Customer Minutes Interrupted (CMI) per Mile	Circuits	Miles
01	Greater than 3,990	165	1,200
02	Between 2,465 and 3,990	97	1,033
03	Between 1,617 and 2,465	69	642
04	Between 1,038 and 1,617	89	1,117
05	Between 600 and 1,038	90	845
06	Between 1.4 and 600	196	1,250
07	Less than 1.4	43	50

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8.2.2 Circuit Performance Curve Fitting

For the 2024 analysis, TECO assessed via observed trends in vegetation related reliability performance data that the performance curves established from the 2020 analysis were representative of present-day circuit performance. To summarize how the curves were originally created, performance data points were derived using historical outage data, trim data, and circuit mileage data. Every outage was expressed as a number of CI or CMI per circuit mile and was plotted relative to the most recent time it was trimmed. Values for 12 consecutive individual months were rolled up to create year-based values, and these were plotted in MS Excel so that a curve could be fit to them.

The following conditions had to be satisfied to ensure that the data points were correct:

- Outage data was omitted in the months when a circuit was being trimmed.
- Outages were associated only to the most recent trim.
- **Figure 8-1** reflects the mileage into which the 12-month roll-up of CI or CMI is divided and represents the total mileage of the system or group of circuits. This ensures that in a situation where several circuits do not have any outages in a particular 12-month roll-up, those circuits were not disregarded, but rather served to appropriately pull the curve downward as part of the averaging process. This provided assurance that the resulting curves were representative of the overall CI or CMI per mile of circuits in the group and not just the CI or CMI per mile on circuits that happened to have outages.

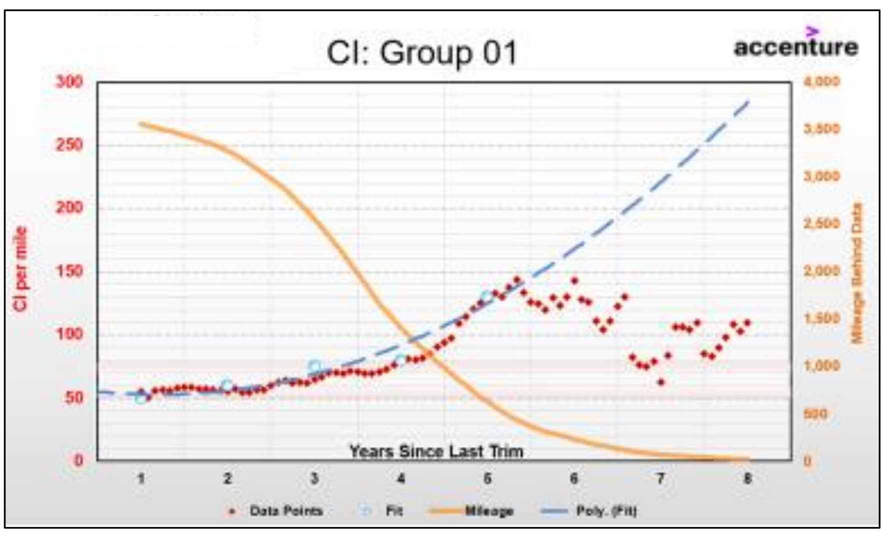

Figure 8-1: Example of Curve Fitting Analysis

A curve similar to that shown in **Figure 8-1** was developed for each of the CMI groups, resulting in a total of fourteen curves. For the 2024 analysis, the curves were shifted vertically while maintaining the same shape established from the original analysis based on the updated 2019 – 2023 weighted average CI and CMI per mile values for each circuit grouping, which are shown in **Figure 8-2** and **Figure 8-3** respectively. These curves provided the critical input required to compute the projected reliability associated with

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trimming each circuit. Eventually, the computed reliability values were used as the denominator to determine the cost-effectiveness score for circuits, which then served as the basis for their prioritization.

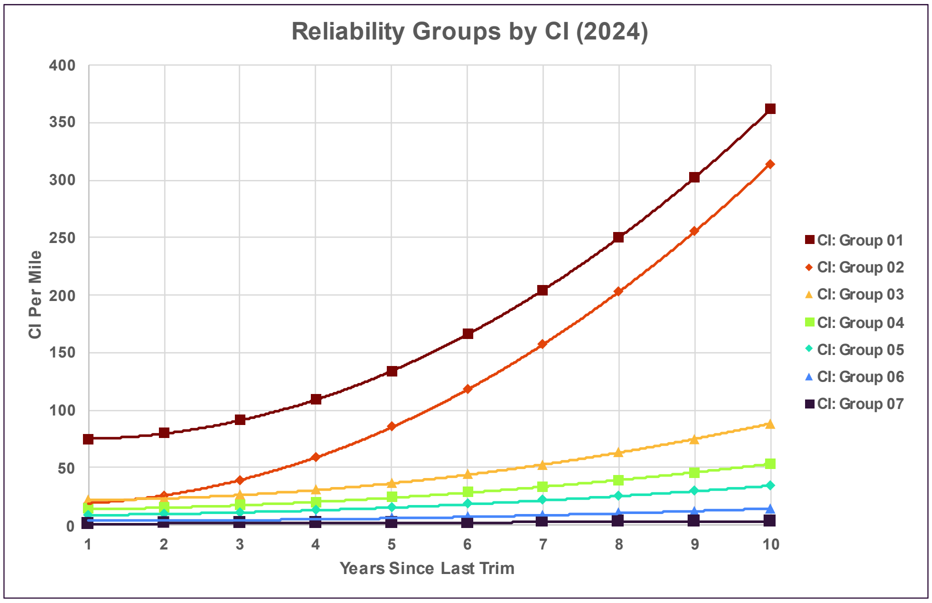

Figure 8-2: Customer Interruption (CI) Curve Groups

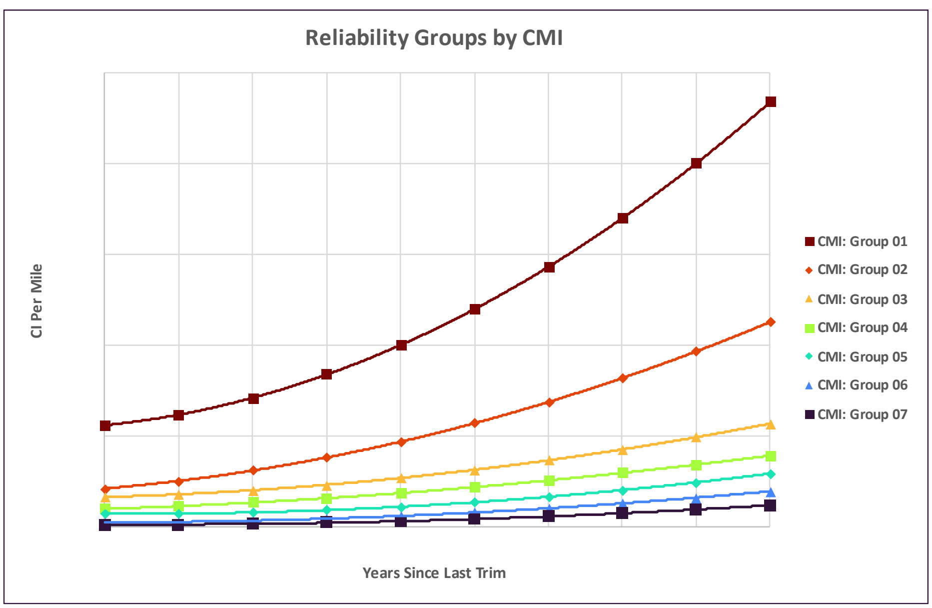

Figure 8-3: Customer Minute Interruption (CMI) Curve Groups

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8.2.3 Cost Curves

Cost curves were the second factor in calculating the cost/benefit score of each circuit in VMOT.

Similar to the reliability curves for the 2024 analysis, the cost curves were shifted vertically while maintaining the same shape established from the original analysis based on the updated 2019 – 2023 data. In 2020, the shapes of the cost curves were based on a proprietary study called the Economic Impacts of Deferring Electric Utility Tree Maintenance by ECI[5] that quantified the percentage increase in the eventual cost of trimming a circuit for each year that it is left untrimmed beyond the recommended clearance cycle. The findings of the ECI study are summarized in Figure 8-4 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20%. Delaying trimming by another year will further inflate costs to 40% of the base cost and further increase it for subsequent years.

The ECI study only considered annual trimming cost increases between the recommended clearance cycle and up to a four-year delay. In generating a comprehensive cost curve that goes from one year since last trim onward, Accenture supplemented the percentages from the ECI study with two assumptions:

- Cost reduction from annual trimming – the percentage reduction from the clearance trim that will be achieved if the circuit was trimmed every year; and,
- Escalation – annual percentage increase in cost to be applied from the ninth year and beyond.

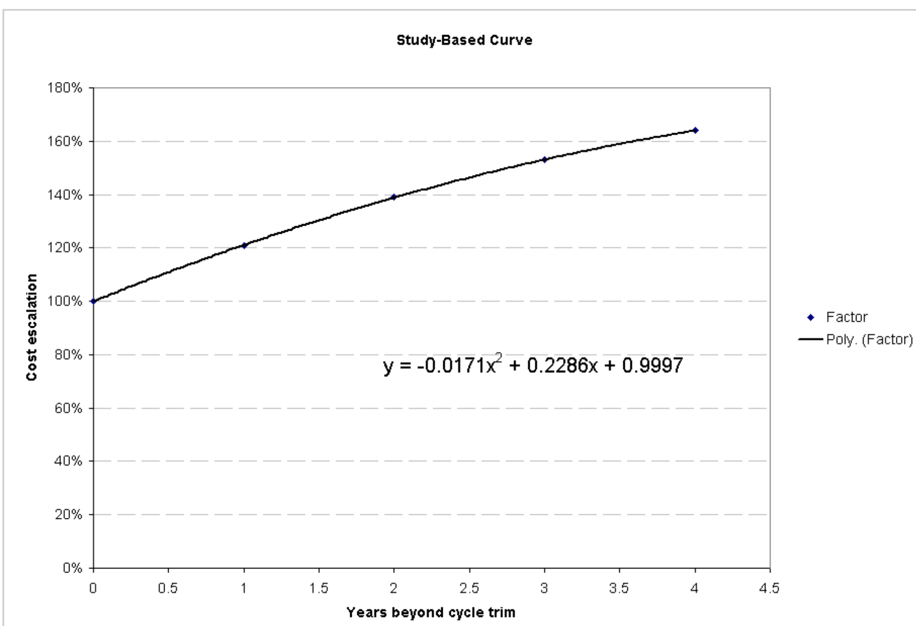

Figure 8-4: ECI Study-Based Cost Curve

[5] Browning, D. Mark, 2003, Deferred Tree Maintenance, Environmental Consultants Incorporated (ECI)

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The following section describes how such a cost curve methodology was applied to each cost group.

Similar to how the performance groups were created, circuits were ordered according to the average cost per mile. From the 2020 analysis, ten cost groups were established for assigning circuits based on recent cost per mile figures ranging from the lowest cost (Group 10: <$1,500) to highest cost (Group 01: >$25,000). To assign circuits to its appropriate cost group, each circuits' cost per mile figures from 2019 through 2023 were analyzed. Of TECO's 749 overhead circuits, 720 have both a documented trim and available cost data during that time span. For the 8 circuits whose last full trim occurred prior to 2019, the cost per miles associated with those circuits from 2017 and 2018 were analyzed instead. Under all circumstances, to properly account for the time value of money and the effects of inflation over time, a modest annual inflation factor (3.5%[6]) was applied for all historical costs to bring all costs to 2024 terms. For the combined 728 overhead circuits with cost data, the grouping assignment for each was based on the circuit's average trim cost per mile, which for each, consisted of either one or an average of multiple trims depending on the number of documented trims which occurred during the analyzed timeframe. The remaining 21 circuits are either new since 2020 and have yet to receive a full trim, or associated cost data wasn't available. For those circuits, grouping assignments were determined based on TECO forestry team knowledge of similar circuits and location-based factors.

Ultimately, circuits were updated and grouped into 10 distinct groups based on recent historical cost per mile data as shown in the following table:

Table 8-4: Cost Grouping Characteristics

Circuit Cost Group	Cost per Mile Criteria	Circuits	Miles
01	Greater than $25,000	36	221
02	Between $15,500 and $25,000	79	523
03	Between $10,000 and $15,500	170	1,210
04	Between $7,600 and $10,000	137	1,111
05	Between $6,100 and $7,600	117	1,337
06	Between $5,000 and $6,100	69	802
07	Between $4,100 and $5,000	43	356
08	Between $3,300 and $4,100	38	393
09	Between $1,500 and $3,300	35	144
10	Less than $1,500	25	39

With this group information a curve was created for each using the weighted average cost per mile for each group. Since TECO is on a four-year trim cycle, the weighted average cost per mile for each cost

[6] Inflation factor was based on publicly available US Bureau of Labor Statistics Consumer Price Index Values, accounting for average annual growth from January 2017 to January 2024

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group is anchored on Year 4. The remaining points were determined using the expertise of TECO and Accenture:

- Year 1: A 25% reduction in average cost if TECO would return to a circuit a year later.
- Years 2-3: Linear increase in cost from Year 1 to Year 4.
- Years 5-8: Follow the cost escalation shown in **Figure 8-4**.
- Years 9-10: A 5% increase for each year trimming is delayed.

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8.3 Storm Report Inputs and Assumptions

Storm protection initiative cost and benefit modeling was accomplished using VMOT and its associated Storm Report which have been used to prioritize VM activities since 2006. The following cost implications were generated for each VM activity considered:

Table 8-5: Storm Report Cost Assumptions

Cost	Cost Generator	Key Assumptions
Distribution VM Four-Year Cycle	VMOT Application	• Cost curves (VMOT Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across service areas
Supplemental Distribution VM	VMOT Application	• Cost curves (VMOT Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across service areas for 25% of supplemental miles • Optimization-based allocation for the remaining 75% of supplemental miles
Mid-Cycle Distribution VM	VMOT Storm Report	• Cost premium for inspection and prescribed VM activities (SME Estimate) • Timing of mid-cycle activities (SME decision) • Proportion of circuit targeted (SME decision)
Corrective Costs	TECO Subject Matter Expert Input	• Proportion of corrective maintenance tickets attributable to tree growth (TECO Records) • Relationship between tree growth corrective maintenance tickets and system effective cycle (SME estimate, past filings)
Resource Premiums	VMOT Application	• VM budget (Cycle + Supplemental + Mid-Cycle + Corrective) • Straight and overtime loaded cost rates for VM crews (SME estimate) • Maximum organic growth rate of the VM workforce (SME estimate) • Productivity adjustment for training new VM resources (SME estimate) • Incentive costs for VM resources required beyond the organic growth capacity (SME estimate)
Day-to-Day Restoration Costs	VMOT Storm Report	• Reliability outputs from VMOT Application • Average cost to restore a Customer Interruption (SME estimate)
Major Event Restoration Costs	VMOT Storm Report	• Trim list from VMOT Application • Storm damage calculation function • FEMA HAZUS windspeed return dataset • Average cost to restore in major event including mutual assistance (Analysis from Hurricanes Irma (2017) & Ian (2022), SME adjustment)

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8.3.1 Distribution VM Four-Year Cycle Costs

Distribution VM four-year cycle costs are projected by the Vegetation Management Optimization Tool based on curves derived in the model configuration stages. For the Distribution VM four-year cycle, the workplan and corresponding budget were allocated such that each service area would be on its own four-year cycle.

8.3.2 Supplemental Distribution VM Costs

Supplemental distribution VM costs are projected by the Vegetation Management Optimization Tool based on curves derived in the model configuration stages.

8.3.3 Mid-Cycle Distribution VM Costs

The following key assumptions pertain to mid-cycle activities:

- The cost premium for inspection and prescribed VM relative to cycle activities
- The timing of mid-cycle activities
- The percentage of trees on a given circuit which are prescribed additional VM following inspection

Inspection-based activities come at a premium. There is first the cost of patrolling and inspecting the lines before VM activities occur. Second, there are cost premiums to trimming selectively. In regular maintenance trimming, vegetation crews can trim multiple trees each time they set up their vehicle and raise the bucket. In selective trimming, the ratio of setup time to actual wood removal goes up, further increasing the per-unit cost. Based on an analysis of corrective maintenance tickets, the TECO subject matter experts estimated that mid-cycle VM would cost 80% more on a per-tree basis relative to routine cyclic VM.

The timing of mid-cycle activities is intended to promote the best possible performance out of the recurring VM initiatives (Initiatives 1 and 2). Based on input from TECO subject matter experts, two years since the last cycle had been selected as the optimal criteria for mid-cycle inspections and prescribed VM activities, and has been the standard approach since the inception of the mid-cycle initiative in 2020. While the mid-cycle initiative is still in its early stages, positive trends in blue and gray sky reliability over recent years suggest that the program has been beneficial in terms of reliability improvement.

However, the original criteria of performing a mid-cycle two years after each cycle results in a significant percentage of circuits never meeting the criteria, specifically circuits which are elevated to a two-year cycle under the VMOT's reliability-optimized approach. Many of these circuits have a history of higher-than-average vegetation-related Customer Interruptions (CI) and Customer Minutes Interrupted (CMI), making them prime candidates to benefit from the mid-cycle initiative. To account for this insight in the updated SPP for 2024, the mid-cycle initiative shall also include circuits which are on a two-year cycle, and such circuits will be revisited for mid-cycle activity during every other off year between trims. This change ensures that all overhead distribution circuits are addressed via the mid-cycle initiative. Under all circumstances, no circuit shall undergo mid-cycle activity more frequently than once every four years.

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The final component of scoping this cost was to predict the maximum number of trees to be targeted for mid-cycle activities as a result of the inspections, which is described in the next two paragraphs.

For circuits which are to be revisited at the two-year point since its last trim (i.e., all circuits with a cycle periodicity less frequent than every two years): TECO subject matter experts estimated up to 25% of a given circuit's trees would grow sufficiently fast to merit additional VM prior to the next scheduled cycle. As the cost for prescribed mid-cycle VM is expected to be 180% of the regular trimming cost, and only 25% of a circuit's trees are expected to be targeted for mid-cycle VM, the total cost should never exceed 45% (180% × 25%) of the cost to trim the entire circuit every four years.

For circuits which are on two-year cycle: TECO subject matter experts estimate that up to 20% of trees would grow sufficiently fast to merit additional VM prior to the next scheduled cycle. The rationale for using 20% as opposed to the 25% assumption described in the prior paragraph is based on the two-year cycle circuits being revisited for mid-cycle during the years in between cycles, or one year after trim. Because of this, a slightly smaller scope (20% of trees vice 25%) is anticipated. Since only 20% of trees on such circuits are expected to be targeted for mid-cycle VM, the total cost should never exceed 36% (180% × 20%) of the cost to trim the entire circuit every four years.

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8.3.4 Corrective Costs

As part of the inaugural SPP analysis conducted in 2020, a curve was established to model the projected annual corrective costs relative to the effective VM cycle. The basic premise of the curve is that incremental corrective cost savings could be achieved if TECO were to increase its effective cycle frequency. The curve points, percentage savings for each effective cycle, are shown in the left two columns of **Table 8-6**.

Table 8-6: Cost Assumptions by Effective Cycle

Effective Cycle (years) *Based on total annual trim mileage*	Percent Cost Reduction *Relative to four-year cycle*	Annual Corrective Costs Assumptions	
		Without Mid-Cycle	With Mid-Cycle *Additional 8% cost savings*
4.00	-	$1.23M	$1.13M
3.75	7.0%	$1.15M	$1.05M
3.50	13.0%	$1.07M	$0.98M
3.25	18.5%	$1.00M	$0.92M
3.00	**23.0%**	**$0.95M**	**$0.87M**
2.75	26.7%	$0.90M	$0.83M
2.50	29.6%	$0.87M	$0.80M
2.25	31.7%	$0.84M	$0.77M
2.00	33.0%	$0.83M	$0.76M

To refresh the analysis for 2024, TECO estimated that annual corrective costs over recent years have averaged approximately $0.95 million. With the addition of the SPP's supplemental VM on top of its existing four-year cycle over recent years, TECO's aggregate annual trimming mileage has equated to conducting VM on roughly one-third of its miles annually. As shown in **Table 8-6**, the $0.95 million assumption is anchored to the 3.00-year point for the effective cycle. Given the ongoing ramp-up of the mid-cycle distribution VM initiative, it is assessed that the mid-cycle initiative at steady-state would yield an additional 8% cost savings, resulting in $0.87 million in estimated corrective costs. Coupling the refreshed cost inputs for the curve's 3.00-year point as well as the percent cost reduction values from the curve, the assumed annual corrective costs for all other effective cycles between two and four years were calculated.

8.3.5 Resource Premium Costs

Experience has shown that there is a limit to the rate at which TECO can expand its FTE headcount without incurring some degree of premium cost. To account for this, the VMOT Storm Report estimates the number of FTEs that would be required to do the Distribution VM Four-Year Cycle, Supplemental Distribution VM, Mid-Cycle Distribution VM, and Corrective Costs in an assumed 2,000-hour work year, and applies a number of cost adjustment factors if that amount is significantly higher than the current size. Cost Premium calculations consider the maximum number of FTEs that can be added within a single year without offering overtime or a per diem premium, and the assumed productivity of new resources in their first year.

It is important to note that as part of the standard scenario evaluation process, both the forces of anticipated annual work scope as well as TECO's hiring capacity are balanced so that ultimately a

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resource-leveled approach entailing a controlled ramp-up of work scope and required FTE headcount can be incorporated into the recommended approach, thereby avoiding resource premiums altogether.

8.3.6 Day-to-Day Restoration Costs

A key output of the Vegetation Management Optimization Tool is the anticipated reliability performance of the system due to vegetation-caused outages in each year of the analysis. The reliability predictions are produced through VMOT's CI and CMI configuration curves, which are derived on the basis of several years of outage and tree trimming data.

Outages trigger restoration costs through the use of the dispatch function, line crews and tree crews. From the 2020 analysis, the average cost for responding to an outage was estimated at $1,300 and the calculated average number of customers interrupted per vegetation outage was 65, resulting in an estimated average cost per CI due to tree-caused outages of twenty dollars.

To account for recent years of high inflation, a 5% annual inflation rate was applied to the original twenty-dollar assumption to bring into 2024 terms, resulting in an updated cost per CI of twenty-five dollars. Annual restoration costs are estimated multiplying the SAIFI values generated by VMOT by the number of customers served by TECO, and in turn multiplying that product by the estimate of $25 per customer interrupted.

8.3.7 Major Event Restoration Costs

The VMOT Storm Report projects major event restoration costs per year using a function which determines the portion of customers who will experience power loss based on wind-speed experienced and the number of years since the circuit was last trimmed, an amalgam of annual windspeed probabilities derived from FEMA's Hazards-US dataset and an estimate of restoration cost per customer derived from TECO's recent experiences with Hurricanes Irma (2017) and Ian (2022).

The VMOT Storm Report's central equation is based on a study conducted in southern Florida around 2005 which determined that wind-driven tree outages are influenced by the length of time since last trim. The equation accepts as parameters the wind speed experienced and the number of years since the circuit was last trimmed. The equation returns a percentage which is then applied to the number of customers served by the circuit to come up with an estimate of customers interrupted. In cases of extremely high winds (150 mph and up) and long intervals since last trim, the equation can return values above 100%, which is taken to mean that while only 100% of the customers on a circuit will be interrupted, the effort to restore them will go beyond the usual cost per customer due to the multitude of damage locations on the circuit.

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	Years Since Last Trim									
Wind Gusts	1	2	3	4	5	6	7	8	9	10
5	0.000%	0.001%	0.002%	0.003%	0.004%	0.005%	0.006%	0.008%	0.009%	0.011%
10	0.003%	0.008%	0.015%	0.023%	0.031%	0.041%	0.051%	0.062%	0.073%	0.086%
15	0.010%	0.028%	0.050%	0.076%	0.105%	0.137%	0.172%	0.209%	0.248%	0.289%
20	0.024%	0.066%	0.119%	0.181%	0.250%	0.326%	0.408%	0.495%	0.588%	0.685%
25	0.047%	0.129%	0.232%	0.353%	0.488%	0.636%	0.796%	0.967%	1.148%	1.338%
30	0.081%	0.222%	0.401%	0.609%	0.843%	1.099%	1.376%	1.671%	1.984%	2.313%
35	0.129%	0.353%	0.637%	0.968%	1.339%	1.746%	2.185%	2.654%	3.150%	3.672%
40	0.192%	0.527%	0.950%	1.444%	1.999%	2.606%	3.262%	3.961%	4.702%	5.482%
45	0.273%	0.750%	1.353%	2.056%	2.846%	3.711%	4.644%	5.640%	6.695%	7.805%
50	0.375%	1.029%	1.856%	2.821%	3.903%	5.090%	6.370%	7.737%	9.184%	10.706%
55	0.499%	1.369%	2.470%	3.755%	5.196%	6.775%	8.479%	10.298%	12.224%	14.250%
60	0.648%	1.777%	3.207%	4.875%	6.745%	8.795%	11.008%	13.369%	15.870%	18.500%
65	0.824%	2.260%	4.077%	6.198%	8.576%	11.182%	13.995%	16.998%	20.177%	23.521%
70	1.029%	2.822%	5.092%	7.741%	10.711%	13.967%	17.480%	21.230%	25.201%	29.378%
75	1.266%	3.471%	6.263%	9.521%	13.174%	17.178%	21.500%	26.112%	30.996%	36.133%
80	1.536%	4.213%	7.601%	11.554%	15.989%	20.848%	26.093%	31.690%	37.617%	43.852%
85	1.842%	5.053%	9.117%	13.859%	19.178%	25.007%	31.297%	38.012%	45.120%	52.599%
90	2.187%	5.998%	10.823%	16.452%	22.765%	29.684%	37.151%	45.122%	53.560%	62.438%
95	2.572%	7.055%	12.729%	19.349%	26.774%	34.912%	43.693%	53.068%	62.992%	73.433%
100	3.000%	8.228%	14.846%	22.567%	31.228%	40.719%	50.962%	61.895%	73.471%	85.649%
105	3.473%	9.525%	17.186%	26.124%	36.150%	47.137%	58.995%	71.652%	85.052%	99.149%
110	3.993%	10.952%	19.760%	30.037%	41.564%	54.197%	67.830%	82.383%	97.790%	113.999%
115	4.563%	12.514%	22.579%	34.322%	47.494%	61.929%	77.507%	94.135%	111.740%	130.261%
120	5.184%	14.218%	25.654%	38.996%	53.962%	70.363%	88.062%	106.955%	126.958%	148.001%
125	5.859%	16.071%	28.997%	44.077%	60.992%	79.530%	99.535%	120.890%	143.498%	167.283%
130	6.591%	18.077%	32.617%	49.580%	68.608%	89.460%	111.963%	135.984%	161.416%	188.170%
135	7.381%	20.244%	36.528%	55.524%	76.832%	100.184%	125.385%	152.286%	180.767%	210.728%
140	8.232%	22.578%	40.738%	61.925%	85.689%	111.733%	139.840%	169.841%	201.605%	235.020%
145	9.146%	25.084%	45.261%	68.799%	95.202%	124.137%	155.364%	188.696%	223.986%	261.111%
150	10.125%	27.770%	50.106%	76.165%	105.394%	137.427%	171.997%	208.897%	247.965%	289.065%
155	11.172%	30.640%	55.286%	84.038%	116.289%	151.633%	189.776%	230.491%	273.597%	318.945%
160	12.288%	33.702%	60.811%	92.436%	127.909%	166.785%	208.740%	253.524%	300.938%	350.817%

Figure 8-5: Expected Damage by Wind Gusts for a Given Year Since Last Trim

The windspeed probabilities employed by the VMOT Storm Report are derived from wind speed return values calculated by FEMA in their Hazards-US (HAZUS) package. HAZUS provides a geographically specific listing of windspeeds that can be expected to return to a given location every year, 10 years, 20 years, 50 years, and so on through 1,000 years based on an analysis of tropical storm tracks over several decades. Those data points are transformed to point probabilities for individual windspeeds, from which expectations for given ranges are calculated. The VMOT Storm Report is loaded with probabilities every 10 miles from 55 miles per hour through 195 miles per hour, representing the probability of seeing windspeeds in the 50-60 mile per hour range, 60-70 mile per hour range and so on through to the 190-200 mile per hour range.

With an estimate of the expected number of customers to experience outages due to extreme weather events established, the final step is to multiply by the expected cost to restore customers. In Accenture's storm benchmark database, storm restoration is assessed based on the total cost per customers out at peak. TECO's experience with Hurricane Irma in 2017 involved approximately 328,000 customers out in total, with a peak of 213,000 customers out. Quick wins were achieved early through switching and the restoration of substation and transmission issues. It's estimated that around two-thirds of the peak value were due to tree-related causes. This peak number of customers out serves as a consistent denominator for cost per customer calculations. For TECO's experience with Irma, the cost per Customer Interruption (CI), including line, tree, planning, logistics, and other costs, was approximately $389. This figure is consistent with other Irma experiences in the state. Considering the demand pressure on tree and line resources following California's wildfire crisis and general inflationary trends in the subsequent years, TECO's subject matter experts estimated a 10% increase in costs in 2020 compared to the 2017 Irma storm costs, or approximately $424 per CI, which was the input assumption used in the 2020 analysis. Applying an annual adjustment to account for recent years of high inflation, the original assumption equates to $535 in 2024 dollars.

To update for 2024, the same costs and outage statistics were evaluated for Hurricane Ian, which made landfall in the Tampa area in September 2022 and was the most prominent storm to hit the area since Irma. TECO’s experience with Hurricane Ian involved approximately 594,000 customers out in total, with

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a peak of 235,000 customers out. Adjusting for inflation to 2024 terms using an annual 5% adjustment, the documented costs equate to $592 per CI. Incorporating this estimate into an average with the inflation-adjusted figure derived from Irma, the resulting figure is $564 per CI, which is the assumption applied for approximating storm costs in the 2024 analysis.

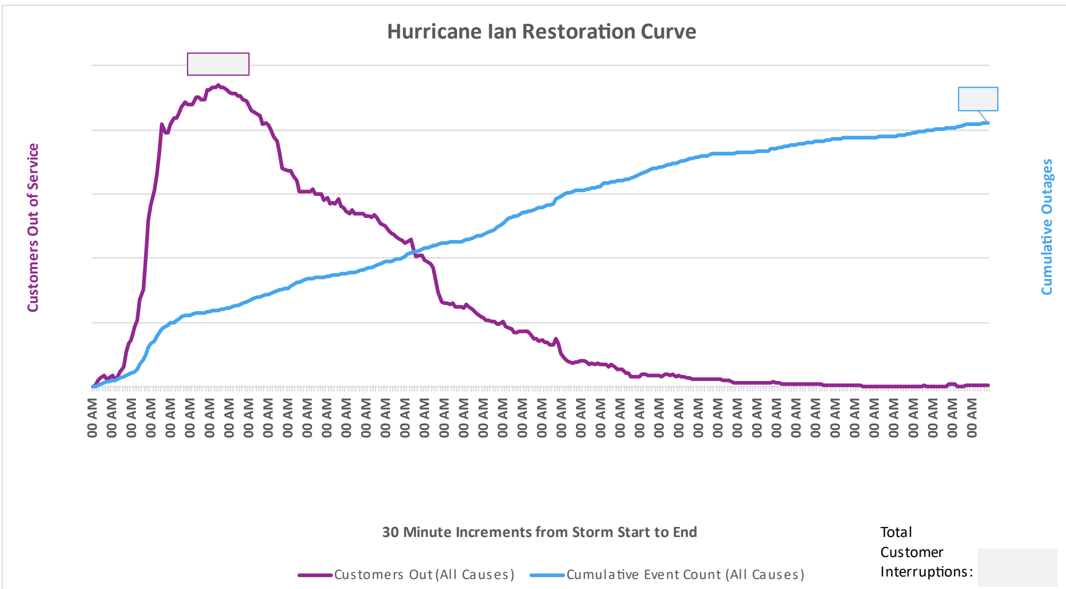

Figure 8-6: TECO Restoration Curve for Hurricane Ian

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9 Work Plan for Recommended Approach

9.1 Distribution VM Four-Year Cycle Summary (Initiative 1 for Program 2-5

Work Area	2025		2026		2027		2028	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	253	47,869	253	44,692	253	47,970	253	39,083
DADE CITY	92	3,521	92	6,102	92	4,387	92	6,102
EASTERN	209	31,115	209	32,783	209	25,263	209	35,373
PLANT CITY	306	14,065	306	22,903	306	12,259	306	23,585
SOUTH HILLSBOROUGH	179	34,077	179	25,350	179	33,485	179	21,368
WESTERN	265	62,158	265	57,782	265	71,168	265	54,679
WINTER HAVEN	229	22,627	229	30,612	229	20,549	229	33,839
Total	**1,534**	**215,433**	**1,534**	**220,224**	**1,534**	**215,081**	**1,534**	**214,028**

9.2 Supplemental Distribution VM Summary (Initiative 2 for Program 2-5

Work Area	2025		2026		2027		2028	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	64	14,348	53	12,162	109	17,007	111	21,523
DADE CITY	177	5,656	7	784	97	2,547	88	3,027
EASTERN	17	5,976	95	20,532	56	6,126	77	14,464
PLANT CITY	23	1,602	150	4,617	24	2,335	74	6,676
SOUTH HILLSBOROUGH	13	7,134	13	3,142	14	3,602	44	12,579
WESTERN	22	4,805	22	4,437	21	4,361	89	18,527
WINTER HAVEN	183	4,846	158	11,754	178	3,306	18	2,453
Total	**500**	**44,366**	**500**	**57,428**	**500**	**39,284**	**500**	**79,250**

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9.3 Mid-Cycle Distribution VM Summary[7] (Initiative for Program 2-5

Work Area	2025		2026		2027		2028	
	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers
CENTRAL	204	47,322	285	60,034	254	43,977	88	15,824
DADE CITY	100	6,886	-	-	81	2,243	189	6,934
EASTERN	44	5,699	308	46,321	247	45,991	101	18,355
PLANT CITY	321	23,154	118	5,962	73	5,901	277	12,137
SOUTH HILLSBOROUGH	118	20,020	191	21,785	50	13,263	137	29,417
WESTERN	334	68,138	148	39,014	147	24,686	92	24,003
WINTER HAVEN	61	5,550	352	20,523	266	36,507	175	12,365
Total	**1,181**	**176,769**	**1,403**	**193,639**	**1,117**	**172,568**	**1,060**	**119,035**

[7] For Mid-cycle activity, it is assumed that 100% of a circuit's overhead mileage is inspected. The actual amount worked is assumed to vary based on circuit type, as outlined in section 8.3.3.

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10 Conclusion

In closing, the analysis conducted by TECO and Accenture recommends continuing the distribution VM four-year cycle, refining the supplemental distribution VM initiative to target 500 miles annually, and expanding the mid-cycle distribution VM initiative to cover an average of 1,200 miles of circuit inspections per year. These initiatives are designed to optimize day-to-day performance and minimize the impact of vegetation on reliability during extreme weather conditions, ultimately reducing outage times and restoration costs. By leveraging the Vegetation Management Optimization Tool (VMOT) and incorporating the latest data to continuously refine its VM strategy, TECO aims to implement cost-effective VM workplans that enhance both operational efficiency and system resilience.

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