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April 11, 2022

VIA: ELECTRONIC FILING

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

Re: Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company; Docket No. 20220048-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Petition to the Commission for approval of the company's 2022-2031 Transmission and Distribution Storm Protection Plan.

Also included are the direct testimonies of the following:

- Jason D. De Stigter
- Sloan Lewis
- David A. Pickles
- David L. Plusquellic

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bmp
Attachment
cc: All parties of record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Review of Storm Protection Plan Pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company	))))	DOCKET NO. 20220048-EI FILED: April 11, 2022

TAMPA ELECTRIC COMPANY'S PETITION
FOR APPROVAL OF STORM PROTECTION PLAN

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Section 366.96, Florida Statutes and Rule 25-6.030, Florida Administrative Code, petitions for Commission approval of its 2022-2031 Transmission and Distribution Storm Protection Plan ("SPP"). In support of this petition, the company states:

I. Preliminary Information

1. The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

2. Any pleading, motion, notice, order or other document required to be served upon Tampa Electric or filed by any party to this proceeding shall be served upon the following individuals:

J. Jeffry Wahlen
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3. Tampa Electric is an investor-owned "public utility" subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes, and is a wholly owned subsidiary of Emera, Inc.

4. Tampa Electric serves over 800,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties, Florida.

5. This petition is filed consistent with Rule 28-106.201, F.A.C. The agency affected is the Florida Public Service Commission, located at 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399. This Petition represents an original proceeding and does not involve reversal or modification of an agency decision or any proposed agency action.

II. Plan Filing Requirement and Review Criteria

6. Pursuant to Section 366.96(3) of the Florida Statutes, each public utility must file "a transmission and distribution storm protection plan that covers the immediate 10-year planning period." The plan must "explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." § 366.96(3), Fla. Stat.

7. The Commission will review Tampa Electric's SPP under the four criteria set out in Section 366.96(4) of the Florida Statutes, which are:

> (a) The extent to which the plan 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.
>
> (b) 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.
>
> (c) The estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan.

(d) The estimated annual rate impact resulting from implementation of the plan during the first 3 years addressed in the plan.

8. Pursuant to Section 366.96(5) of the Florida Statutes, the Commission "shall determine whether it is in the public interest to approve, approve with modification, or deny" approval of Tampa Electric's SPP.

9. Rule 25-6.030 of the Florida Administrative Code is the Commission Rule that implements Section 366.96(3) of the Florida Statutes. It sets out the required contents for a storm protection plan. *See* R. 25-6.030(3)(a)-(j), F.A.C.

III. Statement on Disputed Issues of Material Fact

10. In compliance with paragraph (2)(d) of Rule 28-106.201, F.A.C., Tampa Electric states that it is not aware of any disputed issues of material fact at this time, but acknowledges the possibility that the Office of Public Counsel and other parties could assert disputed issues of material fact during this proceeding.

IV. Statement of Ultimate Facts Alleged and Providing the Basis for Relief

11. Tampa Electric's 2022-2031 SPP is the result of a rigorous and comprehensive analysis of potential storm protection activities, including their potential costs and benefits, and builds off of the company's first SPP and prior storm hardening activities.

12. Tampa Electric's analysis resulted in the identification, development and continuation of eight storm protection programs ("Programs"), five of which are comprised of multiple storm protection projects ("Project"). The Company's SPP also includes the continuation of legacy storm hardening initiatives in place since 2006 and wood pole inspections.

13. Tampa Electric's 2022-2031 SPP is included with this filing as Exhibit DAP-1 to the Direct Testimony of David. A. Pickles. As explained further in the company's 2022-2031 SPP, and in the testimony of David A. Pickles, David L. Plusquellic, A. Sloan Lewis, and Jason D. De

Stigter filed contemporaneously with this petition, these Programs and Projects are the most cost-effective method of achieving the goals of reducing restoration costs and outage times associated with extreme weather and enhancing reliability.

14. Tampa Electric's SPP contains the following Programs:

- Distribution Lateral Undergrounding
- Vegetation Management
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancement
- Infrastructure Inspections
- Legacy Storm Hardening Plan Initiatives

15. These Programs collectively constitute the Company's "systematic approach to achieving the objectives of reducing restoration costs and outage times associated with extreme weather and enhancing reliability" as required by Section 366.96(3) of the Florida Statutes. Each Program is designed to individually achieve one or more of these objectives. The Programs will also operate synergistically to further these objectives.

16. Tampa Electric's SPP also contains each of the plan elements required by Rule 25-6.030(3) of the Florida Administrative Code.

a. Section 3 of the SPP includes a description of how implementation of the plan "will strengthen electric utility infrastructure to withstand extreme weather conditions" through hardening, undergrounding, and vegetation management as required by Rule 25-6.030(3)(a).

b. Section 3 of the SPP includes a description of how it "will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability" as required by Rule 25-6.030(3)(b) in Section 3 of the Plan.

c. Section 1 of the SPP includes a description of the utility's service area with the detail required by Rule 25-6.030(3)(c).

d. Section 6 of the SPP includes a "description of each proposed storm protection program" that includes the detailed information required by Rule 25-6.030(3)(d).

e. Section 6 of SPP includes, for the first year of the plan, a description of each Project including actual or estimated construction start and completion dates, a description of the affected facilities, and a cost estimate including capital and operating expenses as required by Rule 25-6.030(3)(e)1. Some of the Programs, however, do not contain Storm Protection Projects.

f. Section 6 of the SPP includes, for the second and third years of the plan, "project related information in sufficient detail…to allow the development of preliminary estimates of rate impacts…" as required by Rule 25-6.030(3)(e)2. Some of the Programs, however, do not contain Storm Protection Projects.

g. The description of the Vegetation Management Program in the SPP includes a description of proposed vegetation management activities including the detail required by Rule 25-6.030(3)(f).

h. Section 7 of the SPP includes an estimate of the annual jurisdictional revenue requirements for each year of the plan as required by Rule 25-6.030(3)(g).

i. Section 8 of the SPP includes an estimate of the rate impacts for each of the first three years of the Plan for the utility's typical residential, commercial, and industrial customers as required by Rule 25-6.030(3)(h).

j. Finally, Section 9 of the SPP includes a description of all implementation alternatives that could have mitigated the rate impact for each of the first three years of the plan as required by Rule 25-6.030(3)(i).

17. David A. Pickles' testimony introduces Tampa Electric's 2022-2031 SPP and explains how the implementation of the SPP will strengthen the company's infrastructure to withstand extreme weather conditions. His testimony also provides an overview of the company's service area, describes the process that used to develop the Plan, and describes how the Plan's implementing Programs were selected and prioritized.

18. David L. Plusquellic's testimony presents the eight SPP Programs comprising Tampa Electric's 2022-2031 SPP: Distribution Lateral Undergrounding, Vegetation Management, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Transmission Access Enhancement, Infrastructure Inspection, and Legacy Storm Hardening Initiatives. His testimony provides a description and explanation of how each Program will ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

19. A. Sloan Lewis' testimony demonstrates that the company's 2022-2031 Storm Protection Plan complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan rule, by providing an estimate of the annual jurisdictional revenue requirements for each year of the SPP. Her testimony also provides an estimate of rate impacts for each of the

first three years of the SPP for the company's typical residential, commercial, and industrial customers.

20. Jason D. De Stigter's testimony summarizes the results and methodology used by 1898 & Co. to develop a Storm Resilience Model for Tampa Electric. The Storm Resilience Model calculated the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers, prioritized hardening projects with the highest resilience benefit per dollar invested into the system, and established an overall investment level that maximizes customers benefit while not exceeding the company's technical execution constraints.

21. In April of 2020, Tampa Electric and several consumer parties[1] entered into a settlement known as the "2020 Agreement." The 2020 Agreement resolved pending issues in several dockets, including the docket for review of Tampa Electric's 2020-2029 Storm Protection Plan. *See* Document No. 02227-2020, filed April 27, 2020, in Docket No. 20200145-EI.

22. Paragraph 15(c) of the 2020 Agreement required Tampa Electric to meet with the parties to discuss possible modifications to the company's SPP analytical framework and methodology. Tampa Electric complied with this provision by hosting meetings with the parties on October 5 and November 18, 2020. Tampa Electric did not receive any feedback or suggestions regarding modifications to the company's SPP framework from the parties to the 2020 Agreement.

23. In August of 2020, Tampa Electric entered an additional "Stipulation and Settlement Agreement" with the Office of Public Counsel, the Florida Industrial Power Users Group, and Walmart[2] to resolve all outstanding issues in the company's 2020-2029 Storm

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[1] The Office of Public Counsel, the Florida Industrial Power Users Group, the Florida Retail Federation, the Federal Executive Agencies, and the West Central Hospital Utility Alliance.

[2] The other parties to the 2020 Agreement did not intervene in the company's SPP docket.

Protection Plan docket. *See* Document No. 04205-2020, filed August 3, 2020 in Docket No. 20200067-EI.

24. Paragraph 15 of the Stipulation and Settlement Agreement required Tampa Electric to work with Walmart to evaluate potential new SPP Programs. This provision states that these efforts would be “separate from and supplemental to the activity specified in Paragraph 15(c) of the 2020 Agreement.”

25. Tampa Electric complied with Paragraph 15 of the Stipulation and Settlement Agreement by meeting with representatives for Walmart on January 13 and December 9, 2021.

26. Section 366.96(6) of the Florida Statutes requires Tampa Electric to file an updated SPP by 2023. Paragraph 17 of the Stipulation and Settlement Agreement required the company to file an updated SPP one year early, or in 2022. Paragraph 17 also requires that this updated SPP to include a comprehensive review of all programs included in the company’s 2020 SPP and any new programs proposed by the company. The company complied with Paragraph 17 through this filing.

V. Relief Requested

27. Tampa Electric respectfully requests that the Commission find that it is in the public interest to approve the company’s SPP without modification.

WHEREFORE, Tampa Electric Company respectfully urges the Commission to find that it is in the public interest to approve the Company’s 2022-2031 Transmission and Distribution Storm Protection Plan without modification.

DATED this 11th day of April, 2022

Respectfully submitted,

Malcolm N. Means

J. JEFFRY WAHLEN
MALCOLM N. MEANS
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC'S 2022-2031 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

DAVID A. PICKLES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID A. PICKLES

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INTRODUCTION

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

A. My name is David A. Pickles. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Vice President of Electric Delivery and Asset Management for Electric Delivery/Energy Supply.

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

A. My duties and responsibilities include the oversight of all functions within Tampa Electric's Electric Delivery Department including the planning, engineering, operation, maintenance and restoration of the transmission, distribution and substation systems; operation of the distribution and energy control centers; administration of tariffs and compliance; execution of the Company's Transmission and Distribution ("T&D") strategic solutions including advanced metering infrastructure, outdoor and streetlight LED conversion project, and advanced distribution management system; line clearance activities; and fleet equipment. As it relates to this filing, I have executive oversight over development of Tampa Electric's 2022-2031 Storm Protection Plan ("2022 SPP") and the safe, timely, and efficient implementation of that plan.

Q. Please describe your educational background and professional experience?

A. I am a Chemical Engineer and a graduate of Dalhousie University based in Halifax, Nova Scotia, Canada. I am a registered Professional Engineer in the Province of Nova Scotia.

I joined Nova Scotia Power in 2001 as a Plant Engineer and held many roles over the next 15 years including Maintenance Manager, Plant Manager, Senior Plant Manager, Director, and Senior Director of Operations. In 2016, I became the Vice President of Operations for Emera Energy and was responsible for 1,100 MW of generating capacity in three American states and two Canadian provinces.

I joined Tampa Electric in 2018 and assumed responsibility over Big Bend Generating Station and Energy Supply's Engineering and Project Management group. Most recently, I have served as Vice President of Energy Supply and Electric Delivery/Energy Supply Asset Management.

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

A. Yes. I filed direct testimony in Tampa Electric's most recent rate case, and I have also testified and filed testimony before the Nova Scotia Utility and Review Board in 2014 and 2015 in support of the Annual Capital Expenditure Plan; Application by Nova Scotia Power Inc. ("NSPI") for Approval of its Annual Capital Expenditure Plan for 2014 (M05998) and Application by NSPI for Approval of its Annual Capital Expenditure Plan for 2015 (M06514).

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 2022-2031 Storm Protection Plan. I will describe the company's service area and its transmission and distribution system. I will also describe the process the company followed to develop the 2022-2031 Storm Protection Plan and explain how it will accomplish the goals of the statute to reduce restoration costs and outage times associated with extreme weather and enhance reliability.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am. Exhibit No. DAP-1, entitled, "Tampa Electric's 2022-2031 Storm Protection Plan", was prepared under my direction and supervision. This Exhibit details the company's plans to implement the Storm Protection Plan Rule.

Q. Will any other witnesses testify in support of Tampa Electric's Proposed Storm Protection Plan?

A. Yes. David L. Plusquellic will testify about the programs contained within the Storm Protection Plan. Jason D. De Stigter will testify regarding the methodology to select and prioritize Storm Protection Programs and Projects. Finally, A. Sloan Lewis will testify regarding the estimated annual jurisdictional revenue requirements for the Plan and the estimated rate impacts for each of the first three years of the Plan.

TAMPA ELECTRIC'S SERVICE AREA

Q. Please describe Tampa Electric's service area and how many customers does the company serve?

A. 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

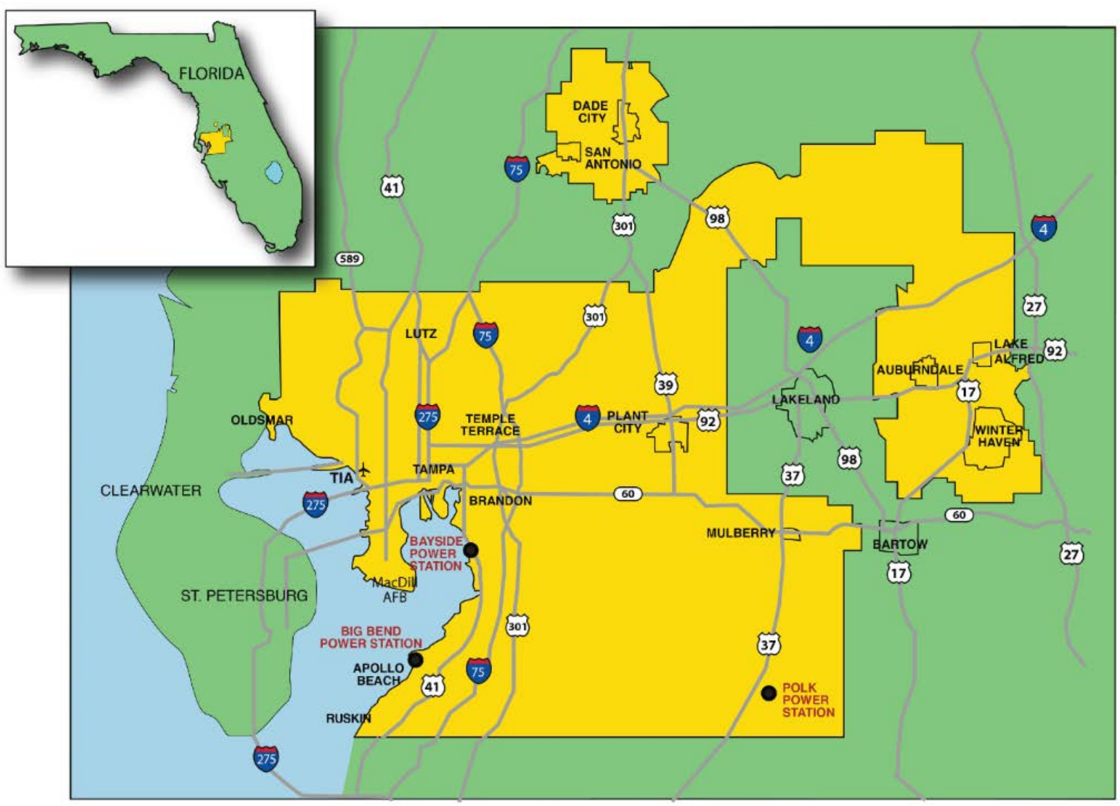
Counties. Tampa Electric provides service to 824,322 retail electric customers as of January 1, 2022.

Q. Do you have a map of Tampa Electric's service area?

A. Yes, a map of Tampa Electric's service area is included below.

TECO TAMPA ELECTRIC AN EMERA COMPANY

SERVICE AREA



Q. How many structures does the company's transmission and distribution electrical system have?

A. The company transmission system has 1,334 miles of overhead facilities, including approximately 26,000 transmission poles. The company's transmission system also includes approximately nine miles of underground facilities. The company's distribution system has 6,235 miles of overhead facilities, including approximately 422,500 poles. The company currently has approximately 5,903 circuit miles of underground facilities. The company currently has 216 substations.

Q. How does extreme weather affect Tampa Electric's system?

A. During extreme weather conditions, the components of Tampa Electric's system are subject to impacts from flooding, storm surge, high winds, wind-blown debris and vegetation, tree fall-ins, and other similar hazards. These impacts can result in interruption of service and costly restoration work such as reactive vegetation management and equipment replacement.

PROCESS TO DEVELOP TAMPA ELECTRIC'S 2022-2031 SPP

Q. How did Tampa Electric begin development of the company's 2022 SPP?

A. The process of developing the company's 2022 SPP began in

2019, when the Florida Legislature enacted the bill that became Section 366.96 of the Florida Statutes. This statute requires utilities to develop a comprehensive ten-year plan for storm hardening and resiliency. The company evaluated its existing storm hardening activities and considered several potential new or incremental programs. This process also involved determining the appropriate level of investment in each new program and for the overall plan.

For the 2020-2029 SPP, the company ultimately settled on eight programs. The company's internal subject-matter experts concluded that these programs would achieve the objectives of the SPP statute to reduce restoration costs, reduce outage times, and enhance reliability. These programs were:

(1) Distribution Lateral Undergrounding;
(2) Vegetation Management;
(3) Transmission Asset Upgrades;
(4) Substation Extreme Weather Hardening;
(5) Distribution Overhead Feeder Hardening;
(6) Transmission Access Enhancement;
(7) Infrastructure Inspections; and
(8) Legacy Storm Hardening Initiatives.

These programs are described in detail in the Direct

Testimony of David L. Plusquellic.

Q. What over-arching principles did you consider in development of the first SPP?

A. First, the company concluded all segments of the system should receive some hardening investment each year. One approach would have been to perform only transmission projects in year one, only distribution lateral projects in year two, etc. Tampa Electric recognized, however, that some customers are served directly from a transmission line, while others may be served at the end of a lateral, yet all customers will pay for the cost of storm resiliency investments. As a result, the company decided to allocate some hardening investment to each of the eight programs each year. Furthermore, some of the programs included in the SPP, such as pole inspections, pre-date the requirement to file a storm protection plan. The company proposed to continue funding those programs.

Second, while the SPP statute does not require the type of net present value savings analysis traditionally used for utility investments, Tampa Electric concluded that some quantitative analysis of costs and benefits should be used to prioritize projects. The company defined these benefits in terms of expected reductions in restoration costs and outage times during extreme weather. This analysis is explained in the Direct Testimony of Jason De Stigter. Tampa Electric's SPP programs will also have "blue sky" reliability benefits, but the company did not attempt to project those benefits as a part of its 2022 SPP. If these "blue sky" benefits were included then the cost-benefit ratios of the proposed projects would be even more favorable.

Third, the company decided that it should prepare a target annual funding level for each program based on the above principles. These targeted funding levels would then be evaluated for cost-effectiveness.

Q. Can you elaborate on the process for identifying the appropriate funding level for each program?

A. The appropriate funding level of each program is based on several factors. The first factor is the overall benefit expected from hardening the assets included in that program, and the identification of point of diminishing returns where additional investment provides only a minor increase in benefits. The company hired 1898 & Co. to analyze the proposed storm protection programs and to evaluate their potential benefits in terms of avoided restoration costs and reduced outage times. The Direct Testimony of Jason De Stigter shows this analysis. Second, in addition to considering the principles I previously described, Tampa Electric understood there are real-world limitations on how many projects the company could complete as activity levels ramped up. The company also understood there would be market constraints on labor and materials, even without the impacts of the coronavirus pandemic. Third, the company was aware of the potential rate impacts of a rapid ramp of investment levels.

Q. What do you mean by real-world limitations?

A. The company recognized that there are certain real-world constraints on implementation of SPP programs, including everything from designing, permitting, scheduling planned outages, managing the work, and maintaining a properly skilled workforce that can safely complete the projects.

Q. Why did you decide to establish annual funding levels for each program instead of allowing the prioritization model to determine the projects each year?

A. There are significant start-up costs and activities required to execute these programs and projects at scale. Furthermore, each program requires different types of resources with different skills and certifications in order to safely execute the projects. In a constrained labor market, the company believed it was more appropriate to establish an annual funding level that provided consistency and stability to both Tampa Electric and our contracting partners. The company also believed it would be impractical to transition this workforce annually from one program to another. This also supports the principle that all customers should have a program that targets the part of the system that provides their service.

Q. In developing the first SPP and this SPP, how was the benefit analysis used to prioritize projects?

A. The company utilized 1898 & Co.'s sophisticated modeling techniques to perform a quantitative analysis of these expected benefits and to prepare an initial prioritization of potential projects. The analysis produces expected benefits in terms of avoided restoration costs, avoided customer outages, and a monetization of the avoided customer outages. Projects were initially prioritized based on their cost benefit NPV ratios. The prioritization model serves as a tool for Tampa Electric in establishing funding levels. As described above, other factors such as execution constraints, ease of construction, start-up and ramp-up rates, and customer rate constraints were also factors in finalizing the prioritization. This process is further described in the Direct Testimonies of David L. Plusquellic and Jason De Stigter.

Q. Did you follow this same development process and apply the same principles in development of the 2022 SPP?

A. Yes. Tampa Electric’s 2022 SPP includes the same eight storm protection programs that were included in the prior SPP. The analysis performed by Tampa Electric and 1898 & Co. to support the 2022 SPP demonstrates that these programs will continue to achieve the objectives of the SPP statute in a cost-effective manner.

Q. Did the company incur any incremental costs in the development of the 2022 SPP?

A. Yes. Tampa Electric re-engaged 1898 & Co. to assist with evaluation and analysis of the 2022 SPP. More specifically, 1898 & Co. assisted with: (1) performing project prioritization and benefits calculations for several of the company’s proposed SPP programs; and (2) analysis of the proposed changes to these programs. This analysis and the proposed changes are described in the Direct Testimonies of David L. Plusquellic and Jason De Stigter.

Q. Did the company encounter any issues with implementation of the 2020-2029 SPP? If so, how were they factored into development of the 2022 SPP?

A. Yes. The company experienced delays related to several unexpected issues including the COVID-19 pandemic; off-system weather and related mutual assistance obligations; customer preferences on location of undergrounded laterals; permitting delays; supply chain issues; and qualified labor shortages.

The company took several steps to address these issues in the 2022 SPP.

First, the company now has a more effective process for developing undergrounding projects. The company initially designed projects to run through new easements across customers' property. As a part of the customer outreach for these projects, Tampa Electric discovered that customers generally prefer for underground laterals to be placed in existing right-of-way. This preference can cause delays as the company works to obtain necessary easements from customers or re-design projects as necessary. As a result, the company is transitioning to designing projects to run through existing right-of-way wherever there is not significant risk of those assets being disturbed, avoiding these delays.

Second, the company changed its programs to accommodate local government permitting delays. While Tampa Electric has never had a permit denied by a local government, the company discovered that it can take up to 3-4 months to obtain a necessary permit before construction can begin. The company now begins design and permitting work for a project further ahead of the anticipated construction start date. This will allow the company to develop an “inventory” of designed and permitted projects that are ready when construction resources become available.

Third, the company discovered it was more cost effective and efficient to underground some electrically-connected distribution lateral segments served by the same feeder at the same time. This change is described in greater detail in the direct testimony of Mr. Plusquellic.

Fourth, the company created new positions for a construction manager and several construction supervisors. These individuals supervise outside contractors performing SPP projects to ensure safety, quality control, and pace of work are consistent with company expectations.

In 2021, the company established a dedicated warehouse for SPP projects staffed by six dedicated Tampa Electric team members. While the company had projected that materials management and inventory storages would be challenging, it became evident in 2020 that the SPP inventory would need to have a dedicated location and staffing. First, the company’s existing locations did not have space to safely accommodate the long-term incremental SPP material inventory. The service areas were also not designed for the incremental traffic flow resulting from a substantially increased workforce picking up and delivering materials. Of equal importance, the dedicated warehouse allows the SPP team to isolate and control the financial impact of the SPP program.

Q. You mentioned earlier that the 2022 SPP contains the same eight programs as the prior SPP. How did you arrive at the recommended funding levels for each of the capital programs in the 2022 SPP?

A. We started the process with ranges for each of the programs and settled on target funding levels that balance the principles of addressing all aspects of our system, projected benefits to customers, and our ability to execute.

Q. How did you arrive at the funding level for the transmission asset upgrade program?

A. Tampa Electric committed to replacing all its wooden transmission poles within 10 years in the prior SPP. The company remains on pace to complete this conversion as per plan.

Q. How did you arrive at the funding levels for substation and transmission access programs?

A. The funding level target for the substation program was determined through a study performed by an outside consultant in 2021. This study is described in greater detail in the direct testimony of Mr. Plusquellic. In general, the substation study examined 24 substations that Tampa Electric identified as having potential extreme weather risk. The substation study identified a subset of nine substations based on an evaluation of each substation's criticality and risk. These nine substations were then evaluated by 1898 & Co. This analysis showed that the potential benefits of hardening warranted the associated costs. The direct testimony of Mr. De Stigter shows the results of this evaluation.

The transmission access program was funded to achieve a balance between completing all projects where the potential benefits warranted the associated costs and impact to customer rates.

Q. How did you arrive at the funding level for the feeder hardening program?

A. Tampa Electric had an existing feeder reliability program in effect at the time the SPP statute was passed. Prior to the SPP, Tampa Electric had a circuit reliability program that served as the basis for what could be reasonably implemented and managed within a calendar year. This experience also provided insight into the labor, materials, project management and outages required. The company also considered the number of potential projects where the potential benefits of hardening warranted the estimated costs. The final funding level was set using those parameters along with sensitivity to customer rate impacts from the SPP program as a whole.

Q. How did you arrive at the target funding level for the distribution lateral undergrounding program?

A. The target funding level is based on several factors. First, the company recognized the need to set an annual target that we believe is executable. Second, the company recognized the need to grow and sustain a sizeable workforce. Third, Tampa Electric spoke with other utilities with existing undergrounding programs as well as potential contractor partners to gauge the labor market and what was achievable. Fourth, the company identified the number of projects where the estimated benefits warranted the estimated costs. These considerations led to the decision to target 75-100 miles per year once the program ramps up to steady state operations.

Q. You stated that your program funding levels were based in part on what level of activity you thought was achievable. You invested less in both 2020 and 2021 than you projected for both distribution lateral undergrounding and overhead feeder hardening. Can you explain this?

A. Yes. As mentioned above, one of the impediments the company encountered was the loss of overhead line crews to mutual assistance obligations. During the eight months of SPP activity in 2020, approximately one month of time was lost to these obligations. In 2021, the company achieved the projected activity level.

The distribution lateral undergrounding program experienced delays related to customer preferences, permitting, and labor market constraints as I described previously. The company has taken steps to mitigate these issues in the 2022 SPP. The company is now beginning to develop an "inventory" of designed, permitted, and supplied undergrounding projects, removing the current bottlenecks in releasing projects to our construction teams.

Q. How did you set the program funding level for vegetation management?

A. As part of the process to develop the 2020-2029 SPP, Tampa Electric retained Accenture, a consultant with expertise that has worked with Tampa Electric on vegetation management analyses in the past. Accenture analyzed multiple scenarios involving incremental vegetation management activities to evaluate the level of incremental activity that would provide the greatest benefit for the estimated cost. Tampa Electric is proposing to continue these vegetation management activities from the prior SPP.

Q. Does Tampa Electric's 2022 Plan place a higher priority on any areas of the company's service area for hardening or enhancement projects?

A. No. As explained above, the company believes that all customers should benefit from storm protection investments. The modeling that supports the company's Plan does, however, include some consideration of geography. For instance, the model incorporates elements such as wind speed zones, flood zones, localized vegetation cover, and accessibility of assets. These considerations are addressed in the direct testimony of Mr. De Stigter.

Q. Has Tampa Electric determined that it would be impractical, unfeasible, or imprudent to harden or enhance any part of the company's system?

A. No. All components of the transmission and distribution system can be hardened to achieve resiliency benefits. Furthermore, as explained above, Tampa Electric believes that all customers should benefit from storm protection investments. The company has, however, prioritized hardening of those components of the system that offer the greatest projected benefits for the associated cost.

ADHERENCE TO COMMISSION RULES AND STATUTORY REQUIREMENTS

Q. Will Tampa Electric's Storm Protection Plan further the objectives of Section 366.96 of the Florida Statutes to reduce restoration costs and outage times associated with extreme weather and enhance reliability?

A. Yes. As Tampa Electric's direct testimony in this docket demonstrates, the continued Storm Protection Plan is based on a rigorous analysis of possible methods to achieve the goals of Section 366.96 of the Florida Statutes. The goal of the company's analysis was to identify those activities that deliver the greatest storm resiliency and reliability benefits for the lowest cost.

Q. Does the process utilized by Tampa Electric's 2022 SPP address the requirements of Rule 25-6.030, F.A.C.?

A. Yes. Under Rule 25-6.030(3), F.A.C., a utility's Storm Protection Plan must contain several specific categories of information. The table below shows where each category of information is located within the company's Proposed Storm Protection Plan.

Tampa Electric's 2022-2031 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 3 - SPP Overview
25-6.030(3)(c)	Section 1 - Tampa Electric's Service Area
25-6.030(3)(d)1-4	Section 6 – Storm Protection Programs
25-6.030(3)(d)5	Section 3 – SPP Overview
25-6.030(3)(e)	Section 6 – Storm Protection Programs
25-6.030(3)(f)	Section 6.2 – Vegetation Management
25-6.030(3)(g)	Section 7 – Projected Costs and Benefits
25-6.030(3)(h)	Section 8 – Estimated Rate Impacts
25-6.030(3)(i)	Section 9 – Alternatives and Considerations
25-6.030(3)(j)	N/A (optional)

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through overhead hardening of electrical transmission and distribution facilities as required by Rule 25-6.030(3)(a)?

A. Implementation of the company's Vegetation Management, Infrastructure Inspections, Transmission Asset Upgrades and

Distribution Overhead Feeder Hardening Programs will accomplish this goal. One of the main causes of failed overhead equipment is wind-blown vegetation. The Vegetation Management Program will trim vegetation across the system to help minimize this risk. Vegetation Management, however, does not completely eliminate this risk since the wind can blow vegetation into conductor from outside the company's trimming area. This risk can be further addressed by upgrading transmission and distribution structures to mitigate failures due to physical loading on the power lines from wind and debris. This includes include transmission pole upgrades from wood to primarily steel or concrete, and the overhead hardening of distribution poles to higher class. Finally, feeder sectionalization and automation will result in fewer customers impacted should the hardened poles fail since all risk cannot be mitigated. These programs are described in greater detail in the direct testimony of Mr. Plusquellic.

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through undergrounding certain portions of electrical distribution lines as required by Rule 25-6.030(3)(a)?

A. Implementation of the company’s Distribution Lateral Undergrounding Program will accomplish this goal. Underground laterals are shielded from many of the potential harmful effects of extreme weather events such as wind loading and debris resulting in significant benefits to customers. Indeed, metrics from past extreme weather events clearly show that underground systems prove to be much stronger and more resilient. This program is described in greater detail in the direct testimony of Mr. Plusquellic.

Q. Please explain how the implementation of the company’s proposed Storm Protection Plan will strengthen the company’s infrastructure to withstand extreme weather conditions through vegetation management as required by Rule 25-6.030(3)(a)?

A. A main driver of failed overhead equipment is wind-blown vegetation contacting circuits. The company’s proposed Vegetation Management Program will mitigate this risk through strategic, incremental vegetation management activity. The Vegetation Management Program is described in greater detail in the direct testimony of Mr. Plusquellic.

Q. Please explain how the implementation of the company’s proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions as required by Rule 25-6.030(3)(b)?

A. Five of the eight SPP programs (Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, and Transmission Access Enhancement) were re-modelled, re-assessed and optimized using a sophisticated storm resilience model employed by the company's consultant, 1899 & Co. This modeling is detailed in the direct testimony of Mr. De Stigter. Tampa Electric also performed a detailed analysis of the Vegetation Management Program, during preparation of the company's initial SPP. In addition, the proposed programs also underwent additional analysis by Tampa Electric. These analyses demonstrate there are significant benefits associated with these programs including reduced restoration costs, reduced outages, and reduced restoration times. Further program benefits will accrue in day-to-day operations. The direct testimony of Mr. Plusquellic includes additional details regarding the estimated improvement in reduced restoration costs and outage times for each program.

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will improve overall service reliability and customer service as required by Rule 25-6.030(3)(b)?

A. Each of the eight Storm Protection Plan programs will not only meet the storm resiliency goals of the Rule and the statute but will also have significant reliability benefits during blue sky operations. The plan will ultimately result in reduced outages, both momentary and sustained, and reduced restoration times resulting in reduced operating and capital costs. The company has not attempted to project "blue sky" cost savings that may result from SPP activities at this time. Tampa Electric expects that SPP activities will ultimately reduce O&M spending, but it is difficult to project those potential savings at this time. Furthermore, these savings may be offset in whole or in part by increases in certain O&M costs such as inspections and maintenance of new system assets.

Q. Did the company consider any implementation alternatives that would mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan as required by Rule 25-6.030(i)?

A. Yes. The company considered an alternative that involved no incremental storm protection activities but quickly rejected it as inconsistent with the objectives of the statute. Tampa Electric also considered and rejected some capital programs and projects including undergrounding distribution feeders, proactively upgrading wood distribution poles, purchasing temporary transmission access solutions such as matting, and installing a private LTE network.

The company also evaluated alternatives in the form of several increments of SPP activity. Given that the statute directs the company to develop a "systematic approach…to achieve the objectives of reducing restoration costs and outage times," the company worked with 1898 & Co. to confirm that the company's projected funding levels are at the optimal point before additional investment does not result in materially greater restoration costs and outage time benefits.

ESTIMATED COSTS OF STORM PROTECTION PLAN

Q. Did the company prepare an estimate of the annual jurisdictional revenue requirements for each year of the proposed Plan?

A. Yes. The estimated annual jurisdictional review requirements for each year of the proposed Storm Protection Plan are included in the company's Storm Protection Plan. A full explanation of the detail of these jurisdictional revenue requirements and how they were calculated for each year of the proposed storm protection plan is included as Exhibit No. ASL-1, Document No. 1 within the Direct Testimony of A. Sloan Lewis in this proceeding.

ESTIMATED RATE IMPACTS OF STORM PROTECTION PLAN

Q. Did the company prepare an estimate of rate impacts for each of the first three years of the proposed storm protection plan for a typical residential, commercial, and industrial Tampa Electric customer?

A. Yes. The estimated rate impacts for each of the first three years of the proposed Storm Protection Plan for a typical residential, commercial, and industrial Tampa Electric customer are included in the table below. A full detail explanation of these rate impacts and how they were calculated for each of the first three years of the proposed storm protection plan is included as Exhibit No. ASL-1, Document No. 2 within A. Sloan Lewis's direct testimony in this proceeding.

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2022	2.70%	2.70%	1.17%	1.08%
2023	4.13%	4.13%	1.28%	1.19%
2024	5.31%	5.31%	1.37%	1.29%

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony and the direct testimony of David L. Plusquellic, A. Sloan Lewis, and Jason D. De Stigter and the accompanying exhibits present and support Tampa Electric's proposed 2022-2031 Storm Protection Plan. This Plan 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 2022-2031 Storm Protection Plan be approved?

A. Yes. Tampa Electric's proposed 2022-2031 Storm Protection

Plan 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 2020-2029 SPP and from the prior Storm Hardening Plans and initiatives that were established by this Commission in 2007. Finally, the Plan will continue to accelerate 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.

EXHIBIT

OF

DAVID A. PICKLES

Tampa Electric's
2022–2031
Storm Protection Plan

Filed: April 11, 2022

Tampa Electric's
2022-2031 Storm Protection Plan Summary

Tampa Electric's 2022-2031 Storm Protection Plan 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 prudent, 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 to customers and improve overall service reliability for customers.

Tampa Electric's 2022-2031 Storm Protection Plan will be its second ten-year protection plan filed in response to Rule 25-6.030, Storm Protection Plan. That Rule, which became effective on February 18, 2020, requires utilities to file storm protection plans. Tampa Electric has developed this Plan to comply with the Rule. The majority of this Plan continues the company's first Commission approved Storm Protection Plan with the existing eight Storm Protection Programs. The company has modified some of the Storm Protection Programs slightly to take advantage of lessons learned that were gained through the initial development and implementation of the original Storm Protection Plan Programs that was filed on April 10, 2020. This Storm Protection Plan contains a description of the company's Storm Protection Programs, the specific supporting Projects to these Programs and required detail as prescribed by Rule 25-6.030. This Plan also incorporates the continuation of those legacy Storm Hardening Plan Initiatives that have been in place since 2006 and wood pole inspections.

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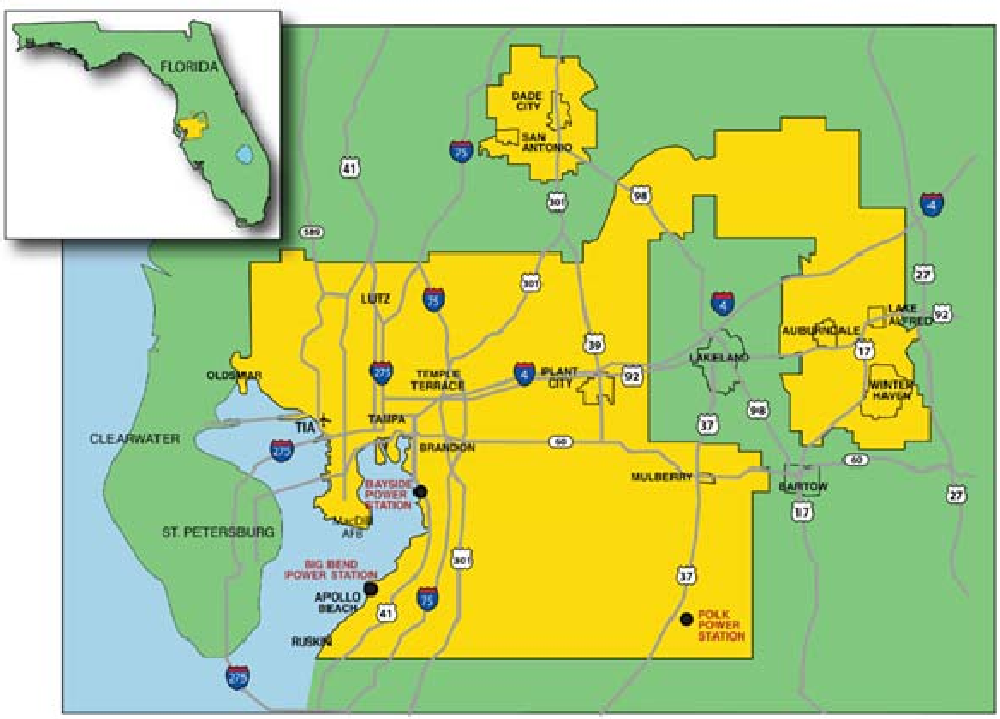
1. Tampa Electric's Service Area:

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 seven "service areas" for operational and administrative purposes. Tampa Electric provides service to 824,322 retail electric customers as of January 1, 2022.

TECO TAMPA ELECTRIC AN EMERA COMPANY

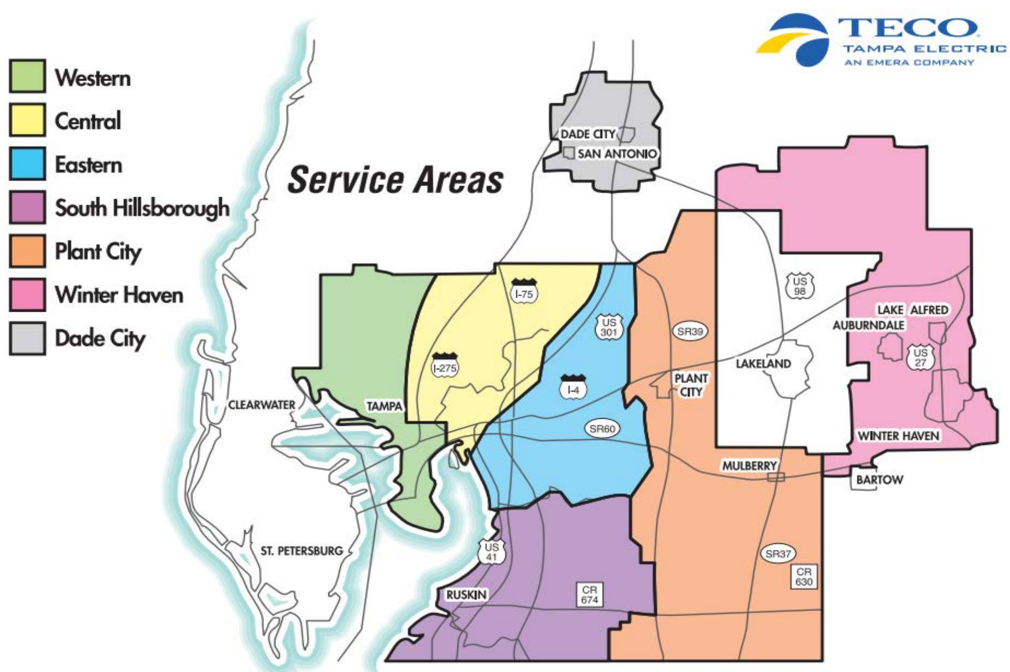
SERVICE AREA



Tampa Electric's transmission system consists of more than 1,200 circuit miles of overhead facilities, including 24,689 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,235 circuit miles of overhead facilities and 422,500 poles. The company currently has approximately 5,903 circuit miles of underground distribution facilities. The company currently has 216 substations. Tampa Electric also has approximately 317,370 authorized joint user attachments on the company's transmission and distribution poles.

The company's service area map below shows how the system is divided into the seven "service areas" for operational and administrative purposes. In addition, the customer counts of customers served in the seven "Service Areas" as of December 31, 2021, are as follows:

	Customer Count
Central Service Area "CSA"	215,086
Dade City Area "DCA"	15,873
Eastern Service Area "ESA"	131,248
Plant City Area "PCA"	64,369
South Hillsborough Area "SHA"	101,875
Western Service Area "WSA"	214,077
Winter Haven Area "WHA"	81,794



Tampa Electric developed the proposed 2022-2031 Storm Protection Plan and its supporting Programs and initiatives by examining the entire company's service area for the most cost-effective enhancement opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness, or practicality concerns.

2. References:

The following resources are referenced in this Plan:

a) 2017 National Electrical Safety Code
b) National Hurricane Center Database
c) Florida State Building Code
d) Hillsborough County Wind Maps
e) Tampa Electric's prior Storm Implementation Plans
f) Tampa Electric's Distribution Engineering Technical Manual
g) Tampa Electric's Standard Electrical Service Requirements
h) Tampa Electric's General Rules and Specifications-Overhead
i) Tampa Electric's General Rules and Specifications-Underground
j) Tampa Electric's Approved Materials Catalog
k) Hillsborough County Flood Hazard Maps

3. Storm Protection Plan Overview

Tampa Electric's Storm Protection Plan ("Plan" or "SPP") continues to set out a 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 continued activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" in a cost-efficient manner.

In 2006 and 2007, the Florida Public Service Commission ("FPSC" or "Commission") issued two orders related to storm hardening and enacted Rule 25-6.0342, Florida Administrative Code ("F.A.C."), which requires utilities to prepare and submit a "Storm Hardening Plan" every three years. Through these actions, the Commission directed utilities to complete specific hardening activities, such as equipment inspections, post-storm data collection, and vegetation management cycles. In the years since, Tampa Electric Company has consistently performed these required activities and delivered significant storm resiliency benefits to customers.

In 2019, the Florida Legislature enacted a new law requiring utilities to prepare a "transmission and distribution storm protection plan." § 366.96(3), Fla. Stat. The statute requires utilities to develop a "transmission and distribution storm protection plan" setting out a "systematic approach" to reducing outage times and restoration costs associated with extreme weather and enhancing reliability. § 366.96(3), Fla. Stat. The Florida Legislature clearly intended that utilities should examine all options for achieving those goals, even those that go beyond the Commission's existing list of required Storm Hardening Plan activities.

In response to the new requirement to develop a comprehensive SPP, Tampa Electric evaluated its existing Storm Hardening Plan activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions which were included in Tampa Electric's 2020-2029

Storm Protection Plan.

In this Storm Protection Plan, Tampa Electric engaged 1898 & Co. to reperform Project prioritization and benefits calculations for several of the company's proposed Storm Protection Programs, including:

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

Tampa Electric and 1898 & Co. continued to 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 consistently models 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, Project, and Program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall 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. A detailed 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 "F".

The storms database includes the future 'universe' of potential storm events to impact the company's service area. 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. Each storm scenario was 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 and CMI for each of the Projects. Finally, the Storm Impact Model calculated the benefit in decreased restoration costs and CMI 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 benefit for each Project in dollars. Feeder Automation Hardening Projects were 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. This was done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric’s technical and operational (Transmission outages) in scheduling the Projects.

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.

The modeling tool continues to allow the company to understand the Storm Protection Programs and the benefits that could be expected. In addition, as in the last Storm Protection Plan justification, Tampa Electric personnel factored the legacy Program Storm Hardening Plan Initiatives into these evaluations. Also, real-world considerations were included that examined practical realities of multi-year implementation, such as growing and sustaining an external workforce, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the modeling tool to develop the final set of Programs, Program funding and ultimately individual Project selection. A complete copy of Tampa Electric’s Storm Protection Plan Resilience Benefits Report is included as Appendix “F”.

Finally, the company used the analyses provided by 1898 & Co. as a basis for establishing the spending levels in the proposed 2022-2031 Storm Protection Plan. 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. The company’s 2022-2031 SPP will continue to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission.

4. 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 assist other utilities have given Tampa Electric’s restoration crews opportunities to gain valuable restoration knowledge and experience in restoring service after a major storm event. This knowledge includes the importance of conducting a damage assessment immediately after the storm has passed and providing customers with an accurate Estimated Time of Restoration (“ETR”). In addition to this experience, Hurricanes Matthew (2016), Hermine (2016), Harvey (2017), Irma (2017), Maria (2017) and Michael (2018) further exposed how vulnerable coastal regions are to the significant damaging effects of storm surge and the significant effort required to restore a system that has been impacted by coastal flooding. These experiences and industry best practices were discussed, analyzed and used to improve Tampa Electric’s storm response plan.

Table 1 below provides the details of named storms affecting Tampa Electric’s service area since 1960. The data is from the National Hurricane Center database.

Table 1: Named Storms Affecting Tampa Electric Service Area since 1960			
Year	**Storm Name**	**Size [1]**	**Wind Speed [2]**
1960	Donna	Cat 3	115
1995	Erin	TS	57
2004	Charley	Cat 2	86
2004	Francis	Cat 1	63
2004	Jeanne	Cat 1	63
2005	Dennis	TS	43
2005	Wilma	TS	44
2006	Alberto	TS	45
2007	Barry	TS	31
2012	Debby	TS	53
2012	Isaac	TS	36
2013	Andrea	TS	47
2015	Erika	TS	<39
2016	Colin	TS	<39
2016	Hermine	Cat 1	37
2016	Matthew	TS	20
2017	Emily	TS	<39
2017	Irma	Cat 1	90
2018	Alberto	TS	29
2019	Nestor	TS	26
2021	Elsa	TS	43

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

Note 2: Maximum sustained surface wind speed measured in miles per hour ("mph") when the storm passed through the Tampa Electric service area.

5. 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 Plan document as important background and context for the Program elements of its Storm Protection Plan. The company will continue to evaluate and enhance its standards, policies, practices and procedures to incorporate new storm hardening and resiliency techniques.

5.1 National Electrical Safety Code Compliance

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

5.2 Wind Loading Standards

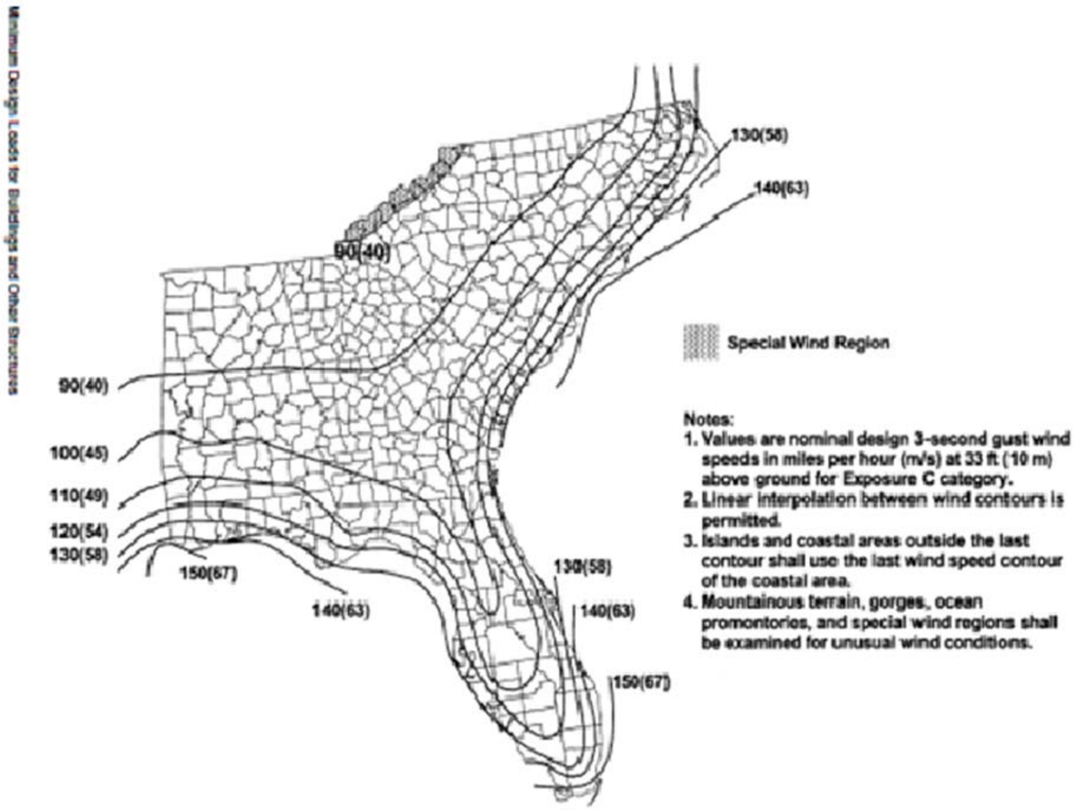
NESC Rule 250, which addresses pole loading requirements in the United States, is divided into three loading districts; Heavy, Medium and Light (see Figure 2 below). Tampa Electric's service area is in the Light loading district, which assumes no ice buildup and a wind pressure rating of nine pounds 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.

5.2.1 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



5.3 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.

5.3.1 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.

5.3.2 Overhead System

5.3.2.1 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.

5.3.2.2 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.

5.3.2.4 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 percent 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 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.

5.3.2.5 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.

5.3.2.6 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 Rights-of-Way (“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.

5.3.2.7 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.

5.3.3 Underground Facilities

5.3.3.1 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.

5.3.3.2 Network Service

Tampa Electric has several types of underground services with associated facilities. One is 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.

5.3.4 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 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 (padmounted 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 percent stainless steel enclosures, and since 2008 all padmounted transformers have been specified using 100 percent 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 padmount 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.

5.3.5 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.

5.3.6 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, 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.

5.4 Transmission

This section of the Plan 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.

5.4.1 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.

5.4.2 Transmission Structures

5.4.2.1 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.

5.4.2.2 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 Tampa Electric installs when replacing or upgrading structures.

5.4.2.3 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:

- Number of circuits
- Conductor size
- Structure strength

- Span length
- Soil conditions
- ROW width
- Potential permitting requirements
- Utilization of adjacent land
- Environmental impacts
- Electric and magnetic field criteria
- Aesthetics
- Economics and cost–effectiveness
- 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.

5.4.3 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.

5.5 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 date 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 216 substations.

5.5.1 Design Philosophy

5.5.1.1 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.

5.5.1.2 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.

5.5.1.3 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 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.

5.5.1.4 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.

5.5.1.5 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.

5.5.2 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 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.

5.6 Deployment Strategy

Tampa Electric’s 2022-2031 Storm Protection Plan’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 Storm Protection Plan Programs and the legacy Storm Hardening Plan Initiatives.

6. Storm Protection Plan Programs

Tampa Electric's proposed 2022-2031 SPP is designed with the primary objective of enhancing the resiliency and reliability of its transmission and distribution systems during extreme weather events. Over the next ten years, Tampa Electric will build upon the success of its initial Storm Protection Plan to materially improve resiliency through targeted investments in the same eight 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)Transmission Access Enhancement; (7)Infrastructure Inspections; and (8)Legacy Storm Hardening Initiatives. These programs will minimize the impact of severe weather by hardening Tampa Electric's infrastructure. These Programs are described in this section and will continue to collectively achieve the goals, objectives and requirements of the Florida Legislature and the Commission.

6.1 Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding Program aims to 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 from 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.

Tampa Electric's Distribution System is currently comprised of the following Key Metrics:

- Total Circuit Miles: 12,138
- Total Overhead Miles: 6,235 (51 percent)
- Total Underground Miles: 5,903 (49 percent)
- Total Overhead Lateral Miles: 4,441
- Total Overhead Feeder Miles: 1,794
- Total Underground Lateral Miles: 5,240
- Total Underground Feeder Miles: 662
- Customers served off Laterals: 94 percent
- Customers served off Feeders: 6 percent

Tampa Electric and its customers have been fortunate because the company's service area has incurred only one direct hit from a large, strong, named storm in the last 15 years (Hurricane Irma in 2017). The table below reflects Tampa Electric's distribution system "OH versus UG" outage comparison across "day-to-day", Major Event Days, and Hurricane Irma.

Tampa Electric's Distribution System Overhead versus Underground Outage Comparison (in Percent)				
	Distribution System	**Day-to-Day Outages**	**Major Event Day Outages**	**Irma Repair/Replace**
Overhead	53	81	89	99.60
Underground	47	19	11	0.40

These metrics show that the underground system proves to be much stronger and more resilient during extreme weather events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years. This SPP 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.

As previously discussed, Tampa Electric used the 1898 & Co. modeling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. Initial model runs provided the optimal 10-year SPP spending levels and demonstrated that this Program’s undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. Tampa Electric relied on the model output to confirm appropriate funding levels in alignment with the Distribution Lateral Undergrounding Program for the duration of the 2022-2031 SPP. The individual Projects, the prioritization of these Projects and the annual Program funding levels are supported by the model. One significant lessons learned that was changed for this proposed SPP was the way laterals were grouped for prioritization. In the company’s original SPP, laterals line segments were prioritized between protection devices. While this prioritized all of the company’s lateral line segments in a very disciplined manner, this method was identified as a lessons learned that it would better from a strategic, construction, operational, cost and customer satisfaction basis to prioritize laterals based upon the entire lateral downstream of the feeder. Laterals were then selected based on their ease of execution (i.e., fewer joint use attachers, fewer rear lot spans, and no major road or railroad crossings) balanced against their customer benefits. The table of identified detailed Projects is included in Appendix "A".

For the SPP years 2025 to 2031, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The table below shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the 2022-2031 SPP:

	Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	646	$105.8
2023	399	$104.7
2024	436	$105.2

The full detail of the supporting Distribution Lateral Undergrounding individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "A".

6.2 Vegetation Management

Tampa Electric's Vegetation Management Program ("VMP") combines a continuation of its existing filed and approved distribution and transmission VMP activities with three additional strategic VM initiatives that were added in the company’s initial SPP.

6.2.1 Vegetation Management Activities

Tampa Electric currently trims the company’s distribution system on a four-year cycle. This approach was approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012. The four-year cycle is flexible enough to allow the company to change circuit prioritization utilizing the company's reliability-based methodology. Since 2007, Tampa Electric has partnered with a third-party consultant and used their proprietary vegetation management software application. The software analyzes 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 optimizes circuit selection in terms of both reliability and cost-effectiveness.

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 the circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission (“FERC”) standard FAC-003-4. 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 includes the maintenance of the transmission ROWs.

6.2.2 Supplemental VMP Initiatives

In addition to continuing its existing VMP plans, Tampa Electric partnered with Accenture during development of the company’s initial SPP to analyze various VMP strategies to further enhance the transmission and distribution facilities while reducing outage times and restoration costs due to extreme weather conditions. Accenture updated its existing vegetation management software to include the 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 original analysis conducted less than two years ago, Tampa Electric is proposing to continue the two additional distribution VM initiatives and one additional transmission VM initiative. The purpose of these additional VM initiatives is to enhance the company’s current cycles, specifically for the purpose of system storm hardening. These additional VM initiatives are:

Initiative 1: Supplemental Distribution Circuit VM
Initiative 2: Mid-Cycle Distribution VM
Initiative 3: 69 kV VM Reclamation

6.2.2.1 Initiative 1: Supplemental Distribution Circuit VM

Tampa Electric and Accenture evaluated the costs and benefits of enhancing the current 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 4-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 700 miles of supplemental VM 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 below:

Supplemental Vegetation Management Project Schedule by Service Area						
	2022		2023		2024	
Service Area	**Miles**	**Customers**	**Miles**	**Customers**	**Miles**	**Customers**
Central	113.5	20,418	127.1	19,538	202.0	26,880
Dade City	127.6	5,578	44.9	681	100.4	4,627
Eastern	72.9	8,794	149.8	18,918	97.9	9,524
Plant City	202.2	8,347	31.1	3,579	174.0	5,645
South Hillsborough	20.2	3,236	138.9	28,399	16.4	2,874
Western	112.4	20,376	155.8	27,165	88.2	10,391
Winter Haven	43.2	5,784	53.2	7,950	24.8	1,276
Total	692	72,533	700.8	106,230	703.7	61,217

The total Supplemental Circuit VM initiative costs are detailed below for the 2022-2031 SPP:

Supplemental Vegetation Management Project Costs (in thousands)	
2022	$6,100
2023	$7,100
2024	$4,800
2025	$5,300
2026	$6,500
2027	$5,900
2028	$5,900
2029	$5,900
2030	$6,200
2031	$6,500

6.2.2.2 Initiative 2: Mid-Cycle Distribution VM

Tampa Electric’s experience with existing VM activities is that some trees cannot be effectively maintained within the four-year distribution VM cycle because of their rapid growth rate. For instance, the company estimates that up to twenty-five percent of trees grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. Additionally, some trees develop into a threat to distribution facilities due to an evident defect or hazard trees. The current four-year cycle has limited tree removal potential. Fall-in trees were determined to be a major damage factor in recent storms.

The Mid-Cycle VM initiative is inspection-based and designed to identify and selectively mitigate these 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. For the first three years of the Storm Protection Plan, the company will inspect feeders that have not been trimmed in the last two years and then prescribe additional VM work based on the inspection findings. After the first three years, the company plans to expand the initiative to include laterals. The Mid-Cycle VM initiative schedule by Tampa Electric’s Service Area and year for the affected miles and customers is detailed below:

Mid-Cycle Vegetation Management Project Schedule by Service Area						
	2022		2023		2024	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	36.0	9,488	176.8	25,321	138.1	18,058
Dade City	5.1	904	0.0	0	0.0	0
Eastern	34.5	12,007	115.3	16,234	129.3	15,835
Plant City	12.0	7,191	231.0	12,380	174.9	6,627
South Hillsborough	23.0	13,900	82.1	3,925	108.6	3,446
Western	53.3	19,073	171.2	27,479	156.8	22,301
Winter Haven	32.1	14,565	241.5	7,779	293.0	10,032
Total	196.0	77,128	1,017.9	93,118	1,000.7	76,299

The total Mid-Cycle VM Project costs are detailed below for the 2022-2031 SPP:

Mid-Cycle Vegetation Management Project Costs (in thousands)	
2022	$3,500
2023	$4,000
2024	$5,600
2025	$6,000
2026	$5,700
2027	$6,200
2028	$7,300
2029	$6,300
2030	$6,600
2031	$6,900

6.2.2.3 Initiative 3: 69kV VM Reclamation

The 69kV Reclamation Project is designed to “reclaim” specific areas of the company’s 69kV system that are particularly problematic due to vegetative conditions. These areas are difficult and expensive to maintain and frequently contain hazard trees. While the company’s robust trim cycles are effective against vegetation to conductor encroachments on 90 percent of the 69kV circuits, the remaining portion are in areas that are either low-lying or restricted by vegetation overgrowth. The focus of this Project is to clear the vegetation undergrowth and remove the hazard trees. The company plans to clear the vegetation within the boundaries of the easement or property but outside of the current 15-foot vegetation-to-conductor clearance specification. The extent of trimming will be driven by the rights set forth in the company's property deeds and easements, so the company plans to research existing easements and deeds and survey where necessary. Affected customers and property owners will be kept abreast of work occurring in their area.

An additional benefit to the Project is improved access. One of the VM lessons learned from recent storm recovery efforts is that unobstructed access to transmission facilities is critical to minimizing restoration times. Clearing these vegetation-obstructed areas will reduce outage potential, allow for faster restoration times, and lower restoration costs due to the following:

- Improving vegetation to conductor clearances will reduce blow-in outages;
- Removing hazard trees will reduce fall-in outages;
- Removing vegetation overgrowth will allow the ground to dry faster, promoting deeper tree roots and improving accessibility, reducing the need for access matting;
- Outage locations can be identified much easier, up to 200 percent faster;
- Damage assessment can be completed more accurately;
- Safer work sites reduce the number of personnel and equipment needed to restore; and
- Normal line and vegetation inspection and maintenance costs will be reduced by the improved clearances and unobstructed access.

The time to restore transmission outages is dependent on several factors, such as voltage, switching, design, and other facility impacts, but the key factor to restoration is accessibility. Outages that occur in areas obstructed by vegetation, on average, take up to 75 percent longer to restore. Tampa Electric has identified areas along the 69kV system where these vegetative conflicts and obstructions exist and mapped them to determine Project scope, cost, and schedule. The Project scope and cost detail for the 69kV Vegetation Reclamation Initiative is listed below.

Project Scope			Total Project Costs (in thousands)
Circuits	Customers	Length (miles)	
170	84,000	83.2	$2,185

6.2.3 Estimated Costs – VMP

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 once the new initiatives are scaled up to their future steady state. The 69kV Reclamation initiative will require approximately 40 VM total contract trimmers to complete.

6.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of 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 this initial ten-year SPP. Tampa Electric has approximately 26,000 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 15.8 percent are supported with wood poles. Historically, the company’s transmission hardening Program focused on replacing existing wood transmission poles with non-wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2021, the company hardened 9,789 wood transmission structures with non-wood material as a part of the Storm Hardening Plan and first two years of the company’s initial SPP. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. 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. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.’s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon 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. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

Once this review was complete a revised prioritization that incorporated access challenges, long lead time for permit requirements and scheduling constraints was developed. The revised prioritization is reflected in this ten-year SPP with Projects that are most feasible to implement accelerated into the first three years of the SPP. The remainder of the SPP years were scheduled by 1898 & Co.'s resilience-based model beginning in year 2023 through 2029 to allow for scheduling, permitting and access issues to be addressed.

The table below shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the 2022-2031 SPP:

The full detail of the supporting Transmission Asset Upgrades Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "B".

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	37	$17.0
2023	26	$18.0
2024	10	$18.1

6.4 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 could 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 engaged 1898 & Co. to perform preliminary analysis and prioritization of the company's 216 substations. The SLOSH model, described in the 1898 & Co. report included as Appendix "F", identified 59 of these 216 substations with some level of flooding risk and the height of a wall needed to mitigate that risk. The 59 substations were evaluated and prioritized in the model using only the single solution of building a flood wall around the perimeter of each substation. Tampa Electric began this Program as planned, in early 2021, by engaging an additional third-party consultant that specializes in substation engineering and asset management to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled.

This study was designed to examine the potential for flooding for each substation, flood mitigation options, and provide an engineering recommendation for station flood protection or mitigation, if applicable. The study was estimated to cost $250,000 and was expected to provide the following deliverables:

- High level cost estimates for the installation of a flood wall or other hardening solutions;
- Mitigation approaches and a scorecard based on prioritization of the hardening strategies intended to increase reliability; and
- An updated and refined prioritization list.

The study was expected to include the 11 identified substations in the company's initial SPP and would also include any other substations that Tampa Electric subject matter experts would determine to have potential vulnerability to extreme weather. The company narrowed this list of substations to be studied further to 24 based on their location by being near or at 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 would be from the impact of water intrusion due to storm surge into the substation control houses and equipment.

In 2021, the company solicited an engineering firm to perform the substation extreme weather hardening study on these 24 substations selected. The substation hardening study was conducted in three phases (discovery, evaluation, and recommendation). A scorecard was developed for all 24 substations and special attention was paid to substations where outages could impact the grid stability or reliability of service. Out of the 24 substations evaluated, nine (9) substations were recommended for extreme weather hardening with the first proposed projects to start in 2023.

The table below shows the Substation Extreme Weather Hardening Program’s Projects by year and projected costs for the first three years of the 2022-2031 SPP:

	Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	0	$0.0
2023	1	$0.7
2024	1	$4.3

6.5 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 provide the ability to reconfigure the electrical system to minimize the number of customers experiencing prolonged outages that may occur as a result 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.

6.5.1 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 plans to harden 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.

6.5.2 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 overall 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.

Upgraded conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgraded 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 their reliability performance and priority customer count to identify the target circuits for 2022. Reliability performance was considered for both extreme weather and blue-sky days with a higher weighting factor assigned to circuit reliability under extreme weather conditions. 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.

The remainder of the SPP years (2023-2031) were prioritized by the model.

Tampa Electric is also proposing to add three applications to the Overhead Feeder Hardening Program that will add the ability to leverage 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 faster and more accurate indication of feeder and feeder section energization state during widescale outages.

The table below shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the 2022-2031 SPP:

	Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	36	$33.4
2023	31	$30.7
2024	23	$30.7

The full detail of the supporting Distribution Overhead Feeder Hardening individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix “D”.

6.6 Transmission Access Enhancement

The Transmission Access Enhancement Program is designed to ensure the company always has access to its transmission facilities for the performance of restoration. Immediate and permanent access to these facilities reduces restoration times and restoration costs. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have impacted the access to the existing transmission infrastructure. This Program will significantly enhance access to critical routes throughout the company’s transmission corridors that were impacted by these environmental and social changes. The Program is divided into two components: Access Roads and Access Bridges.

Access Roads: These Projects are designed to restore access to areas where changes in topography and hydrology have negatively impacted existing access roads or created the need to establish new access roads. The access roads are Tampa Electric’s primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires that all utilities to maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are necessary to ensure compliance.

The company has identified a total of 71 potential Access Road Projects, subdivided by circuit. In many cases, more than one circuit benefits from the installation or repair of the road. While engineering will determine the exact scope and cost of the road, company subject matter experts developed a preliminary cost estimate for each Project that was used in the 1898 & Co. model for cost-benefit prioritization. The costs were based on the number of road miles and construction type. The total Access Roads Project costs are detailed below for the Access Road Projects proposed in the 2022-2031 SPP:

Access Road Projects Costs (in thousands)	
2022	$724
2023	$879
2024	$1,844
2025	$1,614
2026	$2,838
2027	$3,404
2028	$1,932
2029	$1,167
2030	$997
2031	$4,425

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. Since most proposed access roads are in low-lying or wetland areas, most will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and the associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure the Projects remain on budget.

Access Bridges: These Projects are designed to enhance or replace the company's current system of bridges used to access its "off road" transmission facilities. As with Access roads, access bridges are a primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires all utilities to maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are also necessary to ensure compliance. The last several storm seasons have impacted the integrity of the company's bridge network. While necessary repairs were made post-storm to ensure the bridges remain safe for travel, the repairs that were made were temporary to allow for a safe and timely restoration. Tampa Electric's system hardening activities place additional strain on the bridges. For example, the company's aggressive wooden pole replacement Program has created increases in bridge traffic and load from the heavier transmission vehicles needed to install the reinforced steel poles. The Access Bridge Project will bring the bridge(s) up to capacity to meet the current weight of the company's transmission vehicles and secure pilings and position in and over the waterways to ensure constant access to critical transmission infrastructure, particularly during extreme weather events.

The company currently maintains a total of 24 bridges, with three of these bridges being recently installed in a transmission upgrade Project. The company identified a net total of 21 potential bridge projects. The total Access Bridges initiative costs are detailed below for the Access Bridge Projects proposed in the 2022-2031 SPP:

Access Bridge Project Costs (in thousands)	
2022	$1,686
2023	$2,158
2024	$1,163
2025	$2,089
2026	$608
2027	$0
2028	$1,211
2029	$1,672
2030	$1,043
2031	$0

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. The company expects all access bridges will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure that each Project remains on budget.

Tampa Electric used 1898 & Co.'s resilience-based modeling described in Appendix "F" to evaluate the cost-benefit expectation for each of the 95 Access Enhancement Projects. The model then developed a prioritization of these projects based on the cost-benefit expectations. This SPP Plan reflects the completion of 44 Access Enhancement Projects over the 2022-2031 SPP.

The table below shows the Transmission Access Enhancements Program's Projects by year and projected costs for the first three years of the 2022-2031 SPP:

	Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	25	$2.4
2023	25	$3.0
2024	13	$3.0

6.7 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 wooden pole inspection initiative 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, 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.” Order No. PSC-06-0144-PAA-EI. 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." Order No. PSC-06-0144-PAA-EI. The Commission later found that a transmission structure inspection program would offer similar benefits. Order No. PSC-06-0351-PAA-EI. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because "[u]tility poles that are overloaded or approaching overloading are subject to failure in extreme weather." Order No. PSC-06-0351-PAA-EI. 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." Order No. PSC-06-0144-PAA-EI. 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.

6.7.1 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 substation circuit basis with a goal of inspecting the entire wood pole population every eight years. An average of 36,000 wooden 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 estimates that this initiative will cost approximately $1,040,000 annually over the ten-year horizon of this SPP.

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.

6.7.2 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 above ground structure inspection cycle, 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 estimates the annual cost of this initiative is approximately $430,000 over the ten-year Plan horizon. Tampa Electric believes this continued cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

6.7.2.1 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 on an eight-year cycle. Each year approximately 12.5 percent of all wooden transmission structures are scheduled for inspection. For 2022 through 2024, the company plans to perform approximately 1,500 groundline inspections over the three-year period.

6.7.2.2 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.

6.7.2.3 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.

6.7.2.4 Above Ground Inspections

Above ground inspections are performed on transmission structures on an eight-year cycle; therefore, each year approximately 12.5 percent or one-eighth of transmission structures are inspected. This inspection will be performed by either an internal team member or contractor specializing in above ground power pole inspections and may be performed by climbers, bucket truck, helicopter or Unmanned Aerial Systems (“UAS” or Drones). The above ground inspection is a comprehensive inspection that includes assessment of poles, insulators, switches, conductors, static wire, grounding provisions, cross arms, guying, hardware and encroachment issues. This program provides a detailed review of the above ground condition of the pole and the associated hardware on the structure. Due to advances in technology, the capabilities of UAS has allowed the company to complete the Above Ground Inspections in conjunction with the Ground Patrol utilizing the UAS for an aerial view of the structures identified for the comprehensive inspection.

For 2022 through 2024, annual above ground inspections are planned on approximately 10,500 structures. This is in line with the company’s petition that changed the above ground inspection cycle from a six-year cycle to an eight-year cycle which was approved in Docket 20140122-EI, Order No. PSC-14-0684-PAA-EI and confirmed by Consummating Order No. PSC-15-0017-CO-EI.

6.7.3 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 $150,000 over the ten-year horizon of the SPP.

6.7.4 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.

There are no costs associated with this activity since it occurs only when an employee is climbing a pole for another purpose.

6.7.5 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 ensuring that all safety, reliability, capacity and engineering requirement 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.

6.7.6 Infrastructure Inspections Summary

The Infrastructure Inspection Program has no estimated completion date because the inspection activities are continuous and ongoing. 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 Storm Protection Projects under this Program. Instead, the table below shows the number of infrastructure inspections the company is projecting over the 2022-2024 storm Protection Plan period.

Projected Number of Infrastructure Inspections			
	2022	**2023**	**2024**
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	35,625	35,625	16,625
Transmission			
Wood Pole/Groundline Inspections	663	479	401
Above Ground Inspections	3,386	2,641	2,702
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 2024.

The table below provides the annual O&M expenses for each of the inspection programs for the 2022-2024 period.

Projected Costs of Infrastructure Inspections (in thousands)			
	2022	**2023**	**2024**
Distribution			
Wood Pole Inspections	$1,020	$1,040	$1,061
Transmission			
Wood Pole/Groundline Inspections	$62	$64	$65
Above Ground Inspections	$10	$11	$11
Aerial Infrared Patrols	$114	$117	$119
Ground Patrols	$201	$154	$157
Substation Inspections	$146	$146	$148

6.8 Legacy Storm Hardening Plan Initiatives

The final category of storm protection activities consists of those legacy Storm Hardening Plan Initiatives that are well-established and steady state and for which the company does not propose any specific Storm Protection Projects at this time. Tampa Electric will continue these activities because the company believes they continue to offer the storm resiliency benefits identified by the Commission in Order No. PSC-06-0351-PAA-EI, which required the company to perform these activities. Tampa Electric cannot offer an estimated completion date for this Program because the initiatives are still mandated by the Commission and because the initiatives are all integrated into the company's ongoing operations. Historically, Tampa Electric has not performed a formal cost benefit analysis for these activities because they were mandated by the Commission. 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 selected a storm hardening project, Tampa Electric would then perform an internal formal cost analysis prior to initiating the project. In this internal analysis, the company would project the costs and estimate the benefits that should be realized. Tampa Electric recognizes that assigning a monetary value to customer benefits is challenging due to the lack of specific information about the financial impacts of outages, and because assigning value to public safety and health may skew the project's benefit analysis.

6.8.1 Geographic Information System

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. 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. These evaluations further cement GIS as the foundational database for Tampa Electric's facilities.

Tampa Electric does not propose any GIS Storm Protection Projects over the ten-year planning horizon. The company will, however, continue ongoing activities to improve the functionality and ease of use of the GIS for the company's GIS users. Two examples of these ongoing activities include the GIS User's Group, which meets to review, evaluate and recommend enhancements for implementation. The second ongoing activity is the annual publication of the Tampa Electric GIS Annual Report. Tampa Electric does not propose any specific Storm Protection Projects due to the reasons identified above.

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is $0 because 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.

6.8.2 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 hired 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 ten-year planning horizon.

The incremental cost of this initiative is estimated to be approximately $125,000 per storm and will depend on the severity of the storm and extent of system damage.

6.8.3 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 EMS and OMS. 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 canned 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 does not propose 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 ten-year planning horizon.

Tampa Electric does not forecast any annual DOD-related expenditures over the ten years of the SPP because costs are only incurred during a storm. The cost of this initiative is estimated to be approximately $100,000 per storm.

6.8.4 Increase Coordination with Local Governments

Tampa Electric representatives will continue to focus on maintaining existing vital governmental contacts and participating on 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, as well as the FDEM, in planning and facilitating joint storm exercises. In addition, Tampa Electric will continue to be involved in improving emergency response to vulnerable populations.

The company does not propose 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.

6.8.5 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 ten-year period of the SPP. Tampa Electric does not estimate that there will be any collaborative research costs over the same ten-year horizon.

6.8.6 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 set by TECO Energy 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 Operation Centers (“EOC”). 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.

Annually, Tampa Electric participates in the State of Florida's hurricane exercise with the FPSC, 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 $300,000 annually.

6.8.7 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 Storm Protection Projects.

Tampa Electric estimates the annual capital and O&M costs of this initiative is approximately $82,928,000 over the ten-year Plan horizon.

6.8.8 Legacy Storm Hardening Plan Initiatives Costs

The table below shows the projected costs for the first three years of the 2022-2031 SPP for the Legacy Storm Hardening Plan Initiatives:

	Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)	
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2022	$0.3	$13.3
2023	$0.3	$13.7
2024	$0.3	$14.1

7. Storm Protection Plan Projected Costs and Benefits

Tampa Electric developed the projected 2022-2031 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. Initially, the company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This initially was determined to be between 100 to 200 million dollars on an annual basis, based upon work constraints.
2. Recognizing the sustained amount of work it would take for external resource companies to physically build or obtain a work force that could support several ongoing Storm Protection Programs.
3. Recognizing that there will be some competition for resources between utilities which could push costs upward.
4. Identification of the range of work necessary for each Storm Protection 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 Storm Protection Programs and their

associated Projects.

6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2022-2031 spend at approximately $1.59 billion over the ten-year Plan.
7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be between 100 to 200 million on an annual basis.
8. Actual historical costs would be used where the company has significant history and recent experience in developing the cost for each type of Project. Costs were also analyzed for impacts for potential competition and future contractor capacity impacts.
9. Costs were validated for reasonableness and range by a variety of means, either in discussions amongst internal team members with this experience, discussions with 1898 & Co., HDR Engineering, or discussions with neighboring utilities.
10. Costs were used to complete SPP programs within the designated proposed timeline as described in the Transmission Asset Upgrade Program.
11. Costs were 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 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 would show with transparency the total costs for the proposed 2022-2031 SPP, the total revenue

requirements for the proposed 2022-2031 SPP, and the total revenue requirements which would be recoverable through the Storm Protection Plan Cost Recovery Clause.

The table below provides Tampa Electric’s projected 2022-2031 Storm Protection Plan total costs (capital and O&M) by Programs:

Tampa Electric's 2022-2031 Storm Protection Plan Total Costs by Program (in Millions)

Capital	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Distribution Lateral Undergrounding	$105.66	$104.54	$105.00	$105.00	$105.00	$105.00	$105.00	$105.00	$115.00	$115.00	$1,070.21
Transmission Asset Upgrades	$16.48	$17.46	$17.54	$17.92	$18.24	$16.89	$17.35	$17.24	$0.00	$0.00	$139.12
Distribution - Substation Extreme Weather Protection	$0.00	$0.70	$2.22	$1.38	$1.73	$1.53	$2.47	$0.71	$3.75	$0.81	$15.30
Transmission - Substation Extreme Weather Protection	$0.00	$0.00	$2.05	$1.28	$1.60	$1.41	$2.28	$0.66	$3.47	$0.75	$13.50
Distribution Overhead Feeder Hardening	$32.84	$30.12	$30.00	$29.99	$29.99	$30.00	$29.99	$29.99	$36.99	$36.99	$316.90
Transmission Access Enhancements	$2.41	$3.04	$3.01	$3.70	$3.45	$3.40	$3.14	$2.84	$2.04	$4.42	$31.45
Distribution Pole Replacements	$12.51	$12.89	$13.28	$13.68	$9.05	$9.23	$9.41	$9.60	$11.22	$11.40	$112.26
O&M	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Distribution Lateral Undergrounding	$0.18	$0.18	$0.18	$0.15	$0.19	$0.20	$0.20	$0.21	$0.21	$0.33	$2.02
Distribution Vegetation Management - planned	$21.16	$24.00	$24.22	$25.65	$26.77	$27.99	$29.52	$30.94	$32.50	$34.27	$277.02
Distribution Vegetation Management - unplanned	$1.40	$1.40	$1.40	$1.30	$1.30	$1.30	$1.40	$1.40	$1.30	$1.30	$13.50
Transmission Vegetation Management - planned	$3.61	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$3.63	$3.81	$34.25
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	$0.49	$0.52	$0.53	$0.55	$0.56	$0.57	$0.58	$0.59	$0.60	$0.61	$5.60
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	$0.56	$0.62	$0.67	$0.72	$0.77	$0.82	$0.87	$0.92	$0.97	$1.02	$7.94
Transmission Access Enhancements	$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	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$1.20	$1.22	$11.17
Transmission Infrastructure Inspections	$0.58	$0.54	$0.55	$0.57	$0.58	$0.59	$0.60	$0.61	$0.62	$0.64	$5.89
SPP Planning & Common	$0.92	$0.87	$0.88	$0.90	$0.92	$0.94	$0.96	$0.98	$1.00	$1.02	$9.37
Other Legacy Storm Hardening Plan Items	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$0.34	$0.34	$3.14
Distribution Pole Replacements	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$0.71	$0.72	$7.23

Tampa Electric developed the 2022-2031 SPP projected costs and benefits for each of the proposed SPP Programs through the thorough and comprehensive analysis the company performed with 1898 & Co. Tampa Electric and 1898 & Co. modeled the proposed continuing SPP Programs during extreme weather and evaluated the 10-year benefits of these SPP Programs against a status quo scenario. Both the reduction in restoration costs and the reduction in customer minutes of interruption show the percentage improvement expected during major event days from the SPP Programs when compared to the status quo.

Tampa Electric - Proposed 2022-2031 Storm Protection Plan
Projected Costs versus Benefits

Storm Protection Program	Projected Costs (in Millions)		Projected Reduction in Restoration Costs (Approximate Benefits in Percent)	Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)	Program Start Date	Program End Date
	Capital	O&M				
Distribution Lateral Undergrounding	$1,070.2	$2.0	32	45	Q2 2020	After 2031
Vegetation Management	$0.0	$324.8	21	22 to 29	Q2 2020	After 2031
Transmission Asset Upgrades	$139.1	$5.6	85	14	Q2 2020	2029
Substation Extreme Weather	$28.8	$0.0	20 to 25	12 to 45	Q1 2021	After 2031
Distribution Overhead Feeder	$316.9	$7.9	54	46	Q2 2020	After 2031
Transmission Access Enhancements	$31.5	$0.0	28	55	Q1 2021	After 2031

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2022-2031 SPP Programs plus depreciation and return on SPP, as outlined in Rule 25-6.030 F.A.C. 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. 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 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 from the 2021 Stipulation and Settlement. Only capital expenditures for SPP Projects after April 10, 2020, were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

The table below provides Tampa Electric's projected 2022-2031 Storm Protection Plan total revenue requirements (capital and O&M) by Program:

Tampa Electric's 2022-2031 Storm Protection Plan Total Revenue Requirements by Program (in Millions)

Capital	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Distribution Lateral Undergrounding	$9.22	$19.87	$30.81	$42.16	$53.87	$65.44	$76.79	$87.93	$99.25	$110.71	$596.06
Transmission Asset Upgrades	$2.90	$4.99	$6.72	$8.43	$10.26	$12.04	$13.71	$15.35	$16.33	$16.28	$107.01
Distribution - Substation Extreme Weather Protection	$0.00	$0.02	$0.15	$0.34	$0.54	$0.72	$0.93	$1.11	$1.34	$1.56	$6.70
Transmission - Substation Extreme Weather Protection	$0.00	$0.00	$0.08	$0.23	$0.40	$0.55	$0.74	$0.90	$1.10	$1.29	$5.27
Distribution Overhead Feeder Hardening	$3.31	$7.36	$10.61	$13.82	$17.37	$20.84	$24.21	$27.48	$30.93	$34.69	$190.62
Transmission Access Enhancements	$0.15	$0.42	$0.71	$1.03	$1.39	$1.73	$2.05	$2.34	$2.58	$2.86	$15.27
Distribution Pole Replacements	$1.59	$3.14	$4.69	$6.26	$7.57	$8.53	$9.48	$10.42	$11.45	$12.57	$75.70
O&M	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Distribution Lateral Undergrounding	$0.18	$0.18	$0.18	$0.15	$0.19	$0.20	$0.20	$0.21	$0.21	$0.33	$2.02
Distribution Vegetation Management - planned	$21.16	$24.00	$24.22	$25.65	$26.77	$27.99	$29.52	$30.94	$32.50	$34.27	$277.02
Distribution Vegetation Management - unplanned	$1.40	$1.40	$1.40	$1.30	$1.30	$1.30	$1.40	$1.40	$1.30	$1.30	$13.50
Transmission Vegetation Management - planned	$3.37	$3.41	$2.83	$2.92	$3.01	$3.08	$3.15	$3.22	$3.39	$3.55	$31.94
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	$0.46	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$5.23
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	$0.56	$0.62	$0.67	$0.72	$0.77	$0.82	$0.87	$0.92	$0.97	$1.02	$7.94
Transmission Access Enhancements	$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	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$1.20	$1.22	$11.17
Transmission Infrastructure Inspections	$0.54	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$0.58	$0.59	$5.49
SPP Planning & Common	$0.92	$0.87	$0.88	$0.90	$0.92	$0.94	$0.96	$0.98	$1.00	$1.02	$9.37
Other Legacy Storm Hardening Plan Items	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$0.34	$0.34	$3.14
Distribution Pole Replacements	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$0.71	$0.72	$7.23

8. Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts of the Storm Protection Plan for 2022, 2022, and 2023.

Each year's costs derive from the SPP Programs described in this Plan and are the capital and O&M costs 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 same methodology that was shown in Exhibit "K" of the company's 2021 Settlement Agreement ("2021 Agreement") that was approved by Final Order No. PSC-2021-0423-S-EI on November 10, 2021, in Docket No. 20210034-EI to allocate the revenue requirements to the appropriate rate classes. This methodology establishes a base amount of revenue requirement to be allocated, based upon the 2021 baseline amount, that utilizes the cost of service methodology that was approved by the Commission in Docket No. 20130040-EI and the incremental revenue requirement (if applicable) above this base amount to be allocated that utilizes the methodology from the company's 2021 Settlement.

The company then applied the appropriate Revenue Tax Factor to determine the complete base and incremental revenue requirements. Tampa Electric then applied the 2022 billing determinants to each of the revenue requirements amounts (base and incremental revenue increase) to determine the Storm Protection Plan Cost Recovery Factors by rate class for each of these revenue requirements amounts. The two resultant Storm Protection Plan Cost Recovery Factors are then combined to determine the appropriate total Storm Protection Plan Cost Recovery Factor by rate class as if these costs were being recovered through the Storm Protection Plan Cost Recovery Clause

("SPPCRC").

For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. These clause charges 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 each year 2022, 2023, and 2024 for those bills.

This same process is used to derive the actual SPPCRC charges in the clause cost recovery docket with the exception that only appropriate SPPCRC charges are included in the SPPCRC cost recovery 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 (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2022	2.70%	2.70%	1.17%	1.08%
2023	4.13%	4.13%	1.28%	1.19%
2024	5.31%	5.31%	1.37%	1.29%

The rate impacts presented above reflect the total cost of the SPP, even though some of the costs in the Plan are currently being recovered through base rates and the incremental cost of the Plan to customers will be less than shown above.

9. 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 on the company's historical performance and the current ongoing Storm Hardening and Storm Protection Plan activities. This alternative was good for level setting in that it identified the analyses that would be performed would need to examine the entire service area for opportunities for enhancement. In addition, this alternative was quickly dismissed as the statute is clear in that it 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 activities at the forefront.

As described in the overview, the company engaged Accenture to evaluate several initiatives in the company's initial SPP to enhance existing vegetation management plans and performance. 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.

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 2022-2031 ten-year period capturing the Storm Protection Projects that provide the most value to customers.

In addition to the Programs included in the 2022-2031 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in the Plan. Examples of things considered, but not included in this initial ten-year SPP are as follows:

- Undergrounding Distribution Feeders – The majority of customers are on laterals and analysis demonstrated higher cost-benefit to harden feeders and underground laterals.
- 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.
- Purchasing additional temporary access solutions such as increasing the number of mats – The solutions proposed in this Plan are more cost-effective and sustainable

As in the first two years of the company's current SPP, Tampa Electric will continue to examine and analyze the processes and procedures used to implement the company's proposed 2022-2031 SPP Programs for any ongoing 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 COMPANY
DOCKET NO. 20220048-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
APPENDIX A
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FILED: 04/11/2022

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG CSA 13021.60058683	13021	0.31	28	130	11	1	142	3	Q1 - 2021	Q3 - 2022	Q4 - 2022	$634,109
LUG CSA 13021.92350282	13021	0.32	27	14	11	0	25	12	Q1 - 2021	Q4 - 2021	Q1 - 2022	$140,500
LUG CSA 13026.60059452	13026	0.16	11	64	7	2	73	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$152,871
LUG CSA 13026.60059457	13026	0.21	15	24	13	0	37	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$208,780
LUG CSA 13026.60059509	13026	0.09	8	84	11	2	97	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$86,294
LUG CSA 13026.60059524	13026	0.19	16	115	13	0	128	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$484,876
LUG CSA 13093.91004837	13093	0.19	17	143	29	3	175	18	Q3 - 2020	Q1 - 2022	Q2 - 2022	$664,205
LUG CSA 13099.10368943	13099	0.24	13	2	3	0	5	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$238,465
LUG CSA 13099.60125388	13099	0.43	24	68	5	0	73	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$747,872
LUG CSA 13099.90882614	13099	0.24	18	128	9	2	139	0	Q3 - 2020	Q2 - 2022	Q3 - 2022	$577,003
LUG CSA 13100.91340554	13100	0.41	28	403	7	3	413	0	Q4 - 2020	Q4 - 2022	Q3 - 2023	$154,711
LUG CSA 13102.60123654	13102	0.19	15	72	1	2	75	0	Q3 - 2020	Q3 - 2021	Q1 - 2022	$55,000
LUG CSA 13102.90748252	13102	0.23	23	29	2	1	32	0	Q2 - 2021	Q3 - 2022	Q4 - 2022	$854,885
LUG CSA 13102.91293905	13102	0.12	10	47	13	4	64	1	Q1 - 2021	Q2 - 2022	Q3 - 2022	$123,608
LUG CSA 13104.10362869	13104	0.38	30	67	20	3	90	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$497,526
LUG CSA 13104.91241032	13104	0.15	18	19	2	2	23	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$148,692
LUG CSA 13104.91643108	13104	0.34	33	74	19	1	94	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$430,742
LUG CSA 13104.91668251	13104	0.20	17	16	8	0	24	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$187,342
LUG CSA 13105.10580676	13105	0.13	13	14	3	0	17	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$14,000
LUG CSA 13105.10580689	13105	0.13	10	44	3	0	47	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$120,742
LUG CSA 13105.10580690	13105	0.23	21	122	15	1	138	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$238,847
LUG CSA 13105.60164901	13105	0.11	10	79	5	1	85	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$104,230
LUG CSA 13106.10361901	13106	0.75	52	274	21	0	295	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$188,155
LUG CSA 13106.91722510	13106	0.11	9	166	10	1	177	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$259,986
LUG CSA 13107.10376173	13107	0.44	28	119	27	2	148	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$389,527
LUG CSA 13107.10376186	13107	0.12	10	179	4	0	183	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$28,000
LUG CSA 13107.10376201	13107	0.13	10	8	1	0	9	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$130,871
LUG CSA 13158.60011810	13158	0.76	56	226	10	1	237	1	Q1 - 2021	Q1 - 2022	Q2 - 2022	$245,476
LUG CSA 13158.90816343	13158	0.25	18	123	4	1	128	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$612,548
LUG CSA 13158.91461782	13158	0.33	30	39	3	0	42	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$314,198
LUG CSA 13176.10375136	13176	0.66	57	11	9	11	31	2	Q1 - 2021	Q2 - 2022	Q4 - 2022	$621,962
LUG CSA 13176.10375141	13176	0.62	51	89	9	4	102	8	Q1 - 2021	Q4 - 2022	Q2 - 2023	$78,658
LUG CSA 13176.10375148	13176	0.48	54	26	5	3	34	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$131,000
LUG CSA 13188.10655453	13188	0.12	15	46	15	3	64	9	Q4 - 2020	Q3 - 2022	Q4 - 2022	$116,100
LUG CSA 13188.92070695	13188	0.17	11	17	2	0	19	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$83,831
LUG CSA 13204.60170504	13204	0.38	31	113	8	1	122	12	Q1 - 2021	Q2 - 2022	Q3 - 2022	$522,779
LUG CSA 13205.90022802	13205	0.20	18	20	5	1	26	6	Q1 - 2021	Q2 - 2022	Q3 - 2022	$262,324
LUG CSA 13205.90442230	13205	0.25	25	60	0	3	63	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$506,543
LUG CSA 13205.90929181	13205	0.20	15	32	19	2	53	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$380,641
LUG CSA 13354.10582069	13354	0.19	21	281	15	0	296	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$40,180
LUG CSA 13399.60037987	13399	0.19	19	19	13	4	36	11	Q1 - 2021	Q2 - 2022	Q3 - 2022	$400,026
LUG CSA 13418.91924595	13418	0.22	20	25	12	0	37	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$220,188
LUG CSA 13418.92018190	13418	0.33	21	79	5	1	85	6	Q1 - 2021	Q2 - 2022	Q4 - 2022	$323,959
LUG CSA 13418.92357188	13418	0.47	33	61	28	1	90	0	Q4 - 2020	Q3 - 2022	Q1 - 2023	$655,600
LUG CSA 13468.60128362	13468	0.53	38	147	32	0	179	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$494,945
LUG CSA 13468.60128378	13468	0.75	56	444	17	0	461	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$564,226

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG CSA 13468.91640192	13468	0.11	7	6	4	0	10	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$113,932
LUG CSA 13590.91231633	13590	0.34	29	47	11	2	60	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$142,000
LUG CSA 13592.91365233	13592	0.31	25	121	12	0	133	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$616,481
LUG CSA 13593.93057902	13593	0.45	39	83	52	4	139	0	Q4 - 2020	Q1 - 2022	Q3 - 2022	$368,400
LUG CSA 13632.10408272	13632	0.10	9	12	8	0	20	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$93,643
LUG CSA 13632.10408290	13632	1.02	55	245	10	0	255	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$948,857
LUG CSA 13632.60305848	13632	0.40	33	43	15	0	58	0	Q1 - 2021	Q4 - 2022	Q2 - 2023	$196,308
LUG CSA 13633.90564142	13633	0.07	3	2	1	0	3	0	Q2 - 2021	Q1 - 2022	Q2 - 2022	$60,945
LUG CSA 13633.91847345	13633	0.09	7	1	10	0	11	5	Q1 - 2021	Q4 - 2022	Q2 - 2023	$5,185
LUG CSA 13826.60127680	13826	0.27	13	243	17	2	262	1	Q2 - 2021	Q3 - 2022	Q4 - 2022	$81,217
LUG CSA 13831.10427677	13831	0.25	18	313	18	0	331	6	Q1 - 2021	Q2 - 2022	Q3 - 2022	$233,667
LUG CSA 13835.10429505	13835	0.20	17	41	5	2	48	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$541,441
LUG CSA 13835.10429522	13835	0.69	41	163	8	1	172	1	Q1 - 2021	Q2 - 2022	Q1 - 2023	$1,215,306
LUG CSA 13835.60314670	13835	0.21	18	256	15	1	272	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$102,548
LUG CSA 13836.91377944	13836	0.59	41	276	22	2	300	9	Q3 - 2020	Q4 - 2022	Q1 - 2023	$102,041
LUG CSA 13934.10467575	13934	0.09	6	1	3	3	7	3	Q1 - 2021	Q4 - 2021	Q1 - 2022	$33,500
LUG CSA 13934.10467597	13934	0.56	30	51	0	2	53	1	Q1 - 2021	Q2 - 2022	Q4 - 2022	$525,439
LUG CSA 13939.60144164	13939	0.12	8	38	6	4	48	5	Q1 - 2021	Q2 - 2022	Q3 - 2022	$112,739
LUG CSA 13939.60144172	13939	0.15	15	2	4	2	8	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$97,000
LUG CSA 13948.10442379	13948	0.14	12	5	0	1	6	1	Q3 - 2021	Q3 - 2022	Q4 - 2022	$137,902
LUG CSA 13948.10442391	13948	0.22	13	23	6	0	29	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$266,895
LUG CSA 13993.10372414	13993	0.42	27	31	3	2	36	1	Q1 - 2021	Q1 - 2022	Q3 - 2022	$429,829
LUG CSA 13993.10433144	13993	0.12	10	123	2	0	125	6	Q1 - 2021	Q1 - 2022	Q2 - 2022	$90,518
LUG CSA 14040.10786358	14040	0.43	19	12	3	0	15	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$137,793
LUG CSA 14040.10786382	14040	0.23	13	98	6	2	106	10	Q2 - 2020	Q1 - 2022	Q3 - 2022	$213,950
LUG CSA 14102.91582612	14102	0.30	18	136	6	0	142	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$278,492
LUG DCA 13006.92949400	13006	1.29	48	41	2	3	46	2	Q1 - 2021	Q3 - 2022	Q3 - 2023	$546,982
LUG DCA 13432.10761257	13432	1.21	38	21	8	1	30	0	Q2 - 2021	Q1 - 2022	Q4 - 2022	$821,238
LUG DCA 13815.93026469	13815	0.49	15	27	2	0	29	0	Q3 - 2020	Q4 - 2021	Q3 - 2022	$1,205,600
LUG ESA 13127.90334707	13127	0.36	24	150	4	0	154	11	Q1 - 2021	Q2 - 2023	Q1 - 2024	$60,345
LUG ESA 13127.90334731	13127	0.44	22	56	1	0	57	3	Q1 - 2021	Q2 - 2022	Q3 - 2022	$434,238
LUG ESA 13127.92661768	13127	0.53	34	170	3	0	173	1	Q4 - 2020	Q1 - 2023	Q3 - 2023	$25,000
LUG ESA 13127.92663180	13127	0.62	42	33	7	1	41	0	Q1 - 2021	Q1 - 2023	Q1 - 2024	$28,500
LUG ESA 13171.10455381	13171	0.12	11	5	18	1	24	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$30,449
LUG ESA 13171.90598389	13171	0.21	11	370	19	3	392	25	Q3 - 2020	Q2 - 2023	Q4 - 2023	$53,000
LUG ESA 13171.93104605	13171	0.36	21	48	2	2	52	4	Q4 - 2020	Q2 - 2023	Q4 - 2023	$11,000
LUG ESA 13174.10913196	13174	0.21	8	241	14	4	259	4	Q3 - 2020	Q3 - 2022	Q1 - 2023	$1,609,359
LUG ESA 13174.60588225	13174	0.29	15	374	34	1	409	1	Q3 - 2020	Q2 - 2022	Q3 - 2022	$165,000
LUG ESA 13211.60044019	13211	0.53	43	395	27	3	425	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$521,400
LUG ESA 13225.60139973	13225	0.81	54	41	26	6	73	8	Q3 - 2020	Q1 - 2023	Q1 - 2024	$101,000
LUG ESA 13226.10462583	13226	0.12	19	190	19	2	211	0	Q4 - 2020	Q2 - 2022	Q3 - 2022	$130,844
LUG ESA 13226.92664597	13226	0.31	16	348	4	0	352	0	Q4 - 2020	Q1 - 2023	Q2 - 2023	$11,000
LUG ESA 13226.92665539	13226	0.09	5	13	2	2	17	9	Q3 - 2020	Q2 - 2023	Q1 - 2024	$5,000
LUG ESA 13226.92670950	13226	0.20	23	37	15	5	57	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$213,000
LUG ESA 13229.92525393	13229	0.21	21	141	21	2	164	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$22,500
LUG ESA 13230.10471354	13230	0.44	38	49	41	8	98	27	Q4 - 2020	Q2 - 2023	Q1 - 2024	$15,000

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG ESA 13230.10471377	13230	0.48	31	54	2	2	58	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$18,000
LUG ESA 13230.92180224	13230	0.28	21	58	16	0	74	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$866,800
LUG ESA 13230.92496254	13230	0.29	23	12	8	0	20	8	Q1 - 2021	Q1 - 2023	Q2 - 2023	$53,170
LUG ESA 13231.10868121	13231	0.27	22	23	2	0	25	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$58,321
LUG ESA 13231.10868138	13231	0.54	34	269	17	4	290	8	Q4 - 2020	Q1 - 2023	Q3 - 2023	$112,000
LUG ESA 13433.10466911	13433	0.71	47	159	32	0	191	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$739,800
LUG ESA 13433.93369551	13433	0.61	37	5	3	2	10	2	Q3 - 2020	Q1 - 2023	Q3 - 2023	$16,000
LUG ESA 13454.90188551	13454	0.21	13	37	2	0	39	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$65,020
LUG ESA 13454.90397369	13454	0.49	26	19	10	1	30	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$343,370
LUG ESA 13454.90429155	13454	0.64	34	148	6	2	156	4	Q3 - 2020	Q3 - 2022	Q1 - 2023	$1,106,500
LUG ESA 13454.90755954	13454	0.30	23	292	21	1	314	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$216,950
LUG ESA 13454.91522987	13454	0.04	9	47	3	0	50	1	Q1 - 2021	Q3 - 2022	Q4 - 2022	$55,899
LUG ESA 13457.10482593	13457	0.14	9	137	8	2	147	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$30,049
LUG ESA 13457.90176591	13457	0.31	18	155	2	0	157	2	Q1 - 2021	Q2 - 2023	Q1 - 2024	$27,500
LUG ESA 13502.10497396	13502	0.30	22	70	2	0	72	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$44,796
LUG ESA 13502.92573944	13502	0.62	40	514	18	0	532	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$46,000
LUG ESA 13502.92679861	13502	0.18	16	50	25	0	75	0	Q4 - 2020	Q2 - 2022	Q3 - 2022	$188,706
LUG ESA 13509.10501110	13509	0.09	6	3	1	0	4	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$35,374
LUG ESA 13509.10501132	13509	0.11	6	7	22	11	40	1	Q4 - 2020	Q2 - 2023	Q1 - 2024	$10,300
LUG ESA 13509.10501141	13509	0.16	15	13	0	2	15	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13509.10501150	13509	0.51	33	37	7	0	44	0	Q3 - 2020	Q1 - 2023	Q1 - 2024	$73,000
LUG ESA 13509.60287236	13509	0.15	14	144	14	0	158	0	Q3 - 2020	Q2 - 2023	Q1 - 2024	$5,000
LUG ESA 13509.60346595	13509	0.15	10	14	1	1	16	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13509.90504849	13509	0.96	56	676	20	1	697	4	Q4 - 2020	Q2 - 2023	Q1 - 2024	$7,000
LUG ESA 13509.91772133	13509	0.05	8	22	0	1	23	1	Q3 - 2020	Q3 - 2022	Q4 - 2022	$94,000
LUG ESA 13509.92890860	13509	0.33	30	7	1	1	9	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13686.93697046	13686	0.40	14	14	0	0	14	1	Q1 - 2021	Q2 - 2023	Q1 - 2024	$23,500
LUG ESA 13710.92354144	13710	0.28	30	229	12	2	243	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$69,469
LUG ESA 13710.92881445	13710	0.45	32	158	17	0	175	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$586,222
LUG ESA 13793.92685255	13793	0.19	6	26	2	2	30	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$206,880
LUG ESA 13793.92686002	13793	0.23	17	1	7	6	14	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$25,774
LUG ESA 13793.92686712	13793	0.04	4	85	2	0	87	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$66,724
LUG ESA 13793.92686736	13793	0.03	4	85	4	1	90	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$57,250
LUG ESA 13796.10842823	13796	0.45	34	21	20	0	41	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$466,500
LUG ESA 13796.10842826	13796	0.15	13	353	11	0	364	0	Q4 - 2020	Q3 - 2022	Q4 - 2022	$156,000
LUG ESA 13796.92356181	13796	0.26	14	6	1	3	10	7	Q1 - 2021	Q3 - 2022	Q4 - 2022	$205,986
LUG ESA 13796.92728705	13796	0.45	34	318	6	1	325	0	Q4 - 2020	Q2 - 2023	Q1 - 2024	$13,000
LUG ESA 13796.92884623	13796	1.30	54	52	15	1	68	1	Q3 - 2020	Q1 - 2023	Q1 - 2024	$6,000
LUG ESA 13797.93185703	13797	0.04	5	2	0	1	3	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$60,875
LUG ESA 13797.93188519	13797	0.66	50	152	6	5	163	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$654,560
LUG ESA 13799.60395568	13799	0.46	45	260	16	1	277	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$43,000
LUG ESA 13878.10105717	13878	0.31	23	346	5	0	351	2	Q1 - 2021	Q2 - 2023	Q1 - 2024	$86,367
LUG ESA 13878.10105723	13878	0.31	25	46	37	8	91	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$22,500
LUG ESA 13878.10105726	13878	0.54	44	137	2	0	139	2	Q1 - 2021	Q1 - 2023	Q3 - 2023	$24,000
LUG ESA 13878.10105728	13878	0.23	14	26	0	0	26	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$59,996
LUG ESA 13883.91179506	13883	0.08	6	151	7	1	159	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$60,500
LUG ESA 13883.92008787	13883	0.06	8	3	0	1	4	0	Q3 - 2020	Q3 - 2022	Q4 - 2022	$66,050
LUG ESA 13906.10096960	13906	0.38	26	56	4	0	60	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$61,500
LUG ESA 13906.10096964	13906	0.68	40	31	2	3	36	10	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,500

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG ESA 13906.10096968	13906	0.56	53	99	9	5	113	12	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,250
LUG ESA 13906.90137810	13906	0.80	53	62	4	2	68	0	Q1 - 2021	Q2 - 2023	Q4 - 2023	$25,000
LUG ESA 13906.92282884	13906	0.10	7	26	2	1	29	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$119,524
LUG ESA 13909.90380435	13909	0.20	11	41	4	0	45	0	Q1 - 2021	Q2 - 2023	Q4 - 2023	$32,973
LUG ESA 13909.92173076	13909	0.31	22	8	10	4	22	6	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,500
LUG ESA 13911.10554595	13911	0.13	16	4	0	2	6	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$20,000
LUG ESA 13911.60157736	13911	0.05	5	62	1	0	63	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,850
LUG ESA 13911.60157737	13911	0.66	48	747	13	1	761	4	Q1 - 2021	Q1 - 2024	Q4 - 2024	$198,750
LUG ESA 13911.90130568	13911	0.86	53	108	18	0	126	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$22,500
LUG ESA 13911.91995336	13911	0.30	19	93	2	0	95	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$23,500
LUG ESA 13911.92679866	13911	0.56	50	80	27	0	107	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$27,500
LUG ESA 14116.60140011	14116	0.33	29	50	4	3	57	4	Q4 - 2020	Q1 - 2022	Q3 - 2022	$328,562
LUG ESA 14116.91073265	14116	0.09	7	10	8	0	18	0	Q1 - 2021	Q1 - 2024	Q1 - 2024	$34,748
LUG ESA 14355.60258173	14355	0.16	15	356	21	2	379	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$31,299
LUG ESA 14355.92354352	14355	0.32	22	51	3	3	57	1	Q1 - 2021	Q1 - 2024	Q1 - 2024	$21,250
LUG PCA 13120.60015632	13120	0.20	14	135	8	1	144	1	Q3 - 2020	Q4 - 2021	Q2 - 2022	$194,372
LUG PCA 13146.10629014	13146	0.54	30	91	6	0	97	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$56,106
LUG PCA 13243.90684154	13243	0.23	19	7	0	4	11	0	Q3 - 2021	Q1 - 2023	Q2 - 2023	$122,978
LUG PCA 13243.91351288	13243	0.29	18	223	18	0	241	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$298,166
LUG PCA 13268.10705945	13268	1.40	67	76	19	0	95	0	Q2 - 2021	Q1 - 2023	Q4 - 2023	$122,156
LUG PCA 13268.91633548	13268	0.89	48	216	23	2	241	1	Q1 - 2021	Q2 - 2022	Q1 - 2023	$802,646
LUG PCA 13268.92962459	13268	0.43	28	48	6	1	55	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$129,753
LUG PCA 13390.92599119	13390	0.72	46	266	27	3	296	0	Q3 - 2020	Q3 - 2021	Q2 - 2022	$1,511,052
LUG PCA 13655.90431393	13655	1.23	70	298	26	3	327	0	Q2 - 2021	Q1 - 2023	Q4 - 2023	$152,476
LUG PCA 13722.60360851	13722	0.21	17	124	18	1	143	0	Q1 - 2021	Q1 - 2023	Q4 - 2023	$185,066
LUG PCA 13724.10671229	13724	0.30	16	9	5	0	14	0	Q1 - 2021	Q4 - 2021	Q4 - 2022	$375,122
LUG PCA 13724.10671319	13724	1.76	83	181	35	2	218	0	Q1 - 2021	Q3 - 2022	Q3 - 2023	$1,803,592
LUG PCA 13724.10671334	13724	0.57	31	120	22	0	142	0	Q1 - 2021	Q3 - 2022	Q3 - 2023	$145,165
LUG PCA 13724.90911087	13724	0.54	32	31	4	0	35	6	Q3 - 2020	Q3 - 2022	Q2 - 2023	$340,878
LUG PCA 13724.91049435	13724	1.99	103	97	17	2	116	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$122,648
LUG PCA 13785.92299245	13785	1.08	57	174	10	0	184	0	Q1 - 2021	Q4 - 2021	Q4 - 2022	$1,001,289
LUG PCA 13785.92466250	13785	0.72	31	72	13	1	86	0	Q3 - 2020	Q4 - 2021	Q4 - 2022	$858,204
LUG PCA 13961.10696431	13961	0.16	8	4	0	2	6	4	Q1 - 2021	Q1 - 2023	Q3 - 2023	$54,732
LUG PCA 13961.10696486	13961	0.54	32	38	5	0	43	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$267,570
LUG PCA 13961.60193482	13961	0.48	35	118	13	4	135	0	Q3 - 2020	Q4 - 2021	Q3 - 2022	$225,732
LUG PCA 13961.91967308	13961	0.49	32	28	4	1	33	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$157,398
LUG PCA 13961.92820848	13961	0.49	26	509	10	2	521	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$196,174
LUG PCA 13961.92829453	13961	0.34	25	447	3	2	452	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$59,592
LUG PCA 13961.92834683	13961	0.72	37	23	4	1	28	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$789,692
LUG SHA 13001.10663240	13001	0.45	26	16	5	2	23	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$43,272
LUG SHA 13001.10663262	13001	0.09	8	63	4	0	67	10	Q1 - 2021	Q1 - 2024	Q4 - 2024	$21,500
LUG SHA 13001.10663269	13001	0.12	8	16	4	0	20	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 13001.60179144	13001	0.67	42	162	14	2	178	4	Q1 - 2021	Q1 - 2024	Q4 - 2024	$138,000
LUG SHA 13001.60179191	13001	0.36	30	139	11	1	151	1	Q1 - 2021	Q1 - 2024	Q4 - 2024	$60,020
LUG SHA 13001.92048269	13001	0.24	17	137	15	0	152	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$34,323
LUG SHA 13001.93346473	13001	0.81	48	483	22	3	508	5	Q1 - 2021	Q1 - 2024	Q4 - 2024	$47,114
LUG SHA 13003.10895211	13003	2.47	116	179	34	1	214	14	Q1 - 2021	Q1 - 2023	Q4 - 2023	$24,000
LUG SHA 13342.10925094	13342	0.33	22	45	12	1	58	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,500

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG SHA 13342.90527363	13342	0.16	10	29	5	0	34	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$500
LUG SHA 13342.91010293	13342	0.36	27	190	5	2	197	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,500
LUG SHA 13645.91519309	13645	0.50	22	36	3	1	40	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$551,702
LUG SHA 13645.92207754	13645	0.73	28	7	3	2	12	3	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 13652.92748361	13652	0.48	23	23	21	0	44	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$31,398
LUG SHA 13780.10723993	13780	0.27	17	97	4	0	101	1	Q1 - 2021	Q1 - 2024	Q4 - 2024	$38,097
LUG SHA 13817.10722417	13817	1.78	123	569	35	1	605	2	Q1 - 2021	Q1 - 2024	Q4 - 2024	$33,000
LUG SHA 13897.10933151	13897	0.79	33	64	20	1	85	1	Q3 - 2020	Q1 - 2022	Q3 - 2022	$785,112
LUG SHA 13900.10717269	13900	0.42	21	136	15	1	152	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$63,620
LUG SHA 13900.91863298	13900	0.27	18	169	3	0	172	8	Q1 - 2021	Q1 - 2024	Q4 - 2024	$100,465
LUG SHA 13900.92336596	13818	0.46	21	3	1	5	9	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 14020.60223573	14020	0.48	45	415	8	3	426	2	Q1 - 2021	Q1 - 2024	Q4 - 2024	$24,250
LUG SHA 14022.90591555	14022	0.76	49	485	7	3	495	29	Q1 - 2021	Q2 - 2022	Q4 - 2022	$763,012
LUG SHA 14024.10747874	14024	0.15	13	135	7	0	142	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$40,998
LUG SHA 14024.90116190	14024	0.13	11	12	8	0	20	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$32,374
LUG WHA 13118.10535995	13118	0.95	63	363	15	0	378	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$937,189
LUG WHA 13118.10535999	13118	0.35	26	101	5	0	106	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$393,652
LUG WHA 13118.92204382	13118	0.69	41	88	6	0	94	0	Q2 - 2021	Q1 - 2022	Q1 - 2023	$867,707
LUG WHA 13118.92612349	13118	0.94	39	220	17	1	238	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$926,697
LUG WHA 13118.92659172	13118	0.27	26	18	10	3	31	1	Q1 - 2021	Q1 - 2023	Q3 - 2023	$207,720
LUG WHA 13296.10562361	13296	0.23	19	37	5	0	42	0	Q1 - 2021	Q2 - 2022	Q1 - 2023	$438,832
LUG WHA 13296.60531111	13296	0.95	68	90	14	2	106	1	Q1 - 2021	Q1 - 2022	Q1 - 2023	$888,621
LUG WHA 13296.90010289	13296	1.34	81	82	12	1	95	4	Q1 - 2021	Q1 - 2022	Q1 - 2023	$1,206,963
LUG WHA 13296.92376304	13296	0.29	20	200	18	0	218	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$342,484
LUG WHA 13297.10560425	13297	0.31	21	72	3	4	79	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$747,463
LUG WHA 13297.10560432	13297	0.43	29	362	6	0	368	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$713,526
LUG WHA 13297.60269456	13297	0.31	30	59	32	4	95	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$359,801
LUG WHA 13312.60182741	13312	0.15	15	52	11	7	70	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$102,002
LUG WHA 13313.10684581	13313	0.24	23	38	7	3	48	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$302,581
LUG WHA 13313.10684614	13313	0.14	16	106	16	3	125	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$246,592
LUG WHA 13313.90084626	13313	0.09	9	35	78	10	123	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$439,597
LUG WHA 13314.10567076	13314	0.42	32	89	3	2	94	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$417,912
LUG WHA 13473.60168916	13473	0.34	24	419	22	1	442	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$241,437
LUG WHA 13473.60168942	13473	0.35	27	187	7	1	195	0	Q3 - 2021	Q1 - 2022	Q4 - 2022	$411,291
LUG WHA 13473.92097460	13473	0.24	19	152	5	0	157	0	Q2 - 2021	Q3 - 2023	Q1 - 2024	$279,503
LUG WHA 13699.10637240	13699	1.02	48	137	3	1	141	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$690,882
LUG WHA 13699.10637242	13699	0.62	37	284	27	1	312	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$621,815
LUG WHA 13699.10637247	13699	0.19	11	119	5	0	124	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$150,226
LUG WHA 13699.10637259	13699	0.16	13	26	4	0	30	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$169,173
LUG WHA 13699.60165416	13699	0.36	18	10	20	1	31	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$180,975
LUG WHA 13916.60279623	13916	0.19	9	282	15	1	298	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$337,807
LUG WHA 13916.91386005	13916	0.53	36	199	6	0	205	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$596,018
LUG WHA 13916.92509975	13916	0.45	35	71	18	0	89	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$402,018
LUG WHA 13972.10618037	13972	0.25	13	1	2	2	5	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$311,368
LUG WHA 13972.90241880	13972	0.90	49	130	7	6	143	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$54,732
LUG WHA 13972.92421291	13972	0.44	23	379	6	1	386	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$54,798
LUG WSA 13059.60302601	13059	0.51	51	291	18	2	311	0	Q2 - 2021	Q3 - 2022	Q3 - 2023	$95,048
LUG WSA 13071.60170422	13071	0.99	74	362	11	3	376	10	Q3 - 2020	Q1 - 2022	Q2 - 2023	$1,451,994
LUG WSA 13071.92377934	13071	0.98	66	63	7	0	70	0	Q2 - 2021	Q4 - 2022	Q4 - 2023	$95,048

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG WSA 13078.10127955	13078	0.18	15	33	2	1	36	1	Q1 - 2021	Q3 - 2022	Q1 - 2023	$208,039
LUG WSA 13078.10127958	13078	0.75	35	554	7	2	563	18	Q1 - 2021	Q3 - 2022	Q3 - 2023	$65,585
LUG WSA 13079.60077605	13079	0.18	17	32	6	5	43	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$159,727
LUG WSA 13079.60077624	13079	0.34	30	58	4	5	67	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13079.60104344	13079	0.14	21	25	8	6	39	3	Q1 - 2021	Q4 - 2021	Q2 - 2022	$172,906
LUG WSA 13079.90517178	13079	0.13	16	56	10	3	69	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$64,432
LUG WSA 13109.60233901	13109	0.47	42	282	9	0	291	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13109.90643551	13109	0.67	50	95	10	4	109	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$45,331
LUG WSA 13111.60072751	13111	0.20	17	18	1	2	21	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$318,842
LUG WSA 13111.92999604	13111	0.42	32	61	9	2	72	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13113.90422522	13113	0.11	6	3	5	4	12	6	Q3 - 2021	Q4 - 2022	Q2 - 2023	$65,585
LUG WSA 13113.90796385	13113	0.51	34	233	19	1	253	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$565,310
LUG WSA 13113.92909503	13113	0.07	9	215	8	0	223	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$68,672
LUG WSA 13138.10145618	13138	0.07	6	92	2	0	94	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$40,845
LUG WSA 13138.10145628	13138	0.30	18	352	5	4	361	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$335,531
LUG WSA 13138.60170460	13138	0.26	23	170	9	0	179	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$344,455
LUG WSA 13140.10013916	13140	0.10	13	143	7	4	154	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13141.10147344	13141	0.10	7	12	6	1	19	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$77,386
LUG WSA 13141.10147371	13141	0.47	49	94	3	1	98	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$65,585
LUG WSA 13141.91575422	13141	0.10	8	34	1	1	36	25	Q2 - 2021	Q3 - 2022	Q1 - 2023	$102,197
LUG WSA 13141.92442350	13141	0.09	13	12	0	1	13	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13162.10158432	13162	0.16	10	61	3	0	64	12	Q1 - 2021	Q1 - 2022	Q3 - 2022	$93,356
LUG WSA 13162.10158434	13162	0.38	30	47	23	3	73	6	Q2 - 2021	Q4 - 2022	Q2 - 2023	$235,331
LUG WSA 13162.90435139	13162	0.30	24	23	50	5	78	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13162.92185426	13162	0.37	26	19	23	16	58	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13162.93124277	13162	0.16	23	5	15	5	25	5	Q1 - 2021	Q3 - 2022	Q1 - 2023	$162,652
LUG WSA 13164.90252716	13164	0.22	15	59	13	2	74	3	Q1 - 2022	Q3 - 2023	Q1 - 2024	$65,585
LUG WSA 13192.90932106	13192	0.19	13	2	2	5	9	9	Q1 - 2021	Q1 - 2022	Q3 - 2022	$145,753
LUG WSA 13194.90645535	13194	1.10	50	285	2	0	287	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$65,585
LUG WSA 13198.10051851	13198	0.21	21	33	50	2	85	6	Q2 - 2021	Q3 - 2022	Q1 - 2023	$195,985
LUG WSA 13198.10051875	13198	0.10	8	20	2	2	24	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$165,711
LUG WSA 13198.10051896	13198	0.13	11	18	2	1	21	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$120,993
LUG WSA 13198.92183966	13198	0.17	12	86	26	4	116	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$308,073
LUG WSA 13198.92655424	13198	0.09	8	11	7	2	20	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$174,469
LUG WSA 13207.90146892	13207	0.26	25	60	9	4	73	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13207.90147316	13207	0.20	17	23	33	0	56	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$65,585
LUG WSA 13207.90613782	13207	0.38	31	64	1	2	67	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13208.92767537	13208	0.18	18	117	3	1	121	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$90,410
LUG WSA 13220.10191173	13220	0.52	45	66	17	4	87	9	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13220.90901917	13220	0.49	38	55	18	0	73	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$435,674
LUG WSA 13333.10007588	13333	0.16	16	16	31	2	49	0	Q1 - 2021	Q4 - 2022	Q2 - 2023	$88,822
LUG WSA 13333.91785740	13333	0.23	26	13	34	3	50	0	Q4 - 2020	Q1 - 2022	Q3 - 2022	$147,334
LUG WSA 13334.91645657	13334	0.48	46	142	7	1	150	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13425.10244449	13425	0.70	33	195	12	4	211	0	Q3 - 2020	Q3 - 2021	Q2 - 2022	$89,889
LUG WSA 13428.90423835	13428	0.26	16	208	1	0	209	12	Q1 - 2021	Q1 - 2022	Q3 - 2022	$127,958
LUG WSA 13428.91540495	13428	0.23	30	402	20	1	423	1	Q3 - 2020	Q1 - 2022	Q3 - 2022	$353,202
LUG WSA 13483.60393455	13483	1.32	100	525	31	1	557	4	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13490.92815117	13490	0.17	13	163	2	1	166	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$181,351
LUG WSA 13491.10230118	13491	0.51	36	94	2	4	100	2	Q3 - 2020	Q3 - 2021	Q1 - 2022	$147,296

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG WSA 13491.91827162	13491	0.24	21	34	1	1	36	7	Q2 - 2021	Q2 - 2022	Q4 - 2022	$137,390
LUG WSA 13510.10218990	13510	0.36	37	20	18	2	40	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13514.10624934	13514	0.24	20	18	0	1	19	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$95,048
LUG WSA 13514.91361858	13514	0.16	18	70	7	0	77	19	Q1 - 2021	Q3 - 2022	Q1 - 2023	$157,419
LUG WSA 13516.60169592	13516	0.26	19	11	16	4	31	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$267,994
LUG WSA 13520.10242257	13520	0.45	44	28	9	4	41	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13522.10392874	13522	0.16	12	4	6	4	14	10	Q1 - 2021	Q3 - 2022	Q1 - 2023	$121,523
LUG WSA 13522.10392882	13522	0.69	61	162	8	0	170	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$65,585
LUG WSA 13522.10392902	13522	0.67	68	103	30	3	136	0	Q3 - 2021	Q1 - 2023	Q3 - 2023	$90,410
LUG WSA 13522.10392905	13522	0.47	50	105	5	3	113	1	Q2 - 2021	Q4 - 2022	Q2 - 2023	$274,069
LUG WSA 13522.10392924	13522	0.12	9	10	3	2	15	0	Q2 - 2021	Q4 - 2022	Q3 - 2023	$65,585
LUG WSA 13522.60305720	13522	0.07	6	10	0	1	11	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$64,556
LUG WSA 13522.91947423	13522	0.53	50	47	10	3	60	5	Q2 - 2021	Q3 - 2022	Q1 - 2023	$399,056
LUG WSA 13522.92169062	13522	0.32	29	77	13	0	90	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13533.91957169	13533	0.24	21	354	15	3	372	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$251,855
LUG WSA 13535.91618829	13535	0.50	34	70	4	1	75	0	Q3 - 2021	Q1 - 2023	Q3 - 2023	$79,177
LUG WSA 13535.92952190	13535	0.26	18	78	2	0	80	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$220,147
LUG WSA 13535.92983661	13535	0.33	32	10	0	3	13	0	Q3 - 2021	Q2 - 2022	Q4 - 2022	$266,452
LUG WSA 13535.92983670	13535	0.21	14	164	10	1	175	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$198,828
LUG WSA 13544.10053269	13544	0.16	16	19	2	0	21	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$41,888
LUG WSA 13574.10250638	13574	0.17	12	10	6	4	20	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$97,586
LUG WSA 13575.90054386	13575	0.10	13	105	8	3	116	1	Q1 - 2021	Q3 - 2022	Q1 - 2023	$120,188
LUG WSA 13575.90054924	13575	0.11	12	238	2	0	240	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$139,012
LUG WSA 13586.10255333	13586	0.12	9	4	1	0	5	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$21,744
LUG WSA 13586.60303627	13586	1.07	67	69	8	5	82	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$678,421
LUG WSA 13586.91748729	13586	0.67	42	45	0	3	48	0	Q2 - 2021	Q2 - 2023	Q1 - 2024	$90,410
LUG WSA 13586.92442286	13586	0.49	40	180	7	0	187	1	Q4 - 2021	Q4 - 2022	Q4 - 2023	$65,585
LUG WSA 13589.93162023	13589	0.33	16	1	5	0	6	5	Q2 - 2021	Q2 - 2022	Q4 - 2022	$149,295
LUG WSA 13589.93177909	13589	0.12	6	33	13	0	46	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$24,024
LUG WSA 13605.91052996	13605	0.33	27	115	12	0	127	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$783,754
LUG WSA 13612.60002970	13612	0.25	23	131	3	1	135	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$178,914
LUG WSA 13612.60003135	13612	0.30	33	81	3	1	85	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13612.60022877	13612	0.06	7	22	11	0	33	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$177,279
LUG WSA 13612.90291123	13612	0.13	15	10	9	1	20	0	Q2 - 2021	Q2 - 2023	Q1 - 2024	$90,410
LUG WSA 13612.90312305	13612	0.09	7	72	4	1	77	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$95,048
LUG WSA 13612.92956326	13612	0.23	25	20	12	4	36	8	Q2 - 2021	Q4 - 2022	Q2 - 2023	$282,540
LUG WSA 13669.60107076	13669	0.12	9	4	1	4	9	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$131,883
LUG WSA 13669.92770538	13669	0.30	37	204	10	0	214	1	Q2 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 13670.93124410	13670	0.71	25	383	3	1	387	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$289,213
LUG WSA 13672.10493801	13672	0.58	43	368	9	1	378	8	Q2 - 2021	Q2 - 2023	Q1 - 2024	$65,585
LUG WSA 13672.60106849	13672	0.27	26	256	12	0	268	0	Q4 - 2020	Q3 - 2022	Q1 - 2023	$226,557
LUG WSA 13672.91971930	13672	0.19	19	27	3	1	31	3	Q2 - 2021	Q2 - 2023	Q1 - 2024	$95,048
LUG WSA 13674.10277747	13674	0.57	36	361	6	1	368	2	Q1 - 2021	Q1 - 2022	Q3 - 2022	$269,611
LUG WSA 13674.90420693	13674	0.32	29	125	0	0	125	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13678.10254063	13678	0.28	18	11	6	0	17	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$223,422
LUG WSA 13678.10288738	13678	0.58	28	4	1	0	5	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$431,533
LUG WSA 13678.90514672	13678	0.54	29	9	5	0	14	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$361,928
LUG WSA 13737.10297934	13737	0.20	18	24	1	1	26	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$151,121
LUG WSA 13737.10297943	13737	0.20	18	84	5	3	92	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$515,924

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG WSA 13737.60311396	13737	0.19	8	16	13	0	29	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$169,528
LUG WSA 13737.90740214	13737	0.10	12	15	3	0	18	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$90,477
LUG WSA 13737.90740699	13737	0.17	13	17	4	0	21	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$136,971
LUG WSA 13737.91960399	13737	0.43	32	56	3	3	62	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$243,489
LUG WSA 13738.10298299	13738	0.31	27	71	7	4	82	0	Q3 - 2021	Q3 - 2023	Q1 - 2024	$66,535
LUG WSA 13747.10299739	13747	0.10	5	128	16	2	146	0	Q3 - 2020	Q4 - 2021	Q1 - 2022	$28,010
LUG WSA 13750.60110680	13750	0.19	12	43	6	0	49	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$91,376
LUG WSA 13756.10589587	13756	0.14	13	8	4	0	12	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$170,400
LUG WSA 13756.10589595	13756	0.25	22	93	7	0	100	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$105,022
LUG WSA 13756.60165355	13756	0.08	12	55	10	3	68	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$115,052
LUG WSA 13756.90207831	13756	0.38	36	181	18	1	200	44	Q2 - 2021	Q2 - 2023	Q4 - 2023	$59,733
LUG WSA 13860.10307212	13860	0.25	28	2	20	9	31	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$172,514
LUG WSA 13860.10307215	13860	0.28	26	219	17	4	240	3	Q1 - 2021	Q3 - 2022	Q1 - 2023	$255,757
LUG WSA 13863.60279838	13863	0.47	32	259	5	0	264	2	Q1 - 2021	Q4 - 2022	Q2 - 2023	$340,427
LUG WSA 13864.10310477	13864	0.71	57	18	233	67	318	16	Q3 - 2021	Q3 - 2022	Q1 - 2023	$573,160
LUG WSA 13864.10310497	13864	0.15	10	10	41	9	60	2	Q2 - 2021	Q4 - 2022	Q2 - 2023	$319,952
LUG WSA 13864.10310505	13864	0.51	41	3	49	31	83	6	Q1 - 2021	Q1 - 2022	Q3 - 2022	$491,417
LUG WSA 13864.60380454	13864	0.16	13	1	1	1	3	1	Q1 - 2021	Q3 - 2021	Q1 - 2022	$47,404
LUG WSA 13865.90531031	13865	0.26	19	21	11	5	37	9	Q1 - 2021	Q2 - 2023	Q4 - 2023	$59,733
LUG WSA 13870.90428273	13870	0.40	25	104	8	0	112	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$318,493
LUG WSA 13873.60311122	13873	0.79	61	235	7	3	245	3	Q3 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 13892.10338448	13892	1.11	71	256	8	2	266	2	Q3 - 2021	Q2 - 2023	Q1 - 2024	$59,733
LUG WSA 14030.60125643	14030	0.09	14	101	3	0	104	1	Q1 - 2021	Q2 - 2022	Q4 - 2022	$70,413
LUG WSA 14030.60341032	14030	0.13	10	81	1	0	82	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$94,885
LUG WSA 14030.90886759	14030	0.54	49	161	15	1	177	12	Q2 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 14030.92669557	14030	0.01	5	78	12	0	90	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$91,249
LUG WSA 14030.92669942	14030	0.56	34	112	6	0	118	0	Q2 - 2021	Q1 - 2023	Q1 - 2024	$66,535
LUG WSA 14030.92670479	14030	0.11	6	3	3	0	6	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$100,348
Lateral Hardening-Fuse-10007252,1	13737	0.09	9	4	0	1	5	0	Q3 - 2022	Q1 - 2023	Q2 - 2023	$28,850
Lateral Hardening-Fuse-10050730,3	13199	0.53	52	271	22	0	293	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$174,719
Lateral Hardening-Fuse-10051863,1	13198	0.08	10	62	5	0	67	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$25,236
Lateral Hardening-Fuse-10055000,2	13419	0.36	28	33	11	0	44	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$118,639
Lateral Hardening-Fuse-10055941,1	13420	0.15	10	4	1	1	6	0	Q3 - 2022	Q2 - 2023	Q1 - 2024	$48,228
Lateral Hardening-Fuse-10075304,1	13656	0.11	4	2	0	1	3	3	Q4 - 2022	Q1 - 2024	Q3 - 2024	$36,639
Lateral Hardening-Fuse-10075336,1	13656	0.19	15	17	2	5	24	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,931
Lateral Hardening-Fuse-10087587,1	13389	0.10	6	5	4	0	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$32,962
Lateral Hardening-Fuse-10089965,1	13279	0.09	12	10	2	1	13	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$29,722
Lateral Hardening-Fuse-10092875,1	13611	0.25	26	119	2	1	122	75	Q2 - 2022	Q2 - 2023	Q1 - 2024	$81,128
Lateral Hardening-Fuse-10093646,2	13043	0.38	26	47	2	1	50	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$123,873
Lateral Hardening-Fuse-10093658,1	13043	0.10	11	19	1	1	21	0	Q1 - 2022	Q1 - 2023	Q3 - 2023	$32,775
Lateral Hardening-Fuse-10093683,1	13043	0.09	8	8	4	2	14	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$27,977
Lateral Hardening-Fuse-10100716,1	13048	0.44	44	85	2	1	88	12	Q3 - 2022	Q3 - 2022	Q1 - 2023	$145,371
Lateral Hardening-Fuse-10100722,1	13048	0.06	6	14	4	0	18	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$20,438
Lateral Hardening-Fuse-10101247,3	13046	0.41	41	57	2	2	61	5	Q2 - 2022	Q3 - 2023	Q1 - 2024	$134,217
Lateral Hardening-Fuse-10120786,1	13053	0.26	28	73	11	0	84	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$83,932
Lateral Hardening-Fuse-10120788,1	13053	0.26	23	38	2	1	41	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$84,369
Lateral Hardening-Fuse-10124545,1	13063	0.29	26	43	3	1	47	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$96,519
Lateral Hardening-Fuse-10126980,1	13065	0.23	23	35	4	0	39	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$77,203
Lateral Hardening-Fuse-10142238,1	13034	0.18	15	16	1	1	18	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$59,195

TAMPA ELECTRIC COMPANY
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Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details												
Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-10144159,1	13123	0.56	38	8	34	3	45	17	Q3 - 2022	Q1 - 2024	Q3 - 2024	$184,626
Lateral Hardening-Fuse-10147338,1	13141	0.19	22	56	2	0	58	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$62,311
Lateral Hardening-Fuse-10153131,1	13154	0.11	14	5	14	4	23	10	Q2 - 2022	Q3 - 2023	Q1 - 2024	$36,265
Lateral Hardening-Fuse-10158932,1	13164	0.09	10	12	0	1	13	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$30,283
Lateral Hardening-Fuse-10160212,1	13167	0.07	8	51	4	0	55	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$23,803
Lateral Hardening-Fuse-10163224,4	13091	0.41	41	50	7	0	57	0	Q2 - 2022	Q2 - 2022	Q1 - 2023	$135,526
Lateral Hardening-Fuse-10163228,1	13091	0.14	15	16	10	0	26	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$45,611
Lateral Hardening-Fuse-10165356,4	13045	0.68	62	81	15	4	100	7	Q2 - 2022	Q2 - 2023	Q4 - 2023	$223,633
Lateral Hardening-Fuse-10165381,2	13045	0.31	28	53	14	3	70	0	Q2 - 2022	Q2 - 2023	Q1 - 2024	$100,881
Lateral Hardening-Fuse-10165382,1	13045	0.04	5	6	10	1	17	0	Q3 - 2022	Q2 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-10165789,1	13072	0.22	18	16	13	3	32	8	Q3 - 2022	Q1 - 2024	Q3 - 2024	$73,153
Lateral Hardening-Fuse-10165797,1	13072	0.15	15	6	6	1	13	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$48,228
Lateral Hardening-Fuse-10165803,1	13072	0.12	12	8	1	2	11	0	Q2 - 2022	Q1 - 2024	Q2 - 2024	$39,131
Lateral Hardening-Fuse-10167762,1	13206	0.18	20	24	3	1	28	2	Q3 - 2022	Q1 - 2024	Q2 - 2024	$60,566
Lateral Hardening-Fuse-10173494,1	13191	0.21	20	20	1	2	23	1	Q2 - 2022	Q2 - 2023	Q1 - 2024	$67,732
Lateral Hardening-Fuse-10173500,1	13191	0.21	17	47	5	0	52	0	Q3 - 2022	Q1 - 2024	Q2 - 2024	$70,536
Lateral Hardening-Fuse-10173522,1	13191	0.35	34	4	25	8	37	9	Q2 - 2022	Q1 - 2024	Q2 - 2024	$114,714
Lateral Hardening-Fuse-10218987,1	13510	0.09	10	206	11	2	219	1	Q3 - 2022	Q1 - 2024	Q2 - 2024	$28,040
Lateral Hardening-Fuse-10247860,1	13533	0.04	5	45	2	0	47	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-10274748,1	13624	0.28	19	22	3	0	25	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$91,970
Lateral Hardening-Fuse-10297412,1	13754	0.06	8	10	0	1	11	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$19,441
Lateral Hardening-Fuse-10297440,1	13754	0.12	14	87	3	0	90	0	Q2 - 2022	Q1 - 2024	Q2 - 2024	$38,072
Lateral Hardening-Fuse-10297442,1	13754	0.14	16	33	12	2	47	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$45,362
Lateral Hardening-Fuse-10361894,1	13106	0.13	10	35	2	2	39	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$43,493
Lateral Hardening-Fuse-10362869,3	13104	0.62	47	67	20	3	90	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$63,016
Lateral Hardening-Fuse-10363933,1	13096	0.13	8	6	2	1	9	8	Q3 - 2022	Q3 - 2023	Q1 - 2024	$42,994
Lateral Hardening-Fuse-10382337,1	13224	0.09	10	15	2	1	18	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$28,663
Lateral Hardening-Fuse-10384706,1	13351	0.11	8	26	3	0	29	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$36,140
Lateral Hardening-Fuse-10384723,1	13351	0.26	20	65	6	1	72	1	Q2 - 2022	Q2 - 2023	Q4 - 2023	$84,182
Lateral Hardening-Fuse-10389247,2	13365	0.38	35	206	6	0	212	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$125,556
Lateral Hardening-Fuse-10392877,1	13522	0.09	11	10	2	1	13	8	Q3 - 2022	Q1 - 2024	Q3 - 2024	$30,719
Lateral Hardening-Fuse-10424221,1	13828	0.05	4	2	1	6	9	8	Q1 - 2022	Q2 - 2023	Q4 - 2023	$15,640
Lateral Hardening-Fuse-10425054,1	13829	0.12	9	48	7	0	55	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$39,131
Lateral Hardening-Fuse-10427678,1	13831	0.05	4	36	3	0	39	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$15,266
Lateral Hardening-Fuse-10429550,1	13835	0.21	16	32	5	0	37	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$68,791
Lateral Hardening-Fuse-10457713,1	13229	0.05	8	42	4	0	46	7	Q2 - 2022	Q1 - 2024	Q4 - 2024	$18,008
Lateral Hardening-Fuse-10475330,1	14117	0.16	14	5	5	3	13	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$52,590
Lateral Hardening-Fuse-10477228,1	13326	0.19	14	8	16	5	29	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$62,061
Lateral Hardening-Fuse-10535991,1	13115	0.25	20	25	0	1	26	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$83,870
Lateral Hardening-Fuse-10545847,1	13910	0.08	6	6	1	1	8	1	Q2 - 2022	Q1 - 2025	Q4 - 2025	$27,853
Lateral Hardening-Fuse-10565125,1	13291	0.17	16	19	1	1	21	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$54,522
Lateral Hardening-Fuse-10565130,1	13291	0.21	20	20	3	1	24	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$70,536
Lateral Hardening-Fuse-10565136,1	13291	0.13	13	14	3	2	19	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$44,241
Lateral Hardening-Fuse-10565887,1	13290	0.35	34	129	7	0	136	0	Q1 - 2022	Q1 - 2025	Q4 - 2025	$114,278
Lateral Hardening-Fuse-10565895,1	13290	0.07	9	15	5	0	20	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$23,366
Lateral Hardening-Fuse-10572982,1	13371	0.17	15	17	9	0	26	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$56,266
Lateral Hardening-Fuse-10589590,1	13756	0.14	21	29	2	0	31	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$46,982
Lateral Hardening-Fuse-10616460,1	13124	0.07	8	11	1	0	12	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$22,432
Lateral Hardening-Fuse-10625698,1	13011	0.25	21	28	2	0	30	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$81,752

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail: OH to UG Length Converted (miles)	Specific Project Detail: Poles	Customers: Residential	Customers: Small C&I	Customers: Large C&I	Customers: Total	Priority Customers	Project Start Qtr	Construction: Start Qtr	Construction: End Qtr	Project Cost in 2022
Lateral Hardening-Fuse-10632726,1	13312	0.12	17	7	7	3	17	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$39,318
Lateral Hardening-Fuse-10632727,1	13312	0.12	12	24	14	0	38	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$40,689
Lateral Hardening-Fuse-10633695,1	13241	0.06	4	8	3	0	11	0	Q3 - 2022	Q1 - 2025	Q4 - 2025	$21,186
Lateral Hardening-Fuse-10637218,1	13696	0.24	26	25	7	0	32	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$79,820
Lateral Hardening-Fuse-10640103,1	13724	0.18	16	2	4	3	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$60,566
Lateral Hardening-Fuse-10668889,1	13723	0.51	20	29	4	0	33	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$166,556
Lateral Hardening-Fuse-10671179,1	13724	0.03	5	2	2	0	4	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-10674224,1	13414	0.10	9	7	0	1	8	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$31,280
Lateral Hardening-Fuse-10674240,1	13414	0.17	14	21	3	1	25	6	Q3 - 2022	Q1 - 2024	Q3 - 2024	$56,329
Lateral Hardening-Fuse-10674784,1	13464	0.49	33	55	3	0	58	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$162,319
Lateral Hardening-Fuse-10675160,1	13464	0.21	10	21	7	0	28	2	Q3 - 2022	Q1 - 2024	Q3 - 2024	$69,165
Lateral Hardening-Fuse-10686006,1	13808	0.29	19	2	0	3	5	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$94,712
Lateral Hardening-Fuse-10688316,1	13068	0.10	10	9	7	0	16	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$33,710
Lateral Hardening-Fuse-10692795,1	13463	0.07	6	12	2	0	14	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$23,927
Lateral Hardening-Fuse-10692803,1	13463	0.09	7	13	2	0	15	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$29,161
Lateral Hardening-Fuse-10696420,1	13961	0.07	9	18	2	0	20	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$23,553
Lateral Hardening-Fuse-10696464,1	13961	0.05	4	2	2	0	4	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$16,824
Lateral Hardening-Fuse-10710623,1	14000	0.19	14	5	4	0	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,993
Lateral Hardening-Fuse-10716303,1	13959	0.29	17	14	2	0	16	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$93,902
Lateral Hardening-Fuse-10716315,1	13959	0.10	9	17	4	0	21	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$31,965
Lateral Hardening-Fuse-10716318,1	13959	0.09	7	1	1	0	2	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$28,663
Lateral Hardening-Fuse-10791877,1	13243	0.09	6	43	0	1	44	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$27,977
Lateral Hardening-Fuse-10791889,1	13243	0.26	18	48	5	0	53	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$85,926
Lateral Hardening-Fuse-10823013,1	13651	0.17	12	39	3	2	44	5	Q2 - 2022	Q1 - 2025	Q3 - 2025	$57,077
Lateral Hardening-Fuse-10916743,1	13805	0.33	16	5	2	1	8	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$107,548
Lateral Hardening-Fuse-10928275,1	13143	0.09	10	17	12	0	29	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$31,031
Lateral Hardening-Fuse-10933157,1	13896	0.28	16	9	12	0	21	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$90,662
Lateral Hardening-Fuse-60005954,1	13899	0.17	13	5	2	1	8	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$55,145
Lateral Hardening-Fuse-60008652,1	13081	0.08	9	26	5	0	31	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$27,167
Lateral Hardening-Fuse-60011392,1	13047	0.24	25	37	1	1	39	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$80,381
Lateral Hardening-Fuse-60013778,1	13094	0.25	27	84	7	1	92	2	Q3 - 2022	Q3 - 2023	Q1 - 2024	$83,745
Lateral Hardening-Fuse-60015117,1	13008	0.27	18	28	2	2	32	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$88,668
Lateral Hardening-Fuse-60015427,1	13008	0.36	19	6	1	2	9	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$117,019
Lateral Hardening-Fuse-60016282,1	13049	0.06	5	31	0	1	32	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$19,316
Lateral Hardening-Fuse-60016353,1	13049	0.07	9	9	1	1	11	4	Q3 - 2022	Q3 - 2023	Q1 - 2024	$24,550
Lateral Hardening-Fuse-60017429,2	13029	0.43	40	4	21	15	40	7	Q3 - 2022	Q3 - 2022	Q1 - 2023	$139,887
Lateral Hardening-Fuse-60028650,1	13007	0.10	10	15	5	1	21	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$32,526
Lateral Hardening-Fuse-60029011,1	13088	0.07	9	6	11	1	18	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$24,177
Lateral Hardening-Fuse-60029776,1	13093	0.29	29	61	2	1	64	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$94,151
Lateral Hardening-Fuse-60029925,3	13091	0.57	53	101	12	0	113	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$186,807
Lateral Hardening-Fuse-60031511,1	13093	0.18	16	28	0	1	29	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$59,444
Lateral Hardening-Fuse-60033370,1	13163	0.13	12	17	12	3	32	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$42,122
Lateral Hardening-Fuse-60033388,1	13163	0.18	18	19	17	1	37	10	Q2 - 2022	Q3 - 2023	Q1 - 2024	$59,070
Lateral Hardening-Fuse-60034479,1	13143	0.30	32	48	1	0	49	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$99,323
Lateral Hardening-Fuse-60044927,1	13288	0.17	22	15	9	6	30	1	Q2 - 2022	Q1 - 2025	Q3 - 2025	$55,955
Lateral Hardening-Fuse-60046437,1	13310	0.19	19	46	9	3	58	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$62,747
Lateral Hardening-Fuse-60047463,1	13350	0.11	10	64	6	0	70	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$37,137
Lateral Hardening-Fuse-60048514,1	13405	0.13	6	2	2	2	6	6	Q3 - 2022	Q1 - 2024	Q3 - 2024	$42,745
Lateral Hardening-Fuse-60048809,1	13622	0.15	6	3	3	0	6	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$48,228

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-60058546,1	13279	0.11	10	15	9	1	25	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$35,766
Lateral Hardening-Fuse-60058616,1	13610	0.12	14	17	3	1	21	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$37,947
Lateral Hardening-Fuse-60060554,1	13175	0.18	16	14	6	0	20	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$58,634
Lateral Hardening-Fuse-60060564,1	13175	0.13	13	20	5	0	25	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$42,620
Lateral Hardening-Fuse-60060568,1	13175	0.10	13	16	6	0	22	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$31,591
Lateral Hardening-Fuse-60061785,1	13668	0.09	5	288	17	2	307	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$31,218
Lateral Hardening-Fuse-60065898,1	14275	0.03	9	2	2	0	4	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-60073788,1	13082	0.25	25	40	5	1	46	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$80,879
Lateral Hardening-Fuse-60073803,1	13082	0.16	18	31	2	0	33	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$53,151
Lateral Hardening-Fuse-60077860,1	13153	0.11	10	13	0	3	16	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$34,956
Lateral Hardening-Fuse-60087052,1	13359	0.06	7	29	8	4	41	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$19,690
Lateral Hardening-Fuse-60088186,1	13139	0.22	18	27	4	0	31	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$72,218
Lateral Hardening-Fuse-60088567,1	13510	0.30	34	25	4	0	29	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$98,264
Lateral Hardening-Fuse-60124027,1	13218	0.64	53	64	9	0	73	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$210,485
Lateral Hardening-Fuse-60181011,1	13388	0.12	7	6	2	0	8	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$39,318
Lateral Hardening-Fuse-60190659,1	13308	0.22	15	15	9	2	26	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$70,972
Lateral Hardening-Fuse-60200737,1	13961	0.08	7	7	1	0	8	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$25,921
Lateral Hardening-Fuse-60241209,1	13137	0.09	10	159	4	0	163	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$29,847
Lateral Hardening-Fuse-60289071,1	13045	0.10	12	12	3	1	16	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$32,402
Lateral Hardening-Fuse-60302651,1	13091	0.16	13	28	14	0	42	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$52,092
Lateral Hardening-Fuse-60305740,1	13865	0.14	15	38	4	0	42	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$46,048
Lateral Hardening-Fuse-60337684,1	14001	0.06	4	2	14	0	16	0	Q4 - 2022	Q2 - 2023	Q4 - 2023	$18,257
Lateral Hardening-Fuse-60350024,5	13097	1.39	92	67	9	2	78	0	Q2 - 2022	Q1 - 2024	Q4 - 2024	$458,731
Lateral Hardening-Fuse-60365361,1	13962	0.06	6	5	0	1	6	0	Q3 - 2022	Q1 - 2023	Q3 - 2023	$21,186
Lateral Hardening-Fuse-60422059,1	13723	0.31	21	45	16	2	63	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$103,124
Lateral Hardening-Fuse-60463714,1	13853	0.21	16	3	8	7	18	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$69,975
Lateral Hardening-Fuse-60474882,1	13191	0.26	32	11	29	9	49	6	Q2 - 2022	Q3 - 2023	Q1 - 2024	$84,182
Lateral Hardening-Fuse-60518342,1	13219	0.13	10	5	8	4	17	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$43,430
Lateral Hardening-Fuse-60614298,1	13740	0.17	17	20	13	0	33	0	Q2 - 2022	Q1 - 2023	Q3 - 2024	$55,955
Lateral Hardening-Fuse-90097474,7	13754	1.97	170	200	18	2	220	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$648,591
Lateral Hardening-Fuse-90098676,4	13190	2.16	170	445	19	0	464	9	Q2 - 2022	Q1 - 2024	Q3 - 2024	$711,400
Lateral Hardening-Fuse-90152415,1	13208	0.08	8	13	15	1	29	0	Q2 - 2022	Q1 - 2023	Q3 - 2023	$27,417
Lateral Hardening-Fuse-90157556,1	13067	0.19	18	12	6	0	18	5	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,370
Lateral Hardening-Fuse-90165527,1	13431	0.19	12	4	2	1	7	0	Q3 - 2022	Q1 - 2023	Q3 - 2023	$64,055
Lateral Hardening-Fuse-90179103,1	13630	0.24	17	19	17	0	36	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$78,324
Lateral Hardening-Fuse-90211134,1	13162	0.08	10	23	2	0	25	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$27,292
Lateral Hardening-Fuse-90267141,1	13738	0.03	8	305	5	5	315	1	Q2 - 2022	Q3 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-90297635,1	13007	0.13	12	11	0	1	12	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$42,371
Lateral Hardening-Fuse-90377733,1	13389	0.11	9	3	0	1	4	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$37,823
Lateral Hardening-Fuse-90393849,1	13147	0.08	5	21	4	0	25	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$25,734
Lateral Hardening-Fuse-90398961,1	13795	0.07	7	20	2	1	23	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$23,117
Lateral Hardening-Fuse-90399851,6	13419	0.76	64	111	2	3	116	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$251,361
Lateral Hardening-Fuse-90416605,1	13081	0.09	10	222	2	1	225	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$29,535
Lateral Hardening-Fuse-90441325,1	13612	0.07	8	7	6	1	14	6	Q2 - 2022	Q2 - 2023	Q4 - 2023	$23,927
Lateral Hardening-Fuse-90482454,4	13206	0.68	58	73	18	0	91	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$223,259
Lateral Hardening-Fuse-90487798,1	13740	0.12	6	9	6	0	15	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$40,128
Lateral Hardening-Fuse-90522517,5	13359	1.20	115	125	2	1	128	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$395,610
Lateral Hardening-Fuse-90526768,1	13199	0.18	15	20	3	0	23	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$60,815
Lateral Hardening-Fuse-90630567,1	13754	0.13	14	13	2	1	16	5	Q2 - 2022	Q2 - 2023	Q4 - 2023	$43,244

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-90668793,1	14042	0.19	12	55	1	2	58	1	Q2 - 2022	Q2 - 2023	Q4 - 2023	$61,438
Lateral Hardening-Fuse-90704066,4	13370	0.78	65	16	20	9	45	1	Q1 - 2022	Q4 - 2024	Q2 - 2025	$257,280
Lateral Hardening-Fuse-90748138,1	13103	0.08	8	9	5	0	14	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$27,541
Lateral Hardening-Fuse-90823812,1	13329	0.05	4	7	0	1	8	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$16,388
Lateral Hardening-Fuse-90830976,1	13328	0.08	8	3	1	2	6	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$26,918
Lateral Hardening-Fuse-90847913,1	13754	0.25	25	55	5	1	61	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$80,941
Lateral Hardening-Fuse-90848130,1	13656	0.17	11	9	0	1	10	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$55,020
Lateral Hardening-Fuse-90852788,1	13148	0.35	23	10	3	1	14	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$113,592
Lateral Hardening-Fuse-91016874,2	13046	0.38	34	52	4	3	59	7	Q3 - 2022	Q3 - 2022	Q1 - 2023	$123,437
Lateral Hardening-Fuse-91060899,1	13533	0.23	21	142	3	1	146	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$74,835
Lateral Hardening-Fuse-91066431,1	13163	0.23	15	18	3	3	24	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$74,399
Lateral Hardening-Fuse-91076397,1	13048	0.06	7	3	0	3	6	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$18,569
Lateral Hardening-Fuse-91096289,1	13787	0.09	6	3	1	0	4	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$30,034
Lateral Hardening-Fuse-91147533,3	13097	0.67	41	39	5	1	45	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$221,078
Lateral Hardening-Fuse-91151734,1	13364	0.09	9	52	0	1	53	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$30,595
Lateral Hardening-Fuse-91154995,2	13048	0.53	50	74	3	2	79	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$174,532
Lateral Hardening-Fuse-91161524,1	13146	0.24	15	16	1	1	18	6	Q3 - 2022	Q3 - 2023	Q1 - 2024	$78,449
Lateral Hardening-Fuse-91177941,3	13638	0.87	82	79	12	1	92	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$284,697
Lateral Hardening-Fuse-91232937,1	13103	0.49	47	117	7	0	124	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$161,011
Lateral Hardening-Fuse-91234338,1	13124	0.46	33	56	3	0	59	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$150,979
Lateral Hardening-Fuse-91334566,1	13464	0.38	27	60	1	1	62	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$125,618
Lateral Hardening-Fuse-91337725,1	13464	0.20	13	11	2	2	15	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$66,610
Lateral Hardening-Fuse-91354294,1	13065	0.16	18	136	10	1	147	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$53,649
Lateral Hardening-Fuse-91382618,1	13462	0.32	27	51	3	4	58	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$105,056
Lateral Hardening-Fuse-91404359,1	13805	0.56	28	35	9	0	44	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$184,315
Lateral Hardening-Fuse-91418404,1	13621	0.16	11	10	2	0	12	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$51,905
Lateral Hardening-Fuse-91421327,1	13124	0.10	14	1	4	4	9	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$33,087
Lateral Hardening-Fuse-91532289,1	13832	0.10	11	12	22	1	35	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$33,648
Lateral Hardening-Fuse-91532301,1	13832	0.09	7	10	7	0	17	0	Q3 - 2022	Q2 - 2022	Q1 - 2023	$28,663
Lateral Hardening-Fuse-91550764,1	13592	0.06	4	16	3	1	20	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$20,251
Lateral Hardening-Fuse-91565159,4	13044	0.51	55	14	1	1	16	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$168,924
Lateral Hardening-Fuse-91623641,1	13141	0.15	19	39	3	1	43	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$49,475
Lateral Hardening-Fuse-91643964,1	13106	0.13	12	123	9	0	132	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$43,244
Lateral Hardening-Fuse-91702481,1	14012	0.08	8	1	0	1	2	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$25,423
Lateral Hardening-Fuse-91774500,1	13631	0.28	21	56	17	0	73	16	Q1 - 2022	Q2 - 2023	Q4 - 2023	$93,466
Lateral Hardening-Fuse-91782844,1	13434	0.15	13	7	0	2	9	0	Q2 - 2022	Q4 - 2024	Q2 - 2025	$50,596
Lateral Hardening-Fuse-91868130,1	13201	0.11	11	123	3	1	127	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$36,514
Lateral Hardening-Fuse-91910924,1	13165	0.23	20	53	5	5	63	3	Q2 - 2022	Q3 - 2023	Q1 - 2024	$77,016
Lateral Hardening-Fuse-92005809,1	13219	0.24	24	42	11	1	54	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$78,761
Lateral Hardening-Fuse-92027991,1	13420	0.24	18	24	7	0	31	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$78,075
Lateral Hardening-Fuse-92035203,1	13417	0.08	9	30	4	0	34	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$26,295
Lateral Hardening-Fuse-92079502,1	13638	0.13	15	41	12	2	55	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$42,620
Lateral Hardening-Fuse-92097014,1	13217	0.19	11	16	1	1	18	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$62,684
Lateral Hardening-Fuse-92132257,1	13016	0.12	13	57	4	0	61	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$39,816
Lateral Hardening-Fuse-92197131,1	13330	0.19	13	73	2	1	76	1	Q1 - 2022	Q2 - 2023	Q4 - 2023	$61,376
Lateral Hardening-Fuse-92238609,1	13065	0.14	13	25	2	0	27	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$44,801
Lateral Hardening-Fuse-92257437,1	13227	0.15	19	12	9	0	21	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$48,602
Lateral Hardening-Fuse-92320131,1	13656	0.24	16	8	3	2	13	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$79,633
Lateral Hardening-Fuse-92354169,1	13787	0.14	6	2	2	4	8	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$45,424

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-92398222,1	13167	0.12	15	11	0	2	13	0	Q3 - 2022	Q4 - 2023	Q2 - 2025	$38,820
Lateral Hardening-Fuse-92408051,1	13140	0.09	10	40	7	1	48	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$29,161
Lateral Hardening-Fuse-92418323,1	13696	0.06	8	111	3	0	114	0	Q2 - 2022	Q4 - 2024	Q2 - 2025	$19,690
Lateral Hardening-Fuse-92448697,1	13510	0.04	5	5	2	2	9	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$13,272
Lateral Hardening-Fuse-92486363,1	13312	0.22	17	16	3	1	20	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$73,340
Lateral Hardening-Fuse-92497118,1	13146	0.23	8	4	2	0	6	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$74,835
Lateral Hardening-Fuse-92527630,1	13219	0.11	8	17	1	1	19	1	Q3 - 2022	Q4 - 2023	Q2 - 2024	$35,829
Lateral Hardening-Fuse-92527637,1	13219	0.21	24	38	2	1	41	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$70,286
Lateral Hardening-Fuse-92529635,1	13210	0.11	12	13	3	0	16	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$35,704
Lateral Hardening-Fuse-92529638,1	13210	0.09	10	21	1	1	23	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$28,663
Lateral Hardening-Fuse-92537158,1	13150	0.07	7	10	0	2	12	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$23,553
Lateral Hardening-Fuse-92543665,1	13004	0.28	23	70	5	0	75	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$92,282
Lateral Hardening-Fuse-92570284,1	13020	0.07	3	9	1	4	14	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$22,432
Lateral Hardening-Fuse-92597622,1	13390	0.19	12	42	6	0	48	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$62,373
Lateral Hardening-Fuse-92599120,1	13390	0.62	37	45	5	0	50	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$202,946
Lateral Hardening-Fuse-92602262,1	13010	0.09	6	15	2	0	17	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$31,093
Lateral Hardening-Fuse-92603717,1	13390	0.25	15	32	4	0	36	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$81,876
Lateral Hardening-Fuse-92605327,1	13390	0.21	16	65	15	0	80	21	Q3 - 2022	Q3 - 2023	Q1 - 2024	$67,482
Lateral Hardening-Fuse-92605381,1	13390	0.35	33	130	4	0	134	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$113,779
Lateral Hardening-Fuse-92609981,1	13390	0.17	13	31	3	0	34	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$56,204
Lateral Hardening-Fuse-92610250,1	13390	0.93	46	48	11	0	59	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$304,948
Lateral Hardening-Fuse-92612860,1	13390	0.45	27	17	3	0	20	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$147,801
Lateral Hardening-Fuse-92620889,1	13390	0.24	15	66	3	0	69	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$79,384
Lateral Hardening-Fuse-92622569,1	13390	0.61	30	86	11	4	101	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$201,201
Lateral Hardening-Fuse-92655421,1	13198	0.08	6	8	2	0	10	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$24,737
Lateral Hardening-Fuse-92678765,1	13805	0.19	12	3	3	0	6	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$63,931
Lateral Hardening-Fuse-92701725,1	13299	0.18	13	123	28	2	153	2	Q2 - 2022	Q3 - 2024	Q1 - 2025	$60,504
Lateral Hardening-Fuse-92773510,1	13373	0.32	27	13	13	0	26	0	Q1 - 2022	Q3 - 2024	Q1 - 2025	$105,180
Lateral Hardening-Fuse-92814355,1	13344	0.05	7	37	5	2	44	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$15,702
Lateral Hardening-Fuse-92835651,4	13329	0.83	55	89	21	1	111	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$271,986
Lateral Hardening-Fuse-92856634,1	13224	0.25	23	16	17	1	34	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$82,998
Lateral Hardening-Fuse-92859507,1	13460	0.10	7	25	0	1	26	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$31,716
Lateral Hardening-Fuse-92867406,1	13010	0.07	8	2	4	1	7	0	Q3 - 2022	Q1 - 2024	Q4 - 2024	$22,681
Lateral Hardening-Fuse-92874488,1	13112	0.13	14	38	1	1	40	1	Q3 - 2022	Q3 - 2023	Q1 - 2024	$44,241
Lateral Hardening-Fuse-92890357,1	13112	0.18	13	49	6	1	56	0	Q2 - 2022	Q3 - 2023	Q2 - 2024	$58,136
Lateral Hardening-Fuse-92897362,1	13147	0.19	12	26	3	0	29	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$62,248
Lateral Hardening-Fuse-92901825,1	13147	0.46	20	123	2	1	126	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$152,038
Lateral Hardening-Fuse-92905104,1	13826	0.20	10	183	7	2	192	39	Q1 - 2022	Q3 - 2023	Q1 - 2024	$64,928
Lateral Hardening-Fuse-92907479,1	13060	0.06	9	267	24	2	293	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$18,818
Lateral Hardening-Fuse-92922162,1	13224	0.11	13	16	2	1	19	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$35,704
Lateral Hardening-Fuse-92937437,1	13241	0.22	17	22	9	0	31	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$73,090
Lateral Hardening-Fuse-93033231,1	13838	0.20	13	61	13	4	78	27	Q1 - 2022	Q3 - 2023	Q1 - 2024	$65,738
Lateral Hardening-Fuse-93082436,1	13612	0.07	7	8	5	0	13	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$23,678
Lateral Hardening-Fuse-93090160,1	13039	0.21	10	15	7	0	22	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$69,227
Lateral Hardening-Fuse-93113905,1	13034	0.04	4	8	1	1	10	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-93118733,1	13324	0.11	11	6	4	1	11	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$37,199
Lateral Hardening-Fuse-93172625,1	13213	0.13	12	21	3	0	24	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$44,303
Lateral Hardening-Fuse-93218070,1	13656	0.11	6	2	1	0	3	0	Q4 - 2022	Q2 - 2023	Q4 - 2023	$35,205
Lateral Hardening-Fuse-93233174,1	13696	0.14	17	46	5	0	51	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$45,798

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-93235148,1	13696	0.10	9	28	12	2	42	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$32,464
Lateral Hardening-Fuse-93247243,1	13175	0.18	18	33	4	0	37	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$58,198
Lateral Hardening-Fuse-93249426,1	13175	0.15	14	10	1	2	13	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$50,534
Lateral Hardening-Fuse-93263741,1	13042	0.12	12	18	0	2	20	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$40,813
Lateral Hardening-Fuse-93263753,1	13042	0.25	21	27	2	1	30	0	Q1 - 2022	Q3 - 2023	Q1 - 2024	$82,001
Lateral Hardening-Fuse-93264130,1	13042	0.22	22	23	6	2	31	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$71,408
Lateral Hardening-Fuse-93266650,1	13042	0.34	32	55	0	1	56	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$111,848
Lateral Hardening-Fuse-93267158,1	13042	0.18	18	37	3	1	41	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$59,444
Lateral Hardening-Fuse-93276507,1	13213	0.14	8	6	2	1	9	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$44,739
Lateral Hardening-Fuse-93283244,2	13351	0.64	49	73	9	1	83	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$211,794
Lateral Hardening-Fuse-93283740,1	13351	0.06	8	110	8	2	120	0	Q1 - 2022	Q1 - 2023	Q3 - 2023	$18,693
Lateral Hardening-Fuse-93292955,1	14356	0.12	10	184	10	2	196	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$38,446
Lateral Hardening-Fuse-93294943,1	13808	0.14	9	5	0	1	6	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$44,490
Lateral Hardening-Fuse-93324791,1	13723	0.14	6	9	2	0	11	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$45,736
Lateral Hardening-Fuse-93355196,1	13303	0.07	6	10	2	2	14	0	Q2 - 2022	Q2 - 2024	Q4 - 2024	$21,996
Lateral Hardening-Fuse-93432382,1	13532	0.29	22	36	0	1	37	0	Q3 - 2022	Q3 - 2024	Q1 - 2025	$95,086

Tampa Electric's Transmission Asset Upgrades - Year 2022 Details

Project ID	Circuit No.	Pole Count	Project Start Month	Construction Start Month	Construction End Month	Project Cost in 2020
Transmission Upgrades-138/230 kV-230006	230006	101	9/21	11/21	4/22	$1,500,000
Transmission Upgrades-138/230 kV-230402	230402	14	3/22	8/22	12/22	$300,100
Transmission Upgrades-69 kV-66048	66048	5	12/20	4/21	4/22	$50,000
Transmission Upgrades-138/230 kV-230606	230606	28	7/21	10/21	3/22	$210,000
Transmission Upgrades-138/230 kV-230012	230012	16	7/21	10/21	3/22	$50,000
Transmission Upgrades-138/230 kV-230020	230020	61	8/22	1/23	6/23	$41,939
Transmission Upgrades-69 kV-66022	66022	50	12/20	8/21	8/22	$672,980
Transmission Upgrades-69 kV-66001	66001	70	3/21	10/21	6/22	$1,877,473
Transmission Upgrades-69 kV-66016	66016	40	11/20	6/21	6/22	$400,000
Transmission Upgrades-69 kV-66032	66032	40	2/22	1/23	8/23	$40,576
Transmission Upgrades-69 kV-66020	66020	10	7/21	3/22	8/22	$305,900
Transmission Upgrades-69 kV-66035	66035	65	8/22	1/23	8/23	$35,029
Transmission Upgrades-138/230 kV-230602	230602	112	5/21	8/21	3/22	$50,000
Transmission Upgrades-69 kV-66008	66008	9	10/21	7/21	12/21	$281,970
Transmission Upgrades-69 kV-66030	66030	50	7/21	4/22	9/22	$1,498,910
Transmission Upgrades-69 kV-66045	66045	52	9/21	5/22	12/22	$1,708,376
Transmission Upgrades-138/230 kV-230033	230033	14	6/21	3/22	6/22	$294,700
Transmission Upgrades-69 kV-66025	66025	105	3/21	8/21	8/22	$2,324,840
Transmission Upgrades-138/230 kV-230623	230623	65	10/22	1/23	7/23	$44,720
Transmission Upgrades-69 kV-66021	66021	45	2/22	6/22	3/23	$45,648
Transmission Upgrades-69 kV-66017	66017	97	2/22	7/22	6/23	$234,972
Transmission Upgrades-138/230 kV-230609	230609	5	12/21	12/21	3/22	$105,250
Transmission Upgrades-69 kV-66033	66033	26	11/20	11/21	5/22	$50,000
Transmission Upgrades-69 kV-66036	66036	31	11/20	6/21	5/22	$300,000
Transmission Upgrades-69 kV-66027	66027	17	7/21	2/22	6/22	$550,620
Transmission Upgrades-69 kV-66060	66060	6	11/20	7/21	4/22	$10,000
Transmission Upgrades-138/230 kV-230604	230604	36	10/22	2/23	7/23	$24,768
Transmission Upgrades-69 kV-66407	66407	29	12/20	5/21	5/22	$10,000
Transmission Upgrades-138/230 kV-230013	230013	20	7/21	3/22	6/22	$421,000
Transmission Upgrades-69 kV-66427	66427	7	11/20	6/21	6/22	$10,000
Transmission Upgrades-69 kV-66026	66026	83	10/21	4/22	10/22	$2,582,952
Transmission Upgrades-69 kV-66098	66098	22	9/22	1/23	6/23	$22,210
Transmission Upgrades-69 kV-66011	66011	24	9/21	5/22	12/22	$22,317
Transmission Upgrades-69 kV-66028	66028	49	9/22	1/23	6/23	$49,244
Transmission Upgrades-69 kV-66047	66047	1	2/21	4/22	6/22	$1,014
Transmission Upgrades-69 kV-66415	66415	10	12/20	3/22	8/22	$317,000
Transmission Upgrades-69 kV-66436	66436	36	8/22	2/23	8/23	$34,490

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.

No Substation Extreme Weather Hardening

Projects Planned for 2022

Reserved for Future Use

Tampa Electric's Distribution Overhead Feeder Hardening - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2022
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
SPP FH - 13008	13008	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	249	159	25	433	0	Jul-22	Jan-23	Jun-23	$50,000
SPP FH - 13028	13028	(6) new reclosers, (43) fuses, (27) trip savers, and upgrade (52) feeder poles	3,595	242	24	3,861	35	Aug-22	Jan-23	Jun-23	$50,000
SPP FH - 13039	13039	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	299	178	24	501	29	Sep-22	Jan-23	Aug-23	$50,000
SPP FH - 13040	13040	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	992	112	51	1,155	18	Oct-22	Jan-23	Oct-23	$50,000
SPP FH - 13048	13048	(6) new reclosers, (43) fuses, (27) trip savers, and upgrade (52) feeder poles	2,720	324	81	3,125	84	Jun-22	Aug-22	Oct-22	$2,077,657
SPP FH - 13077	13077	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	105	332	48	485	15	Sep-22	Jan-23	Sep-23	$50,000
SPP FH - 13094	13094	(7) new reclosers, (50) fuses, (28) trip savers, and upgrade (100) feeder poles	1,191	375	83	1,649	15	This one we had to put it			$5,554,203
SPP FH - 13118	13118	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	1,696	199	23	1,918	3	Nov-21	Mar-22	Aug-22	$3,377,800
SPP FH - 13148	13148	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	1,393	91	16	1,500	13	Jan-22	Mar-22	Aug-22	$1,219,093
SPP FH - 13187	13187	(9) new reclosers, (37) fuses, (21) trip savers, and upgrade (77) feeder poles	1,560	191	30	1,781	30	Nov-22	Jan-23	Nov-23	$50,000
SPP FH - 13227	13227	(9) new reclosers, (37) fuses, (21) trip savers, and upgrade (77) feeder poles	1,447	159	19	1,625	46	Nov-20	Jan-21	Feb-22	$50,000
SPP FH - 13230	13230	(2) new reclosers, (54) fuses, (42) trip savers, and upgrade (107) feeder poles	572	411	22	1,005	46	Nov-22	Jan-23	Nov-23	$50,000
SPP FH - 13292	13292	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	730	33	8	771	14	Aug-22	Jan-23	Mar-23	$50,000
SPP FH - 13296	13296	(10) new reclosers, (35) fuses, (12) trip savers, and upgrade (70) feeder poles	1,430	120	14	1,564	4	Feb-22	Mar-22	Sep-22	$4,494,494
SPP FH - 13299	13299	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	729	55	18	802	2	Dec-22	Jan-23	Nov-23	$50,000
SPP FH - 13308	13308	(3) new reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles	1,220	260	36	1,516	26	Jun-20	Aug-20	Mar-22	$50,000
SPP FH - 13312	13312	(1) new reclosers, (3) fuses, (9) trip savers, and upgrade (96) feeder poles	986	351	97	1,434	4	Apr-22	Jun-22	Nov-22	$312,011
SPP FH - 13313	13313	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	196	459	74	729	25	Apr-21	Oct-21	May-22	$73,036

Tampa Electric's Distribution Overhead Feeder Hardening - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2022
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
SPP FH - 13314	13314	(2) new reclosers, (97) fuses, (13) trip savers, and upgrade (61) feeder poles	683	240	85	1,008	4	Apr-21	Oct-21	May-22	$29,668
SPP FH - 13346	13346	(2) new reclosers, (74) fuses, (51) trip savers, and upgrade (148) feeder poles	1,404	238	94	1,736	12	Feb-22	Apr-22	Oct-22	$80,786
SPP FH - 13433	13433	(2) new reclosers, (111) fuses, (42) trip savers, and upgrade (101) feeder poles	339	318	69	726	61	Apr-21	Oct-21	Apr-22	$688,400
SPP FH - 13651	13651	(2) new reclosers, (70) fuses, (35) trip savers, and upgrade (139) feeder poles	2,453	63	10	2,526	50	Mar-22	May-22	Nov-22	$50,386
SPP FH - 13687	13687	(2) new reclosers, (70) fuses, (35) trip savers, and upgrade (139) feeder poles	2,054	70	2	2,126	17	Oct-22	Jan-23	Sep-23	$50,000
SPP FH - 13770	13770	(9) new reclosers, (52) fuses, (3) trip savers, and upgrade (103) feeder poles	1,769	57	5	1,831	3	Jan-22	Mar-22	Nov-22	$5,898,017
SPP FH - 13984	13984	(6) new reclosers, (37) fuses, (51) trip savers, and upgrade (73) feeder poles	1,415	114	51	1,580	51	May-22	Jul-22	Nov-22	$1,171,851
SPP FH - 13989	13989	(3) new reclosers, (27) fuses, (10) trip savers, and upgrade (54) feeder poles	2,216	53	7	2,276	26	Feb-22	Apr-22	Aug-22	$832,493
SPP FH - 14094	14094	(2) new reclosers, (12) fuses, (6) trip savers, and upgrade (23) feeder poles	2,584	256	45	2,885	6	Jun-22	Jul-22	Dec-22	$8,559
SPP FH - 14123	14123	(2) new reclosers, (54) fuses, (42) trip savers, and upgrade (107) feeder poles	1,069	59	6	1,134	13	May-22	Jun-22	Nov-22	$1,248,736
SPP FH - East Winter Haven 13309	13309	(1) new reclosers, (35) fuses, (6) trip savers, and upgrade (61) feeder poles	0	0	0	0	0	Apr-21	Oct-21	May-22	$125,468

Project ID	Project Type Road/Bridge	Project Start Qtr	Project End Qtr	Project Cost in 2022
HAMPTON SUBSTATION	Bridge	Qtr 2 2021	Qtr 4 2022	$ 622,025
WEST OF FORBES RD	Bridge	Qtr 2 2021	Qtr 4 2024	$ 92,429
EAST OF SYDNEY WASHER RD	Bridge	Qtr 2 2021	Qtr 4 2024	$ 100,525
TAMPA PALMS #1	Bridge	Qtr 2 2021	Qtr 4 2023	$ 94,755
TAMPA PALMS #2	Bridge	Qtr 2 2021	Qtr 4 2023	$ 106,899
TAMPA PALMS #3	Bridge	Qtr 2 2021	Qtr 4 2023	$ 102,851
TAMPA PALMS #4	Bridge	Qtr 2 2021	Qtr 4 2023	$ 108,249
MORRIS BRIDGE RD	Bridge	Qtr 2 2021	Qtr 4 2022	$ 434,769
COLUMBUS DRIVE #1	Bridge	Qtr 2 2021	Qtr 4 2025	$ 27,000
COLUMBUS DRIVE #2	Bridge	Qtr 2 2021	Qtr 4 2025	$ 22,000
230606	Road	Qtr 2 2021	Qtr 4 2025	$ 20,000
230020	Road	Qtr 2 2021	Qtr 4 2024	$ 219,221
230008	Road	Qtr 2 2021	Qtr 4 2022	$ 146,924
230007	Road	Qtr 2 2021	Qtr 4 2023	$ 67,399
66839	Road	Qtr 2 2021	Qtr 4 2025	$ 26,000
66046	Road	Qtr 1 2022	Qtr 4 2024	$ 90,914
66035	Road	Qtr 2 2021	Qtr 4 2025	$ 26,000
66033	Road	Qtr 1 2022	Qtr 4 2023	$ 45,072
66016	Road	Qtr 2 2021	Qtr 4 2025	$ 20,000
66007	Road	Qtr 2 2021	Qtr 4 2023	$ 21,229
66001	Road	Qtr 1 2022	Qtr 4 2023	$ 48,641

2022 – 2031 Storm Protection Plan Resilience Benefits Report

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 132540

Revision 0
2/16/2022

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AHI	Asset Health Index
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
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
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 2022 to 2031 10-year Storm Protection Plan 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 through 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 an overall investment level that maximizes customers benefit while not exceeding 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 Storm Protection Plan. 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 the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

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 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
- Transmission Access Enhancements

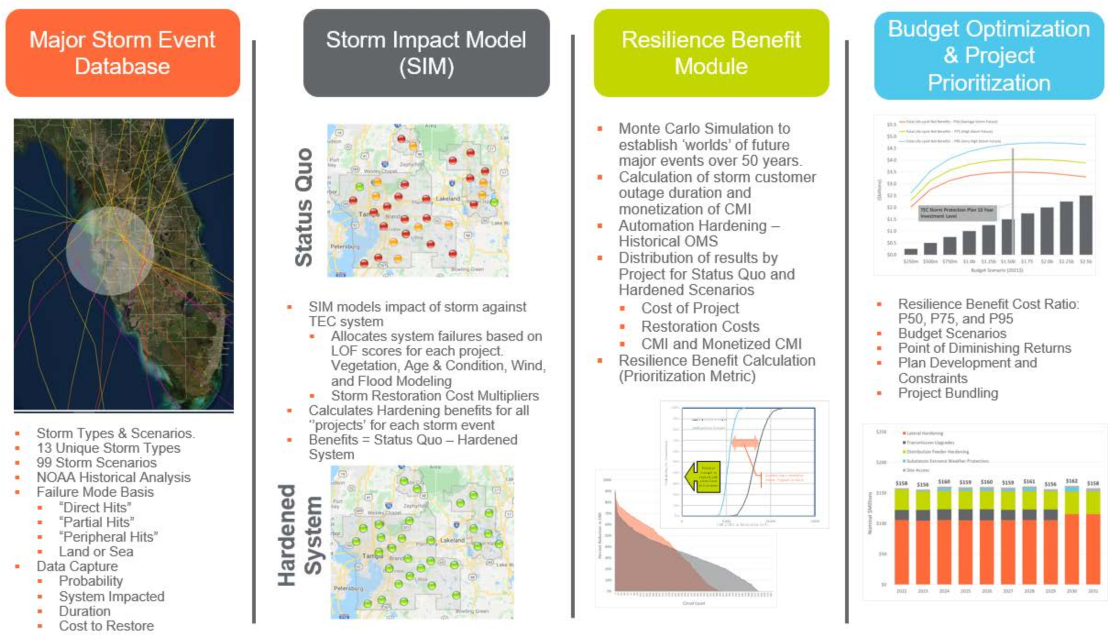
The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

1.1 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, to a tropical storm. Section 3.0 provides additional details on the 99 different storm scenarios.

Figure 1-1: Storm Resilience Model Overview



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 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 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	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of 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 in decreased restoration costs and CMI if that project is hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on 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 model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the 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.

1.2 Key Updates to Storm Resilience Model from 2020 to 2029 SPP to 2022 to 2031 SPP

The following are the key updates from the 2020-2029 to the 2022-2031 Storm Resilience Model:

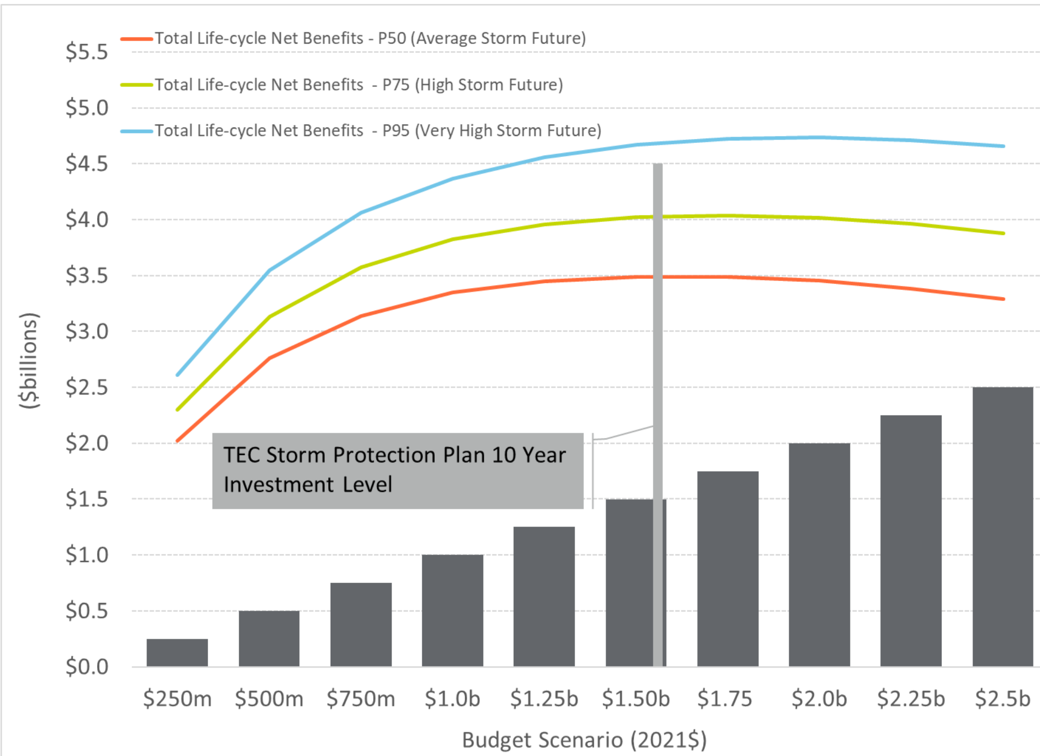
1. General – these updates include shifting of the time horizon, adding another year of storms to the historical analysis, and accounting for completed projects.
2. Capital Cost Assumptions – based on actual completed projects and communicated increases in commodity prices the cost assumptions for all project types were adjusted.
3. Substation Projects Development – TEC completed a technical evaluation of substation hardening alternatives since the 2020-2029 Storm Protection Plan filing. The results of that evaluation, including specific substation hardening activities and their cost were included in the model.

4. Site Access Project Development – TEC performed additional evaluation of transmission site access and updated the projects and associated costs.
5. Automation Hardening Capital Costs – 1898 & Co. performed detailed analysis on 300 circuits to identify more specific scope and cost. Based on lessons learned from the 2020 projects, the cost to deploy automation had a wide range given the uncertainty in circuit reconductoring and substation upgrades needed to not overload and burn down circuits. With improved cost estimates for the 300 circuits the prioritization of projects in the Storm Resilience Model is improved. This increasing the overall benefit in decreasing major outage events for customers.
6. Lateral Undergrounding Branching' Approach – Based on a lessons learned evaluation, the project definition for lateral projects was adjusted to include a collection of electrically connected protection zones, or 'branches'. TEC's undergrounding design standard includes looping for added resilience. Based on the 2020 project execution it was identified that some of the projects included higher costs to achieve the full loop. By undergrounding all the electrically connected protection zones off a circuit feeder / mainline the higher costs will be mitigated since it can be designed to minimize the number of new underground miles.

1.3 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to establish an overall budget level and identify and prioritize resilience investment in the T&D system. Figure 1-2 shows the results of the budget optimization analysis. Given the total level of potential investment, the budget optimization analysis was performed in $250 million increments up to $2.5 billion. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95. P50 to P65 levels represent a future world in which storm frequency and impact are close to average, P70 to P85 level represent a future world where storms are more frequent and intense, and P90 and P95 levels represent a future world where storm frequency and impacts are all high.

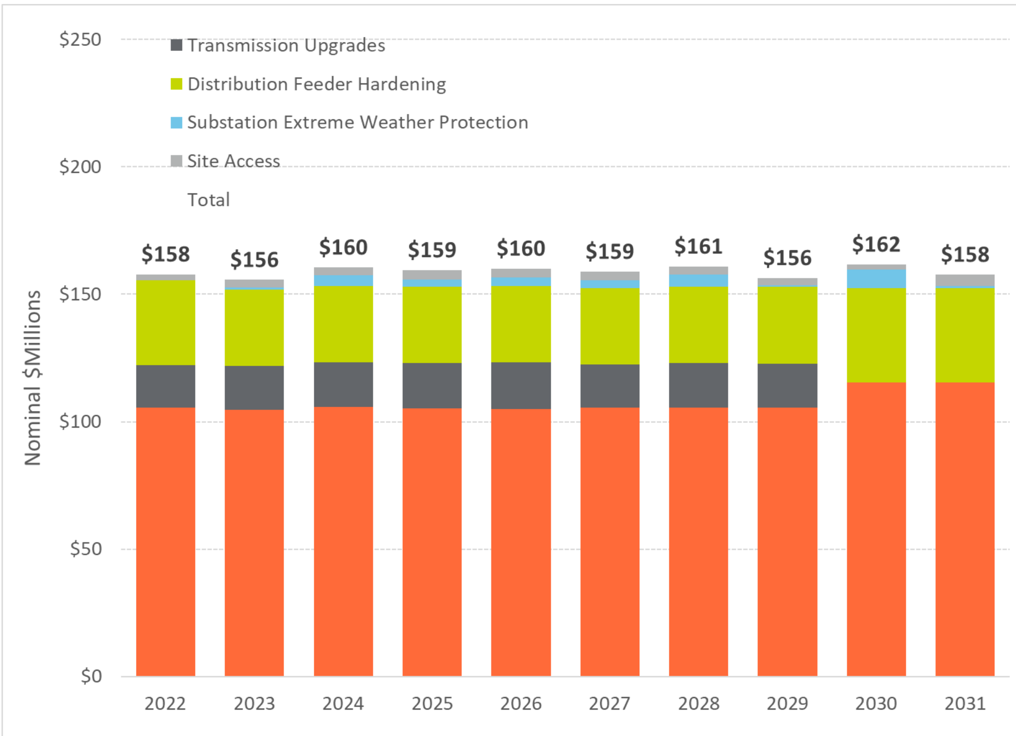
Figure 1-2: Budget Optimization Results



The figure shows 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 figure also shows the total investment level in 2021 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.59 billion. Lateral undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Feeder Hardening is second accounting for 20.0 percent. Transmission upgrades make up approximately 8.8 percent of the total with substations and transmission site access making up 1.7 percent and 2.0 percent, respectively.

Figure 1-3: Storm Protection Plan Investment Profile

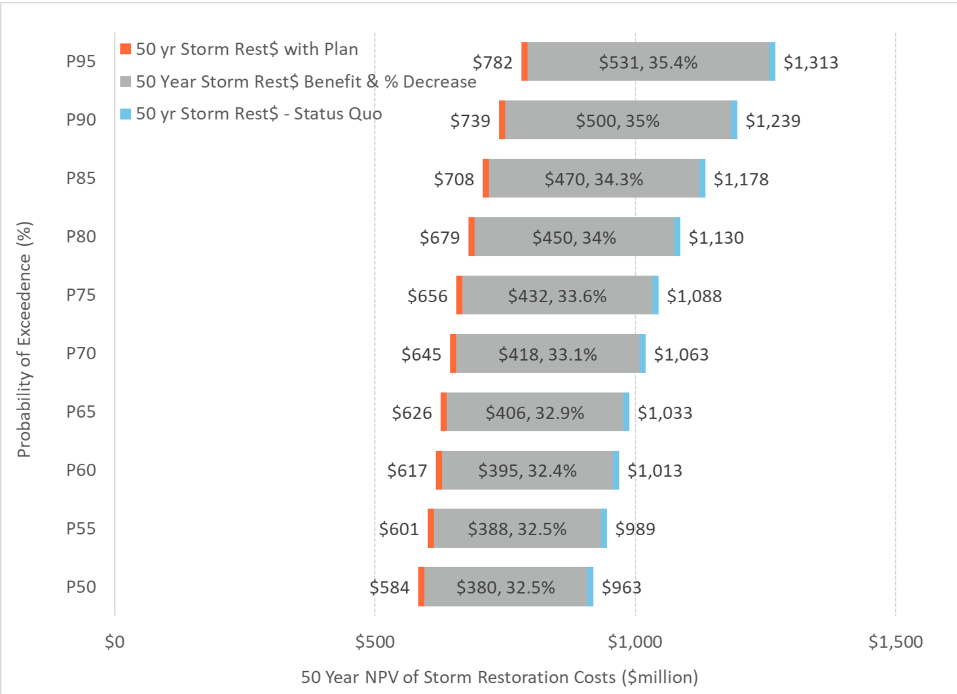


Customer benefits are calculated in terms of the:

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 1-4 shows the range in restoration cost reduction at various probability of exceedance levels. To reiterate, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 levels represent a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impacts are all high.

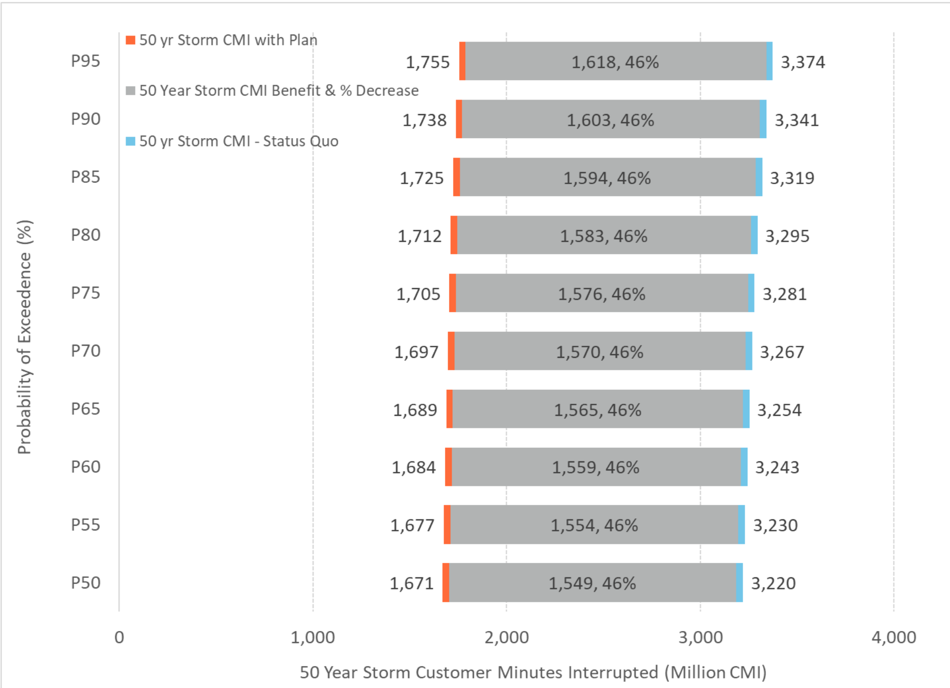
Figure 1-4: Storm Protection Plan Restoration Cost Benefit



The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the restoration costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration cost benefit is approximately 24 to 33 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 24 to 33 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 46 percent decrease in the storm CMI over the next 50 years.

Figure 1-5: Storm Protection Plan Customer Benefit



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

- The overall investment level of $1.59 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 46 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

2.0 INTRODUCTION

Hurricanes have inflicted significant damage to Florida in recent years and parts of the state face years of recovery. 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[1]. 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 impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

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 likelihood of failure 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

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

- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Upgrades, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

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

- 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 which 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 (PNNL) 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.

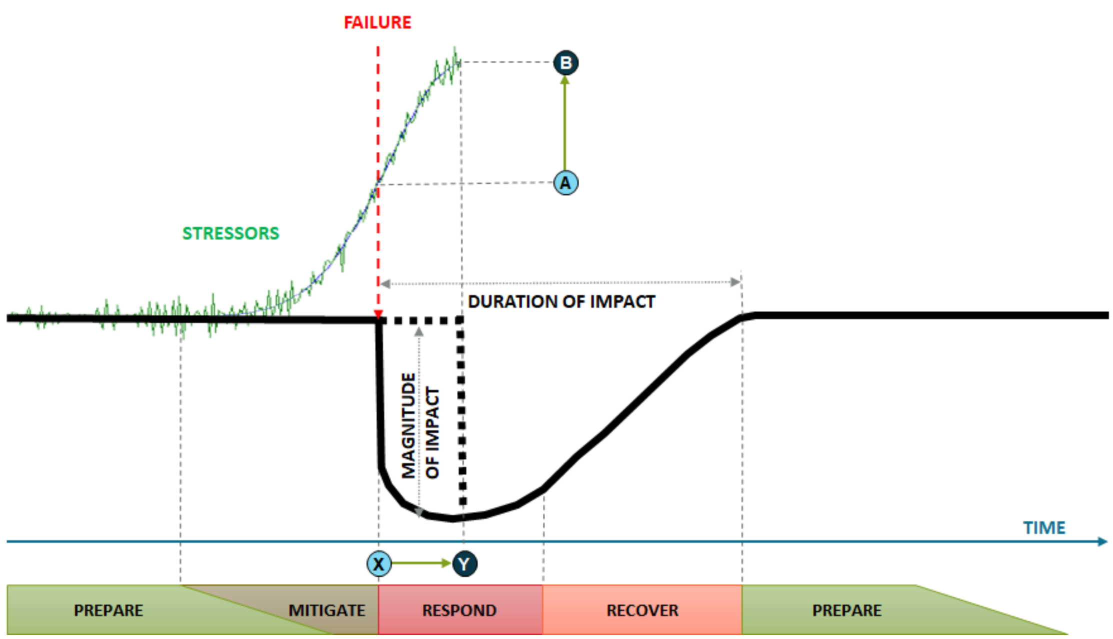
- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The 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.

This is depicted graphically in Figure 2-1. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers

(IEEE) 1366 to calculate reliability metrics. If TEC is able to detect the strain on the grid caused by these stresses then it increases the opportunity to act before a failure occurs, thus reducing or avoiding the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system. If the figure is used to represent a specific line, it represents the impact of the event on that line. If the figure is used to represent the impact on the whole TEC system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience there is no quantification of time. Time increases from left to right but due to the nature of events that may occur there are no timescales used.

Figure 2-1: Phases of Resilience



For example, 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 stresses 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.

In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example suppose a steel monopole was used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if less steel monopoles failed relative to the number of wood poles that would have failed, there would be less to replace and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a multiplying effect on outage reduction time.

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]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**9**
Site Access	**[count]**	**44**
Roads	[count]	25
Bridges	[count]	19

1. 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, trip savers, or a fuse. For lateral projects, where applicable, several protection zones were combined that were electrically connected right off the circuit feeder. 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 the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening 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 identified 44 separate transmission access, road, and bridge projects based on field inspection of the system.

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, 9 substations were identified 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. As seen below, there are a significant number of potential hardening projects, over 13,800. The following sections outline the approach to selecting the 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	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

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 a:

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

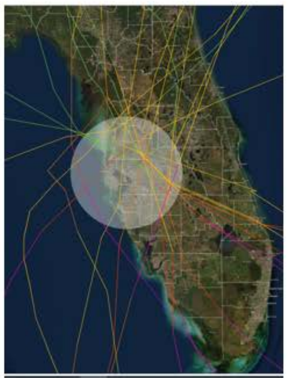
Figure 2-2 provides an overview of the resilience planning approach to calculate the customer benefit, restoration cost reduction and CMI reduction of hardening projects and prioritization of the projects.

2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is 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 Events Storms Database.

Figure 2-2: Resilience Planning Approach Overview

Major Storm Event Database



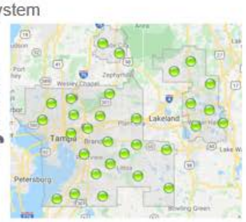
- Storm Types & Scenarios.
- 13 Unique Storm Types
- 99 Storm Scenarios
- NOAA Historical Analysis
- Failure Mode Basis
  - "Direct Hits"
  - "Partial Hits"
  - "Peripheral Hits"
  - Land or Sea
- Data Capture
  - Probability
  - System Impacted
  - Duration
  - Cost to Restore

Storm Impact Model (SIM)

Status Quo

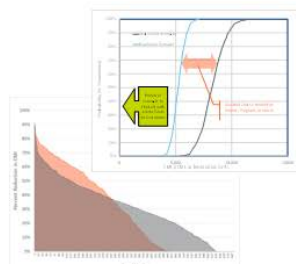
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all "projects' for each storm event
- Benefits = Status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

Hardened System

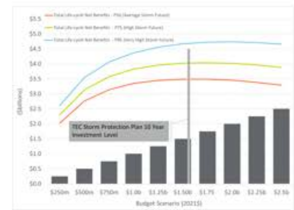


Resilience Benefit Module

- 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

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The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events 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 events database includes 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 detail on the Major Storms 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 conductor causing 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 that the asset is located within. 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 each project 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.

Each transmission site access project provides access to one or more transmission circuits. If a major storm event causes a transmission outage and the access location is also impacted, it can take longer to restore the system. The Storm Impact Model uses each transmission circuit's storm LOF to estimate the LOF of each site access during a storm. For instance, if site access 'A' is needed to gain access to Circuit '1' and '4', the storm likelihood for site access 'A' equals the storm likelihood of failure for Circuit '1' and '4' combined.

Once the Storm Impact model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using TEC labor and procured materials only. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

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 for 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 select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on 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 ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10-year period and portions of the system evaluated.

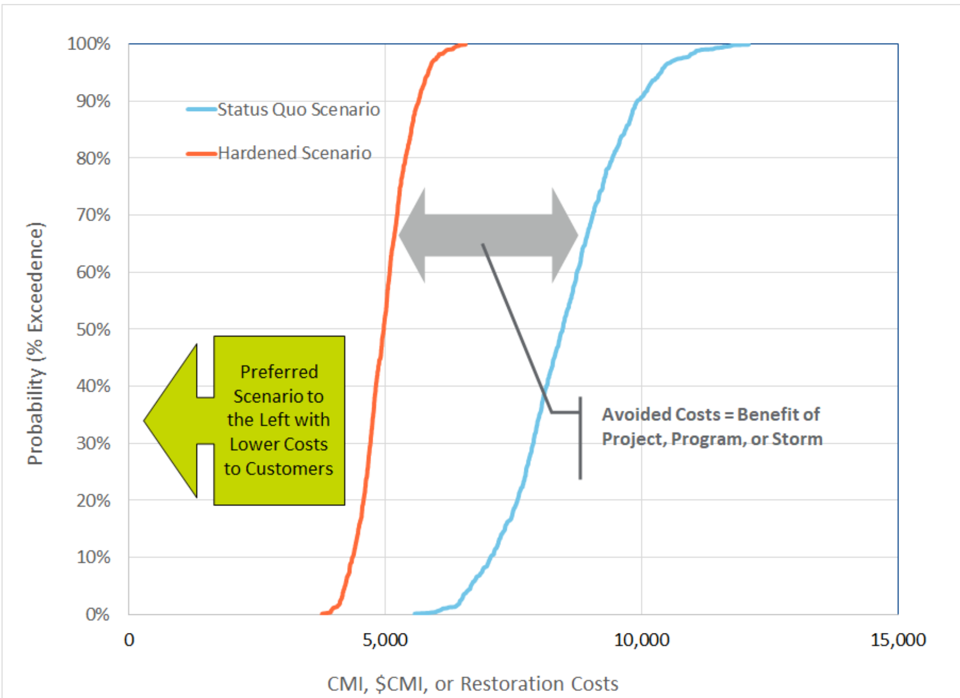
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and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

Budget optimization is performed by running the model over a wide range of budget scenarios. Each budget scenario calculates the range in reduction of restoration costs and CMI. The budget optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example

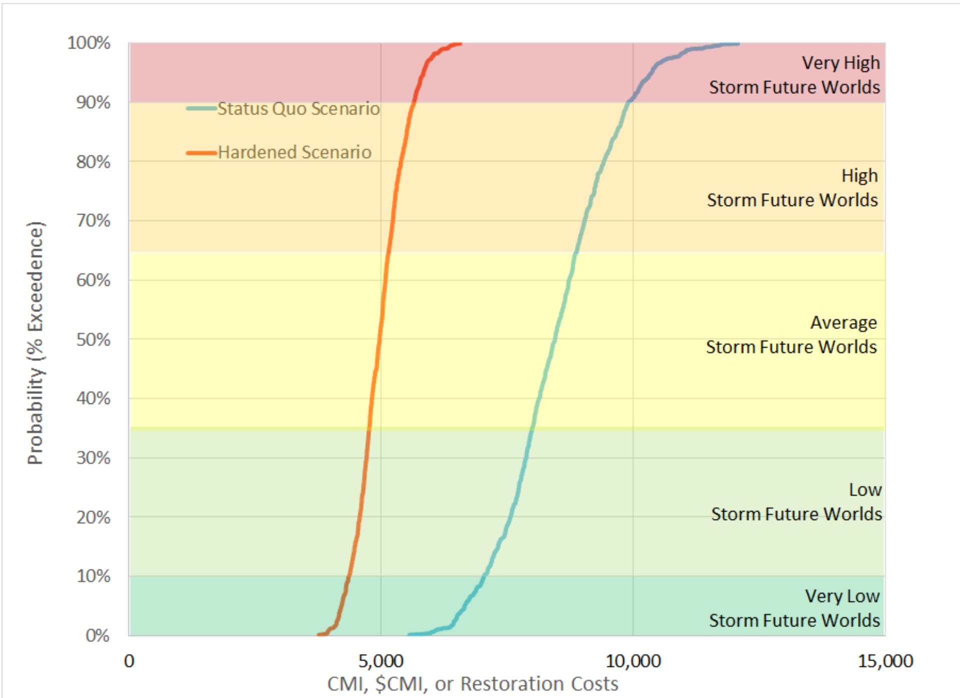


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case the P40 (40 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. The gap or delta between the two curves is the overall benefit.

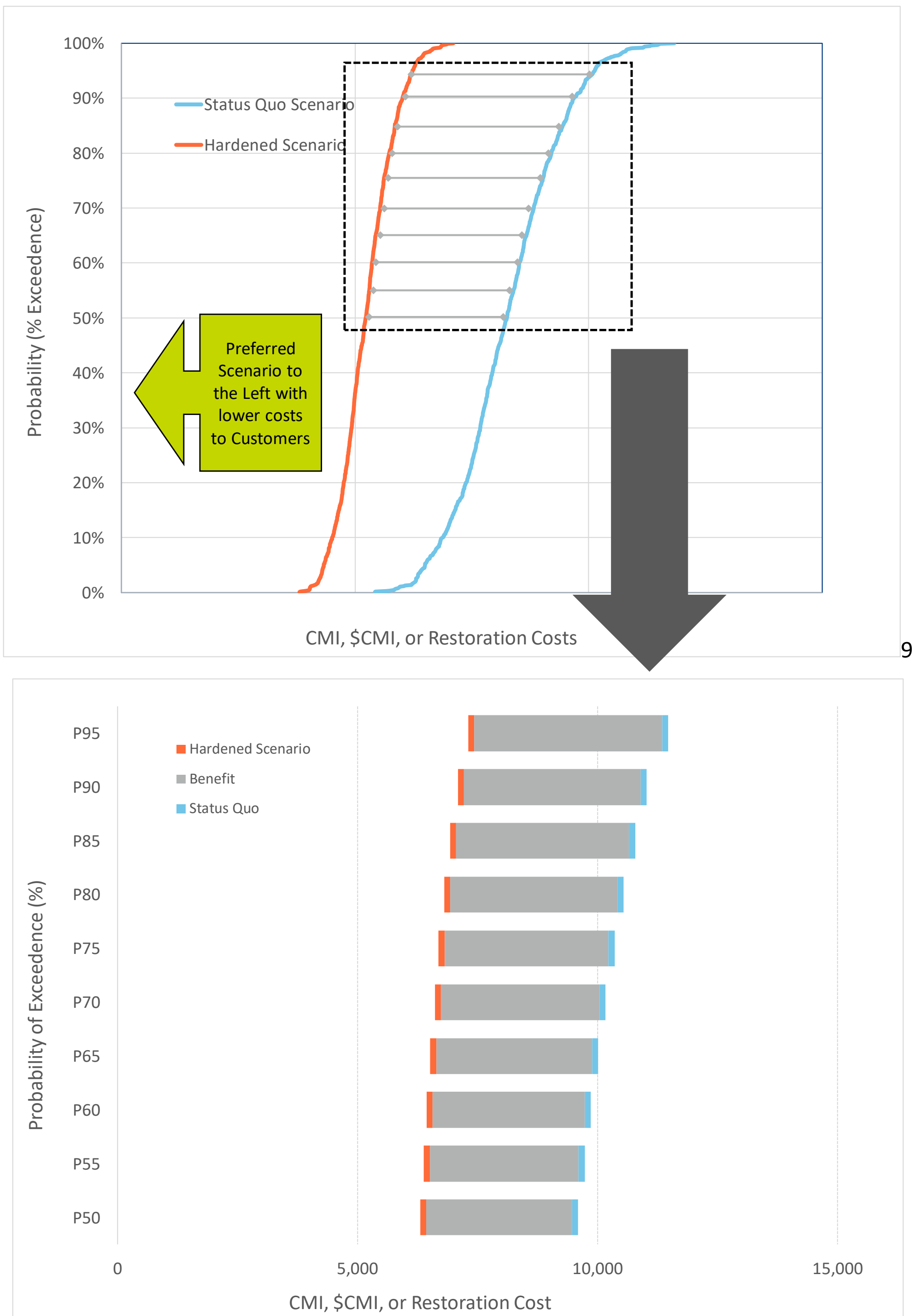
The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

Figure 2-4: 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. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

Figure 2-5: S-Curves and Resilience Focus



3.0 MAJOR STORMS EVENT DATABASE

The first main component of the Storm Resilience Model is the Major Storms 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 to the TEC system is dependent on following:

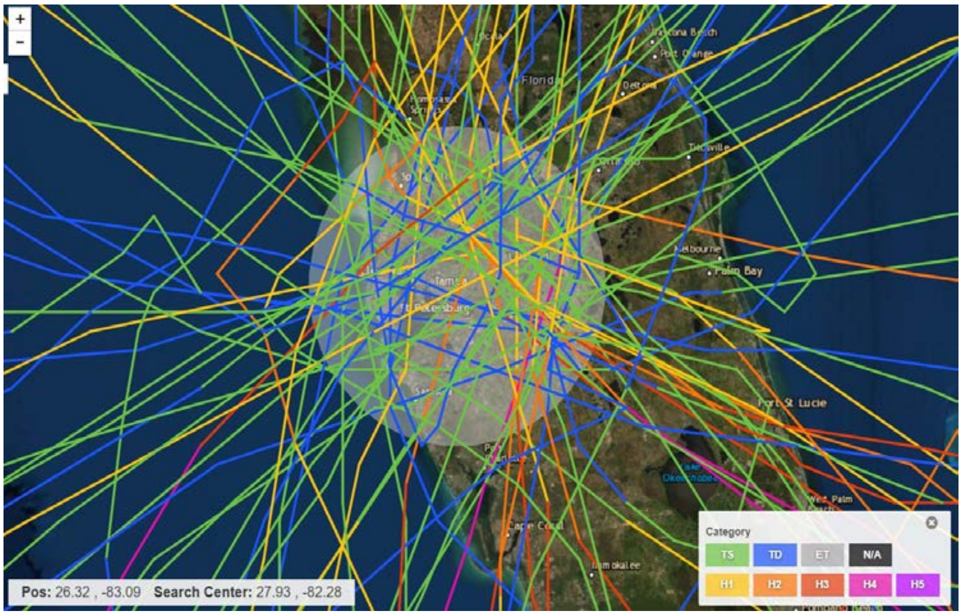
- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if 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, only a few storm bands may hit the TEC service territory.

The major storms 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 storms 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 169years, beginning in 1852. 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, minimizing damage

relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' 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 1852.

Table 3-1: Historical Storm Summary

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	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	12	20	32	30	29	91
Tropical Depression	10	8	18	17	NA	35
Total	32	37	69	68	50	187

Table 3-1 shows a total of 187 storms to hit the Tampa area since 1852. A total of 69 were direct hits within 50 miles, 68 were partial hits in the 51 to 100-mile radius, and 50 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 187, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from 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 serves 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 causes an outage 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.

3.1.2 Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 169 years. 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 1852 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[2]

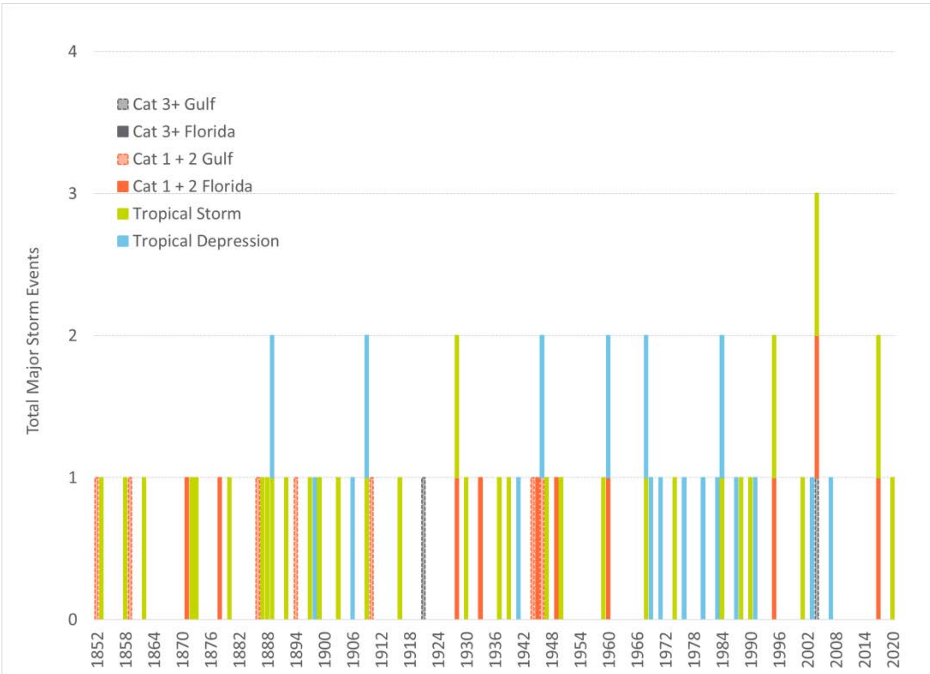


Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2020. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over 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.

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

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

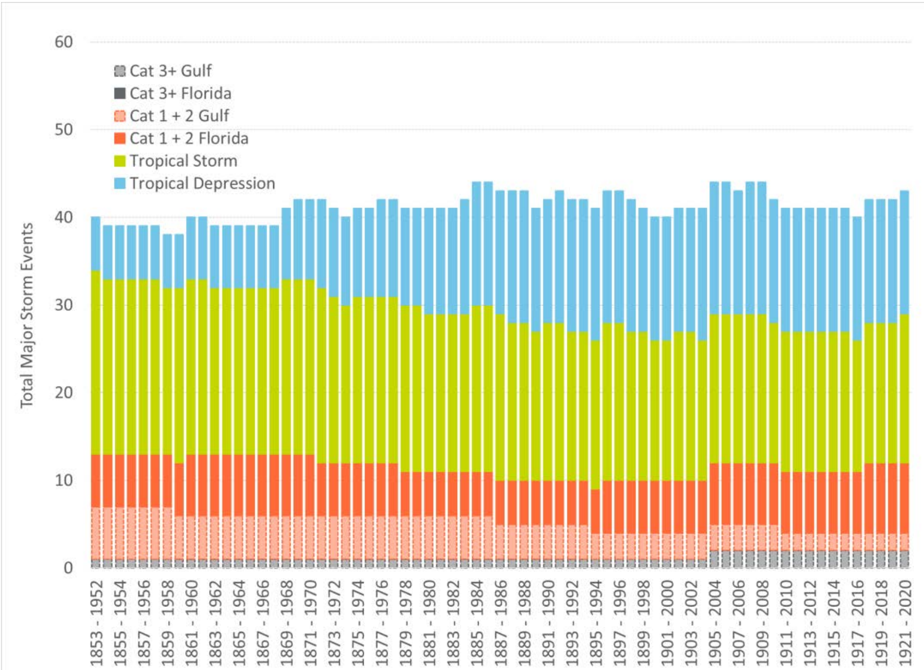
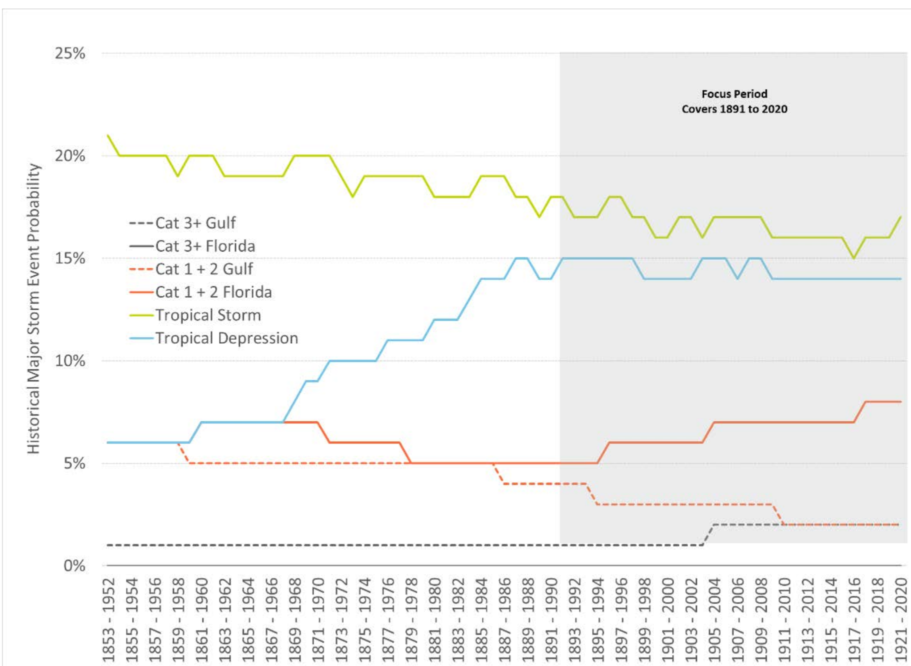


Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]



[3] See Footnote 2

The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. 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 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2020, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3 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 169 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 1852 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)[4]

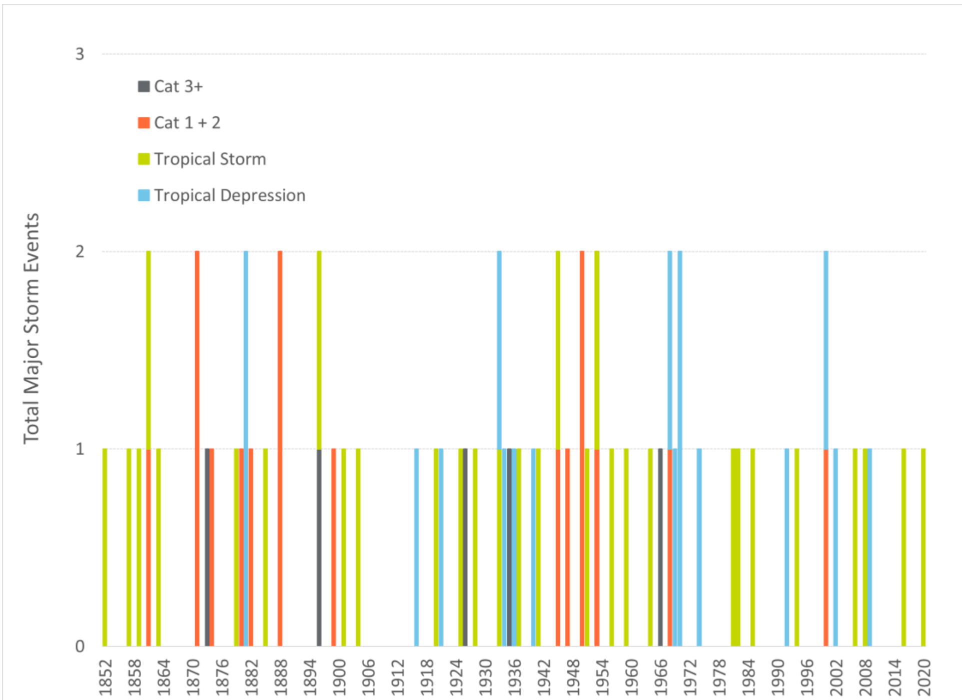
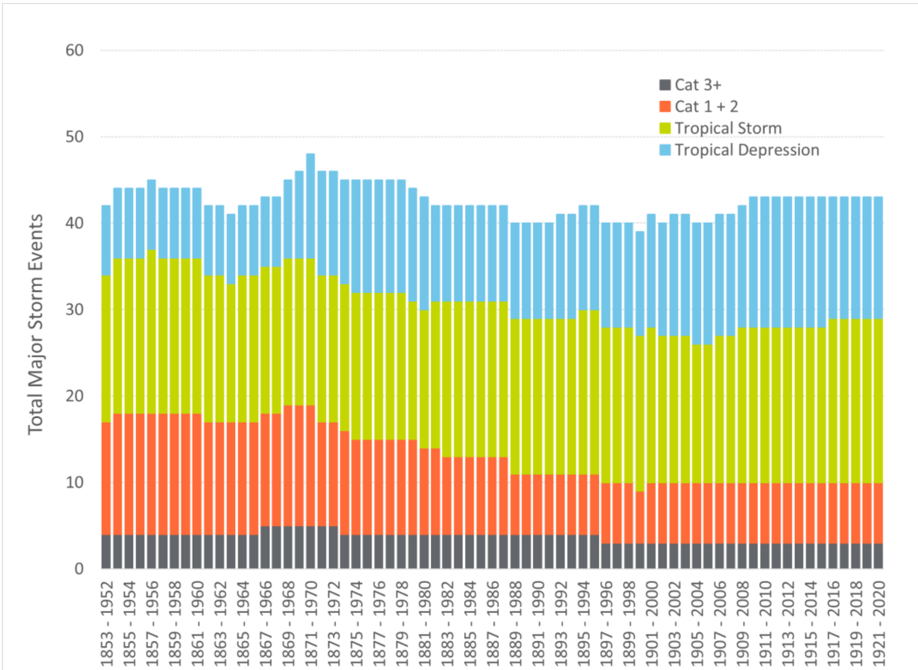


Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2020. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over 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.

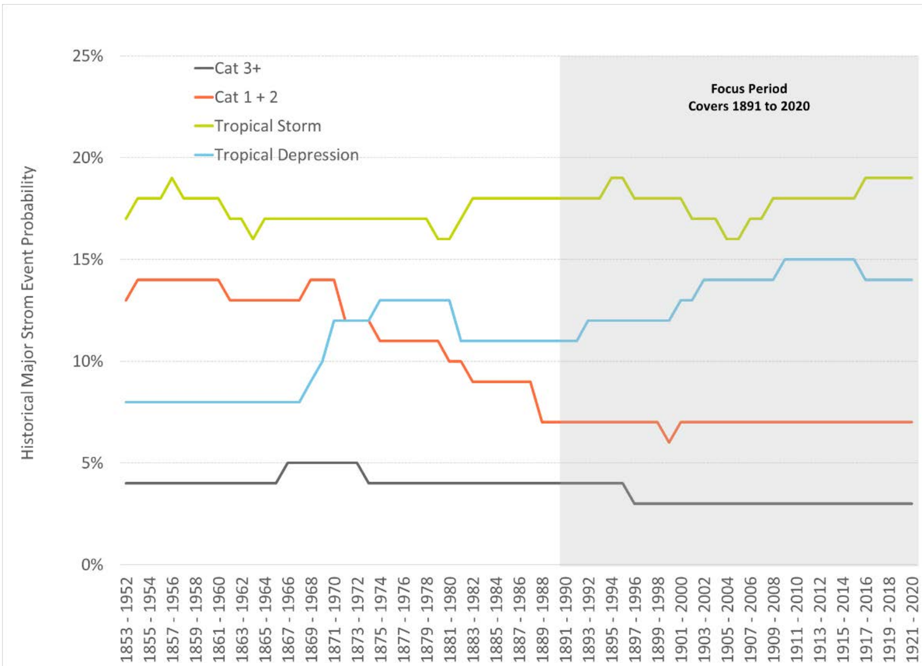
[4] See Footnote 2

Figure 3-6: "Partial Hits" (51 to 100 Miles) 100 Year Rolling Average[5]



[5] See Footnote 2

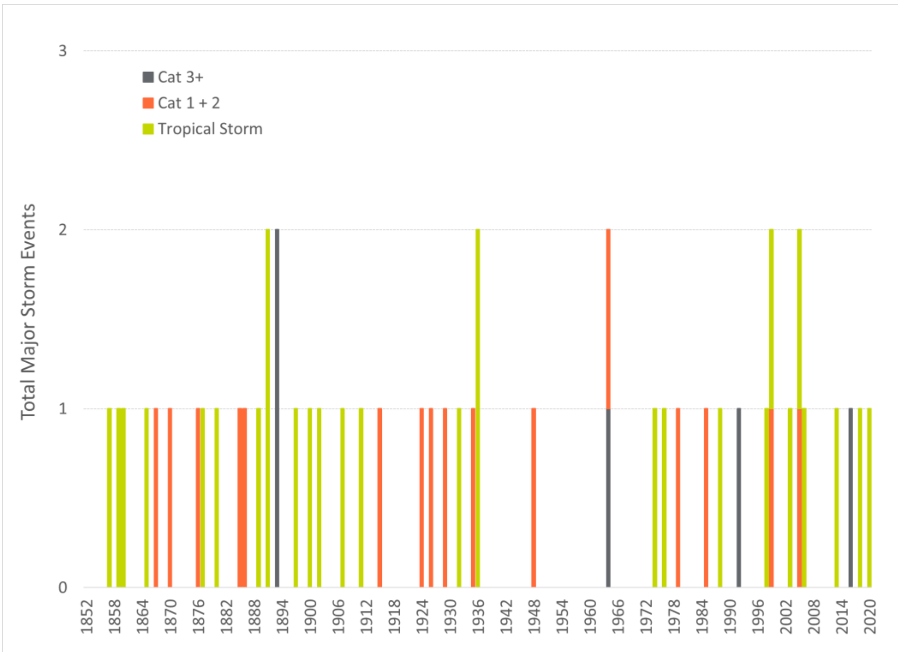
Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]



3.1.4 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 169 years. A storm is classified as a partial 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)[6]



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.

[6] See Footnote 2

Figure 3-9: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Avg.[7]

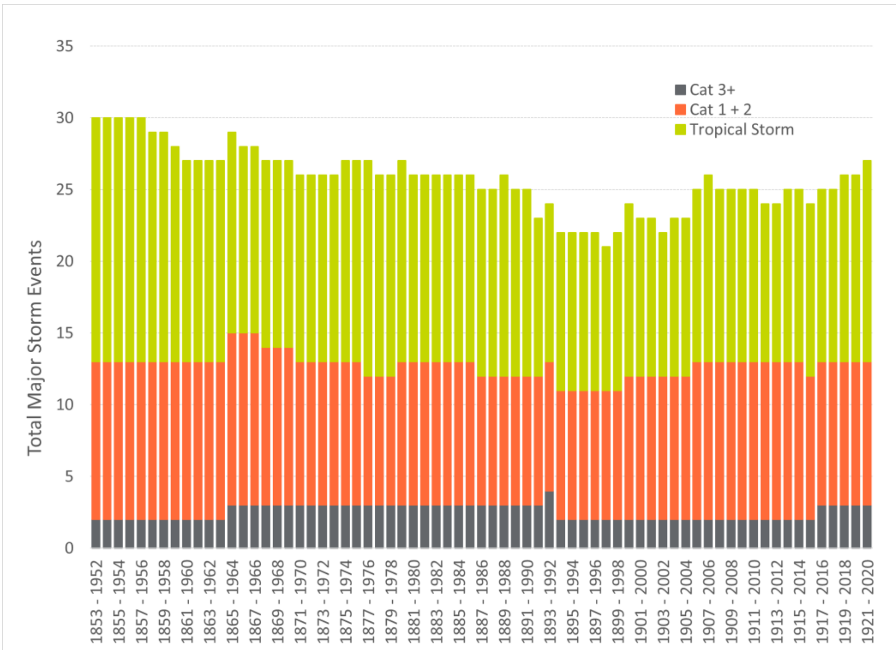


Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]

[7] See Footnote 2

3.2 Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 169 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 is significant.

Table 3-2: Recent Major Event Damages Cost

Storm Name	Category	Year	Damages (2018 $Billions)
Michael	5	2018	$25
Irma	4	2017	$51
Matthew	5	2016	$10
Wilma	3	2005	$10
Dennis	3	2005	$3
Jeanne	3	2004	$9
Ivan	3	2004	$19
Frances	2	2004	$12
Charley	4	2004	$19

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 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

Figure 3-11: Hurricane Irma Impact to TEC Service Territory[8]

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

System Impact:
15 T-Lines
200 Circuits
55% of Customers

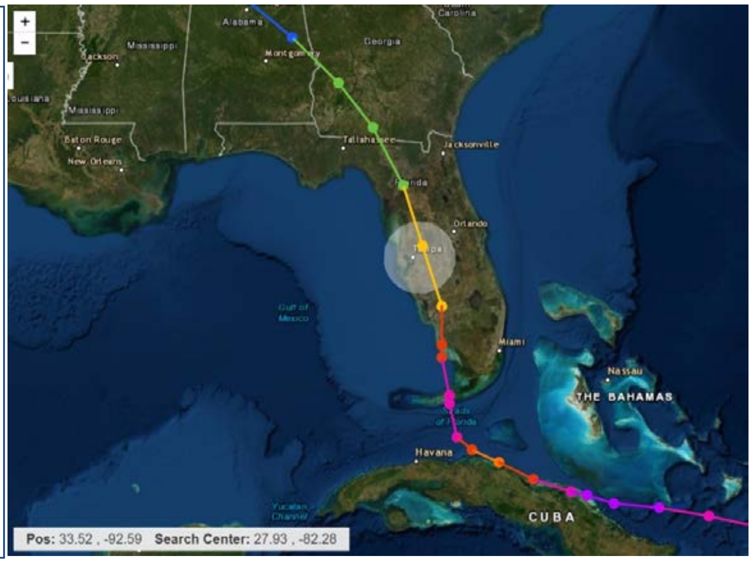


Table 3-3: Storm Report Summary

Storm Name	Category	Year	Damages (2018 $Millions)
Irma	1	2017	$102
Matthew	3	2016	$1
Hermine	1	2016	$6
Colin	TS	2016	$3

3.4 Major Storms Database

TEC and 1898 & Co collaborated in developing the Major Storm Events Database. The database utilizes the results of the NOAA analysis to identify 13 unique storm types. With the range of storm probabilities, the range in cost for each unique storm type, and the range in system impact, the 13 unique storm types are represented by 99 different storm events. 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.

[8] See Footnote 2

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% - 8%	$76.5 - $153	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$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	14.5%	$5.1 - $15.3	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$91.8 - $184	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15.3 - $91.8	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11.5 - $30.6	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.1	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 22.2	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.9	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

4.0 STORM IMPACT MODEL

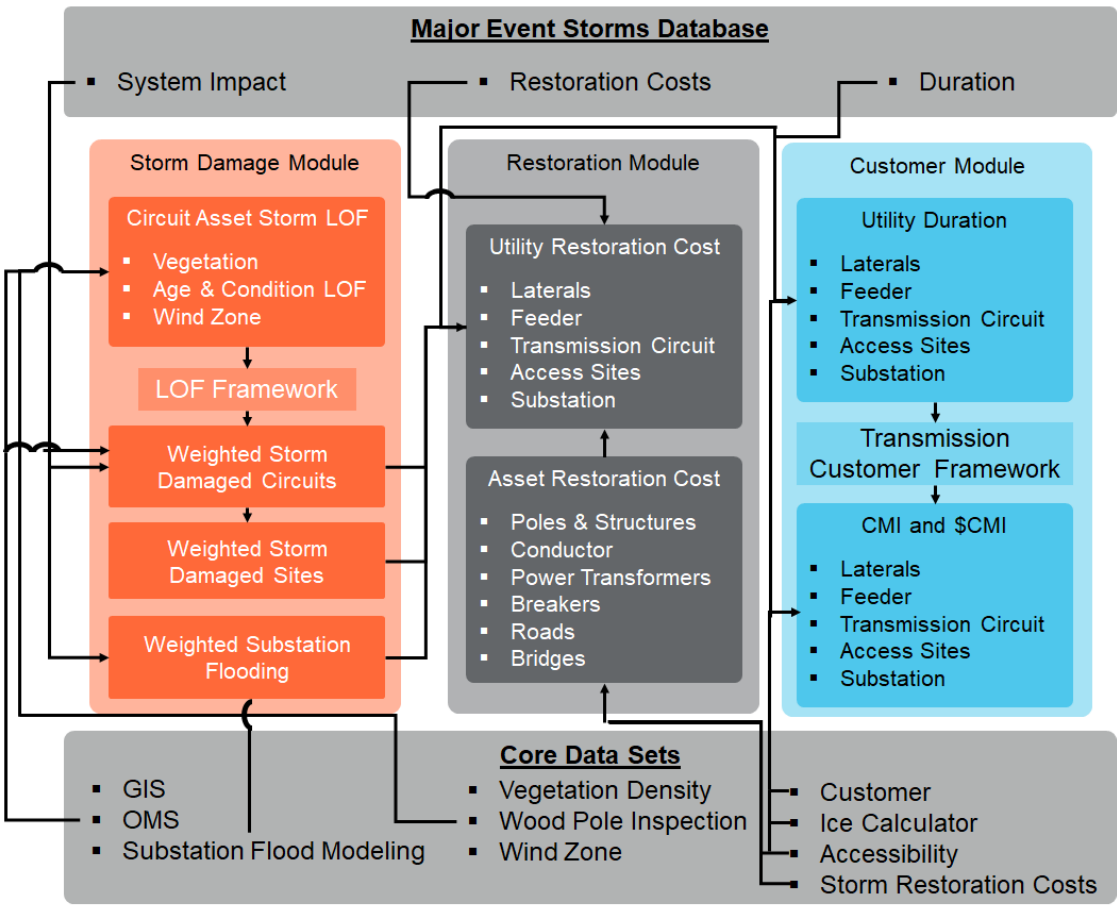
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases 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 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 to 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 in more detail 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 Geographical Information System (GIS), the Outage Management System (OMS), and Customer Information.

4.1.1 Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the 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 Storm Protection Plan.

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]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	[count]	**9**

Table 4-2: Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	930
Total	13,356

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, lightening, 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 XX 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 TEC system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * 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	695,000
Small Commercial and Industrial	71,200
Large Commercial and Industrial	16,300
Total	782,500

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 square foot 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 mostly 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 approximately 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

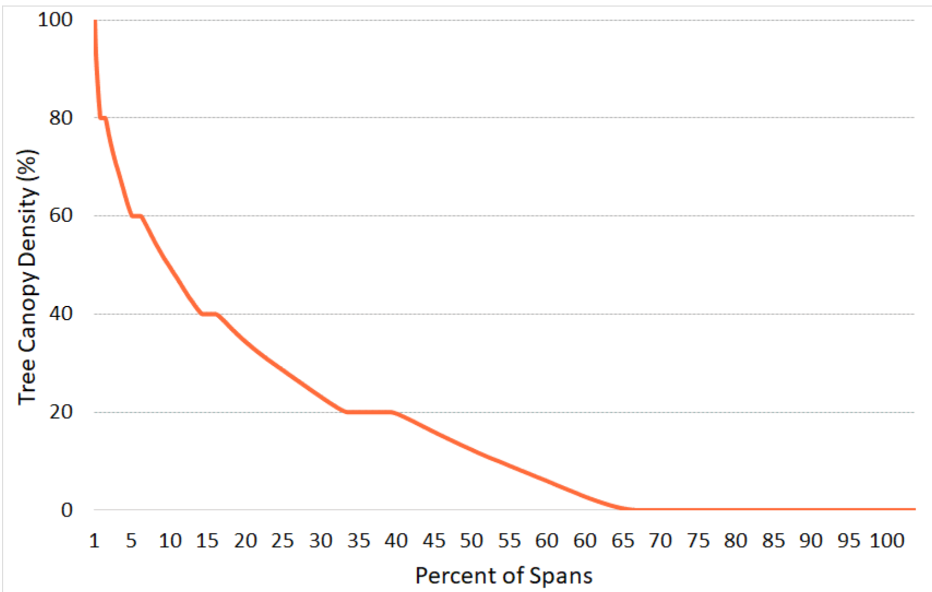
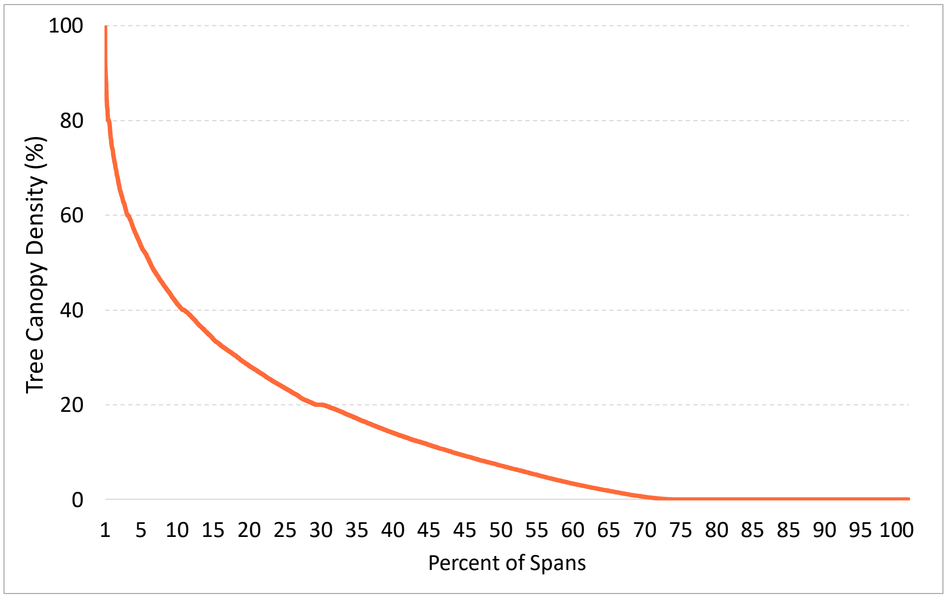


Figure 4-3: Vegetation Density on TEC Transmission Conductor

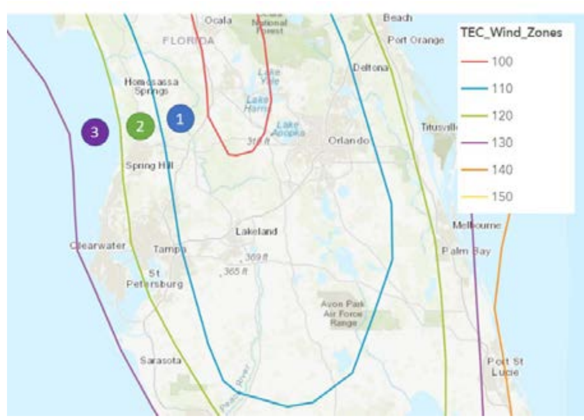


4.1.5 Wood Pole Inspection Data

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 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) 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.

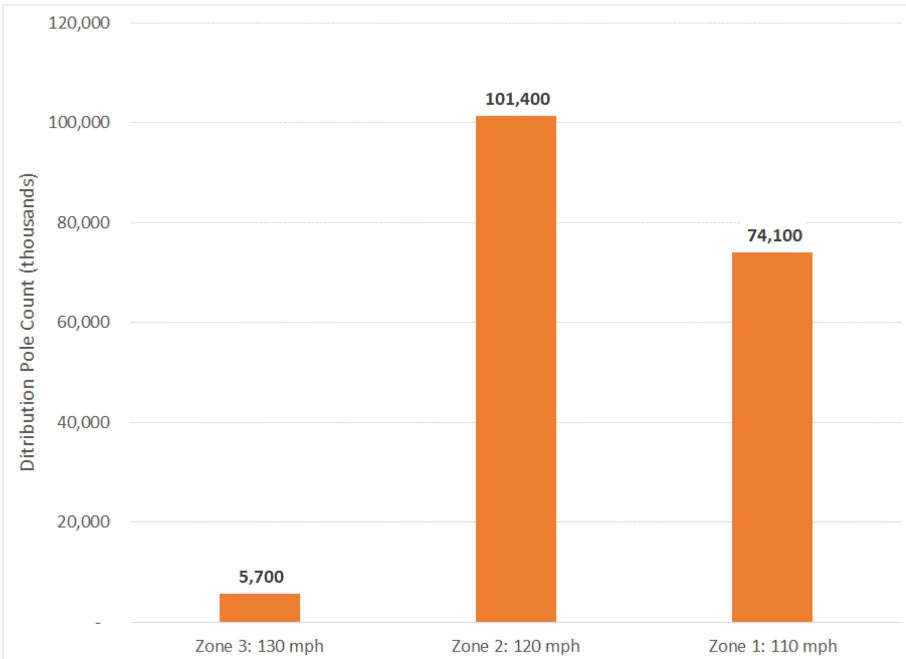
4.1.6 Wind Zone

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 4-4 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.

Figure 4-4: Pole Wind Zone Distribution



4.1.7 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 (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8 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 U.S. Department of Energy (DOE).

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial (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.

4.1.9 Substation Flood Modeling

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (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 9 substations were identified that included flooding risk to the level that could justify investment.

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 Storms 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 Storms 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 condition for storm surge that would cause substation flooding.

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. 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 could not be used for a typical hurricane category to 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.

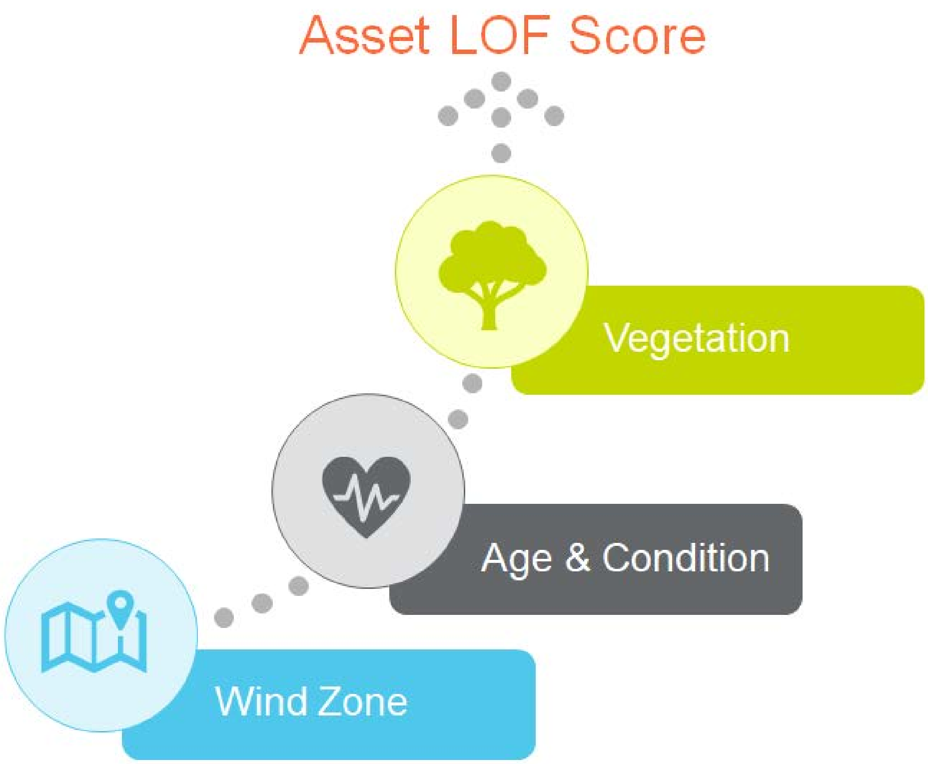
4.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into conductor. The conductor is weighted 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 4-5 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.

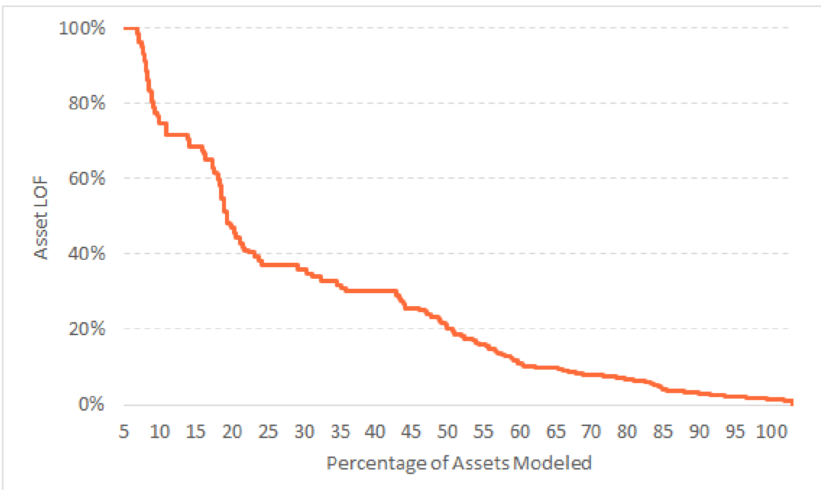
Figure 4-5: Storm LOF Framework for Circuit Assets



The Storm Impact Model utilizes 1898 & Co.'s asset management solution, Capital Asset Planning Solution (CAPS), to estimate the age and condition based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. 1898 & Co.'s CAPS utilizes 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 4-6 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 4-6: 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.

4.2.3 Site Access Storm Likelihood of Failure

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF equals the total of the circuits it provides access to. Section 4.2.2, above, provides the details on how the circuit LOF is calculated.

4.3 Project & Asset Reactive Storm Restoration

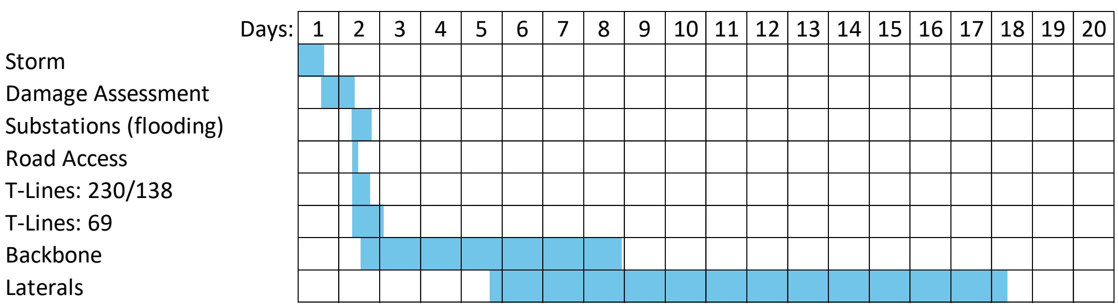
The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers 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. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

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 Event Storms Database.

4.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 4-7 provides an example duration profile for the Category 3 and above storm event.

Figure 4-7: 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 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small 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.

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 stochastic modeling, or 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 feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (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 over 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that 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 4.1.7) were leveraged to estimate:

- Miles of overhead conductor for 1, 2, and 3 phase laterals
- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

Each of these values creates the scope for each of the projects. TEC provided unit costs 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 are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

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 don’t 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.

5.2.5 Transmission Access Enhancements

TEC provided all the project costs for the Transmission Access Enhancements. The cost estimates were based on the length of the bridge or road. Those lengths were developed using geospatial solutions using TEC's GIS for each problem area.

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. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of 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 169 years.

Table 5-1 shows the selection of storm events for each storm type for the first 7 iterations and iteration 1,000. The selected 13 storm events for each iteration represent the future world of storms to impact the TEC service territory over the next 50 years. Each storm has a different frequency and impact to the TEC system. The Monte Carlo Simulation is performed over 1,000 iterations creating a 1,000 of these future storm 'worlds'.

Each project's CMI, monetized CMI, and restoration costs are calculated for the 13 storm events for each iteration for both the 'Status Quo' and Hardened Scenarios over a 50-year time horizon. The difference between the 'Status Quo' and Hardened Scenarios is the benefit of the project for that storm event. The sum of the benefits for all 13 storm events for each iteration 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

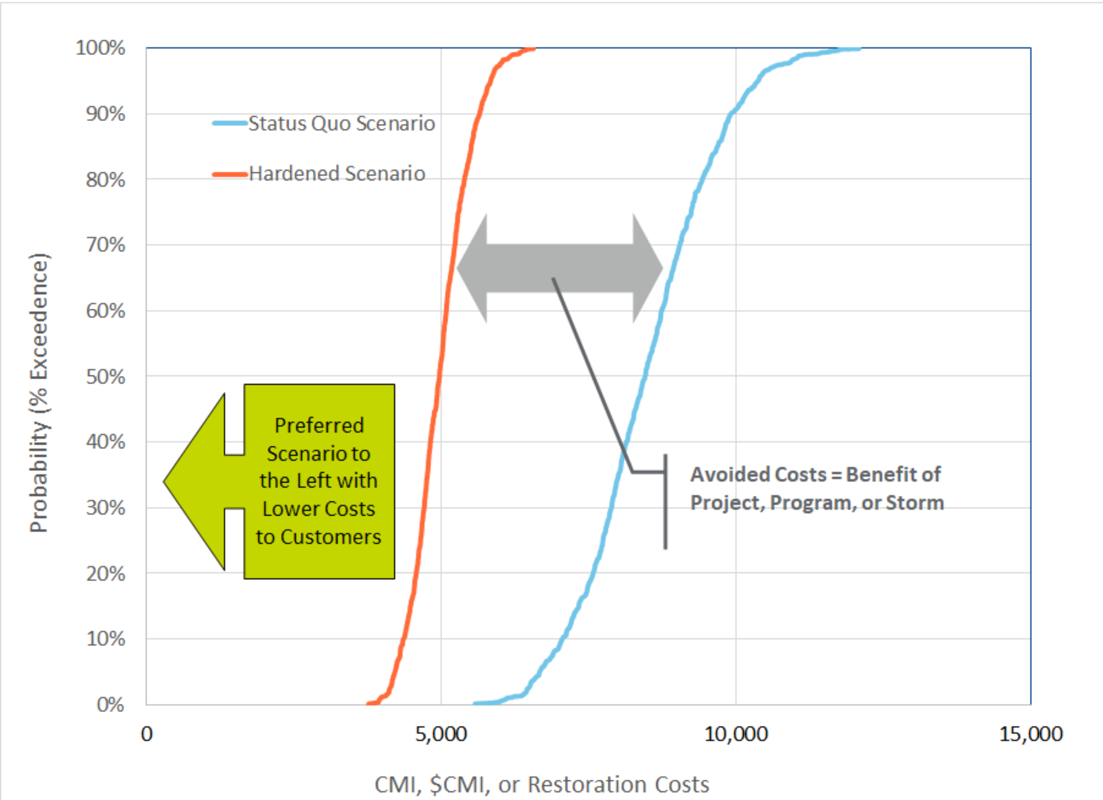
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits 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 over 20,000 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

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. Figure 5-1 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 5-1: Status Quo and Hardened Results Distribution Example



5.4 Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 350 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 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (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 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

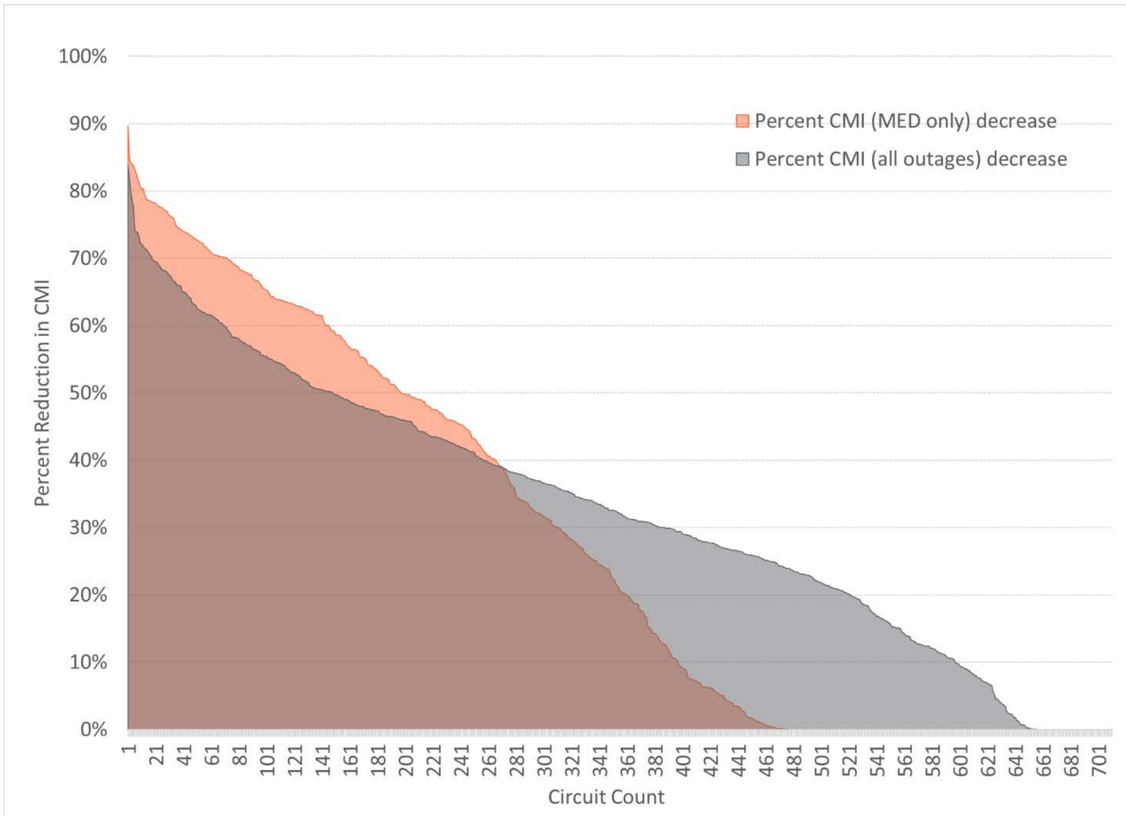
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED 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 350 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 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

The feeder automation projects include a range of investment types including reclosers, poles, re-conductoring, adding tie lines, and substation upgrades to handle the load transfer. TEC provided the itemized costs for feeder automation for projects installed in years 2020 and 2021, and expected average feeder costs for years 2022 through 2029.

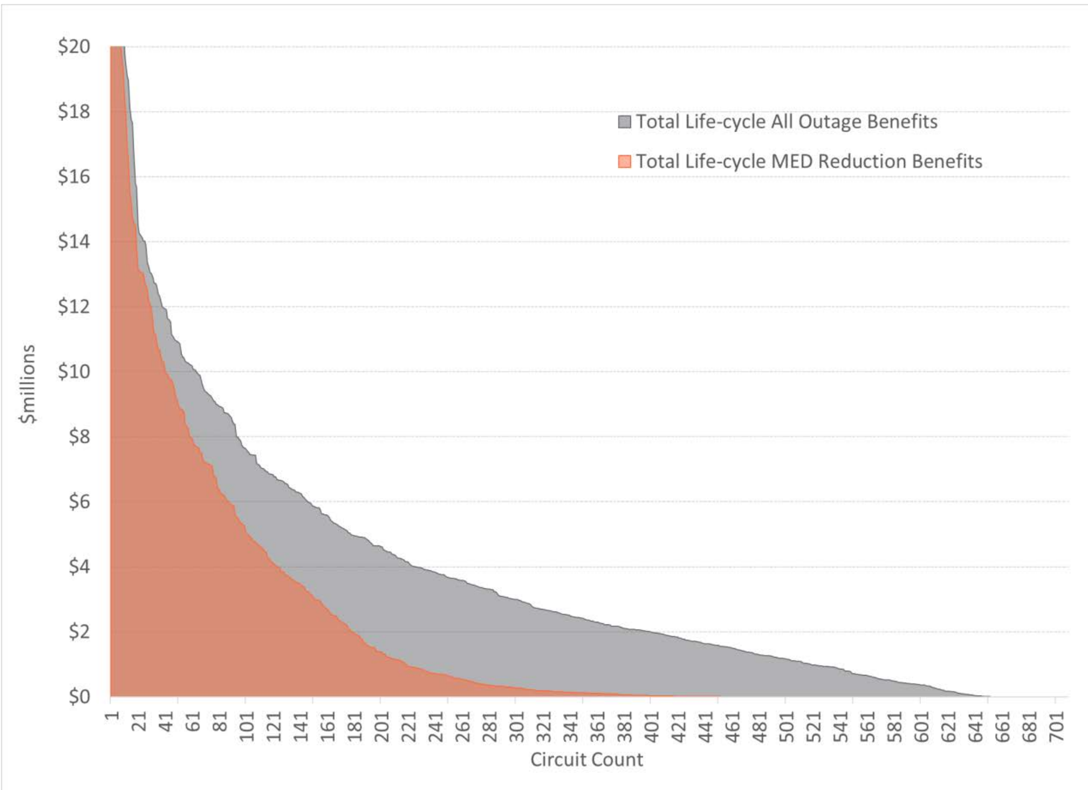
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting in a 40 percent or more decrease in MED CMI. Additionally, the figure shows that approximately two thirds of the circuits would decrease MED CMI.

Figure 5-2: Automation Hardening Percent CMI Decrease



The resilience benefit calculation also monetized the CMI decrease using the ICE Calculator (Section 4.1.8). Figure 5-3 shows the percent decrease in monetized CMI for each circuit. The CMI was monetized and discounted over the 50-year time horizon to calculate the NPV. The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Figure 5-3: Automation Hardening Monetization of CMI Decrease



6.0 BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 13,500 projects. Resilience benefit values 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 Storm Protection Plan.

6.1 Prioritization Metric - Benefit Cost Ratio

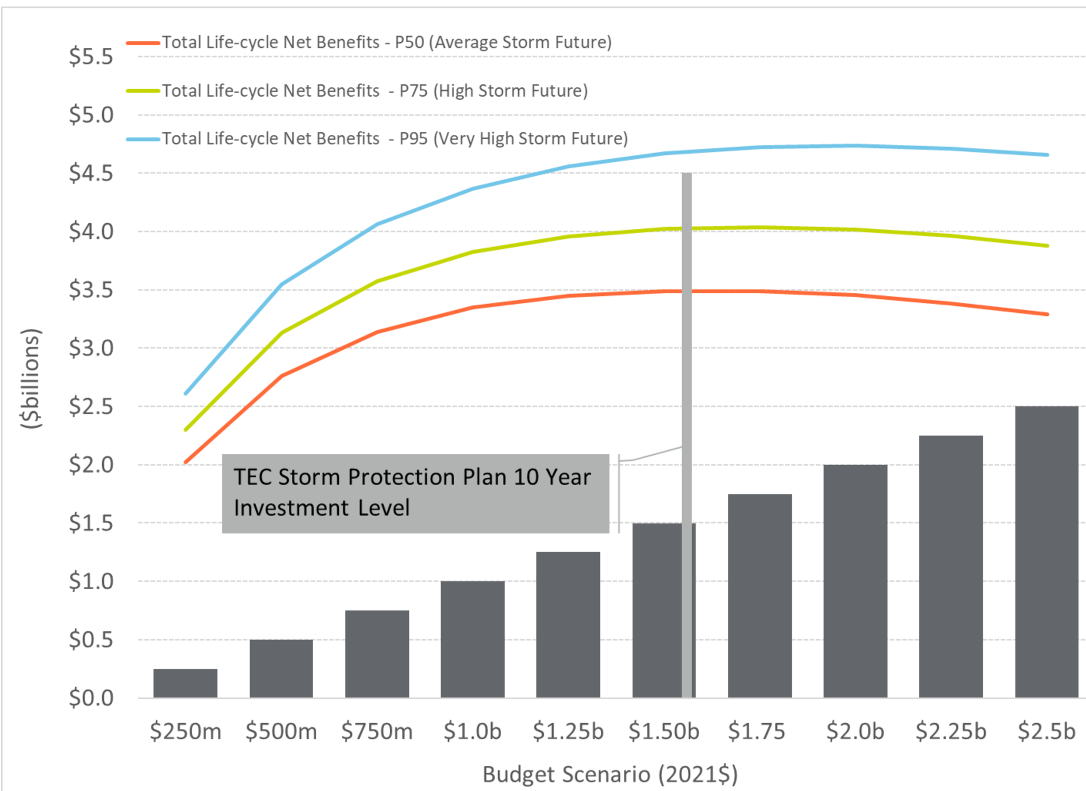
With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each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

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. TEC and 1898 & Co. settled on a weighting on the three values for 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 Budget Optimization

The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. Figure 6-1 shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 6-1: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2021 dollars for the TEC Storm Protection

Plan. The TEC overall investment level is right before the point of diminishing returns showing that TEC's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

6.3 Storm Protection Plan Project Prioritization

In developing TEC's Storm Protection Plan, TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. 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 robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing the TEC Storm Protection plan 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 (i.e. project A before project B, project Y and project Z at the same time).

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 Storm Protection Plan. 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 Storm Protection Plan.

7.1.1 Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.59 billion. Lateral undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Feeder Hardening is second, accounting for 20.0 percent. Transmission upgrades make up 8.8 percent of the total, with substations and site access making up 1.7 percent and 2.0 percent, respectively.

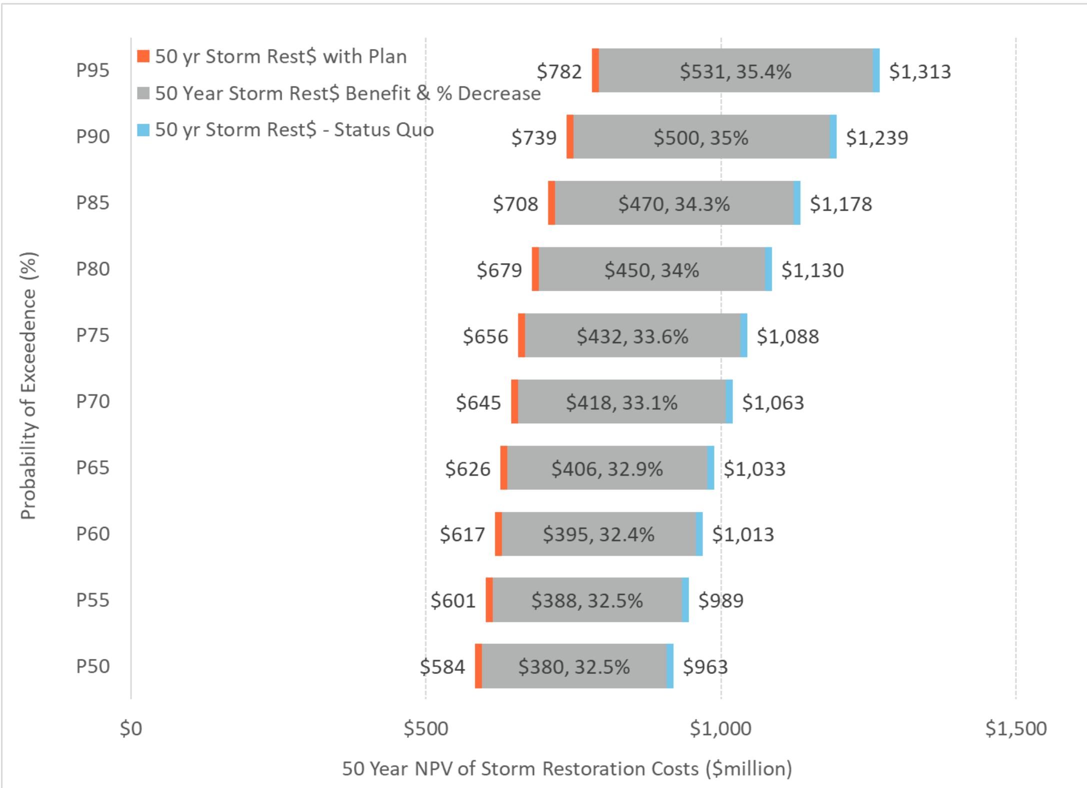
Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2022	$105,600	$16,500	$-	$33,300	$2,400	$157,800
2023	$104,500	$17,500	$700	$29,900	$3,000	$155,600
2024	$105,700	$17,500	$4,300	$30,000	$3,000	$160,500
2025	$105,100	$17,900	$2,700	$30,000	$3,700	$159,400
2026	$105,000	$18,200	$3,300	$30,000	$3,400	$159,900
2027	$105,600	$16,900	$2,900	$30,000	$3,400	$158,800
2028	$105,600	$17,300	$4,800	$30,000	$3,100	$160,800
2029	$105,600	$17,200	$700	$30,000	$2,800	$156,300
2030	$115,400	$-	$7,200	$37,000	$2,000	$161,600
2031	$115,400	$-	$900	$37,000	$4,400	$157,700
Total	$1,073,500	$139,000	$27,500	$317,200	$31,200	$1,594,700

7.1.2 Restoration Cost Reduction

Figure 7-1 shows the range in restoration cost reduction at various probability of exceedance levels. 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, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

Figure 7-1: Storm Protection Plan Restoration Cost Benefit

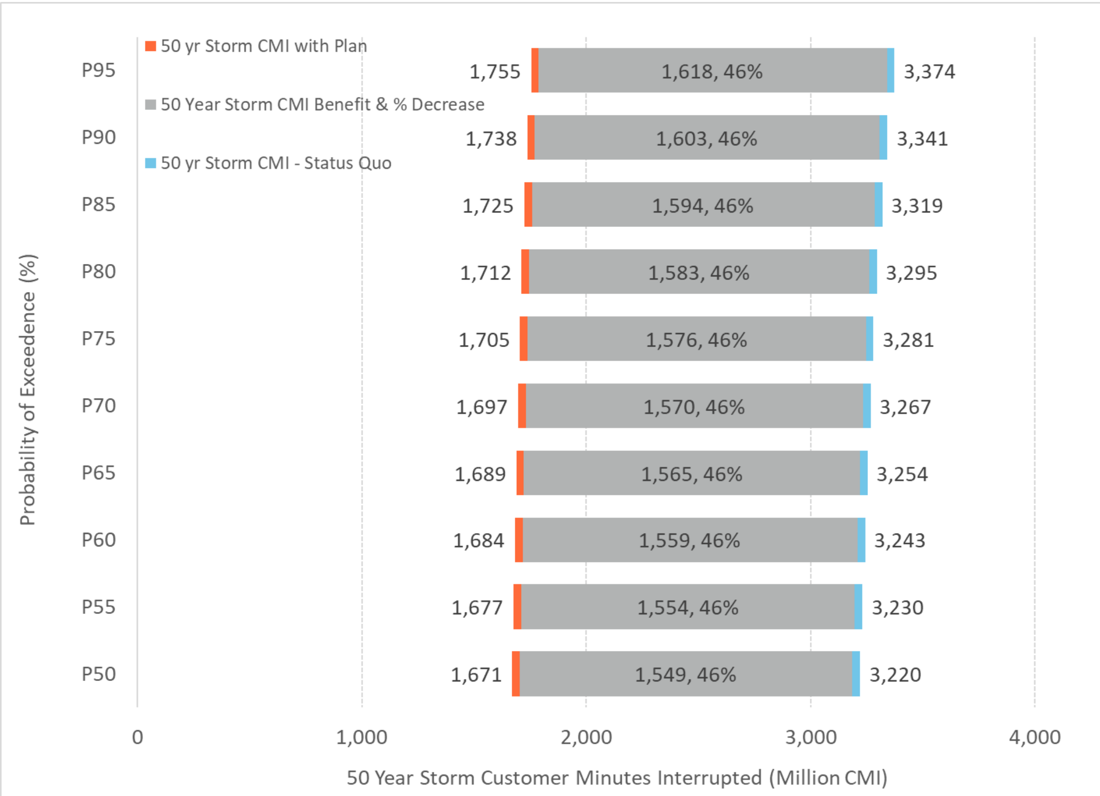


The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration costs decrease benefit is approximately 24 to 33 percent of the project costs.

7.1.3 Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 46 percent decrease in the storm CMI over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit



7.2 Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 97 different circuits.

Table 7-2: Distribution Lateral Undergrounding Investment Profile

Year	Lateral Count	Miles	Nominal Cost ($000)
2022	225	76	$105,600
2023	268	83	$104,500
2024	436	108	$105,700
2025	538	111	$105,100
2026	471	110	$105,000
2027	426	107	$105,600
2028	443	112	$105,600
2029	389	106	$105,600
2030	436	123	$115,400
2031	502	143	$115,400
Total	4,134	1,079	$1,073,500

Table 7-3: Transmission Asset Upgrades Investment Profile

Year	Circuits Worked On	Nominal Cost ($000)
2022	37	$16,500
2023	26	$17,500
2024	10	$17,500
2025	10	$17,900
2026	5	$18,200
2027	11	$16,900
2028	14	$17,300
2029	24	$17,200
2030	0	$-
2031	0	$-
Total	137	$139,000

Table 7-4: Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2022	0	$-
2023	1	$700
2024	1	$4,300
2025	1	$2,700
2026	1	$3,300
2027	1	$2,900
2028	1	$4,800
2029	1	$700
2030	1	$7,200
2031	1	$900
Total	9	$33,800

Table 7-5: Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2022	37	$33,300
2023	31	$29,900
2024	23	$30,000
2025	28	$30,000
2026	28	$30,000
2027	32	$30,000
2028	25	$30,000
2029	29	$30,000
2030	57	$37,000
2031	51	$37,000
Total	341	$317,200

Table 7-6: Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2022	25	$2,400
2023	25	$3,000
2024	4	$3,000
2025	7	$3,700
2026	4	$3,400
2027	3	$3,400
2028	3	$3,100
2029	5	$2,800
2030	5	$2,000
2031	1	$4,400
Total	82	$31,200

7.3 Program Benefits

Table 7-7 shows the restoration cost and CMI benefit for each of the programs. The ranges include the P50 to P95 values. Figure 7-3 shows each program's percentage of the total benefits compared to the program's percentage of the total capital investment. The figure shows the benefit values for both restoration cost and CMI.

Table 7-7: Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~32%	~45%
Transmission Asset Upgrades	~85%	~14%
Substation Extreme Weather Hardening	20%-25%	12%-45%
Distribution Feeder Hardening	~54%	~46%
Transmission Access Enhancements	~28%	~55%

Figure 7-3: Program Benefits vs. Capital Investment

Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 88 percent of the total capital investment, nearly all the CMI benefit, and approximately 81 percent of the restoration benefit.
- The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 45 and 32 percent, respectively.

Additionally, the program accounts for approximately 68 percent of the total plan's invested capital, approximately 57 percent of the plan's restoration benefit, and approximately 17 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.

- The Distribution Feeder Hardening program contributes approximately 82 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.
- While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).
- Substation Hardening accounts for over 3.4 percent of the restoration benefit of the plan while only accounting for approximately 1.7 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 Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.59 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 46 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.
- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low

probability events and investment in the distribution system, which is impacted by all ranges of event types.

- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC's 2022-2031 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

DAVID L. PLUSQUELLIC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID L. PLUSQUELLIC

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INTRODUCTION

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

A. My name is David L. Plusquellic. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director Storm Protection and Support Services. My business address is 820 South 78th Street, Tampa, FL 33619.

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 plan, prioritization of projects within each of the programs, development of project and program costs, and overall implementation of the plan. Organizationally, the Tampa Electric employees responsible for management and implementation of the Vegetation Management, Feeder Hardening, and Distribution Lateral Underground programs report through my organization. In addition, the Tampa Electric employees responsible for operating the SPP warehouse report through my organization.

Q. Please describe your educational background and professional experience.

A. I graduated from Kent State University in June 1996 with a bachelor's degree in Finance. In December of 2000, I graduated from the University of Akron with a Master of Business Administration degree specializing in Finance. I have been employed at Tampa Electric since November of 2019. Prior to joining Tampa Electric, I was employed at FirstEnergy from 1999 to 2018 in a variety of roles. During my 19 years, I progressed from an Analyst to a Director in roles covering financial reporting and analysis, business analytics, fossil fuel generation, renewable portfolio management, process and performance improvement, and Transmission and Distribution ("T&D") operations. For the final four years, I was Director of Operations Support at Ohio Edison, one of the FirstEnergy T&D operating companies. Throughout the 19 years, I played a leadership role in efforts that ranged from valuing businesses, entering into 20-year purchase agreements, evaluating and implementing storm process improvements, evaluating asset investments, and improving operational and safety performance.

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

A. The purpose of my direct testimony is to explain the eight Storm Protection Programs in the company's proposed 2022-2031 Storm Protection Plan ("2022 SPP" or "Storm Protection Plan"), which is included as Exhibit No. DAP-1 to the Direct Testimony of David A. Pickles. I will also describe the Storm Protection Projects associated with these programs as applicable. My testimony will describe how the company's 2022 SPP complies with Rule 25-6.030(3) by providing all the information required for each of these eight programs and their implementing projects.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I have prepared an exhibit entitled, "Exhibit of David L. Plusquellic." It consists of eight documents and has been identified as Exhibit No. DLP-1, which contains the following documents:

- Document No. 1 provides Tampa Electric's proposed 2022 SPP Projected Costs versus Benefits by Program.
- Document No. 2 provides the project detail for the Distribution Lateral Undergrounding Program.
- Document No. 3 is the Vegetation Management Program

study.

- Document No. 4 provides the project detail for the Transmission Asset Upgrades Program.
- Document No. 5 provides the Substation Hardening study that was performed in 2021 for the Substation Extreme Weather Hardening Program.
- Document No. 6 provides the project detail for the Substation Extreme Weather Hardening Program.
- Document No. 7 provides the project detail for the Distribution Overhead Feeder Hardening Program.
- Document No. 8 provides the project detail for the Transmission Access Enhancement Program.

TAMPA ELECTRIC'S 2022-2031 STORM PROTECTION PLAN

Q. Would you describe the programs that support Tampa Electric's Storm Protection Plan?

A. Tampa Electric's 2022 SPP is comprised of eight distinct programs. The programs are as follows.

1. Distribution Lateral Undergrounding
2. Vegetation Management
3. Transmission Asset Upgrades
4. Substation Extreme Weather Hardening
5. Distribution Overhead Feeder Hardening
6. Transmission Access Enhancement

7. Infrastructure Inspections
8. Legacy Storm Hardening Plan Initiatives

Q. How is your testimony organized?

A. For each program, my testimony explains how the company developed the information required by Rule 25-6.030(d)1-4, including: (1) a description of how the program is designed to enhance existing T&D facilities, including an estimate of the resulting restoration in outage times and restoration costs; (2) actual or estimated start and completion dates of the program; (3) a cost estimate including capital and operating expenses; and (4) an analysis of costs and benefits. I also explain the differences, if any, in the 2022 SPP programs as compared to the company's initial Commission-approved SPP programs.

Q. Will you testify regarding the information required by Rule 25-6.030(3)(d)5, the criteria the company used to select and prioritize its 2022 SPP programs?

A. No. The prepared direct testimony of David A. Pickles, submitted contemporaneously in this docket, describes the process Tampa Electric used to select and prioritize programs.

Q. Will your testimony address certain SPP projects?

A. Yes. In addition to explaining the required program details, for each program with projects, I also explain how the company developed the required project-level details for the first year of the 2022 SPP, including (1) actual or estimated construction start and completion dates; (2) a description of the affected facilities, including the number and type of customers served; and (3) a cost estimate including capital and operating expenses. I also describe how the company forecasted project-level detail for the second and third years of the 2022 SPP.

Q. In his direct testimony, Mr. Pickles states that Tampa Electric used a consultant to assist with the development of the 2022 SPP. Why did Tampa Electric use this consultant?

A. Tampa Electric hired the same consulting firm (1898 & Co.) that helped with the development of the company's 2020-2029 Storm Protection Plan. Tampa Electric hired the consultant to provide an independent, third-party review of the company's SPP programs and to reevaluate the company's methodology and prioritization approach. In addition, Tampa Electric used 1898 & Co.'s model for cost-benefit analysis. The consultant's model gave us the capability to perform an updated scenario analysis and ultimately prepare a robust cost-benefit analysis for several of our proposed programs, including the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, and Distribution Overhead Feeder Hardening programs. This analysis was critical to incorporate the lessons learned from the initial implementation of the programs and supporting projects of the company's 2020-2029 SPP. The consultant's model prioritized the projects within each of the programs outlined above and analyzed the costs and benefits of the programs. In addition, the consultant gave the company the ability to model the combined improvements from multiple programs simultaneously, model multiple scenarios, optimize portfolio spending, and confirm that modelled benefits were appropriate, achievable, and in range with the industry. The prepared direct testimony of Jason D. De Stigter from 1898 & Co., filed contemporaneously in this docket, more fully details the approach taken for each of these programs.

Q. Please explain how Tampa Electric and 1898 & Co. estimated the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, and

Distribution Overhead Feeder Hardening programs.

A. Mr. De Stigter explains the methodology used to estimate the reduction in outage times and restoration costs in detail. In general, 1898 & Co. developed a storm resilience model that simulated 99 different storm scenarios, and each scenario identified which parts of the electric system are most likely to fail. The likelihood of failure is driven by the age and condition of the asset, the wind zone the asset is located within, and the vegetation density around each conductor asset. 1898 & Co.'s storm impact model also created an estimate of the restoration costs and Customer Minutes of Interruption ("CMI") associated with each potential project for each storm scenario. Next, the model calculated the benefit of decreased restoration cost and reduced CMI if that hardening project were implemented per the company's hardening standards. This approach was repeated for every potential hardening project within each of these programs. Finally, the estimated benefits of avoided restoration costs and outages were summed over the life of all hardened assets proposed for each program during the 2022 SPP and compared to the projected performance of the current assets, or status quo. This comparison gave the company an estimated relative percentage reduction in restoration costs and outage times for each program. These estimates are included in my Exhibit No. DLP-1, Document No. 1 and are represented in terms of the relative benefit or improvement that the 2022 SPP will provide. The benefits of a reduction in restoration costs and outage times are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo.

Q. Please explain the methodology Tampa Electric used to prioritize the projects the company is including in the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, and Distribution Overhead Feeder Hardening programs.

A. The methodology used to prioritize projects in these programs is described in detail by Mr. De Stigter. In general, we developed a project cost estimate for each potential project, based on several factors depending on the program. For example, for distribution lateral undergrounding, we considered factors such as the length of the total lateral line and location of the facilities (front or rear lot). Next, we estimated the benefits each potential project could provide by determining the savings of avoided restoration costs and the reduction in outage times or reduced CMI. We converted the outage time reductions or savings to financial benefits using the Department of Energy's Interruption Cost Estimator ("ICE") calculator. The ICE Calculator is an electric reliability planning tool designed for electric reliability planners to estimate interruption costs and/or the benefits associated with reliability improvements. We combined both benefits, avoided restoration costs and monetized customer outages, and calculated a cost benefit Net Present Value ("NPV") ratio for each potential project. We used the NPV ratios to prioritize each project within a given SPP program.

Q. Does the final ranking of projects in the SPP strictly follow 1898 & Co.'s prioritization?

A. No. The ranking serves as a guide, but the company also applied operational experience and judgment when selecting projects. The company considered things like ensuring that all areas and communities are represented equitably within our service territory and ensuring that critical customers are appropriately considered in setting the final ranking.

Q. Does the number of projects listed in your 2022 SPP for the year 2022 match the count of projects for 2022 that will be listed in your filings in the Storm Protection Plan Cost Recovery Clause?

A. No. The company developed a list of projects in late 2021 to evaluate for inclusion in the 2022 SPP. At that time, the company believed that some projects that were underway in 2021 would be completed by the end of the calendar year. These projects were accordingly excluded from the 2022 SPP and its supporting analyses. Some of these projects, however, were not completed in 2021. As a result, the project count for 2022 in the Storm Protection Plan Cost Recovery Clause filings is slightly higher than the project count in the 2022 SPP.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades, and Distribution Overhead Feeder Hardening programs?

A. Yes. As I mentioned earlier, the company created cost estimates for each potential project within each program and then determined the benefit of each project by using 1898 & Co.'s model to compare its performance before and after hardening. The benefits of a reduction in restoration costs and outage times for all the projects planned for each program are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo. A table comparing the estimated costs and benefits for each program is included as Exhibit No. DLP-1, Document No. 1.

Q. You stated previously that the company compared the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, and the Distribution Overhead Feeder Hardening programs. How did the company use the project-level costs and benefits described above to perform this comparison?

A. A detailed description of how the company used project-level costs and benefits is provided in Mr. De Stigter's direct testimony. In general, we calculated a cost benefit NPV ratio for each potential project and used it to first determine projects' relative cost-effectiveness and then to prioritize projects within each of the programs. As I mentioned earlier, we established a ranked project listing that the company will use, along with business and operational judgement, to determine when projects will be implemented. Then we aggregated the estimated costs and benefits for all projects selected for each program during the ten-year 2022 SPP period to determine the total costs and benefits of each program illustrated in my Exhibit No. DLP-1, Document No. 1.

DISTRIBUTION LATERAL UNDERGROUNDING

Q. Please provide a description of the Distribution Lateral Undergrounding Program.

A. The primary objective of Tampa Electric’s Distribution Lateral Undergrounding Program is to increase the resiliency and reliability of the distribution system serving our customers during and following a major storm event by converting existing overhead distribution facilities to underground facilities. Tampa Electric has approximately 6,235 miles of overhead distribution lines, of which approximately 4,441 miles or 71 percent of the overhead distribution system are considered lateral lines or fused lines that branch off the main feeder lines. These lateral lines can be one, two, or three phase lines and typically serve communities and neighborhoods.

Q. How are projects prioritized under this program?

A. As described further in the Storm Protection Plan and in the direct testimony of Mr. De Stigter, the company worked with 1898 & Co. to prioritize all lateral lines based on the cost-benefit NPV ratio for each project. We factored in the avoided probability or likelihood of failure and the impact in terms of restoration costs and customer outages if a failure occurs during a major weather event.

Q. Did Tampa Electric learn any lessons from the initial implementation of this program under the prior SPP?

A. Yes. Mr. Pickles describes several lessons learned in his direct testimony. In addition to these lessons, the company also learned that there is a more efficient way to prioritize and implement undergrounding projects.

Under the prior plan, Tampa Electric evaluated each distribution line segment between protection devices individually, which meant that one lateral would be broken up into any number of potential projects. The company discovered through implementation that this methodology, while still effective and beneficial, is not the optimal method for prioritizing and planning projects.

Q. How did Tampa Electric's prioritization methodology change from the company's prior SPP for this program?

A. The company still uses the cost-benefit NPV ratio for prioritizing projects. However, the definition of a project has changed. The company now evaluates some electrically connected distribution lateral segments served by the same feeder together to improve design, communication and construction efficiency, and customer satisfaction. This method has several benefits. First and foremost, the design and customer outreach process for full laterals allows clearer communication to customers and enables broader support than doing piecemeal projects. Secondly, the design of a single larger footprint allows for more efficient looping, than looping each small section. Lastly, the mobilization and demobilization of resources in a larger but related footprint is more efficient than completing a small project and returning in the future for another small project.

Q. Is the company changing the way this program is facilitated?

A. Yes. Mr. Pickles explains how the company is proposing changes related to use of public right-of-way and the project permitting process based on lessons learned from implementation of the prior plan.

Over the past two years the company has been ramping up overhead to underground conversion projects and supporting processes to maintain momentum as this program will continue past the ten-year horizon of this 2022 SPP. The company’s projected 75 to 100 miles of annual distribution lateral undergrounding is the same that was approved in Tampa Electric's initial SPP.

Q. What role does community outreach play in an undergrounding program?

A. Community and customer outreach is critical to the success of this program. The company has placed a significant emphasis on this and has implemented staffing to ensure the community and customer outreach is customer supportive, comprehensive, and effective. Tampa Electric is currently working on creating more educational media to help customers, property owners, and neighborhoods understand the steps necessary to convert their overhead service to underground service, and the company has been working to improve the success rate of obtaining easement agreements from customers. The company has also learned that customers generally prefer for undergrounded laterals to be in existing right-of-way, so the company now initially designs projects with this in mind where it is practical to do so.

Q. Please explain how Tampa Electric's Distribution Lateral Undergrounding Program will enhance the utility's existing transmission and distribution facilities?

A. The Distribution Lateral Undergrounding Program provides many benefits including reducing the number of outages and momentary interruptions experienced during extreme weather events and day-to-day conditions, reducing the amount of storm damage, and reducing restoration costs. Historically, 94 percent of the outages on the company's distribution system originate from an event on an overhead distribution lateral line. In addition, a significant amount of a utility's restoration efforts address failures on lateral lines following major storm events. Many of the lateral lines in the older areas served are in the rear of customers' homes. These "rear lot" lateral lines are more likely to be impacted during a storm given proximity to vegetation and are more difficult to access and restore when they are impacted. Given that most of the failures experienced during major storm events, as well as day-to-day, originate on a lateral line, the primary objective of this program is to underground the lateral lines that have the highest likelihood of failing and create the most significant impact during a major storm event. Comparatively very few, if any, outages originated on underground facilities during the recently experienced named storms and only six percent during blue sky, day-to-day conditions. By undergrounding these overhead lateral lines, the risk of failure during a major storm event will be significantly mitigated.

Q. Did Tampa Electric prepare a list of Distribution Lateral Undergrounding projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Yes, we included the list of Distribution Lateral Undergrounding projects for 2022 and their associated starting and projected completion dates in Appendix A of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 2. The company also developed a preliminary list of projects for 2023.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes, I provide a description of facilities affected by project in my Exhibit No. DLP-1, Document No. 2. For this SPP program, Tampa Electric will continue to include a unique project identifier, the number of and type of customers served by the facilities, and the number of miles of overhead line converted to underground for each project.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. The company developed cost estimates for each project within this program for 2022, 2023, and 2024 and then totaled those estimates to derive the annual cost estimates for the program. The company utilized several characteristics of the existing overhead facilities targeted for conversion to develop the cost estimates for each project, for example, the number of phases involved, the length of the line, and the location of the facilities (front or rear lot). Based on the results of 1898 & Co.'s budget optimization model, the company then estimated the number of projects it expects to complete in years 2025-2031 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are $106 million in 2022, $105 million in 2023, $105 million in 2024, and approximately $105 million to $115 million each year during the period 2025 through 2031. The estimated O&M costs for this program include $0.18 million in 2022, $0.18 million in 2023, $0.18 million in 2024, and approximately $0.15 million to $0.33 million each year from 2025 through 2031. The table below sets out the estimated number of projects and annual costs for 2022 through 2024.

	Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	646	$105.8
2023	399	$104.7
2024	436	$105.2

VEGETATION MANAGEMENT

Q. What are the components of the proposed Vegetation Management Program ("VMP") in the company's 2022 SPP?

A. For purposes of its 2022 SPP, the company's VMP consists of four parts. The company's four Vegetation Management ("VM") initiatives are described below.

Distribution and Transmission VM: Tampa Electric's VMP calls for trimming the company's distribution system on a four-year cycle. The company's maintains the 138kV and 230kV bulk transmission lines on a two-year cycle and the 69kV and 34kV lines on a three-year cycle. Distribution and Transmission VM includes planned and unplanned (reactive) trimming.

Supplemental Distribution VM: Supplemental Distribution Circuit VM increases the volume of full circuit maintenance performed on an annual basis.

Mid-cycle Distribution VM: Mid-cycle Distribution VM is an inspection-driven, site-specific approach designed to target vegetation that cannot be effectively maintained by cycle trimming. This initiative also targets hazard trees.

69 kV Transmission VM Reclamation: 69 kV Transmission VM Reclamation is designed to remove obstructing vegetation and hazard trees from specific sites along the company's 69kV transmission system.

Q. When did Tampa Electric begin a four-year trim cycle for its distribution system?

A. The company received approval from the Commission in Order No. PSC 12-0303-PAA-EI, issued June 12, 2012, in Docket No. 20120038-EI, to convert from a three-year trim cycle to a four-year trim cycle. This approved trim cycle change gave Tampa Electric flexibility to change circuit prioritization using the company's reliability-based methodology.

Q. Approximately how many miles of distribution lines does Tampa Electric trim per year as part of this four-year cycle?

A. Tampa Electric's current four-year trim cycle calls for trimming approximately 1,560 distribution miles annually.

Q. Describe Tampa Electric's transmission VM cycle.

A. As I mentioned previously, the company maintains the 138kV and 230kV bulk transmission lines on a two-year cycle and the 69kV and 34 kV lines on a three-year cycle. We manage transmission circuits on a 'strict' or 'hard' cycle. Although strict, the schedule allows adequate flexibility to accommodate new or redesigned circuits. We manage all circuits above 200kV in accordance with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4.

Q. Approximately how many miles of transmission lines does Tampa Electric trim per year as a part of these cycles?

A. Tampa Electric's current transmission cycle calls for trimming approximately 530 total transmission miles annually, 250 non-bulk miles and 280 bulk miles.

Q. Would you explain the company's reliability-based methodology?

A. Tampa Electric's System Reliability and Line Clearance departments use a third-party vegetation management software application to develop a multi-year VMP which optimizes activities from a reliability-based and a cost-effective standpoint. This approach allows the company to model circuit behavior and schedule trimming at the optimal time.

Q. Please describe the company's current VM specifications.

A. Tampa Electric uses a contract workforce of approximately 280 tree trim personnel dedicated to distribution and transmission planned VM. The company has a total of 331 tree trim personnel throughout the company's distribution and transmission system. Vegetation to conductor clearance for distribution primary facilities is ten feet, and vegetation to conductor clearances for transmission varies from fifteen feet to thirty feet, depending on voltage. All Tampa Electric contractors are required to follow American National Standards Institute ("ANSI") A300 pruning guidelines.

Q. What are the ANSI pruning guidelines?

A. The ANSI uses industry research to generate a set of guidelines for a variety of industry practices. The ANSI A300 guidelines help arborists determine the way vegetation should be trimmed to achieve desired objectives while preserving tree health and structure. The ANSI Z133 guidelines help arborists and non-arborists follow safe work practices.

Q. How did the company analyze the costs and benefits of the incremental vegetation management activities?

A. Tampa Electric used a consultant to determine the costs and benefits of the three incremental VM activities when it developed the initial SPP that was filed on April 10, 2020.

Q. Did the company update this information for the 2022 SPP that was filed in this proceeding?

A. No. Tampa Electric believes that the scenarios and associated cost-effective results and priorities of the study performed to support the SPP filed on April 10, 2020 are still valid. This study is included in my Exhibit No. DLP-1, Document No. 3.

Q. How many incremental miles of distribution and transmission overhead facilities does Tampa Electric plan to trim over the first three years of the 2022 Plan?

A. For the first three years, the company plans to trim approximately 2,090 additional miles of distribution lines and an additional 75 miles of 69 kV transmission lines. The number of miles of mid-cycle trimming and removal will be determined by the inspection findings; however, the company plans to inspect 2,210 miles in the first three years of the 2022 SPP.

Q. What is the total number of miles, including both baseline and incremental trimming, that Tampa Electric plans to trim over the first three years of the 2022 SPP?

A. The company plans to trim approximately 4,680 miles of distribution facilities under the baseline cycle and 2,090 miles under the Supplemental Trimming Initiative. We also plan to inspect 2,210 miles under the Mid-Cycle Initiative, for a total of approximately 8,980 miles of distribution trimming. The company plans to trim approximately 1,590 miles of transmission facilities under the baseline cycle, plus an additional 75 miles under the 69kV Reclamation Initiative, for a total of approximately 1,665 miles of transmission facility trimming.

Q. What are the estimated annual labor and equipment costs for the VMP during the first three years of the 2022 SPP?

A. The estimated annual labor and equipment costs for the first three years of the 2022 SPP total $83.9 million. The four-year distribution cycle labor and equipment costs for the first three years are $38.3 million, and the incremental distribution VM labor and equipment costs are $31.1 million. The first three years of transmission cycle labor and equipment costs are $8.9 million, and the incremental transmission VM labor and equipment costs are $1.4 million. The first three years of unplanned VM labor and equipment costs are $4.2 million. The total cost for the program is set out in Section 6.2 of the company’s 2022 SPP.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the program?

A. Yes. Pursuant to Rule 25-6.030(3)(i), the company explored incremental VM strategies for the express purposes of protecting its electrical infrastructure against extreme weather events and reducing restoration times and costs. The company further acquired the assistance of Accenture, an outside consultant with expertise in data analysis and utility VM, to help with the analysis. Based on the data available and the analysis that was performed, Tampa Electric determined that the 26 percent improvement in storm restoration time and cost are worth the estimated

$10.7 million annual average increase in distribution VM O&M expenses. In addition, the benefits associated with reduced restoration time and cost and lessened vegetation contact potential clearly show that the 69kV reclamation project additional annual expense is a tremendous value for Tampa Electric customers.

The table below provides the annual costs for VM activities for 2022 through 2024.

	Tampa Electric's Vegetation Management Program Projected Costs (in thousands)		
	2022	2023	2024
Supplemental Vegetation Management Project Costs	$6,100	$7,100	$4,800
Mid-Cycle Vegetation Management Project Costs	$3,500	$4,000	$5,600
69 kV Reclamation	$695	$695	$0
Planned Distribution	$11,561	$12,901	$13,823
Planned Transmission	$2,917	$2,966	$3,035
Unplanned	$1,400	$1,400	$1,400
Total	$26,173	$29,062	$28,658

TRANSMISSION ASSET UPGRADES

Q. Please provide a description of the Transmission Asset Upgrades program.

A. The main objective of the Transmission Asset Upgrades program is to address the vulnerability that the company's remaining wood transmission poles pose by systematically upgrading them to a higher strength steel or concrete pole. Tampa Electric plans to replace all existing transmission wood poles with non-wood material by December 31, 2029. The company has identified 126 of its existing 225 transmission circuits that have at least one wooden pole and will replace those remaining transmission wood poles on an entire circuit basis.

Q. Please explain how Tampa Electric's Transmission Asset Upgrade program will enhance the utility's existing transmission and distribution facilities.

A. Tampa Electric has over 1,300 miles of overhead transmission lines at voltage levels of 230kV, 138kV, and 69kV. While the company experiences far fewer transmission outages and pole failures during major storm events than on the distribution system, an outage on the transmission system can have far greater impact and significance. Most of these pole failures are associated with wood poles. Of the 10 transmission poles replaced due to Hurricane Irma in 2017, nine were wooden poles with no previously identified deficiencies that would warrant the pole to be replaced under the previous Storm Hardening Plan Initiative. The company has made significant progress in reducing storm-related transmission outages through implementation of Extreme Wind Loading design and construction standards. In the early 1990s, Tampa Electric changed its standards and began building all new transmission circuits with non-wood structures. As of January 1, 2022, approximately 84 percent of Tampa Electric's transmission system is constructed of steel or concrete poles/structures. The remaining 16 percent, however, are wood poles installed over 30 years ago. Replacing the remaining wood transmission poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, more robust wind loading standards than those required at the time of installation. This will greatly reduce the likelihood of a failure during a major storm event.

Q. Is Tampa Electric proposing any changes to the existing Transmission Asset program?

A. No, the company is not proposing any changes to the Transmission Asset program and remains on track for replacing the remaining wood transmission wood poles with non-wood material by the end of 2029.

Q. Did Tampa Electric prepare a list of Transmission Asset Upgrades projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Yes, we included the list of Transmission Asset Upgrades projects for 2022 and their associated starting and projected completion dates in Appendix C of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 4. The company plans 37 projects for 2022 and identified a preliminary list of 26 projects for 2023 and 10 projects for 2024. The remaining transmission circuits with wood poles are scheduled for upgrade in the years 2025 through 2029.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes. I provide a description of the affected facilities for each Transmission Asset Upgrades project in my Exhibit No. DLP-1, Document No. 4. The description includes the total number of wood poles replaced on a circuit basis for each project. Given that the high voltage transmission system is designed to transmit power over long distances to end-use distribution substations, Tampa Electric does not attribute customer counts directly to individual transmission lines.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. The company developed cost estimates for each project within this program for 2022, 2023, and 2024 and totaled those estimates to derive the annual cost estimates for the program. The company used its experience of average costs to upgrade a wood transmission pole to non-wood and the number of poles associated with each project to develop the cost estimates. The company then estimated the number of projects it expects to complete in years 2024 through 2029 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are $16.5 million in 2022, $17.5 million in 2023, $17.5 million in 2024, and approximately $17.5 million in each year during the period 2025 through 2029. The incremental annual O&M costs associated with this program are approximately $0.5 million. The table below sets out the estimated number of projects and estimated annual costs for this program for 2022 through 2024.

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	37	$17.0
2023	26	$18.0
2024	10	$18.1

SUBSTATION EXTREME WEATHER HARDENING

Q. Please provide a description of the Substation Extreme Weather Hardening program?

A. The primary objective of this program is to harden and protect the company's substation assets that are vulnerable to flood or storm surge. The program minimizes outages, reduces restoration times, and enhances emergency response during extreme weather events. In its prior SPP, the company identified 59 of its 216 substations that have risk due to flood or surge. 1898 & Co. modeled these 59 substations and prioritized them based on the expected benefits of mitigation after hardening with a flood wall solution and selected 11 substation hardening projects for the 2022 SPP. 1898 & Co.'s model indicated that the substation hardening projects accounted for a sizable restoration benefit while requiring a small percentage of the prior SPP capital investment. Given this dramatic benefit to cost ratio, the company decided that further evaluation and assessment of this program is needed. In March 2021, the company obtained the assistance of a third-party engineering firm to perform a study to evaluate various substation hardening solutions and assess the potential vulnerability of the identified substations to extreme weather, including flooding or storm surge.

Q. What were the results of the Substation Hardening Study?

A. The Substation Hardening Study evaluated 24 coastal substations that are a mix of Transmission and Distribution Substations that serve as switching stations to distribute large generation resources. Each of the 24 substations results was reviewed for its susceptibility to storm surge flooding, in addition to those substations which would have the greatest impact on grid stability, reliability of service, safety, and environmental risks if an extended outage from an extreme weather event occurred. The Substation Hardening Study recommended nine specific substation projects to be initiated for the company's 2022 SPP. I provide the Substation Hardening Study in my Exhibit No. DLP-1, Document No. 5.

Q. Please explain how Tampa Electric's Substation Extreme Weather Protection program will enhance the utility's existing transmission and distribution facilities?

A. This program increases the resiliency and reliability of the substations using permanent or temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding. For the substations located closest to the coastline and at greatest risk, substation hardening efforts eliminate or mitigate the impact of water intrusion due to storm surge into the substation control houses and equipment. By avoiding these types of impacts, restoration costs will be reduced, as will outage times.

Q. Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Substation Extreme Weather Protection Program?

A. As we developed the substation hardening projects, we also created budgetary cost estimates for the projects. The cost estimates are for turnkey construction, including engineering, equipment, construction, testing, and commissioning. These costs were used in a cost-benefit analysis to determine the project impact in improving grid resiliency and its cost-effectiveness.

Q. Did Tampa Electric prepare a list of Substation Extreme Weather Hardening projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. The company does not propose initiating any Substation Extreme Weather Hardening projects for 2022.

Q. Is Tampa Electric proposing any changes to the existing Substation Extreme Weather Hardening program?

A. Yes, the company is proposing to start work on substation extreme weather capital projects in the latter part of 2023, as compared to a start date in 2024 in the company’s prior SPP. All other aspects of this proposed 2022-2031 Substation Extreme Weather Hardening program are identical to those of the program in the prior SPP.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes. I provide a description of the facilities that will be affected by each project, including the number and type of customers served, in my Exhibit No. DLP-1, Document No. 6.

Q. Did Tampa Electric prepare an estimate of benefits (reduction in outage time, reduction in extreme weather restoration cost) for the projects the company is planning on initiating for this Substation Extreme Weather Hardening program?

A. Yes. The company prepared an estimate of benefits (reduction in outage time, reduction in extreme weather restoration cost) for the projects the company is planning on initiating for this Substation Extreme Weather Hardening program, and it is included in my Exhibit No. DLP-1, Document No. 6.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. The company developed cost estimates for each project within this program for 2022, 2023, and 2024 and totaled those estimates to derive the annual cost estimates for the program. As I previously stated, the costs for each of the substation extreme weather hardening projects were developed in the substation hardening study. The estimated capital costs for this program are $0.0 million in 2022, $0.7 million in 2023, and $4.3 million in 2024. There are no estimated incremental O&M costs for this program at this time. The table below sets out the estimated number of projects and annual costs for 2022 through 2024.

	Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	0	$0.0
2023	1	$0.7
2024	1	$4.3

DISTRIBUTION OVERHEAD FEEDER HARDENING

Q. Please provide a description of the Distribution Overhead Feeder Hardening Program.

A. Tampa Electric’s distribution system includes feeders, also referred to as mainline or backbone lines, and laterals, which are tap lines off the main feeder line. The feeder is the main line that originates from the substation and is the most critical to ensuring power is reliably delivered to our customers once it leaves the substation. This SPP program will continue to expand efforts to harden and protect some of the company’s highest priority feeders, starting with those that have the worst historical day-to-day performance and performance during major storm events, the highest likelihood of failure, and that would present the greatest impact if an outage were to occur.

Q. How will this program harden the company’s feeders?

A. The Distribution Overhead Feeder Hardening program enhances the resiliency and reliability of the distribution network by further hardening the grid to minimize interruptions and reduce customer outage counts during extreme weather events and abnormal system conditions. The implementation includes installing stronger hardened poles and facilities; installation of switching equipment to allow automatic isolation of damaged facilities; upgrading small wire conductor to ensure automatic service restoration is not limited by capacity constraints; and the use of new equipment to minimize the interruption of service during atypical system configurations.

In addition, we will upgrade feeder conductors, install sectionalizing switching devices and fault current indicators, and create circuit ties to allow automation and

SCADA control. These steps harden the feeders and reduce restoration times.

Q. What switching equipment does the company plan to install as a part of this program?

A. The company will install reclosers and trip savers to minimize the number of customers interrupted during events as well as reduce the outage time for customers. This equipment will allow for the automatic isolation of faults on the system and then ultimately allow the network to re-configure itself real-time without operator intervention.

Q. How does the company plan to harden poles on feeder lines?

A. We will harden these feeders by upgrading poles smaller than class 2 and ensuring the feeders meet National Electric Safety Code ("NESC") extreme wind loading standards to increase the overall resiliency of the feeder. In addition, certain poles are designated as "Critical Poles" that have critical equipment such as reclosers or capacitor banks, and that are critical locations on the system, such as terminations, and 3-phase laterals. For these "Critical Poles" we will use even stronger poles (class 1 wood or class H! concrete).

Q. Is Tampa Electric proposing any changes to the existing Overhead Feeder Hardening program?

A. Yes. The company includes all components of the existing Commission-approved Overhead Feeder Hardening program and adds three applications to leverage the data of the company's advanced metering infrastructure system 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. They include the following applications.

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 faster and more accurate indication of feeder and feeder section energized state during widescale outages.

Q. Please explain how Tampa Electric's Distribution Overhead Feeder Hardening program will enhance the utility's existing transmission and distribution facilities?

A. The Distribution Overhead Feeder Hardening program will enhance the resiliency of the distribution system by increasing the strength of the poles at most risk of failing during a major weather event as well as the poles at key locations along the feeder that would cause the greatest impact if a failure occurred. Tampa Electric has approximately 800 distribution feeders that serve near 1,000 customers on average each, so mitigating the potential of an outage on these feeders is critical to minimizing customer outages. In addition, the company plans to add fault detection, isolation, and restoration devices on the feeder, which will significantly reduce the number of customers experiencing an outage during an event and allow those that do to be restored significantly quicker.

Q. Did Tampa Electric prepare a list of Distribution Overhead Feeder Hardening projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Yes. We include the list of Distribution Overhead Feeder Hardening projects for 2022 and their associated starting and projected completion dates in Appendix D of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 7. The company has a preliminary list of projects for 2023 and 2024 and has identified how many distribution feeders the company plans to harden in the years 2025 through 2031.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project including the number and type of customers served?

A. Yes. We show in Appendix D of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 7, the description of facilities affected, including a unique project identifier, the number and type of major equipment upgraded or installed, and the number and type of customers served by the facilities.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. The company developed cost estimates for each project within this program for 2022 through 2024 and totaled those estimates to derive the annual cost estimates for the program. The company first defined the attributes of a hardened feeder and then applied the new criteria to each potential overhead feeder to develop its cost estimate. The estimated costs for each project reflect bringing that feeder to the new hardened standard, which includes poles meeting NESC Extreme Wind loading criteria, no poles lower than a class 2, no conductor size smaller than 336 ACSR, single phase reclosers on laterals, feeder segmented and automated with no more than 200 to 400 customers per section, and no segment longer than two to three miles, no more than two to three MW of load served on each segment, and circuit ties to other feeders with available switching capacity. The company then estimated the number of projects it expects to complete in years 2024 through 2031 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are $32.8 million in 2022, $30.1 million in 2023, and $30.0 million in 2024. There are approximately $0.6 million in incremental annual O&M costs associated with this program. The table below includes the estimated number of projects and estimated costs per year for 2022 through 2024.

	Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	36	$33.4
2023	31	$30.7
2024	23	$30.7

TRANSMISSION ACCESS PROGRAM

Q. Please describe the Transmission Access program.

A. Tampa Electric's Transmission Access program is designed to ensure the company always has access to its transmission facilities so it can promptly restore its transmission system when outages occur. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have negatively impacted the company's access to its transmission infrastructure. The company's proposed Transmission Access program involves repairing and restoring transmission access by constructing access roads and access bridges to critical routes throughout the company's transmission corridors.

Q. Is Tampa Electric proposing any changes to the existing Transmission Access program?

A. Yes. The company is keeping all the components of the existing Commission-approved Transmission Access program, but the company is proposing that this program should be structured with no end date to facilitate projects as needed in the future.

Q. Please explain how Tampa Electric's Transmission Access program will enhance the utility's existing transmission facilities.

A. This program will enhance the existing transmission facilities by improving the company's access to its critical transmission circuits, especially during 'wet' and storm seasons, which will promote system resiliency and more timely storm restoration.

Q. How did the company analyze the costs and benefits of the transmission access program?

A. Tampa Electric used a consultant in the prior SPP, filed on April 10, 2020, to determine the costs and benefits of the transmission access program projects that the company is currently performing or planning to perform in the future.

Q. Did the company update this information for the 2022 SPP?

A. Yes. The company made a slight modification to the list of Transmission Access projects based upon further internal evaluation.

Q. Please explain how Tampa Electric and 1898 & Co. prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Transmission Access program.

A. Mr. De Stigter describes the methodology used to develop the estimate of the reduction in outage times and restoration costs in detail. In general, 1898 & Co. developed a model that calculates the benefit in terms of decreased restoration cost and reduced CMI for each proposed transmission access project.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Transmission Access program?

A. Yes. A table comparing the estimated costs and benefits of this program is included below.

Tampa Electric - Proposed 2022-2031 Storm Protection Plan Transmission Access Enhancements Program Projected Costs versus Benefits						
Storm Protection Program	**Projected Costs (in Millions)**		**Projected Reduction in Restoration Costs (Approximate Benefits in Percent)**	**Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)**	**Program Start Date**	**Program End Date**
	Capital	**O&M**				
Transmission Access Enhancements	$31.5	$0.0	28	55	Q1 2021	After 2031

Q. Please explain the methodology Tampa Electric used in prioritizing the projects the company is including in the Transmission Access program.

A. Mr. De Stigter describes the methodology used to develop the prioritization of projects in these programs in detail. In general, the company and 1898 & Co. developed a potential cost estimate and estimated benefits for each potential project. The estimated benefits include reduced CMI and reduced restoration costs. We combined the benefits and calculated a cost-benefit NPV ratio for each potential project. We used the NPV ratios to prioritize each project within the program. The rankings serve as a guide, and the company also applies operational experience and judgment when selecting projects.

Q. Did Tampa Electric prepare an estimated number of Transmission Access projects it plans on initiating in 2022 through 2024?

A. Yes. Using the analysis provided by 1898 & Co., the company prioritized a list of 48 projects it plans to begin in 2022, 2023, and 2024. We include the list of Transmission Access projects for 2022 and their associated starting and projected completion dates in Appendix E of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 8.

Q. Did Tampa Electric prepare an estimate of the costs for the projects planned for 2022 through 2024?

A. Yes. The company estimates the capital costs to be $2.4 million in 2022, $3.0 million in 2023, and $3.0 million in 2024. There are no estimated incremental O&M costs for this program. The table below sets out the total number of projects and the estimated costs for the first three years of the plan.

	Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	25	$2.4
2023	25	$3.0
2024	13	$3.0

Q. Did Tampa Electric prepare individual cost estimates for this program, including capital and operating expenses for access roads and access bridges?

A. Yes, the table below sets out the estimated costs for the program by year over the ten-year plan horizon, showing the access roads and access bridges portions.

	Total Transmission Access Enhancements Program Costs (in thousands)		
	Access Road Projects Costs	**Access Bridge Project Costs**	**Total Transmission Access Project Costs**
2022	$724	$1,686	$2,410
2023	$879	$2,158	$3,037
2024	$1,844	$1,163	$3,007
2025	$1,614	$2,089	$3,703
2026	$2,838	$608	$3,447
2027	$3,404	$0	$3,404
2028	$1,932	$1,211	$3,142
2029	$1,167	$1,672	$2,839
2030	$997	$1,043	$2,041
2031	$4,425	$0	$4,425

INFRASTRUCTURE INSPECTIONS

Q. Please provide a description of the Infrastructure Inspections program.

A. Thorough inspections of Tampa Electric’s poles, structures, and substations is critical for ensuring the system is maintained and resilient to a major storm event. This SPP program involves the inspections performed on the company’s T&D infrastructure, including all wooden distribution and transmission poles, transmission structures, and transmission substations, as well as the audit of all joint use attachments.

Q. Does Tampa Electric currently carry out infrastructure inspections?

A. Yes. Tampa Electric's Infrastructure Inspection program is part of a comprehensive program initiated by the Florida Public Service Commission for Florida investor-owned electric utilities to harden the electric system against severe weather and to identify unauthorized and unnoticed non-electric pole attachments which affect the loadings on poles. This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 20060078-EI, which requires each investor-owned electric utility to implement an inspection program of its wooden transmission, distribution, and lighting poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair or replacement to meet NESC strength requirements. Tampa Electric performs inspections of all wood poles on an eight-year cycle. Tampa Electric has approximately 285,000 wooden distribution and lighting poles and 26,000 transmission poles and structures that are part of the inspection program. Approximately 12.5 percent of the known pole population will be targeted for inspections annually, although the actual number of poles may vary from year to year due to recently constructed circuits, de-energized circuits, or reconfigured circuits.

Q. How will the Infrastructure Inspection program identify potential system issues?

A. The Tampa Electric Transmission System Inspection program identifies potential system issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. Formal inspection activities included in the program are ground line inspection, ground patrol, aerial infrared patrol, above ground inspection, and transmission substation inspections. Typically, the ground patrol, aerial infrared patrol, and substation inspections are performed every year while the above ground inspections and the ground line inspection are performed on an eight-year cycle.

The company also performs joint use audits and inspections to mitigate the impact unknown foreign attachments could create by placing additional loading on a facility. All Tampa Electric joint use agreements allow for periodic inspections and audits of joint use attachments to the company's facilities to be paid for by the attaching entities.

Q. Please explain how Tampa Electric's Infrastructure Inspections program will enhance the utility's existing transmission and distribution facilities?

A. Timely inspections and identification of required maintenance items can greatly reduce the impact of major storm events to the transmission and distribution system. Given that poles are critical to the integrity of the transmission and distribution grid, pole inspections are a key component of this SPP program. Pole failures during a major storm event can cause a significant impact since there is a high probability that the equipment attached to the pole also will be damaged. Cascading failures of other poles are also likely to occur. Specifically, wood poles pose the greatest risk of failure and must be maintained and eventually replaced given they are prone to deterioration. The eight-year wood pole inspection requirement put in place by the Florida Public Service Commission is aimed at identifying any problems with a pole so it can be mitigated before it causes a problem during a major storm event. In addition, the other FPSC required inspections included in this SPP program are aimed at identifying equipment issues that are compromised and that may create a vulnerability so that they can be addressed prior to causing a problem during a major storm event.

Q. Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Infrastructure Inspections program.

A. While Tampa Electric did not prepare estimates of the reduction in outage times and restoration costs for this program, as I previously discussed, inspections play a critical role in identifying issues with infrastructure and facilities so appropriate repairs can be made before a failure and resulting outage occurs. By doing so, the number of outages and outage times, not only during a major storm event, but also during day-to-day operations are significantly reduced. In addition, planned repairs of equipment and facilities identified through an inspection are significantly less costly than restoring after a failure or following a major storm event.

Q. Did Tampa Electric prepare a list of Infrastructure Inspections projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Tampa Electric conducts thousands of inspections each year, so rather than identify various projects the company has identified the number of inspections by type planned for 2022 through 2024, along with the estimated cost. The table below sets out this information. Typically, these inspections are conducted throughout the year and have no specific start and completion date, except for the bulk electric transmission and critical 69kV transmission substation and line inspections which are inspected first and prior to the peak of hurricane season each year.

Projected Number of Infrastructure Inspections			
	2022	**2023**	**2024**
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	35,625	35,625	16,625
Transmission			
Wood Pole/Groundline Inspections	663	479	401
Above Ground Inspections	3,386	2,641	2,702
Aerial Infrared Patrols	Annually	Annually	Annually
Ground Patrols	Annually	Annually	Annually
Substation Inspections	Annually	Annually	Annually

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. As I previously mentioned, Tampa Electric conducts thousands of inspections each year, and we did not identify specific projects or affected facilities. The company identified the number of inspections by type planned for 2022 through 2024. While all customers will certainly benefit from this SPP program, it is not practical to list specific customers or type of customers benefiting from a particular inspection.

Q. Would you explain in detail the methodology Tampa Electric used in prioritizing the projects the company is including in this Infrastructure Inspections program?

A. Tampa Electric typically prioritizes its inspections by age or date of last inspection. We also consider the following criteria:

- bulk electric transmission and critical 69kV transmission substations and lines are inspected first and prior to the peak of hurricane season each year,
- circuits are patrolled based on their criticality or priority ranking, and
- aerial infrared scans are scheduled in the summertime when load is highest, which improves the accuracy of the results.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. The estimated costs for this program include $1.6 million in 2022, $1.5 million in 2023, $1.6 million in 2024, and approximately $1.8 million in each year from 2025 through 2031. All costs associated with this program are O&M and are summarized in the following table.

Projected Costs of Infrastructure Inspections (in thousands)			
	2022	2023	2024
Distribution			
Wood Pole Inspections	$1,020	$1,040	$1,061
Transmission			
Wood Pole/Groundline Inspections	$62	$64	$65
Above Ground Inspections	$10	$11	$11
Aerial Infrared Patrols	$114	$117	$119
Ground Patrols	$201	$154	$157
Substation Inspections	$146	$146	$148

Q. Did Tampa Electric prepare a comparison of the estimated costs and benefits of the program?

A. Yes. The company has provided the costs associated with this program and a description of the benefits provided.

LEGACY STORM HARDENING INITIATIVES

Q. Please provide a description of the Legacy Storm Hardening Initiatives.

A. The company plans to continue several well-established storm protection activities that are referred to as legacy storm hardening plan initiatives. Tampa Electric believes these initiatives will continue to offer the storm resiliency benefits previously identified by the Commission. These initiatives include the Geographical Information System, Post-Storm Data Collection, Outage Data - Overhead and Underground Systems, Increase Coordination with Local Governments, Collaborative Research, Disaster Preparedness and Recovery Plan, and Distribution Pole Replacements.

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation, and distribution facilities. Regarding Post-Storm Data Collection, Tampa Electric has a formal process in place to randomly sample and collect system damage information following a major weather event. Tampa Electric has a Distribution Outage Database that it uses to track and store overhead and underground system outage data. Tampa Electric has an Emergency Preparedness team and representatives that will continue to focus on maintaining existing vital governmental contacts and participating on committees to collaborate in disaster recovery planning, protection, response, recovery, and mitigation efforts. Tampa Electric will also continue to participate in the 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 to reduce storm restoration costs and customer outage times. Tampa Electric will continue to maintain and improve its Disaster Preparedness and Emergency Response Plans and be active in many ongoing activities to support the improved restoration of the system before, during, and after storm activation. Tampa Electric's distribution pole replacement initiative starts with the company's distribution wood pole and groundline inspections and includes restoring, replacing, or upgrading those distribution facilities identified to meet or exceed the company's current storm hardening design and construction standards.

Q. Please explain how Tampa Electric's Legacy Storm Hardening Plan Initiatives will enhance the utility's existing transmission and distribution facilities.

A. As I mentioned, all these initiatives are well-established and have been in place since the Commission determined that they should be implemented and would provide benefits by enhancing the transmission and distribution system, reducing restoration costs and/or customer outage times.

Q. Did Tampa Electric prepare a cost estimate for this program, including capital and operating expenses?

A. Yes. In the table below, the company summarizes the expected capital and operating expenses for these initiatives during the 2022 through 2024 period. Tampa Electric plans to invest $12.5 million in 2022, $12.98 million in 2023, and $13.3 million in 2024 of capital for distribution pole replacements. There is an associated operating expense of $0.8 million in 2022, $0.8 million in 2023, and $0.9 million in 2024 for this activity. In addition, the company plans to incur approximately $0.3 million per year during 2022 through 2024 in operating expenses for Disaster Preparedness and Emergency Response activities.

	Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)	
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2022	$0.3	$13.3
2023	$0.3	$13.7
2024	$0.3	$14.1

ADHERENCE TO F.A.C. RULES AND STATUTORY REQUIREMENTS

Q. Does Tampa Electric’s 2022 SPP include all of the program-level detail required by Rule 25-6.030(3)(d) and the project-level detail required by Rule 25-6.030(3)(e)?

A. Yes. The 2022 SPP includes the required program-level detail for the eight storm protection programs described in my testimony. The 2022 SPP also includes the necessary project-level detail for the programs that contain SPP projects.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony demonstrates that the programs I discussed in Tampa Electric's proposed Storm Protection Plan are consistent with Rule 25-6.030(3)(d)-(e), F.A.C. My testimony also demonstrates that these programs will reduce restoration costs and outage times and enhance reliability in a cost-effective manner.

Q. Should Tampa Electric's proposed Distribution Lateral Undergrounding, Vegetation Management, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Transmission Access, Infrastructure Inspections, and Legacy Storm Hardening programs be approved?

A. Yes. These programs should be approved. The programs meet the requirements of Rule 25-6.030, and they are designed to strengthen the company's infrastructure to withstand extreme weather conditions, reduce restoration costs, reduce outage times, improve overall reliability, and increase customer satisfaction in a cost-effective manner.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

DAVID L. PLUSQUELLIC

Tampa Electric - Proposed 2022-2031 Storm Protection Plan
Projected Costs versus Benefits

Storm Protection Program	Projected Costs (in Millions)		Projected Reduction in Restoration Costs (Approximate Benefits in Percent)	Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)	Program Start Date	Program End Date
	Capital	O&M				
Distribution Lateral Undergrounding	$1,070.2	$2.0	32	45	Q2 2020	After 2031
Vegetation Management	$0.0	$324.8	21	22 to 29	Q2 2020	After 2031
Transmission Asset Upgrades	$139.1	$5.6	85	14	Q2 2020	2029
Substation Extreme Weather Hardening	$28.8	$0.0	20 to 25	12 to 45	Q1 2021	After 2031
Distribution Overhead Feeder Hardening	$316.9	$7.9	54	46	Q2 2020	After 2031
Transmission Access Enhancements	$31.5	$0.0	28	55	Q1 2021	After 2031

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Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details												
Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG CSA 13021.60058683	13021	0.31	28	130	11	1	142	3	Q1 - 2021	Q3 - 2022	Q4 - 2022	$634,109
LUG CSA 13021.92350282	13021	0.32	27	14	11	0	25	12	Q1 - 2021	Q4 - 2021	Q1 - 2022	$140,500
LUG CSA 13026.60059452	13026	0.16	11	64	7	2	73	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$152,871
LUG CSA 13026.60059457	13026	0.21	15	24	13	0	37	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$208,780
LUG CSA 13026.60059509	13026	0.09	8	84	11	2	97	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$86,294
LUG CSA 13026.60059524	13026	0.19	16	115	13	0	128	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$484,876
LUG CSA 13093.91004837	13093	0.19	17	143	29	3	175	18	Q3 - 2020	Q1 - 2022	Q2 - 2022	$664,205
LUG CSA 13099.10368943	13099	0.24	13	2	3	0	5	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$238,465
LUG CSA 13099.60125388	13099	0.43	24	68	5	0	73	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$747,872
LUG CSA 13099.90882614	13099	0.24	18	128	9	2	139	0	Q3 - 2020	Q2 - 2022	Q3 - 2022	$577,003
LUG CSA 13100.91340554	13100	0.41	28	403	7	3	413	0	Q4 - 2020	Q4 - 2022	Q3 - 2023	$154,711
LUG CSA 13102.60123654	13102	0.19	15	72	1	2	75	0	Q3 - 2020	Q3 - 2021	Q1 - 2022	$55,000
LUG CSA 13102.90748252	13102	0.23	23	29	2	1	32	0	Q2 - 2021	Q3 - 2022	Q4 - 2022	$854,885
LUG CSA 13102.91293905	13102	0.12	10	47	13	4	64	1	Q1 - 2021	Q2 - 2022	Q3 - 2022	$123,608
LUG CSA 13104.10362869	13104	0.38	30	67	20	3	90	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$497,526
LUG CSA 13104.91241032	13104	0.15	18	19	2	2	23	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$148,692
LUG CSA 13104.91643108	13104	0.34	33	74	19	1	94	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$430,742
LUG CSA 13104.91668251	13104	0.20	17	16	8	0	24	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$187,342
LUG CSA 13105.10580676	13105	0.13	13	14	3	0	17	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$14,000
LUG CSA 13105.10580689	13105	0.13	10	44	3	0	47	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$120,742
LUG CSA 13105.10580690	13105	0.23	21	122	15	1	138	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$238,847
LUG CSA 13105.60164901	13105	0.11	10	79	5	1	85	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$104,230
LUG CSA 13106.10361901	13106	0.75	52	274	21	0	295	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$188,155
LUG CSA 13106.91722510	13106	0.11	9	166	10	1	177	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$259,986
LUG CSA 13107.10376173	13107	0.44	28	119	27	2	148	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$389,527
LUG CSA 13107.10376186	13107	0.12	10	179	4	0	183	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$28,000
LUG CSA 13107.10376201	13107	0.13	10	8	1	0	9	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$130,871
LUG CSA 13158.60011810	13158	0.76	56	226	10	1	237	1	Q1 - 2021	Q1 - 2022	Q2 - 2022	$245,476
LUG CSA 13158.90816343	13158	0.25	18	123	4	1	128	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$612,548
LUG CSA 13158.91461782	13158	0.33	30	39	3	0	42	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$314,198
LUG CSA 13176.10375136	13176	0.66	57	11	9	11	31	2	Q1 - 2021	Q2 - 2022	Q4 - 2022	$621,962
LUG CSA 13176.10375141	13176	0.62	51	89	9	4	102	8	Q1 - 2021	Q4 - 2022	Q2 - 2023	$78,658
LUG CSA 13176.10375148	13176	0.48	54	26	5	3	34	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$131,000
LUG CSA 13188.10655453	13188	0.12	15	46	15	3	64	9	Q4 - 2020	Q3 - 2022	Q4 - 2022	$116,100
LUG CSA 13188.92070695	13188	0.17	11	17	2	0	19	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$83,831
LUG CSA 13204.60170504	13204	0.38	31	113	8	1	122	12	Q1 - 2021	Q2 - 2022	Q3 - 2022	$522,779
LUG CSA 13205.90022802	13205	0.20	18	20	5	1	26	6	Q1 - 2021	Q2 - 2022	Q3 - 2022	$262,324
LUG CSA 13205.90442230	13205	0.25	25	60	0	3	63	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$506,543
LUG CSA 13205.90929181	13205	0.20	15	32	19	2	53	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$380,641
LUG CSA 13354.10582069	13354	0.19	21	281	15	0	296	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$40,180
LUG CSA 13399.60037987	13399	0.19	19	19	13	4	36	11	Q1 - 2021	Q2 - 2022	Q3 - 2022	$400,026
LUG CSA 13418.91924595	13418	0.22	20	25	12	0	37	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$220,188
LUG CSA 13418.92018190	13418	0.33	21	79	5	1	85	6	Q1 - 2021	Q2 - 2022	Q4 - 2022	$323,959
LUG CSA 13418.92357188	13418	0.47	33	61	28	1	90	0	Q4 - 2020	Q3 - 2022	Q1 - 2023	$655,600
LUG CSA 13468.60128362	13468	0.53	38	147	32	0	179	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$494,945
LUG CSA 13468.60128378	13468	0.75	56	444	17	0	461	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$564,226

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Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail: OH to UG Length Converted (miles)	Specific Project Detail: Poles	Customers: Residential	Customers: Small C&I	Customers: Large C&I	Customers: Total	Priority Customers	Project Start Qtr	Construction: Start Qtr	Construction: End Qtr	Project Cost in 2022
LUG CSA 13468.91640192	13468	0.11	7	6	4	0	10	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$113,932
LUG CSA 13590.91231633	13590	0.34	29	47	11	2	60	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$142,000
LUG CSA 13592.91365233	13592	0.31	25	121	12	0	133	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$616,481
LUG CSA 13593.93057902	13593	0.45	39	83	52	4	139	0	Q4 - 2020	Q1 - 2022	Q3 - 2022	$368,400
LUG CSA 13632.10408272	13632	0.10	9	12	8	0	20	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$93,643
LUG CSA 13632.10408290	13632	1.02	55	245	10	0	255	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$948,857
LUG CSA 13632.60305848	13632	0.40	33	43	15	0	58	0	Q1 - 2021	Q4 - 2022	Q2 - 2023	$196,308
LUG CSA 13633.90564142	13633	0.07	3	2	1	0	3	0	Q2 - 2021	Q1 - 2022	Q2 - 2022	$60,945
LUG CSA 13633.91847345	13633	0.09	7	1	10	0	11	5	Q1 - 2021	Q4 - 2022	Q2 - 2023	$5,185
LUG CSA 13826.60127680	13826	0.27	13	243	17	2	262	1	Q2 - 2021	Q3 - 2022	Q4 - 2022	$81,217
LUG CSA 13831.10427677	13831	0.25	18	313	18	0	331	6	Q1 - 2021	Q2 - 2022	Q3 - 2022	$233,667
LUG CSA 13835.10429505	13835	0.20	17	41	5	2	48	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$541,441
LUG CSA 13835.10429522	13835	0.69	41	163	8	1	172	1	Q1 - 2021	Q2 - 2022	Q1 - 2023	$1,215,306
LUG CSA 13835.60314670	13835	0.21	18	256	15	1	272	0	Q1 - 2021	Q4 - 2022	Q1 - 2023	$102,548
LUG CSA 13836.91377944	13836	0.59	41	276	22	2	300	9	Q3 - 2020	Q4 - 2022	Q1 - 2023	$102,041
LUG CSA 13934.10467575	13934	0.09	6	1	3	3	7	3	Q1 - 2021	Q4 - 2021	Q1 - 2022	$33,500
LUG CSA 13934.10467597	13934	0.56	30	51	0	2	53	1	Q1 - 2021	Q2 - 2022	Q4 - 2022	$525,439
LUG CSA 13939.60144164	13939	0.12	8	38	6	4	48	5	Q1 - 2021	Q2 - 2022	Q3 - 2022	$112,739
LUG CSA 13939.60144172	13939	0.15	15	2	4	2	8	0	Q1 - 2021	Q4 - 2021	Q1 - 2022	$97,000
LUG CSA 13948.10442379	13948	0.14	12	5	0	1	6	1	Q3 - 2021	Q3 - 2022	Q4 - 2022	$137,902
LUG CSA 13948.10442391	13948	0.22	13	23	6	0	29	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$266,895
LUG CSA 13993.10372414	13993	0.42	27	31	3	2	36	1	Q1 - 2021	Q1 - 2022	Q3 - 2022	$429,829
LUG CSA 13993.10433144	13993	0.12	10	123	2	0	125	6	Q1 - 2021	Q1 - 2022	Q2 - 2022	$90,518
LUG CSA 14040.10786358	14040	0.43	19	12	3	0	15	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$137,793
LUG CSA 14040.10786382	14040	0.23	13	98	6	2	106	10	Q2 - 2020	Q1 - 2022	Q3 - 2022	$213,950
LUG CSA 14102.91582612	14102	0.30	18	136	6	0	142	0	Q1 - 2021	Q2 - 2022	Q3 - 2022	$278,492
LUG DCA 13006.92949400	13006	1.29	48	41	2	3	46	2	Q1 - 2021	Q3 - 2022	Q3 - 2023	$546,982
LUG DCA 13432.10761257	13432	1.21	38	21	8	1	30	0	Q2 - 2021	Q1 - 2022	Q4 - 2022	$821,238
LUG DCA 13815.93026469	13815	0.49	15	27	2	0	29	0	Q3 - 2020	Q4 - 2021	Q3 - 2022	$1,205,600
LUG ESA 13127.90334707	13127	0.36	24	150	4	0	154	11	Q1 - 2021	Q2 - 2023	Q1 - 2024	$60,345
LUG ESA 13127.90334731	13127	0.44	22	56	1	0	57	3	Q1 - 2021	Q2 - 2022	Q3 - 2022	$434,238
LUG ESA 13127.92661768	13127	0.53	34	170	3	0	173	1	Q4 - 2020	Q1 - 2023	Q3 - 2023	$25,000
LUG ESA 13127.92663180	13127	0.62	42	33	7	1	41	0	Q1 - 2021	Q1 - 2023	Q1 - 2024	$28,500
LUG ESA 13171.10455381	13171	0.12	11	5	18	1	24	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$30,449
LUG ESA 13171.90598389	13171	0.21	11	370	19	3	392	25	Q3 - 2020	Q2 - 2023	Q4 - 2023	$53,000
LUG ESA 13171.93104605	13171	0.36	21	48	2	2	52	4	Q4 - 2020	Q2 - 2023	Q4 - 2023	$11,000
LUG ESA 13174.10913196	13174	0.21	8	241	14	4	259	4	Q3 - 2020	Q3 - 2022	Q1 - 2023	$1,609,359
LUG ESA 13174.60588225	13174	0.29	15	374	34	1	409	1	Q3 - 2020	Q2 - 2022	Q3 - 2022	$165,000
LUG ESA 13211.60044019	13211	0.53	43	395	27	3	425	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$521,400
LUG ESA 13225.60139973	13225	0.81	54	41	26	6	73	8	Q3 - 2020	Q1 - 2023	Q1 - 2024	$101,000
LUG ESA 13226.10462583	13226	0.12	19	190	19	2	211	0	Q4 - 2020	Q2 - 2022	Q3 - 2022	$130,844
LUG ESA 13226.92664597	13226	0.31	16	348	4	0	352	0	Q4 - 2020	Q1 - 2023	Q2 - 2023	$11,000
LUG ESA 13226.92665539	13226	0.09	5	13	2	2	17	9	Q3 - 2020	Q2 - 2023	Q1 - 2024	$5,000
LUG ESA 13226.92670950	13226	0.20	23	37	15	5	57	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$213,000
LUG ESA 13229.92525393	13229	0.21	21	141	21	2	164	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$22,500
LUG ESA 13230.10471354	13230	0.44	38	49	41	8	98	27	Q4 - 2020	Q2 - 2023	Q1 - 2024	$15,000

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG ESA 13230.10471377	13230	0.48	31	54	2	2	58	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$18,000
LUG ESA 13230.92180224	13230	0.28	21	58	16	0	74	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$866,800
LUG ESA 13230.92496254	13230	0.29	23	12	8	0	20	8	Q1 - 2021	Q1 - 2023	Q2 - 2023	$53,170
LUG ESA 13231.10868121	13231	0.27	22	23	2	0	25	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$58,321
LUG ESA 13231.10868138	13231	0.54	34	269	17	4	290	8	Q4 - 2020	Q1 - 2023	Q3 - 2023	$112,000
LUG ESA 13433.10466911	13433	0.71	47	159	32	0	191	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$739,800
LUG ESA 13433.93369551	13433	0.61	37	5	3	2	10	2	Q3 - 2020	Q1 - 2023	Q3 - 2023	$16,000
LUG ESA 13454.90188551	13454	0.21	13	37	2	0	39	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$65,020
LUG ESA 13454.90397369	13454	0.49	26	19	10	1	30	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$343,370
LUG ESA 13454.90429155	13454	0.64	34	148	6	2	156	4	Q3 - 2020	Q3 - 2022	Q1 - 2023	$1,106,500
LUG ESA 13454.90755954	13454	0.30	23	292	21	1	314	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$216,950
LUG ESA 13454.91522987	13454	0.04	9	47	3	0	50	1	Q1 - 2021	Q3 - 2022	Q4 - 2022	$55,899
LUG ESA 13457.10482593	13457	0.14	9	137	8	2	147	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$30,049
LUG ESA 13457.90176591	13457	0.31	18	155	2	0	157	2	Q1 - 2021	Q2 - 2023	Q1 - 2024	$27,500
LUG ESA 13502.10497396	13502	0.30	22	70	2	0	72	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$44,796
LUG ESA 13502.92573944	13502	0.62	40	514	18	0	532	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$46,000
LUG ESA 13502.92679861	13502	0.18	16	50	25	0	75	0	Q4 - 2020	Q2 - 2022	Q3 - 2022	$188,706
LUG ESA 13509.10501110	13509	0.09	6	3	1	0	4	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$35,374
LUG ESA 13509.10501132	13509	0.11	6	7	22	11	40	1	Q4 - 2020	Q2 - 2023	Q1 - 2024	$10,300
LUG ESA 13509.10501141	13509	0.16	15	13	0	2	15	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13509.10501150	13509	0.51	33	37	7	0	44	0	Q3 - 2020	Q1 - 2023	Q1 - 2024	$73,000
LUG ESA 13509.60287236	13509	0.15	14	144	14	0	158	0	Q3 - 2020	Q2 - 2023	Q1 - 2024	$5,000
LUG ESA 13509.60346595	13509	0.15	10	14	1	1	16	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13509.90504849	13509	0.96	56	676	20	1	697	4	Q4 - 2020	Q2 - 2023	Q1 - 2024	$7,000
LUG ESA 13509.91772133	13509	0.05	8	22	0	1	23	1	Q3 - 2020	Q3 - 2022	Q4 - 2022	$94,000
LUG ESA 13509.92890860	13509	0.33	30	7	1	1	9	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$18,000
LUG ESA 13686.93697046	13686	0.40	14	14	0	0	14	1	Q1 - 2021	Q2 - 2023	Q1 - 2024	$23,500
LUG ESA 13710.92354144	13710	0.28	30	229	12	2	243	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$69,469
LUG ESA 13710.92881445	13710	0.45	32	158	17	0	175	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$586,222
LUG ESA 13793.92685255	13793	0.19	6	26	2	2	30	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$206,880
LUG ESA 13793.92686002	13793	0.23	17	1	7	6	14	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$25,774
LUG ESA 13793.92686712	13793	0.04	4	85	2	0	87	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$66,724
LUG ESA 13793.92686736	13793	0.03	4	85	4	1	90	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$57,250
LUG ESA 13796.10842823	13796	0.45	34	21	20	0	41	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$466,500
LUG ESA 13796.10842826	13796	0.15	13	353	11	0	364	0	Q4 - 2020	Q3 - 2022	Q4 - 2022	$156,000
LUG ESA 13796.92356181	13796	0.26	14	6	1	3	10	7	Q1 - 2021	Q3 - 2022	Q4 - 2022	$205,986
LUG ESA 13796.92728705	13796	0.45	34	318	6	1	325	0	Q4 - 2020	Q2 - 2023	Q1 - 2024	$13,000
LUG ESA 13796.92884623	13796	1.30	54	52	15	1	68	1	Q3 - 2020	Q1 - 2023	Q1 - 2024	$6,000
LUG ESA 13797.93185703	13797	0.04	5	2	0	1	3	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$60,875
LUG ESA 13797.93188519	13797	0.66	50	152	6	5	163	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$654,560
LUG ESA 13799.60395568	13799	0.46	45	260	16	1	277	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$43,000
LUG ESA 13878.10105717	13878	0.31	23	346	5	0	351	2	Q1 - 2021	Q2 - 2023	Q1 - 2024	$86,367
LUG ESA 13878.10105723	13878	0.31	25	46	37	8	91	4	Q1 - 2021	Q2 - 2023	Q1 - 2024	$22,500
LUG ESA 13878.10105726	13878	0.54	44	137	2	0	139	2	Q1 - 2021	Q1 - 2023	Q3 - 2023	$24,000
LUG ESA 13878.10105728	13878	0.23	14	26	0	0	26	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$59,996
LUG ESA 13883.91179506	13883	0.08	6	151	7	1	159	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$60,500
LUG ESA 13883.92008787	13883	0.06	8	3	0	1	4	0	Q3 - 2020	Q3 - 2022	Q4 - 2022	$66,050
LUG ESA 13906.10096960	13906	0.38	26	56	4	0	60	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$61,500
LUG ESA 13906.10096964	13906	0.68	40	31	2	3	36	10	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,500

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG ESA 13906.10096968	13906	0.56	53	99	9	5	113	12	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,250
LUG ESA 13906.90137810	13906	0.80	53	62	4	2	68	0	Q1 - 2021	Q2 - 2023	Q4 - 2023	$25,000
LUG ESA 13906.92282884	13906	0.10	7	26	2	1	29	0	Q1 - 2021	Q3 - 2022	Q4 - 2022	$119,524
LUG ESA 13909.90380435	13909	0.20	11	41	4	0	45	0	Q1 - 2021	Q2 - 2023	Q4 - 2023	$32,973
LUG ESA 13909.92173076	13909	0.31	22	8	10	4	22	6	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,500
LUG ESA 13911.10554595	13911	0.13	16	4	0	2	6	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$20,000
LUG ESA 13911.60157736	13911	0.05	5	62	1	0	63	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,850
LUG ESA 13911.60157737	13911	0.66	48	747	13	1	761	4	Q1 - 2021	Q1 - 2024	Q4 - 2024	$198,750
LUG ESA 13911.90130568	13911	0.86	53	108	18	0	126	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$22,500
LUG ESA 13911.91995336	13911	0.30	19	93	2	0	95	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$23,500
LUG ESA 13911.92679866	13911	0.56	50	80	27	0	107	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$27,500
LUG ESA 14116.60140011	14116	0.33	29	50	4	3	57	4	Q4 - 2020	Q1 - 2022	Q3 - 2022	$328,562
LUG ESA 14116.91073265	14116	0.09	7	10	8	0	18	0	Q1 - 2021	Q1 - 2024	Q1 - 2024	$34,748
LUG ESA 14355.60258173	14355	0.16	15	356	21	2	379	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$31,299
LUG ESA 14355.92354352	14355	0.32	22	51	3	3	57	1	Q1 - 2021	Q1 - 2024	Q1 - 2024	$21,250
LUG PCA 13120.60015632	13120	0.20	14	135	8	1	144	1	Q3 - 2020	Q4 - 2021	Q2 - 2022	$194,372
LUG PCA 13146.10629014	13146	0.54	30	91	6	0	97	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$56,106
LUG PCA 13243.90684154	13243	0.23	19	7	0	4	11	0	Q3 - 2021	Q1 - 2023	Q2 - 2023	$122,978
LUG PCA 13243.91351288	13243	0.29	18	223	18	0	241	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$298,166
LUG PCA 13268.10705945	13268	1.40	67	76	19	0	95	0	Q2 - 2021	Q1 - 2023	Q4 - 2023	$122,156
LUG PCA 13268.91633548	13268	0.89	48	216	23	2	241	1	Q1 - 2021	Q2 - 2022	Q1 - 2023	$802,646
LUG PCA 13268.92962459	13268	0.43	28	48	6	1	55	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$129,753
LUG PCA 13390.92599119	13390	0.72	46	266	27	3	296	0	Q3 - 2020	Q3 - 2021	Q2 - 2022	$1,511,052
LUG PCA 13655.90431393	13655	1.23	70	298	26	3	327	0	Q2 - 2021	Q1 - 2023	Q4 - 2023	$152,476
LUG PCA 13722.60360851	13722	0.21	17	124	18	1	143	0	Q1 - 2021	Q1 - 2023	Q4 - 2023	$185,066
LUG PCA 13724.10671229	13724	0.30	16	9	5	0	14	0	Q1 - 2021	Q4 - 2021	Q4 - 2022	$375,122
LUG PCA 13724.10671319	13724	1.76	83	181	35	2	218	0	Q1 - 2021	Q3 - 2022	Q3 - 2023	$1,803,592
LUG PCA 13724.10671334	13724	0.57	31	120	22	0	142	0	Q1 - 2021	Q3 - 2022	Q3 - 2023	$145,165
LUG PCA 13724.90911087	13724	0.54	32	31	4	0	35	6	Q3 - 2020	Q3 - 2022	Q2 - 2023	$340,878
LUG PCA 13724.91049435	13724	1.99	103	97	17	2	116	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$122,648
LUG PCA 13785.92299245	13785	1.08	57	174	10	0	184	0	Q1 - 2021	Q4 - 2021	Q4 - 2022	$1,001,289
LUG PCA 13785.92466250	13785	0.72	31	72	13	1	86	0	Q3 - 2020	Q4 - 2021	Q4 - 2022	$858,204
LUG PCA 13961.10696431	13961	0.16	8	4	0	2	6	4	Q1 - 2021	Q1 - 2023	Q3 - 2023	$54,732
LUG PCA 13961.10696486	13961	0.54	32	38	5	0	43	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$267,570
LUG PCA 13961.60193482	13961	0.48	35	118	13	4	135	0	Q3 - 2020	Q4 - 2021	Q3 - 2022	$225,732
LUG PCA 13961.91967308	13961	0.49	32	28	4	1	33	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$157,398
LUG PCA 13961.92820848	13961	0.49	26	509	10	2	521	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$196,174
LUG PCA 13961.92829453	13961	0.34	25	447	3	2	452	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$59,592
LUG PCA 13961.92834683	13961	0.72	37	23	4	1	28	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$789,692
LUG SHA 13001.10663240	13001	0.45	26	16	5	2	23	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$43,272
LUG SHA 13001.10663262	13001	0.09	8	63	4	0	67	10	Q1 - 2021	Q1 - 2024	Q4 - 2024	$21,500
LUG SHA 13001.10663269	13001	0.12	8	16	4	0	20	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 13001.60179144	13001	0.67	42	162	14	2	178	4	Q1 - 2021	Q1 - 2024	Q4 - 2024	$138,000
LUG SHA 13001.60179191	13001	0.36	30	139	11	1	151	1	Q1 - 2021	Q1 - 2024	Q4 - 2024	$60,020
LUG SHA 13001.92048269	13001	0.24	17	137	15	0	152	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$34,323
LUG SHA 13001.93346473	13001	0.81	48	483	22	3	508	5	Q1 - 2021	Q1 - 2024	Q4 - 2024	$47,114
LUG SHA 13003.10895211	13003	2.47	116	179	34	1	214	14	Q1 - 2021	Q1 - 2023	Q4 - 2023	$24,000
LUG SHA 13342.10925094	13342	0.33	22	45	12	1	58	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,500

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG SHA 13342.90527363	13342	0.16	10	29	5	0	34	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$500
LUG SHA 13342.91010293	13342	0.36	27	190	5	2	197	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$26,500
LUG SHA 13645.91519309	13645	0.50	22	36	3	1	40	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$551,702
LUG SHA 13645.92207754	13645	0.73	28	7	3	2	12	3	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 13652.92748361	13652	0.48	23	23	21	0	44	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$31,398
LUG SHA 13780.10723993	13780	0.27	17	97	4	0	101	1	Q1 - 2021	Q1 - 2024	Q4 - 2024	$38,097
LUG SHA 13817.10722417	13817	1.78	123	569	35	1	605	2	Q1 - 2021	Q1 - 2024	Q4 - 2024	$33,000
LUG SHA 13897.10933151	13897	0.79	33	64	20	1	85	1	Q3 - 2020	Q1 - 2022	Q3 - 2022	$785,112
LUG SHA 13900.10717269	13900	0.42	21	136	15	1	152	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$63,620
LUG SHA 13900.91863298	13900	0.27	18	169	3	0	172	8	Q1 - 2021	Q1 - 2024	Q4 - 2024	$100,465
LUG SHA 13900.92336596	13818	0.46	21	3	1	5	9	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$23,774
LUG SHA 14020.60223573	14020	0.48	45	415	8	3	426	2	Q1 - 2021	Q1 - 2024	Q4 - 2024	$24,250
LUG SHA 14022.90591555	14022	0.76	49	485	7	3	495	29	Q1 - 2021	Q2 - 2022	Q4 - 2022	$763,012
LUG SHA 14024.10747874	14024	0.15	13	135	7	0	142	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$40,998
LUG SHA 14024.90116190	14024	0.13	11	12	8	0	20	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$32,374
LUG WHA 13118.10535995	13118	0.95	63	363	15	0	378	0	Q1 - 2021	Q1 - 2022	Q4 - 2022	$937,189
LUG WHA 13118.10535999	13118	0.35	26	101	5	0	106	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$393,652
LUG WHA 13118.92204382	13118	0.69	41	88	6	0	94	0	Q2 - 2021	Q1 - 2022	Q1 - 2023	$867,707
LUG WHA 13118.92612349	13118	0.94	39	220	17	1	238	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$926,697
LUG WHA 13118.92659172	13118	0.27	26	18	10	3	31	1	Q1 - 2021	Q1 - 2023	Q3 - 2023	$207,720
LUG WHA 13296.10562361	13296	0.23	19	37	5	0	42	0	Q1 - 2021	Q2 - 2022	Q1 - 2023	$438,832
LUG WHA 13296.60531111	13296	0.95	68	90	14	2	106	1	Q1 - 2021	Q1 - 2022	Q1 - 2023	$888,621
LUG WHA 13296.90010289	13296	1.34	81	82	12	1	95	4	Q1 - 2021	Q1 - 2022	Q1 - 2023	$1,206,963
LUG WHA 13296.92376304	13296	0.29	20	200	18	0	218	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$342,484
LUG WHA 13297.10560425	13297	0.31	21	72	3	4	79	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$747,463
LUG WHA 13297.10560432	13297	0.43	29	362	6	0	368	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$713,526
LUG WHA 13297.60269456	13297	0.31	30	59	32	4	95	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$359,801
LUG WHA 13312.60182741	13312	0.15	15	52	11	7	70	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$102,002
LUG WHA 13313.10684581	13313	0.24	23	38	7	3	48	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$302,581
LUG WHA 13313.10684614	13313	0.14	16	106	16	3	125	0	Q3 - 2021	Q1 - 2022	Q1 - 2023	$246,592
LUG WHA 13313.90084626	13313	0.09	9	35	78	10	123	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$439,597
LUG WHA 13314.10567076	13314	0.42	32	89	3	2	94	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$417,912
LUG WHA 13473.60168916	13473	0.34	24	419	22	1	442	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$241,437
LUG WHA 13473.60168942	13473	0.35	27	187	7	1	195	0	Q3 - 2021	Q1 - 2022	Q4 - 2022	$411,291
LUG WHA 13473.92097460	13473	0.24	19	152	5	0	157	0	Q2 - 2021	Q3 - 2023	Q1 - 2024	$279,503
LUG WHA 13699.10637240	13699	1.02	48	137	3	1	141	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$690,882
LUG WHA 13699.10637242	13699	0.62	37	284	27	1	312	0	Q1 - 2021	Q1 - 2022	Q1 - 2023	$621,815
LUG WHA 13699.10637247	13699	0.19	11	119	5	0	124	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$150,226
LUG WHA 13699.10637259	13699	0.16	13	26	4	0	30	0	Q1 - 2021	Q4 - 2022	Q3 - 2023	$169,173
LUG WHA 13699.60165416	13699	0.36	18	10	20	1	31	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$180,975
LUG WHA 13916.60279623	13916	0.19	9	282	15	1	298	0	Q1 - 2021	Q3 - 2022	Q2 - 2023	$337,807
LUG WHA 13916.91386005	13916	0.53	36	199	6	0	205	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$596,018
LUG WHA 13916.92509975	13916	0.45	35	71	18	0	89	0	Q1 - 2021	Q1 - 2024	Q4 - 2024	$402,018
LUG WHA 13972.10618037	13972	0.25	13	1	2	2	5	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$311,368
LUG WHA 13972.90241880	13972	0.90	49	130	7	6	143	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$54,732
LUG WHA 13972.92421291	13972	0.44	23	379	6	1	386	0	Q3 - 2020	Q1 - 2023	Q3 - 2023	$54,798
LUG WSA 13059.60302601	13059	0.51	51	291	18	2	311	0	Q2 - 2021	Q3 - 2022	Q3 - 2023	$95,048
LUG WSA 13071.60170422	13071	0.99	74	362	11	3	376	10	Q3 - 2020	Q1 - 2022	Q2 - 2023	$1,451,994
LUG WSA 13071.92377934	13071	0.98	66	63	7	0	70	0	Q2 - 2021	Q4 - 2022	Q4 - 2023	$95,048

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Project ID	Circuit No.	Specific Project Detail: OH to UG Length Converted (miles)	Specific Project Detail: Poles	Customers: Residential	Customers: Small C&I	Customers: Large C&I	Customers: Total	Priority Customers	Project Start Qtr	Construction: Start Qtr	Construction: End Qtr	Project Cost in 2022
LUG WSA 13078.10127955	13078	0.18	15	33	2	1	36	1	Q1 - 2021	Q3 - 2022	Q1 - 2023	$208,039
LUG WSA 13078.10127958	13078	0.75	35	554	7	2	563	18	Q1 - 2021	Q3 - 2022	Q3 - 2023	$65,585
LUG WSA 13079.60077605	13079	0.18	17	32	6	5	43	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$159,727
LUG WSA 13079.60077624	13079	0.34	30	58	4	5	67	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13079.60104344	13079	0.14	21	25	8	6	39	3	Q1 - 2021	Q4 - 2021	Q2 - 2022	$172,906
LUG WSA 13079.90517178	13079	0.13	16	56	10	3	69	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$64,432
LUG WSA 13109.60233901	13109	0.47	42	282	9	0	291	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13109.90643551	13109	0.67	50	95	10	4	109	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$45,331
LUG WSA 13111.60072751	13111	0.20	17	18	1	2	21	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$318,842
LUG WSA 13111.92999604	13111	0.42	32	61	9	2	72	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13113.90422522	13113	0.11	6	3	5	4	12	6	Q3 - 2021	Q4 - 2022	Q2 - 2023	$65,585
LUG WSA 13113.90796385	13113	0.51	34	233	19	1	253	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$565,310
LUG WSA 13113.92909503	13113	0.07	9	215	8	0	223	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$68,672
LUG WSA 13138.10145618	13138	0.07	6	92	2	0	94	0	Q1 - 2021	Q1 - 2022	Q2 - 2022	$40,845
LUG WSA 13138.10145628	13138	0.30	18	352	5	4	361	0	Q3 - 2020	Q4 - 2021	Q2 - 2022	$335,531
LUG WSA 13138.60170460	13138	0.26	23	170	9	0	179	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$344,455
LUG WSA 13140.10013916	13140	0.10	13	143	7	4	154	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13141.10147344	13141	0.10	7	12	6	1	19	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$77,386
LUG WSA 13141.10147371	13141	0.47	49	94	3	1	98	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$65,585
LUG WSA 13141.91575422	13141	0.10	8	34	1	1	36	25	Q2 - 2021	Q3 - 2022	Q1 - 2023	$102,197
LUG WSA 13141.92442350	13141	0.09	13	12	0	1	13	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13162.10158432	13162	0.16	10	61	3	0	64	12	Q1 - 2021	Q1 - 2022	Q3 - 2022	$93,356
LUG WSA 13162.10158434	13162	0.38	30	47	23	3	73	6	Q2 - 2021	Q4 - 2022	Q2 - 2023	$235,331
LUG WSA 13162.90435139	13162	0.30	24	23	50	5	78	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13162.92185426	13162	0.37	26	19	23	16	58	0	Q4 - 2020	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13162.93124277	13162	0.16	23	5	15	5	25	5	Q1 - 2021	Q3 - 2022	Q1 - 2023	$162,652
LUG WSA 13164.90252716	13164	0.22	15	59	13	2	74	3	Q1 - 2022	Q3 - 2023	Q1 - 2024	$65,585
LUG WSA 13192.90932106	13192	0.19	13	2	2	5	9	9	Q1 - 2021	Q1 - 2022	Q3 - 2022	$145,753
LUG WSA 13194.90645535	13194	1.10	50	285	2	0	287	0	Q1 - 2021	Q1 - 2023	Q3 - 2023	$65,585
LUG WSA 13198.10051851	13198	0.21	21	33	50	2	85	6	Q2 - 2021	Q3 - 2022	Q1 - 2023	$195,985
LUG WSA 13198.10051875	13198	0.10	8	20	2	2	24	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$165,711
LUG WSA 13198.10051896	13198	0.13	11	18	2	1	21	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$120,993
LUG WSA 13198.92183966	13198	0.17	12	86	26	4	116	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$308,073
LUG WSA 13198.92655424	13198	0.09	8	11	7	2	20	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$174,469
LUG WSA 13207.90146892	13207	0.26	25	60	9	4	73	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13207.90147316	13207	0.20	17	23	33	0	56	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$65,585
LUG WSA 13207.90613782	13207	0.38	31	64	1	2	67	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13208.92767537	13208	0.18	18	117	3	1	121	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$90,410
LUG WSA 13220.10191173	13220	0.52	45	66	17	4	87	9	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13220.90901917	13220	0.49	38	55	18	0	73	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$435,674
LUG WSA 13333.10007588	13333	0.16	16	16	31	2	49	0	Q1 - 2021	Q4 - 2022	Q2 - 2023	$88,822
LUG WSA 13333.91785740	13333	0.23	26	13	34	3	50	0	Q4 - 2020	Q1 - 2022	Q3 - 2022	$147,334
LUG WSA 13334.91645657	13334	0.48	46	142	7	1	150	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13425.10244449	13425	0.70	33	195	12	4	211	0	Q3 - 2020	Q3 - 2021	Q2 - 2022	$89,889
LUG WSA 13428.90423835	13428	0.26	16	208	1	0	209	12	Q1 - 2021	Q1 - 2022	Q3 - 2022	$127,958
LUG WSA 13428.91540495	13428	0.23	30	402	20	1	423	1	Q3 - 2020	Q1 - 2022	Q3 - 2022	$353,202
LUG WSA 13483.60393455	13483	1.32	100	525	31	1	557	4	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13490.92815117	13490	0.17	13	163	2	1	166	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$181,351
LUG WSA 13491.10230118	13491	0.51	36	94	2	4	100	2	Q3 - 2020	Q3 - 2021	Q1 - 2022	$147,296

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG WSA 13491.91827162	13491	0.24	21	34	1	1	36	7	Q2 - 2021	Q2 - 2022	Q4 - 2022	$137,390
LUG WSA 13510.10218990	13510	0.36	37	20	18	2	40	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13514.10624934	13514	0.24	20	18	0	1	19	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$95,048
LUG WSA 13514.91361858	13514	0.16	18	70	7	0	77	19	Q1 - 2021	Q3 - 2022	Q1 - 2023	$157,419
LUG WSA 13516.60169592	13516	0.26	19	11	16	4	31	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$267,994
LUG WSA 13520.10242257	13520	0.45	44	28	9	4	41	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$59,733
LUG WSA 13522.10392874	13522	0.16	12	4	6	4	14	10	Q1 - 2021	Q3 - 2022	Q1 - 2023	$121,523
LUG WSA 13522.10392882	13522	0.69	61	162	8	0	170	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$65,585
LUG WSA 13522.10392902	13522	0.67	68	103	30	3	136	0	Q3 - 2021	Q1 - 2023	Q3 - 2023	$90,410
LUG WSA 13522.10392905	13522	0.47	50	105	5	3	113	1	Q2 - 2021	Q4 - 2022	Q2 - 2023	$274,069
LUG WSA 13522.10392924	13522	0.12	9	10	3	2	15	0	Q2 - 2021	Q4 - 2022	Q3 - 2023	$65,585
LUG WSA 13522.60305720	13522	0.07	6	10	0	1	11	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$64,556
LUG WSA 13522.91947423	13522	0.53	50	47	10	3	60	5	Q2 - 2021	Q3 - 2022	Q1 - 2023	$399,056
LUG WSA 13522.92169062	13522	0.32	29	77	13	0	90	0	Q2 - 2021	Q1 - 2023	Q3 - 2023	$66,535
LUG WSA 13533.91957169	13533	0.24	21	354	15	3	372	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$251,855
LUG WSA 13535.91618829	13535	0.50	34	70	4	1	75	0	Q3 - 2021	Q1 - 2023	Q3 - 2023	$79,177
LUG WSA 13535.92952190	13535	0.26	18	78	2	0	80	0	Q4 - 2020	Q2 - 2022	Q4 - 2022	$220,147
LUG WSA 13535.92983661	13535	0.33	32	10	0	3	13	0	Q3 - 2021	Q2 - 2022	Q4 - 2022	$266,452
LUG WSA 13535.92983670	13535	0.21	14	164	10	1	175	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$198,828
LUG WSA 13544.10053269	13544	0.16	16	19	2	0	21	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$41,888
LUG WSA 13574.10250638	13574	0.17	12	10	6	4	20	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$97,586
LUG WSA 13575.90054386	13575	0.10	13	105	8	3	116	1	Q1 - 2021	Q3 - 2022	Q1 - 2023	$120,188
LUG WSA 13575.90054924	13575	0.11	12	238	2	0	240	5	Q1 - 2021	Q1 - 2022	Q3 - 2022	$139,012
LUG WSA 13586.10255333	13586	0.12	9	4	1	0	5	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$21,744
LUG WSA 13586.60303627	13586	1.07	67	69	8	5	82	0	Q3 - 2020	Q3 - 2022	Q1 - 2023	$678,421
LUG WSA 13586.91748729	13586	0.67	42	45	0	3	48	0	Q2 - 2021	Q2 - 2023	Q1 - 2024	$90,410
LUG WSA 13586.92442286	13586	0.49	40	180	7	0	187	1	Q4 - 2021	Q4 - 2022	Q4 - 2023	$65,585
LUG WSA 13589.93162023	13589	0.33	16	1	5	0	6	5	Q2 - 2021	Q2 - 2022	Q4 - 2022	$149,295
LUG WSA 13589.93177909	13589	0.12	6	33	13	0	46	0	Q1 - 2021	Q3 - 2021	Q1 - 2022	$24,024
LUG WSA 13605.91052996	13605	0.33	27	115	12	0	127	0	Q3 - 2020	Q1 - 2022	Q3 - 2022	$783,754
LUG WSA 13612.60002970	13612	0.25	23	131	3	1	135	0	Q1 - 2021	Q4 - 2021	Q2 - 2022	$178,914
LUG WSA 13612.60003135	13612	0.30	33	81	3	1	85	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13612.60022877	13612	0.06	7	22	11	0	33	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$177,279
LUG WSA 13612.90291123	13612	0.13	15	10	9	1	20	0	Q2 - 2021	Q2 - 2023	Q1 - 2024	$90,410
LUG WSA 13612.90312305	13612	0.09	7	72	4	1	77	0	Q1 - 2021	Q2 - 2023	Q1 - 2024	$95,048
LUG WSA 13612.92956326	13612	0.23	25	20	12	4	36	8	Q2 - 2021	Q4 - 2022	Q2 - 2023	$282,540
LUG WSA 13669.60107076	13669	0.12	9	4	1	4	9	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$131,883
LUG WSA 13669.92770538	13669	0.30	37	204	10	0	214	1	Q2 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 13670.93124410	13670	0.71	25	383	3	1	387	0	Q3 - 2020	Q2 - 2022	Q4 - 2022	$289,213
LUG WSA 13672.10493801	13672	0.58	43	368	9	1	378	8	Q2 - 2021	Q2 - 2023	Q1 - 2024	$65,585
LUG WSA 13672.60106849	13672	0.27	26	256	12	0	268	0	Q4 - 2020	Q3 - 2022	Q1 - 2023	$226,557
LUG WSA 13672.91971930	13672	0.19	19	27	3	1	31	3	Q2 - 2021	Q2 - 2023	Q1 - 2024	$95,048
LUG WSA 13674.10277747	13674	0.57	36	361	6	1	368	2	Q1 - 2021	Q1 - 2022	Q3 - 2022	$269,611
LUG WSA 13674.90420693	13674	0.32	29	125	0	0	125	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$65,585
LUG WSA 13678.10254063	13678	0.28	18	11	6	0	17	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$223,422
LUG WSA 13678.10288738	13678	0.58	28	4	1	0	5	0	Q3 - 2021	Q3 - 2022	Q1 - 2023	$431,533
LUG WSA 13678.90514672	13678	0.54	29	9	5	0	14	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$361,928
LUG WSA 13737.10297934	13737	0.20	18	24	1	1	26	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$151,121
LUG WSA 13737.10297943	13737	0.20	18	84	5	3	92	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$515,924

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
EXHIBIT NO. DLP-1
WITNESS: PLUSQUELLIC
DOCUMENT NO. 2

FILED: 04/11/2022

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
LUG WSA 13737.60311396	13737	0.19	8	16	13	0	29	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$169,528
LUG WSA 13737.90740214	13737	0.10	12	15	3	0	18	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$90,477
LUG WSA 13737.90740699	13737	0.17	13	17	4	0	21	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$136,971
LUG WSA 13737.91960399	13737	0.43	32	56	3	3	62	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$243,489
LUG WSA 13738.10298299	13738	0.31	27	71	7	4	82	0	Q3 - 2021	Q3 - 2023	Q1 - 2024	$66,535
LUG WSA 13747.10299739	13747	0.10	5	128	16	2	146	0	Q3 - 2020	Q4 - 2021	Q1 - 2022	$28,010
LUG WSA 13750.60110680	13750	0.19	12	43	6	0	49	0	Q1 - 2021	Q1 - 2022	Q3 - 2022	$91,376
LUG WSA 13756.10589587	13756	0.14	13	8	4	0	12	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$170,400
LUG WSA 13756.10589595	13756	0.25	22	93	7	0	100	0	Q2 - 2021	Q4 - 2022	Q2 - 2023	$105,022
LUG WSA 13756.60165355	13756	0.08	12	55	10	3	68	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$115,052
LUG WSA 13756.90207831	13756	0.38	36	181	18	1	200	44	Q2 - 2021	Q2 - 2023	Q4 - 2023	$59,733
LUG WSA 13860.10307212	13860	0.25	28	2	20	9	31	0	Q1 - 2021	Q2 - 2022	Q4 - 2022	$172,514
LUG WSA 13860.10307215	13860	0.28	26	219	17	4	240	3	Q1 - 2021	Q3 - 2022	Q1 - 2023	$255,757
LUG WSA 13863.60279838	13863	0.47	32	259	5	0	264	2	Q1 - 2021	Q4 - 2022	Q2 - 2023	$340,427
LUG WSA 13864.10310477	13864	0.71	57	18	233	67	318	16	Q3 - 2021	Q3 - 2022	Q1 - 2023	$573,160
LUG WSA 13864.10310497	13864	0.15	10	10	41	9	60	2	Q2 - 2021	Q4 - 2022	Q2 - 2023	$319,952
LUG WSA 13864.10310505	13864	0.51	41	3	49	31	83	6	Q1 - 2021	Q1 - 2022	Q3 - 2022	$491,417
LUG WSA 13864.60380454	13864	0.16	13	1	1	1	3	1	Q1 - 2021	Q3 - 2021	Q1 - 2022	$47,404
LUG WSA 13865.90531031	13865	0.26	19	21	11	5	37	9	Q1 - 2021	Q2 - 2023	Q4 - 2023	$59,733
LUG WSA 13870.90428273	13870	0.40	25	104	8	0	112	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$318,493
LUG WSA 13873.60311122	13873	0.79	61	235	7	3	245	3	Q3 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 13892.10338448	13892	1.11	71	256	8	2	266	2	Q3 - 2021	Q2 - 2023	Q1 - 2024	$59,733
LUG WSA 14030.60125643	14030	0.09	14	101	3	0	104	1	Q1 - 2021	Q2 - 2022	Q4 - 2022	$70,413
LUG WSA 14030.60341032	14030	0.13	10	81	1	0	82	0	Q2 - 2021	Q2 - 2022	Q4 - 2022	$94,885
LUG WSA 14030.90886759	14030	0.54	49	161	15	1	177	12	Q2 - 2021	Q2 - 2023	Q1 - 2024	$79,177
LUG WSA 14030.92669557	14030	0.01	5	78	12	0	90	0	Q2 - 2021	Q3 - 2022	Q1 - 2023	$91,249
LUG WSA 14030.92669942	14030	0.56	34	112	6	0	118	0	Q2 - 2021	Q1 - 2023	Q1 - 2024	$66,535
LUG WSA 14030.92670479	14030	0.11	6	3	3	0	6	0	Q1 - 2021	Q3 - 2022	Q1 - 2023	$100,348
Lateral Hardening-Fuse-10007252,1	13737	0.09	9	4	0	1	5	0	Q3 - 2022	Q1 - 2023	Q2 - 2023	$28,850
Lateral Hardening-Fuse-10050730,3	13199	0.53	52	271	22	0	293	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$174,719
Lateral Hardening-Fuse-10051863,1	13198	0.08	10	62	5	0	67	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$25,236
Lateral Hardening-Fuse-10055000,2	13419	0.36	28	33	11	0	44	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$118,639
Lateral Hardening-Fuse-10055941,1	13420	0.15	10	4	1	1	6	0	Q3 - 2022	Q2 - 2023	Q1 - 2024	$48,228
Lateral Hardening-Fuse-10075304,1	13656	0.11	4	2	0	1	3	3	Q4 - 2022	Q1 - 2024	Q3 - 2024	$36,639
Lateral Hardening-Fuse-10075336,1	13656	0.19	15	17	2	5	24	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,931
Lateral Hardening-Fuse-10087587,1	13389	0.10	6	5	4	0	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$32,962
Lateral Hardening-Fuse-10089965,1	13279	0.09	12	10	2	1	13	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$29,722
Lateral Hardening-Fuse-10092875,1	13611	0.25	26	119	2	1	122	75	Q2 - 2022	Q2 - 2023	Q1 - 2024	$81,128
Lateral Hardening-Fuse-10093646,2	13043	0.38	26	47	2	1	50	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$123,873
Lateral Hardening-Fuse-10093658,1	13043	0.10	11	19	1	1	21	0	Q1 - 2022	Q1 - 2023	Q3 - 2023	$32,775
Lateral Hardening-Fuse-10093683,1	13043	0.09	8	8	4	2	14	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$27,977
Lateral Hardening-Fuse-10100716,1	13048	0.44	44	85	2	1	88	12	Q3 - 2022	Q3 - 2022	Q1 - 2023	$145,371
Lateral Hardening-Fuse-10100722,1	13048	0.06	6	14	4	0	18	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$20,438
Lateral Hardening-Fuse-10101247,3	13046	0.41	41	57	2	2	61	5	Q2 - 2022	Q3 - 2023	Q1 - 2024	$134,217
Lateral Hardening-Fuse-10120786,1	13053	0.26	28	73	11	0	84	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$83,932
Lateral Hardening-Fuse-10120788,1	13053	0.26	23	38	2	1	41	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$84,369
Lateral Hardening-Fuse-10124545,1	13063	0.29	26	43	3	1	47	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$96,519
Lateral Hardening-Fuse-10126980,1	13065	0.23	23	35	4	0	39	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$77,203
Lateral Hardening-Fuse-10142238,1	13034	0.18	15	16	1	1	18	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$59,195

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Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-10144159,1	13123	0.56	38	8	34	3	45	17	Q3 - 2022	Q1 - 2024	Q3 - 2024	$184,626
Lateral Hardening-Fuse-10147338,1	13141	0.19	22	56	2	0	58	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$62,311
Lateral Hardening-Fuse-10153131,1	13154	0.11	14	5	14	4	23	10	Q2 - 2022	Q3 - 2023	Q1 - 2024	$36,265
Lateral Hardening-Fuse-10158932,1	13164	0.09	10	12	0	1	13	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$30,283
Lateral Hardening-Fuse-10160212,1	13167	0.07	8	51	4	0	55	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$23,803
Lateral Hardening-Fuse-10163224,4	13091	0.41	41	50	7	0	57	0	Q2 - 2022	Q2 - 2022	Q1 - 2023	$135,526
Lateral Hardening-Fuse-10163228,1	13091	0.14	15	16	10	0	26	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$45,611
Lateral Hardening-Fuse-10165356,4	13045	0.68	62	81	15	4	100	7	Q2 - 2022	Q2 - 2023	Q4 - 2023	$223,633
Lateral Hardening-Fuse-10165381,2	13045	0.31	28	53	14	3	70	0	Q2 - 2022	Q2 - 2023	Q1 - 2024	$100,881
Lateral Hardening-Fuse-10165382,1	13045	0.04	5	6	10	1	17	0	Q3 - 2022	Q2 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-10165789,1	13072	0.22	18	16	13	3	32	8	Q3 - 2022	Q1 - 2024	Q3 - 2024	$73,153
Lateral Hardening-Fuse-10165797,1	13072	0.15	15	6	6	1	13	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$48,228
Lateral Hardening-Fuse-10165803,1	13072	0.12	12	8	1	2	11	0	Q2 - 2022	Q1 - 2024	Q2 - 2024	$39,131
Lateral Hardening-Fuse-10167762,1	13206	0.18	20	24	3	1	28	2	Q3 - 2022	Q1 - 2024	Q2 - 2024	$60,566
Lateral Hardening-Fuse-10173494,1	13191	0.21	20	20	1	2	23	1	Q2 - 2022	Q2 - 2023	Q1 - 2024	$67,732
Lateral Hardening-Fuse-10173500,1	13191	0.21	17	47	5	0	52	0	Q3 - 2022	Q1 - 2024	Q2 - 2024	$70,536
Lateral Hardening-Fuse-10173522,1	13191	0.35	34	4	25	8	37	9	Q2 - 2022	Q1 - 2024	Q2 - 2024	$114,714
Lateral Hardening-Fuse-10218987,1	13510	0.09	10	206	11	2	219	1	Q3 - 2022	Q1 - 2024	Q2 - 2024	$28,040
Lateral Hardening-Fuse-10247860,1	13533	0.04	5	45	2	0	47	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-10274748,1	13624	0.28	19	22	3	0	25	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$91,970
Lateral Hardening-Fuse-10297412,1	13754	0.06	8	10	0	1	11	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$19,441
Lateral Hardening-Fuse-10297440,1	13754	0.12	14	87	3	0	90	0	Q2 - 2022	Q1 - 2024	Q2 - 2024	$38,072
Lateral Hardening-Fuse-10297442,1	13754	0.14	16	33	12	2	47	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$45,362
Lateral Hardening-Fuse-10361894,1	13106	0.13	10	35	2	2	39	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$43,493
Lateral Hardening-Fuse-10362869,3	13104	0.62	47	67	20	3	90	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$63,016
Lateral Hardening-Fuse-10363933,1	13096	0.13	8	6	2	1	9	8	Q3 - 2022	Q3 - 2023	Q1 - 2024	$42,994
Lateral Hardening-Fuse-10382337,1	13224	0.09	10	15	2	1	18	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$28,663
Lateral Hardening-Fuse-10384706,1	13351	0.11	8	26	3	0	29	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$36,140
Lateral Hardening-Fuse-10384723,1	13351	0.26	20	65	6	1	72	1	Q2 - 2022	Q2 - 2023	Q4 - 2023	$84,182
Lateral Hardening-Fuse-10389247,2	13365	0.38	35	206	6	0	212	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$125,556
Lateral Hardening-Fuse-10392877,1	13522	0.09	11	10	2	1	13	8	Q3 - 2022	Q1 - 2024	Q3 - 2024	$30,719
Lateral Hardening-Fuse-10424221,1	13828	0.05	4	2	1	6	9	8	Q1 - 2022	Q2 - 2023	Q4 - 2023	$15,640
Lateral Hardening-Fuse-10425054,1	13829	0.12	9	48	7	0	55	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$39,131
Lateral Hardening-Fuse-10427678,1	13831	0.05	4	36	3	0	39	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$15,266
Lateral Hardening-Fuse-10429550,1	13835	0.21	16	32	5	0	37	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$68,791
Lateral Hardening-Fuse-10457713,1	13229	0.05	8	42	4	0	46	7	Q2 - 2022	Q1 - 2024	Q4 - 2024	$18,008
Lateral Hardening-Fuse-10475330,1	14117	0.16	14	5	5	3	13	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$52,590
Lateral Hardening-Fuse-10477228,1	13326	0.19	14	8	16	5	29	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$62,061
Lateral Hardening-Fuse-10535991,1	13115	0.25	20	25	0	1	26	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$83,870
Lateral Hardening-Fuse-10545847,1	13910	0.08	6	6	1	1	8	1	Q2 - 2022	Q1 - 2025	Q4 - 2025	$27,853
Lateral Hardening-Fuse-10565125,1	13291	0.17	16	19	1	1	21	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$54,522
Lateral Hardening-Fuse-10565130,1	13291	0.21	20	20	3	1	24	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$70,536
Lateral Hardening-Fuse-10565136,1	13291	0.13	13	14	3	2	19	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$44,241
Lateral Hardening-Fuse-10565887,1	13290	0.35	34	129	7	0	136	0	Q1 - 2022	Q1 - 2025	Q4 - 2025	$114,278
Lateral Hardening-Fuse-10565895,1	13290	0.07	9	15	5	0	20	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$23,366
Lateral Hardening-Fuse-10572982,1	13371	0.17	15	17	9	0	26	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$56,266
Lateral Hardening-Fuse-10589590,1	13756	0.14	21	29	2	0	31	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$46,982
Lateral Hardening-Fuse-10616460,1	13124	0.07	8	11	1	0	12	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$22,432
Lateral Hardening-Fuse-10625698,1	13011	0.25	21	28	2	0	30	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$81,752

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-10632726,1	13312	0.12	17	7	7	3	17	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$39,318
Lateral Hardening-Fuse-10632727,1	13312	0.12	12	24	14	0	38	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$40,689
Lateral Hardening-Fuse-10633695,1	13241	0.06	4	8	3	0	11	0	Q3 - 2022	Q1 - 2025	Q4 - 2025	$21,186
Lateral Hardening-Fuse-10637218,1	13696	0.24	26	25	7	0	32	0	Q2 - 2022	Q1 - 2025	Q4 - 2025	$79,820
Lateral Hardening-Fuse-10640103,1	13724	0.18	16	2	4	3	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$60,566
Lateral Hardening-Fuse-10668889,1	13723	0.51	20	29	4	0	33	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$166,556
Lateral Hardening-Fuse-10671179,1	13724	0.03	5	2	2	0	4	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-10674224,1	13414	0.10	9	7	0	1	8	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$31,280
Lateral Hardening-Fuse-10674240,1	13414	0.17	14	21	3	1	25	6	Q3 - 2022	Q1 - 2024	Q3 - 2024	$56,329
Lateral Hardening-Fuse-10674784,1	13464	0.49	33	55	3	0	58	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$162,319
Lateral Hardening-Fuse-10675160,1	13464	0.21	10	21	7	0	28	2	Q3 - 2022	Q1 - 2024	Q3 - 2024	$69,165
Lateral Hardening-Fuse-10686006,1	13808	0.29	19	2	0	3	5	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$94,712
Lateral Hardening-Fuse-10688316,1	13068	0.10	10	9	7	0	16	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$33,710
Lateral Hardening-Fuse-10692795,1	13463	0.07	6	12	2	0	14	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$23,927
Lateral Hardening-Fuse-10692803,1	13463	0.09	7	13	2	0	15	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$29,161
Lateral Hardening-Fuse-10696420,1	13961	0.07	9	18	2	0	20	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$23,553
Lateral Hardening-Fuse-10696464,1	13961	0.05	4	2	2	0	4	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$16,824
Lateral Hardening-Fuse-10710623,1	14000	0.19	14	5	4	0	9	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,993
Lateral Hardening-Fuse-10716303,1	13959	0.29	17	14	2	0	16	0	Q4 - 2022	Q1 - 2024	Q3 - 2024	$93,902
Lateral Hardening-Fuse-10716315,1	13959	0.10	9	17	4	0	21	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$31,965
Lateral Hardening-Fuse-10716318,1	13959	0.09	7	1	1	0	2	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$28,663
Lateral Hardening-Fuse-10791877,1	13243	0.09	6	43	0	1	44	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$27,977
Lateral Hardening-Fuse-10791889,1	13243	0.26	18	48	5	0	53	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$85,926
Lateral Hardening-Fuse-10823013,1	13651	0.17	12	39	3	2	44	5	Q2 - 2022	Q1 - 2025	Q3 - 2025	$57,077
Lateral Hardening-Fuse-10916743,1	13805	0.33	16	5	2	1	8	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$107,548
Lateral Hardening-Fuse-10928275,1	13143	0.09	10	17	12	0	29	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$31,031
Lateral Hardening-Fuse-10933157,1	13896	0.28	16	9	12	0	21	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$90,662
Lateral Hardening-Fuse-60005954,1	13899	0.17	13	5	2	1	8	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$55,145
Lateral Hardening-Fuse-60008652,1	13081	0.08	9	26	5	0	31	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$27,167
Lateral Hardening-Fuse-60011392,1	13047	0.24	25	37	1	1	39	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$80,381
Lateral Hardening-Fuse-60013778,1	13094	0.25	27	84	7	1	92	2	Q3 - 2022	Q3 - 2023	Q1 - 2024	$83,745
Lateral Hardening-Fuse-60015117,1	13008	0.27	18	28	2	2	32	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$88,668
Lateral Hardening-Fuse-60015427,1	13008	0.36	19	6	1	2	9	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$117,019
Lateral Hardening-Fuse-60016282,1	13049	0.06	5	31	0	1	32	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$19,316
Lateral Hardening-Fuse-60016353,1	13049	0.07	9	9	1	1	11	4	Q3 - 2022	Q3 - 2023	Q1 - 2024	$24,550
Lateral Hardening-Fuse-60017429,2	13029	0.43	40	4	21	15	40	7	Q3 - 2022	Q3 - 2022	Q1 - 2023	$139,887
Lateral Hardening-Fuse-60028650,1	13007	0.10	10	15	5	1	21	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$32,526
Lateral Hardening-Fuse-60029011,1	13088	0.07	9	6	11	1	18	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$24,177
Lateral Hardening-Fuse-60029776,1	13093	0.29	29	61	2	1	64	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$94,151
Lateral Hardening-Fuse-60029925,3	13091	0.57	53	101	12	0	113	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$186,807
Lateral Hardening-Fuse-60031511,1	13093	0.18	16	28	0	1	29	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$59,444
Lateral Hardening-Fuse-60033370,1	13163	0.13	12	17	12	3	32	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$42,122
Lateral Hardening-Fuse-60033388,1	13163	0.18	18	19	17	1	37	10	Q2 - 2022	Q3 - 2023	Q1 - 2024	$59,070
Lateral Hardening-Fuse-60034479,1	13143	0.30	32	48	1	0	49	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$99,323
Lateral Hardening-Fuse-60044927,1	13288	0.17	22	15	9	6	30	1	Q2 - 2022	Q1 - 2025	Q3 - 2025	$55,955
Lateral Hardening-Fuse-60046437,1	13310	0.19	19	46	9	3	58	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$62,747
Lateral Hardening-Fuse-60047463,1	13350	0.11	10	64	6	0	70	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$37,137
Lateral Hardening-Fuse-60048514,1	13405	0.13	6	2	2	2	6	6	Q3 - 2022	Q1 - 2024	Q3 - 2024	$42,745
Lateral Hardening-Fuse-60048809,1	13622	0.15	6	3	3	0	6	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$48,228

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		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-60058546,1	13279	0.11	10	15	9	1	25	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$35,766
Lateral Hardening-Fuse-60058616,1	13610	0.12	14	17	3	1	21	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$37,947
Lateral Hardening-Fuse-60060554,1	13175	0.18	16	14	6	0	20	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$58,634
Lateral Hardening-Fuse-60060564,1	13175	0.13	13	20	5	0	25	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$42,620
Lateral Hardening-Fuse-60060568,1	13175	0.10	13	16	6	0	22	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$31,591
Lateral Hardening-Fuse-60061785,1	13668	0.09	5	288	17	2	307	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$31,218
Lateral Hardening-Fuse-60065898,1	14275	0.03	9	2	2	0	4	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$13,160
Lateral Hardening-Fuse-60073788,1	13082	0.25	25	40	5	1	46	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$80,879
Lateral Hardening-Fuse-60073803,1	13082	0.16	18	31	2	0	33	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$53,151
Lateral Hardening-Fuse-60077860,1	13153	0.11	10	13	0	3	16	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$34,956
Lateral Hardening-Fuse-60087052,1	13359	0.06	7	29	8	4	41	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$19,690
Lateral Hardening-Fuse-60088186,1	13139	0.22	18	27	4	0	31	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$72,218
Lateral Hardening-Fuse-60088567,1	13510	0.30	34	25	4	0	29	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$98,264
Lateral Hardening-Fuse-60124027,1	13218	0.64	53	64	9	0	73	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$210,485
Lateral Hardening-Fuse-60181011,1	13388	0.12	7	6	2	0	8	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$39,318
Lateral Hardening-Fuse-60190659,1	13308	0.22	15	15	9	2	26	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$70,972
Lateral Hardening-Fuse-60200737,1	13961	0.08	7	7	1	0	8	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$25,921
Lateral Hardening-Fuse-60241209,1	13137	0.09	10	159	4	0	163	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$29,847
Lateral Hardening-Fuse-60289071,1	13045	0.10	12	12	3	1	16	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$32,402
Lateral Hardening-Fuse-60302651,1	13091	0.16	13	28	14	0	42	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$52,092
Lateral Hardening-Fuse-60305740,1	13865	0.14	15	38	4	0	42	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$46,048
Lateral Hardening-Fuse-60337684,1	14001	0.06	4	2	14	0	16	0	Q4 - 2022	Q2 - 2023	Q4 - 2023	$18,257
Lateral Hardening-Fuse-60350024,5	13097	1.39	92	67	9	2	78	0	Q2 - 2022	Q1 - 2024	Q4 - 2024	$458,731
Lateral Hardening-Fuse-60365361,1	13962	0.06	6	5	0	1	6	0	Q3 - 2022	Q1 - 2023	Q3 - 2023	$21,186
Lateral Hardening-Fuse-60422059,1	13723	0.31	21	45	16	2	63	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$103,124
Lateral Hardening-Fuse-60463714,1	13853	0.21	16	3	8	7	18	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$69,975
Lateral Hardening-Fuse-60474882,1	13191	0.26	32	11	29	9	49	6	Q2 - 2022	Q3 - 2023	Q1 - 2024	$84,182
Lateral Hardening-Fuse-60518342,1	13219	0.13	10	5	8	4	17	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$43,430
Lateral Hardening-Fuse-60614298,1	13740	0.17	17	20	13	0	33	0	Q2 - 2022	Q1 - 2023	Q3 - 2024	$55,955
Lateral Hardening-Fuse-90097474,7	13754	1.97	170	200	18	2	220	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$648,591
Lateral Hardening-Fuse-90098676,4	13190	2.16	170	445	19	0	464	9	Q2 - 2022	Q1 - 2024	Q3 - 2024	$711,400
Lateral Hardening-Fuse-90152415,1	13208	0.08	8	13	15	1	29	0	Q2 - 2022	Q1 - 2023	Q3 - 2023	$27,417
Lateral Hardening-Fuse-90157556,1	13067	0.19	18	12	6	0	18	5	Q3 - 2022	Q1 - 2024	Q3 - 2024	$63,370
Lateral Hardening-Fuse-90165527,1	13431	0.19	12	4	2	1	7	0	Q3 - 2022	Q1 - 2023	Q3 - 2023	$64,055
Lateral Hardening-Fuse-90179103,1	13630	0.24	17	19	17	0	36	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$78,324
Lateral Hardening-Fuse-90211134,1	13162	0.08	10	23	2	0	25	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$27,292
Lateral Hardening-Fuse-90267141,1	13738	0.03	8	305	5	5	315	1	Q2 - 2022	Q3 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-90297635,1	13007	0.13	12	11	0	1	12	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$42,371
Lateral Hardening-Fuse-90377733,1	13389	0.11	9	3	0	1	4	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$37,823
Lateral Hardening-Fuse-90393849,1	13147	0.08	5	21	4	0	25	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$25,734
Lateral Hardening-Fuse-90398961,1	13795	0.07	7	20	2	1	23	0	Q2 - 2022	Q1 - 2025	Q3 - 2025	$23,117
Lateral Hardening-Fuse-90399851,6	13419	0.76	64	111	2	3	116	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$251,361
Lateral Hardening-Fuse-90416605,1	13081	0.09	10	222	2	1	225	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$29,535
Lateral Hardening-Fuse-90441325,1	13612	0.07	8	7	6	1	14	6	Q2 - 2022	Q2 - 2023	Q4 - 2023	$23,927
Lateral Hardening-Fuse-90482454,4	13206	0.68	58	73	18	0	91	0	Q2 - 2022	Q1 - 2024	Q3 - 2024	$223,259
Lateral Hardening-Fuse-90487798,1	13740	0.12	6	9	6	0	15	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$40,128
Lateral Hardening-Fuse-90522517,5	13359	1.20	115	125	2	1	128	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$395,610
Lateral Hardening-Fuse-90526768,1	13199	0.18	15	20	3	0	23	0	Q3 - 2022	Q1 - 2024	Q3 - 2024	$60,815
Lateral Hardening-Fuse-90630567,1	13754	0.13	14	13	2	1	16	5	Q2 - 2022	Q2 - 2023	Q4 - 2023	$43,244

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Lateral Hardening-Fuse-90668793,1	14042	0.19	12	55	1	2	58	1	Q2 - 2022	Q2 - 2023	Q4 - 2023	$61,438
Lateral Hardening-Fuse-90704066,4	13370	0.78	65	16	20	9	45	1	Q1 - 2022	Q4 - 2024	Q2 - 2025	$257,280
Lateral Hardening-Fuse-90748138,1	13103	0.08	8	9	5	0	14	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$27,541
Lateral Hardening-Fuse-90823812,1	13329	0.05	4	7	0	1	8	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$16,388
Lateral Hardening-Fuse-90830976,1	13328	0.08	8	3	1	2	6	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$26,918
Lateral Hardening-Fuse-90847913,1	13754	0.25	25	55	5	1	61	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$80,941
Lateral Hardening-Fuse-90848130,1	13656	0.17	11	9	0	1	10	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$55,020
Lateral Hardening-Fuse-90852788,1	13148	0.35	23	10	3	1	14	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$113,592
Lateral Hardening-Fuse-91016874,2	13046	0.38	34	52	4	3	59	7	Q3 - 2022	Q3 - 2022	Q1 - 2023	$123,437
Lateral Hardening-Fuse-91060899,1	13533	0.23	21	142	3	1	146	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$74,835
Lateral Hardening-Fuse-91066431,1	13163	0.23	15	18	3	3	24	0	Q3 - 2022	Q3 - 2022	Q1 - 2023	$74,399
Lateral Hardening-Fuse-91076397,1	13048	0.06	7	3	0	3	6	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$18,569
Lateral Hardening-Fuse-91096289,1	13787	0.09	6	3	1	0	4	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$30,034
Lateral Hardening-Fuse-91147533,3	13097	0.67	41	39	5	1	45	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$221,078
Lateral Hardening-Fuse-91151734,1	13364	0.09	9	52	0	1	53	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$30,595
Lateral Hardening-Fuse-91154995,2	13048	0.53	50	74	3	2	79	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$174,532
Lateral Hardening-Fuse-91161524,1	13146	0.24	15	16	1	1	18	6	Q3 - 2022	Q3 - 2023	Q1 - 2024	$78,449
Lateral Hardening-Fuse-91177941,3	13638	0.87	82	79	12	1	92	1	Q2 - 2022	Q1 - 2024	Q3 - 2024	$284,697
Lateral Hardening-Fuse-91232937,1	13103	0.49	47	117	7	0	124	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$161,011
Lateral Hardening-Fuse-91234338,1	13124	0.46	33	56	3	0	59	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$150,979
Lateral Hardening-Fuse-91334566,1	13464	0.38	27	60	1	1	62	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$125,618
Lateral Hardening-Fuse-91337725,1	13464	0.20	13	11	2	2	15	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$66,610
Lateral Hardening-Fuse-91354294,1	13065	0.16	18	136	10	1	147	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$53,649
Lateral Hardening-Fuse-91382618,1	13462	0.32	27	51	3	4	58	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$105,056
Lateral Hardening-Fuse-91404359,1	13805	0.56	28	35	9	0	44	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$184,315
Lateral Hardening-Fuse-91418404,1	13621	0.16	11	10	2	0	12	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$51,905
Lateral Hardening-Fuse-91421327,1	13124	0.10	14	1	4	4	9	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$33,087
Lateral Hardening-Fuse-91532289,1	13832	0.10	11	12	22	1	35	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$33,648
Lateral Hardening-Fuse-91532301,1	13832	0.09	7	10	7	0	17	0	Q3 - 2022	Q2 - 2022	Q1 - 2023	$28,663
Lateral Hardening-Fuse-91550764,1	13592	0.06	4	16	3	1	20	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$20,251
Lateral Hardening-Fuse-91565159,4	13044	0.51	55	14	1	1	16	0	Q2 - 2022	Q2 - 2023	Q4 - 2023	$168,924
Lateral Hardening-Fuse-91623641,1	13141	0.15	19	39	3	1	43	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$49,475
Lateral Hardening-Fuse-91643964,1	13106	0.13	12	123	9	0	132	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$43,244
Lateral Hardening-Fuse-91702481,1	14012	0.08	8	1	0	1	2	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$25,423
Lateral Hardening-Fuse-91774500,1	13631	0.28	21	56	17	0	73	16	Q1 - 2022	Q2 - 2023	Q4 - 2023	$93,466
Lateral Hardening-Fuse-91782844,1	13434	0.15	13	7	0	2	9	0	Q2 - 2022	Q4 - 2024	Q2 - 2025	$50,596
Lateral Hardening-Fuse-91868130,1	13201	0.11	11	123	3	1	127	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$36,514
Lateral Hardening-Fuse-91910924,1	13165	0.23	20	53	5	5	63	3	Q2 - 2022	Q3 - 2023	Q1 - 2024	$77,016
Lateral Hardening-Fuse-92005809,1	13219	0.24	24	42	11	1	54	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$78,761
Lateral Hardening-Fuse-92027991,1	13420	0.24	18	24	7	0	31	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$78,075
Lateral Hardening-Fuse-92035203,1	13417	0.08	9	30	4	0	34	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$26,295
Lateral Hardening-Fuse-92079502,1	13638	0.13	15	41	12	2	55	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$42,620
Lateral Hardening-Fuse-92097014,1	13217	0.19	11	16	1	1	18	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$62,684
Lateral Hardening-Fuse-92132257,1	13016	0.12	13	57	4	0	61	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$39,816
Lateral Hardening-Fuse-92197131,1	13330	0.19	13	73	2	1	76	1	Q1 - 2022	Q2 - 2023	Q4 - 2023	$61,376
Lateral Hardening-Fuse-92238609,1	13065	0.14	13	25	2	0	27	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$44,801
Lateral Hardening-Fuse-92257437,1	13227	0.15	19	12	9	0	21	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$48,602
Lateral Hardening-Fuse-92320131,1	13656	0.24	16	8	3	2	13	3	Q3 - 2022	Q3 - 2023	Q1 - 2024	$79,633
Lateral Hardening-Fuse-92354169,1	13787	0.14	6	2	2	4	8	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$45,424

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-92398222,1	13167	0.12	15	11	0	2	13	0	Q3 - 2022	Q4 - 2023	Q2 - 2025	$38,820
Lateral Hardening-Fuse-92408051,1	13140	0.09	10	40	7	1	48	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$29,161
Lateral Hardening-Fuse-92418323,1	13696	0.06	8	111	3	0	114	0	Q2 - 2022	Q4 - 2024	Q2 - 2025	$19,690
Lateral Hardening-Fuse-92448697,1	13510	0.04	5	5	2	2	9	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$13,272
Lateral Hardening-Fuse-92486363,1	13312	0.22	17	16	3	1	20	0	Q2 - 2022	Q4 - 2023	Q2 - 2024	$73,340
Lateral Hardening-Fuse-92497118,1	13146	0.23	8	4	2	0	6	0	Q4 - 2022	Q3 - 2023	Q1 - 2024	$74,835
Lateral Hardening-Fuse-92527630,1	13219	0.11	8	17	1	1	19	1	Q3 - 2022	Q4 - 2023	Q2 - 2024	$35,829
Lateral Hardening-Fuse-92527637,1	13219	0.21	24	38	2	1	41	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$70,286
Lateral Hardening-Fuse-92529635,1	13210	0.11	12	13	3	0	16	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$35,704
Lateral Hardening-Fuse-92529638,1	13210	0.09	10	21	1	1	23	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$28,663
Lateral Hardening-Fuse-92537158,1	13150	0.07	7	10	0	2	12	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$23,553
Lateral Hardening-Fuse-92543665,1	13004	0.28	23	70	5	0	75	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$92,282
Lateral Hardening-Fuse-92570284,1	13020	0.07	3	9	1	4	14	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$22,432
Lateral Hardening-Fuse-92597622,1	13390	0.19	12	42	6	0	48	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$62,373
Lateral Hardening-Fuse-92599120,1	13390	0.62	37	45	5	0	50	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$202,946
Lateral Hardening-Fuse-92602262,1	13010	0.09	6	15	2	0	17	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$31,093
Lateral Hardening-Fuse-92603717,1	13390	0.25	15	32	4	0	36	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$81,876
Lateral Hardening-Fuse-92605327,1	13390	0.21	16	65	15	0	80	21	Q3 - 2022	Q3 - 2023	Q1 - 2024	$67,482
Lateral Hardening-Fuse-92605381,1	13390	0.35	33	130	4	0	134	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$113,779
Lateral Hardening-Fuse-92609981,1	13390	0.17	13	31	3	0	34	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$56,204
Lateral Hardening-Fuse-92610250,1	13390	0.93	46	48	11	0	59	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$304,948
Lateral Hardening-Fuse-92612860,1	13390	0.45	27	17	3	0	20	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$147,801
Lateral Hardening-Fuse-92620889,1	13390	0.24	15	66	3	0	69	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$79,384
Lateral Hardening-Fuse-92622569,1	13390	0.61	30	86	11	4	101	5	Q3 - 2022	Q3 - 2023	Q1 - 2024	$201,201
Lateral Hardening-Fuse-92655421,1	13198	0.08	6	8	2	0	10	0	Q3 - 2022	Q4 - 2023	Q2 - 2024	$24,737
Lateral Hardening-Fuse-92678765,1	13805	0.19	12	3	3	0	6	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$63,931
Lateral Hardening-Fuse-92701725,1	13299	0.18	13	123	28	2	153	2	Q2 - 2022	Q3 - 2024	Q1 - 2025	$60,504
Lateral Hardening-Fuse-92773510,1	13373	0.32	27	13	13	0	26	0	Q1 - 2022	Q3 - 2024	Q1 - 2025	$105,180
Lateral Hardening-Fuse-92814355,1	13344	0.05	7	37	5	2	44	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$15,702
Lateral Hardening-Fuse-92835651,4	13329	0.83	55	89	21	1	111	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$271,986
Lateral Hardening-Fuse-92856634,1	13224	0.25	23	16	17	1	34	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$82,998
Lateral Hardening-Fuse-92859507,1	13460	0.10	7	25	0	1	26	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$31,716
Lateral Hardening-Fuse-92867406,1	13010	0.07	8	2	4	1	7	0	Q3 - 2022	Q1 - 2024	Q4 - 2024	$22,681
Lateral Hardening-Fuse-92874488,1	13112	0.13	14	38	1	1	40	1	Q3 - 2022	Q3 - 2023	Q1 - 2024	$44,241
Lateral Hardening-Fuse-92890357,1	13112	0.18	13	49	6	1	56	0	Q2 - 2022	Q3 - 2023	Q2 - 2024	$58,136
Lateral Hardening-Fuse-92897362,1	13147	0.19	12	26	3	0	29	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$62,248
Lateral Hardening-Fuse-92901825,1	13147	0.46	20	123	2	1	126	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$152,038
Lateral Hardening-Fuse-92905104,1	13826	0.20	10	183	7	2	192	39	Q1 - 2022	Q3 - 2023	Q1 - 2024	$64,928
Lateral Hardening-Fuse-92907479,1	13060	0.06	9	267	24	2	293	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$18,818
Lateral Hardening-Fuse-92922162,1	13224	0.11	13	16	2	1	19	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$35,704
Lateral Hardening-Fuse-92937437,1	13241	0.22	17	22	9	0	31	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$73,090
Lateral Hardening-Fuse-93033231,1	13838	0.20	13	61	13	4	78	27	Q1 - 2022	Q3 - 2023	Q1 - 2024	$65,738
Lateral Hardening-Fuse-93082436,1	13612	0.07	7	8	5	0	13	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$23,678
Lateral Hardening-Fuse-93090160,1	13039	0.21	10	15	7	0	22	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$69,227
Lateral Hardening-Fuse-93113905,1	13034	0.04	4	8	1	1	10	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$13,160
Lateral Hardening-Fuse-93118733,1	13324	0.11	11	6	4	1	11	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$37,199
Lateral Hardening-Fuse-93172625,1	13213	0.13	12	21	3	0	24	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$44,303
Lateral Hardening-Fuse-93218070,1	13656	0.11	6	2	1	0	3	0	Q4 - 2022	Q2 - 2023	Q4 - 2023	$35,205
Lateral Hardening-Fuse-93233174,1	13696	0.14	17	46	5	0	51	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$45,798

Tampa Electric's Distribution Lateral Undergrounding - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2022
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-93235148,1	13696	0.10	9	28	12	2	42	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$32,464
Lateral Hardening-Fuse-93247243,1	13175	0.18	18	33	4	0	37	0	Q3 - 2022	Q2 - 2022	Q4 - 2022	$58,198
Lateral Hardening-Fuse-93249426,1	13175	0.15	14	10	1	2	13	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$50,534
Lateral Hardening-Fuse-93263741,1	13042	0.12	12	18	0	2	20	0	Q3 - 2022	Q3 - 2023	Q1 - 2024	$40,813
Lateral Hardening-Fuse-93263753,1	13042	0.25	21	27	2	1	30	0	Q1 - 2022	Q3 - 2023	Q1 - 2024	$82,001
Lateral Hardening-Fuse-93264130,1	13042	0.22	22	23	6	2	31	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$71,408
Lateral Hardening-Fuse-93266650,1	13042	0.34	32	55	0	1	56	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$111,848
Lateral Hardening-Fuse-93267158,1	13042	0.18	18	37	3	1	41	0	Q1 - 2022	Q2 - 2023	Q4 - 2023	$59,444
Lateral Hardening-Fuse-93276507,1	13213	0.14	8	6	2	1	9	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$44,739
Lateral Hardening-Fuse-93283244,2	13351	0.64	49	73	9	1	83	0	Q2 - 2022	Q3 - 2023	Q1 - 2024	$211,794
Lateral Hardening-Fuse-93283740,1	13351	0.06	8	110	8	2	120	0	Q1 - 2022	Q1 - 2023	Q3 - 2023	$18,693
Lateral Hardening-Fuse-93292955,1	14356	0.12	10	184	10	2	196	0	Q2 - 2022	Q3 - 2024	Q1 - 2025	$38,446
Lateral Hardening-Fuse-93294943,1	13808	0.14	9	5	0	1	6	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$44,490
Lateral Hardening-Fuse-93324791,1	13723	0.14	6	9	2	0	11	0	Q3 - 2022	Q2 - 2023	Q4 - 2023	$45,736
Lateral Hardening-Fuse-93355196,1	13303	0.07	6	10	2	2	14	0	Q2 - 2022	Q2 - 2024	Q4 - 2024	$21,996
Lateral Hardening-Fuse-93432382,1	13532	0.29	22	36	0	1	37	0	Q3 - 2022	Q3 - 2024	Q1 - 2025	$95,086

VEGETATION MANAGEMENT STORM PROTECTION PROGRAM ANALYTIC SUPPORT REPORT

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1 Executive Summary

In 2019, the Florida Legislature enacted a law stating that each investor-owned electric utility (utility) must file a Transmission and Distribution Storm Protection Plan (SPP) with the Florida Public Service Commission ("FPSC").[1] The SPP must cover the utility's immediate ten-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every three years.[2] The SPP must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.[3] The FPSC later promulgated a rule to implement the SPP filing requirement.[4] This rule went into effect in February of 2020.

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities 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; and
D. A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

TECO is proposing a VM Storm Protection Program that includes three distribution vegetation management initiatives:[6]

1. Four-year distribution vegetation management cycle
2. Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
    a. 400 miles in 2020
    b. 500 miles in 2021
    c. 700 miles in 2022 and beyond
3. Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
    a. Ensure fast-growing species are kept in check until the next scheduled trimming.
    b. Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.

    The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

Beyond the day-to-day and storm benefits, the distribution portion of the VM Storm Protection Program is planned to scale up over time, moving from today's complement of 196 field resources to a peak of 280 field resources across three years, and then settling into a steady-state number of approximately

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[1] § 366.96(3), Fla. Stat.
[2] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 1, lines 2-6
[3] § 366.96(3), Fla. Stat. 1
[44] *See* R. 25-6.030, F.A.C.
[5] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 3, lines 10-17
[6] The Vegetation Management Program also includes the baseline transmission trim cycles as well an incremental transmission vegetation management initiative, but those activities are outside of the scope of this report.

270 field resources. The phased rollout and associated resource load and budget are outlined in Table 1-1, below:

Table 1-1: Recommended Approach

	Baseline 4-Year Cycle	Supplemental Miles	Feeder Mid-Cycle	Lateral Mid-Cycle	Estimated Resource Load[7]	Budget[8]
2020	Yes	400	Pilot 1-5 Circuits	None	228	$17.1M
2021	Yes	500	Inspect 60 Miles	None	257	$20.0M
2022	Yes	700	Inspect 48 Miles	Pilot 1-5 Circuits	262	$21.4M
2023	Yes	700	Inspect 46 Miles	Inspect 208 Miles	280	$24.0M
2024	Yes	700	Inspect 45 Miles	Inspect 177 Miles	270	$24.3M
2025	Yes	700	Inspect 96 Miles	Inspect 156 Miles	270	$25.5M
2026	Yes	700	Inspect 60 Miles	Inspect 150 Miles	270	$26.8M
2027	Yes	700	Inspect 45 Miles	Inspect 198 Miles	270	$28.1M
2028	Yes	700	Inspect 52 Miles	Inspect 155 Miles	270	$29.5M
2029	Yes	700	Inspect 54 Miles	Inspect 186 Miles	270	$31.0M

These initiatives are projected to reduce day-to-day vegetation-caused customer interruptions by 21 percent and storm-related vegetation-caused outages by 29 percent relative to carrying out the 4-Year Trimming Cycle alone.

[7] Resource projections from 2023 forward fluctuate with the specific blend of circuits that come up for mid-cycle trimming each year. 270 represents the average for these years, and TECO will manage the mid-cycle scope to match budget.

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

2 Overview

TECO engages in 4-year distribution cycle trimming activities on an ongoing basis, working approximately one quarter of their overhead distribution system mileage every year. The goal is to trim tree limbs such that it will take four years before they can grow sufficiently to encroach on the clearances established for their lines. At various locations in the system, certain fast-growing tree species and/or right-of-way constraints on trimming result in isolated patches that may require attention between scheduled cycle trims. This often takes the form of Corrective Maintenance, where a crew is called out to address an impending issue on a specific tree because its limbs have grown too close to the line or because a tree, aided by the elements, makes contact with the lines and triggers an outage.

TECO continuously analyzes its vegetation management program using some of the industry's leading analytic tools. One of these tools is the Tree Trimming Model (TTM), originally developed by Davies Consulting (acquired by Accenture in 2017). Since the initial implementation of the model in 2006, TECO has continued to refine its program and update the tool's configuration using its growing set of historical spending and reliability performance data.

The TTM employs an analysis of day-to-day outages caused by vegetation, as well as a sampling of outages with unknown and weather cause codes which might be attributable to vegetation. TTM considers such outages in the context of the amount of time that has elapsed since the last time the trees on that circuit were trimmed. Universally, the analysis shows that outage volumes rise as a function of time since last trim, but the degree to which outages and their reliability impact escalate vary as a result of factors such as tree density, tree species, voltage, customer density, microclimate and a variety of others. In the configuration stages of the TTM modeling, circuits are grouped according to their similarity in terms of outage escalation and grouped separately as a function of how expensive it is to trim them, yielding a matrix of combinations of reliability and cost groupings. These expressions of cost and reliability, as a function of time, drive a ten-year prioritization aimed at getting the best day-to-day performance per dollar spent on trimming activities.

During extreme weather conditions, the proximity of limbs to lines and the cross-sectional area of vegetation upon which winds can exert force (referred to herein as the 'sail area') play a large factor in the degree of damage the electrical system will sustain due to vegetation-caused outages. Because the time elapsed since last trim is a direct driver of vegetation to conductor clearances when a storm arrives, the relationship between years since last trim, wind speed, and the extent of damage sustained has been studied and built into TTM's Storm Module. Using the trim list outputs of the TTM and an array of probable windspeeds for the Tampa area, the Storm Module predicts damage levels and associated restoration costs for typical years and can also project the impact of storms of specified magnitude.

Both TTM and the Storm Module address the effects of trimming circuits in their entirety, but some of TECO's proposed Vegetation Management initiatives are more targeted and address only portions of circuits in any given year. To accommodate this, Accenture crafted an Enhanced Storm Module for TTM to estimate the value derived from these targeted initiatives which change the state of only part of any given circuit at a time.

3 Approach

TECO used TTM and its storm modules to establish a set of baseline performance metrics associated with its four-year cycle, and then evaluated supplemental activities against that baseline:

- Supplemental trimming scenarios in which TECO targeted and trimmed an additional 100, 300, 500, 700 or 900 miles per year, and
- Mid-cycle activities whereupon circuits (either the feeder or the complete circuit) are inspected two years after their most recent trim, and follow-up vegetation management activities are prescribed to enhance both the day-to-day and extreme weather condition performance of the system.

The effects of the supplemental trimming and mid-cycle initiatives build upon the base of the 4-year trimming cycle. For consistency of presentation throughout the document, all three are referred to herein as initiatives:

Table 3-1: Initiative Approach

Initiative	Name
1	Baseline 4-year Trimming Cycle
2	Supplemental Trimming
3	Mid-cycle Inspection & VM Activities

The effects of these initiatives are cumulative, in that any version of Initiative 2 requires that the baseline 4-year cycle to be in effect, and Initiative 3 would not be implemented without the baseline trim cycle and Initiative 2 in place. There are many different combinations of activities, any of which could serve as the company's VM program. The benefits of each possible activity can only be evaluated by comparing the benefits of different programs, or combinations of activities. Consequently, the team created different possible VM programs, each with a different set of component activities. The programs which appear in this document consist of component activities as follows:

Table 3-2: Program Nomenclature and Initiative Components

Program Name	Initiative 1 Component	Initiative 2 Component	Initiative 3 Component
Program 1	4-year cycle trim	n/a	n/a
Program 2 – 100	4-year cycle trim	100 Supplemental Miles	n/a
Program 2 – 300	4-year cycle trim	300 Supplemental Miles	n/a
Program 2 – 500	4-year cycle trim	500 Supplemental Miles	n/a
Program 2 – 700	4-year cycle trim	700 Supplemental Miles	n/a
Program 2 – 900	4-year cycle trim	900 Supplemental Miles	n/a
Program 3a – 700	4-year cycle trim	700 Supplemental Miles	Mid-cycle on feeders only
Program 3b – 700	4-year cycle trim	700 Supplemental Miles	Mid-cycle on whole circuits
Program 2 – 457	4-year cycle trim	Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond	n/a
Program 3ab - 457	4-year cycle trim	Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond	Phased approach – mid-cycle on feeders only in 2021 and 2022, mid-cycle on full circuits in 2023 and beyond

Upon finding an optimal endpoint, TECO examined the resource implications of the program and adapted the approach to phase in both the supplemental trimming initiative and the mid-cycle initiative to allow for a smooth transition into the program.

Prior to running the various scenarios, TECO engaged Accenture to refresh the TTM configuration and the various assumptions built into the TTM Storm Module. The configuration process and associated assumptions are captured in Section 6: Tree Trimming Model & Modules Configuration.

4 Storm Protection Initiatives Analysis

TECO and Accenture analyzed several vegetation management activities to determine an optimal level of supplemental trimming to reduce vegetation related outages during extreme weather events while continuing to minimize day-to-day vegetation related outages.

The following initiatives were considered:

Table 4-1: Vegetation Management Initiatives Analyzed

	Initiative Name	Initiative Description	Modeling Methodology
1	Baseline: 4-Year Effective Cycle	Trim 25% of TECO's overhead lines (~1,562 miles) annually.	Target 25% of the miles in each of TECO's 7 districts for trimming annually.
2	Supplemental Circuit Trimming	Trim an additional 100 – 900 targeted miles annually with a view to mitigating outage risk on those circuits most susceptible to storm damage	Five scenarios modeled – 100, 300, 500, 700 and 900 miles. Due to the nature of the algorithm and available targeting data, targeting is based on SAIFI performance in regular weather.
3a	Mid-cycle VM Initiative – Feeders Only	Add mid-cycle inspections to feeder portions of circuits (~35% of line miles) two years after trim, prescribing additional VM activities to a fraction of the trees inspected.	The TTM Enhanced Storm Module assumes that one quarter of the trees inspected will be targeted for re-trimming when inspected and promptly trimmed. As TTM works with miles of circuit rather than individual trees, this is modeled as one quarter of the feeder 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, storm restoration, and corrective maintenance costs are re-calculated to reflect the new trim-age profile of the circuit.
3b	Mid-cycle VM Initiative – Full Circuits	Extend the inspection and prescribed activities described in Initiative 3a to the entire circuit. As with 3a, it is assumed that a fraction of the trees inspected will require mid-cycle VM activities.	As described above in Initiative 3a, TTM Enhanced Storm Module assumes one quarter of the entire circuit is re-trimmed at two years, with an impact on day-to-day restoration costs, storm restoration costs and corrective maintenance costs.

The Supplemental Circuit Trimming initiative 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.

The Mid-cycle VM initiative focuses on some of the same proximity and sail area reduction efforts on the trees which grow the quickest and may encroach on lines despite the best efforts of the trimming cycle and supplemental trimming, as well as other activities to slow tree growth or eliminate hazard trees altogether.

4.1 Baseline Trim Cycle and Initiative 1 Variants

TECO and Accenture ran the company's ongoing 4-year cycle trim through the model to project its full budget implications across seven categories of cost to form a baseline against which the incremental benefits of supplemental trimming activities can be measured. The associated costs are broken out as follows, along with indicators as to whether the cost component in question 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 4-2: Cost Categories

Cost Category	Applies to what resources?	Part of Storm Protection Program	Part of VM Budget?
Cycle Trimming	Vegetation	Yes	Yes
Supplemental Trimming	Vegetation	Yes	Yes
Mid-Cycle	Vegetation	Yes	Yes
Corrective Cost	Vegetation	No	Yes
Resource Premiums	Vegetation	Yes	Yes
Day to Day Restoration Costs	Line & Vegetation	No	No
Storm Restoration Costs	Line & Vegetation	No	No

Note that the anticipated spending levels for the two categories of restoration cost are driven by vegetation management decisions but are not part of the vegetation management budget. They are considered and presented within this analysis because the investments in enhancing vegetation management for the Storm Protection Plan should be offset by reductions in cost due to outage response.

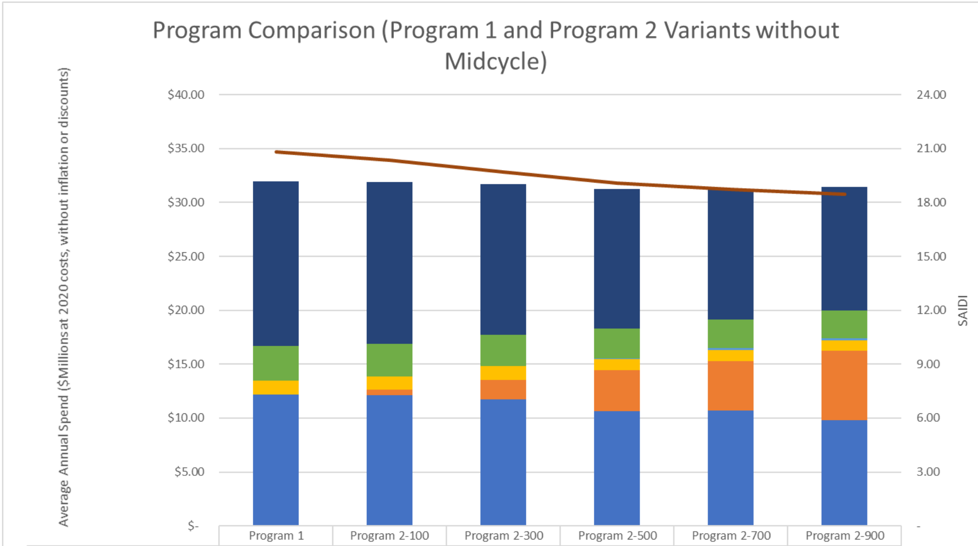
In the baseline scenario, each service area is allotted one quarter of its mileage every year, or approximately 1,562 miles in total. Central, for example, accounts for one sixth of TECO's overhead miles, and is afforded one sixth of the annual 1,562-mile budget as depicted below.

Table 4-3: Baseline 4-Year Effective Cycle Mileage Targets

Service Area	Mileage Target	Percentage
Central	260	16.6%
Dade City	93	6.0%
Eastern	209	13.4%
Plant City	310	19.8%
South Hillsborough	182	11.7%
Western	277	17.7%
Winter Haven	231	14.8%
Total	1,562	100.0%

In the supplemental trimming initiatives, one quarter of the supplemental miles is allocated across the service areas in the same proportions as the 4-year distribution trim cycle. The remainder of the miles are directed where they will deliver the greatest benefit. Thus, in a scenario where 400 supplemental miles were trimmed, 100 miles would be constrained with 16.6 occurring in Central, 6.0 miles in Dade City, 13.4 miles in Eastern, and so on with the remaining 300 miles of trimming directed to the areas where it would deliver the greatest benefit.

The costs for the baseline scenario and five variants of supplemental trimming, without mid-cycle, are plotted below:



	Program 1	Program 2-100	Program 2-300	Program 2-500	Program 2-700	Program 2-900
Storm Restoration Cost	$15.31	$14.99	$13.97	$12.92	$12.08	$11.42
Day-to-Day Restoration Cost	$3.19	$3.05	$2.91	$2.77	$2.69	$2.63
Resource Premiums	$-	$0.03	$0.00	$0.05	$0.14	$0.15
Corrective Cost	$1.30	$1.23	$1.30	$1.08	$1.03	$0.99
Mid-Cycle Cost	$-	$-	$-	$-	$-	$-
Supplemental Trimming Cost	$-	$0.50	$1.80	$3.81	$4.62	$6.44
Baseline 4-Year Cycle Cost	$12.19	$12.10	$11.72	$10.61	$10.69	$9.79
SAIDI	20.83	20.36	19.70	19.09	18.75	18.45

Figure 4-1: Program Comparison

The average annual vegetation management budget, without inflation, for these six options ranges from $13.5M for the as-is 4-year trimming cycle to $17.4M for the cycle plus 900 miles of supplemental trimming annually. Meanwhile the annual total restoration costs, which include all line work and vegetation management costs for storm restoration, trend in the opposite direction from $18.5M for the baseline 4-year cycle to $14.1M for the 900-mile variant. The total anticipated cost of the VM budget and restoration combined sits in a narrower range, at $32.0M for the baseline 4-year cycle and $31.25 M for the 500 and 700-mile variants.

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

- The introduction of supplemental trimming drives down the cost of the baseline four-year cycle. This is because the extra activity on the lines makes trimming the annual 1,562 miles less expensive each year since the tree limbs have had less time to grow and are neither as long nor as close to the lines as they would have been otherwise.
- The increases in cost associated with the Storm Protection Program 2 variants and associated resource premiums is offset by decreases in cost in the 4-year cycle trim, corrective maintenance, day-to-day restoration costs and storm restoration costs, up to the 500 to 700-mile range.
- Although difficult to see in Figure 4-1, the 500 mile and 700-mile programs yield the best overall average annual cost, which, due to diminishing returns, begins to trend back upwards starting with the 900-mile program. See Figure 4-2, below, for a view focused on total cost.
- Each supplemental increase in Program 2 yields an improvement in SAIFI and SAIDI, although the gains slow in the 500-mile to 700-mile range.

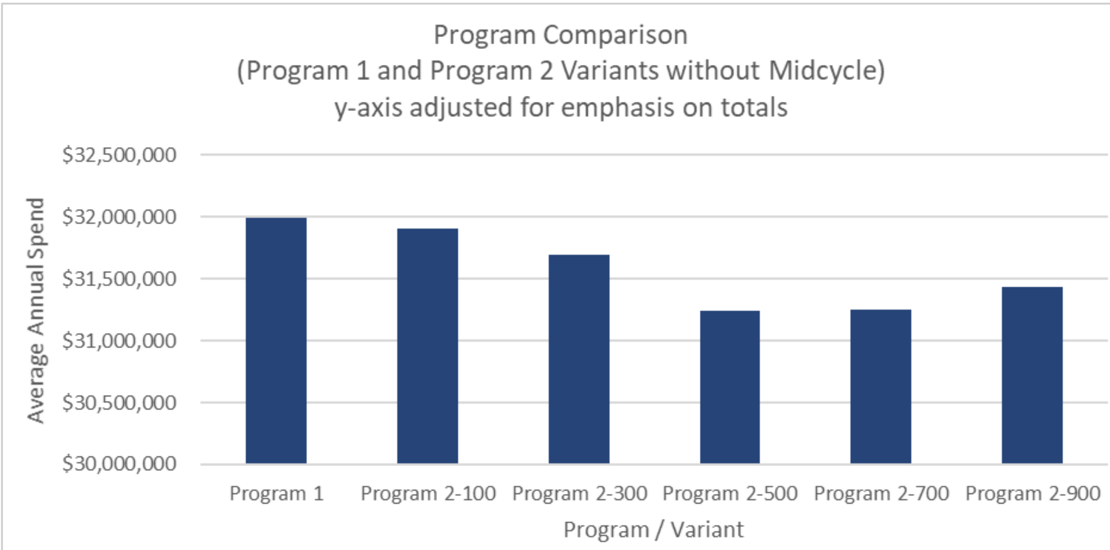


Figure 4-2: Program Comparison with Focus on Total Average Annual Spend

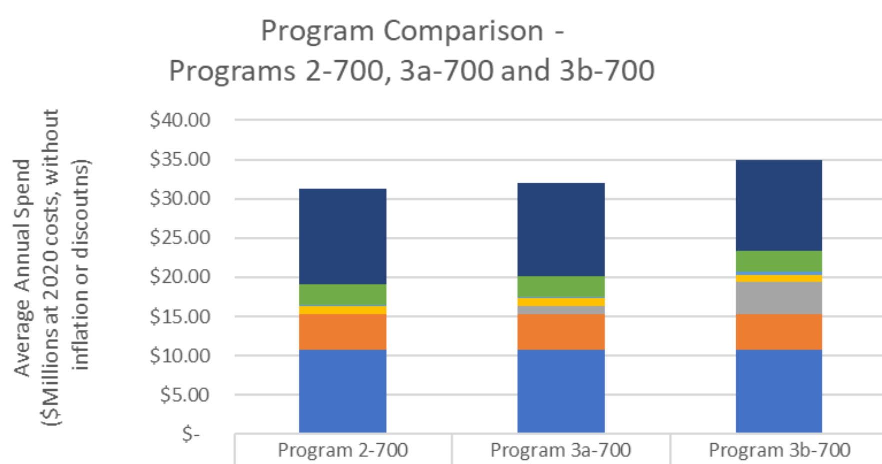
- While the 500 mile and 700-mile programs are in a virtual tie from an overall cost perspective, there is a clear advantage to the 700-mile program from the customer experience perspective. The 700-mile program drives 16 percent and 21 percent improvements in the ten-year average day-to-day and storm restoration costs, which are directly linked to customer interruptions. Across the ten-year span of the 500-mile program, these figures are 13 percent and 16 percent.

Table 4-4: 10-year Average Outage Restoration Improvements for Programs 2-500 and 2-700 Relative to Program 1

Cost Element	Program 1 Average 2020-2029	Program 2-500 Average 2020-2029	Program 2-700 Average 2020-2029	Improvement for Program 2-500	Improvement for Program 2-700
Day-to-Day Restoration	$3.19 M	$2.77 M	$2.69M	13.2%	15.7%
Storm Restoration	$15.31 M	$12.92M	$12.08M	15.6%	21.1%

4.2 Storm Protection Initiative 3a & 3b – Mid-cycle Inspection and VM Activities

Based on the results presented in Section 4.1, Initiatives 3a and 3b were analyzed in the context of Program 2-700, where 700 supplemental and targeted miles are trimmed each year. The average annual cost of the inspectors and VM resources for the mid-cycle initiatives was $1.06M and $4.05M, respectively, and they yielded a further 2.5 percent and 4.5 percent improvements to storm restoration costs from $12.08M to $11.77M and $11.54M.



	Program 2-700	Program 3a-700	Program 3b-700
Storm Restoration Cost	$12.08	$11.77	$11.54
Day-to-Day Restoration Cost	$2.69	$2.68	$2.65
Resource Premiums	$0.14	$0.16	$0.45
Corrective Cost	$1.03	$0.99	$0.95
Mid-Cycle Cost		$1.06	$4.05
Supplemental Trimming Cost	$4.62	$4.62	$4.62
Baseline 4-Year Cycle Cost	$10.69	$10.69	$10.69

Figure 4-3: Storm Protection Program Mid-Cycle Comparison

Table 4-5: 10-year Average Outage Restoration Improvements for Programs 3a-700 and 3b-700 Relative to Program 2-700

Cost Element	Program 2-700 Average 2020-2029	Program 3a-700 Average 2020-2029	Program 3b-700 Average 2020-2029	Improvement for Program 3a-700	Improvement for Program 3b-700
Storm Restoration	$12.08M	$11.77M	$11.54M	2.6%	4.5%
Day-to-Day Restoration	$2.69M	$2.68M	$2.65M	0.4%	1.5%

As noted previously, the modeling approach may not reflect the full value of the mid-cycle activities. While the Tree Trimming Model considers circuits in their entirety, the mid-cycle initiative would be targeted based on inspections and storm impact and is highly likely to yield greater benefits than what is reflected here. Also, some of the prescribed activities under the mid-cycle initiative, such as tree removals, will yield permanent and cumulative results not captured here. Simply put, it is believed that the benefits of the mid-cycle initiative will exceed what is shown here.

4.3 Developing a Blended Strategy to Accommodate Resource Constraint

Resource impact is one final element to draw out of the Storm Protection Program 2 and Storm Protection Program 3a/3b analyses. The 500, 700, and 900-mile versions of Storm Protection Program 2 all incur cost premiums associated with the rapid increase in size to the workforce required. Programs

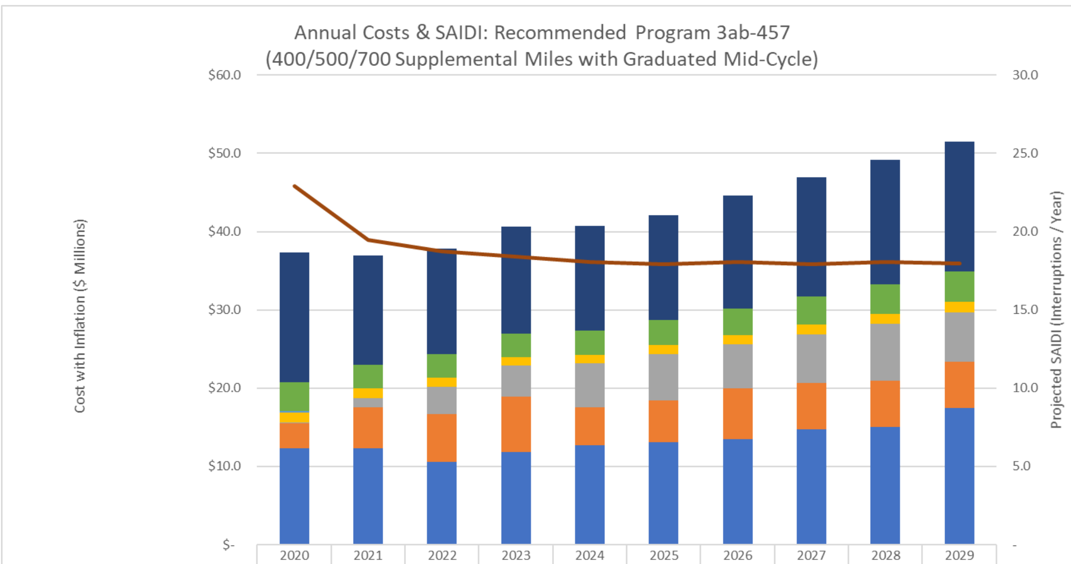
3a-700 and 3b-700 exacerbate the resource crunch. While the average annual VM budget (without inflation) for Program 2-700 (Baseline + 700 supplemental miles) is estimated at $16.4M and would require an average of 220 resources to execute, the first year VM budget would be $19.0M and require roughly 256 resources. With 196 resources in the field at present, the uptake of 60 workers in a single year would represent a very large challenge and require significant expenditure on overtime and premium incentives to achieve, particularly if the transition happens later in the year. Adding Initiative 3a or 3b simultaneously would further exacerbate the issue.

TECO is proposing instead to transition towards the 700-mile version of Initiative 2 over the course of three years by trimming 400 extra miles in 2020, 500 extra miles in 2021 and finally arriving at the 700-mile program in 2022. The mid-cycle initiative will also be introduced gradually, addressing feeders alone in the second and third years and moving towards inspecting full circuits in the fourth year and beyond as better data becomes available about the success of mid-cycle inspections and VM activities.

5 Recommendation

The recommended Vegetation Management Storm Protection Program (Program 3ab-457) consists of the following activities:

1) **Baseline Cycle**: continue the 4-year trimming cycle
2) **Supplemental trimming initiative**: scale up supplemental trimming miles by targeting an additional 400 miles in 2020, 500 miles in 2021, and 700 miles from 2022 going forward
3) **Mid-cycle VM initiative**: introduce mid-cycle inspections and associated targeted activities for the feeder portions of circuits in 2021, extending the inspections and prescribed activities to cover entire circuits from 2023 forward, with 60 miles inspected in 2021, 48 miles in 2022 and 254 miles in 2023 as the program rolls out to entire circuits.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Storm Restoration Cost	$16.6	$13.9	$13.5	$13.6	$13.3	$13.4	$14.4	$15.3	$16.0	$16.6
Day-to-Day Restoration Cost	$3.6	$3.0	$2.9	$3.0	$3.1	$3.2	$3.4	$3.5	$3.7	$3.9
Resource Premiums	$0.2	$-	$-	$-	$-	$-	$-	$-	$-	$-
Corrective Cost	$1.3	$1.3	$1.2	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3
Mid-Cycle Cost	$0.1	$1.2	$3.5	$4.0	$5.6	$6.0	$5.7	$6.2	$7.3	$6.3
Supplemental Trimming Cost	$3.2	$5.2	$6.1	$7.1	$4.8	$5.3	$6.5	$5.9	$5.9	$5.9
Baseline 4-Year Cycle Cost	$12.4	$12.3	$10.5	$11.8	$12.7	$13.1	$13.4	$14.7	$15.0	$17.5
SAIDI	22.9	19.5	18.8	18.4	18.1	17.9	18.1	17.9	18.1	18.0
Estimated Resource Requirement	228	257	262	280	270	270	270	270	270	270

Figure 5-1: Annual Costs and SAIDI – Recommended VM Program

The VM Budget (SPP and Non-SPP) and Restoration Costs are summarized below:

Table 5-1: VM Storm Protection Program 3ab-457 Performance Characteristics

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total VM Budget	$17.1	$20.0	$21.4	$24.0	$24.3	$25.5	$26.8	$28.1	$29.5	$31.0
Restoration Costs	$20.3	$17.0	$16.5	$16.6	$16.4	$16.6	$17.8	$18.8	$19.7	$20.5
Total VM-Influenced Costs	**$37.4**	**$36.9**	**$37.9**	**$40.6**	**$40.7**	**$42.1**	**$44.6**	**$46.9**	**$49.2**	**$51.5**

From a benefits perspective, two measures are worth exploring because the program takes a few years to establish: 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. For the 10-year and 5-year end state averages, all years and cost elements are priced at 2020 rates, with no inflation.

Table 5-2: VM Storm Protection Program 3ab-457 Performance Characteristics

	10-Year Average			Future Steady-State (Average of Last Five Years)		
	Program 1	Program 2-457	Program 3ab-457	Program 1	Program 2-457	Program 3ab-457
SAIFI	0.229	0.195	0.193	0.227	0.184	0.181
SAIDI	20.8	18.9	18.8	20.7	18.2	18.0
Typical Storm Season	$15.3 M	$12.4 M	$11.9M	$15.1 M	$11.4 M	$10.7 M
65 mph Storm	$16.6 M	$14.0 M	$13.3 M	$16.3 M	$13.2 M	$12.4 M
85 mph Storm	$37.1 M	$31.3 M	$29.8 M	$36.5 M	$29.6 M	$27.6 M
105 mph Storm	$69.9 M	$59.0 M	$56.1 M	$68.7 M	$55.7 M	$52.1 M
125 mph Storm	$117.9 M	$99.5 M	$94.6M	$109.8 M	$94.0 M	$87.9 M

The proposed Program 3ab-457 is projected to improve SAIFI by 15.3 percent relative to the baseline 4-year cycle over the full period, or by 21.3 percent if just the final five years are considered. SAIDI improvement is 9.6 percent across ten years, or 14.0 percent in the future steady state. Storm performance improves by 22.2 percent across ten years, or 29.1 percent in the future steady state.

6 Tree Trimming Model & Modules Configuration

The Tree Trimming Model requires intermittent 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 module requires updates to a variety of cost and workforce assumptions to perform its functions correctly.

6.1 TTM Inputs and Assumptions

TTM requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count, overhead mileage, and geographic coordinates;
- The outage database or databases; and,
- A history of trimming activity, preferably including start and end dates, costs, and covering multiple trims for each circuit.

6.1.1 Circuit List

A comprehensive list of circuits was obtained from TECO, which contained a total of 780 circuits.

Not all circuits and mileage were of interest, as TTM is only relevant to the overhead portion of circuits for which trimming is a regular concern. Ultimately, 709 "trimmable" circuits were included in the analysis, representing some 6,247 miles of overhead circuit length.

6.1.2 Performance Data

Circuit reliability performance data was gathered from TECO's Distribution Outage Database (DOD). The analysis included outages from January 1, 2006 through November 26, 2019, thus accommodating at least thirteen years of data. Of interest were outages with the tree-related cause codes found in Table 6-1below. 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 6-1: Tree-Related Cause Codes (January 1, 2006 - November 26, 2019)

Cause Code	Events	CI	CMI
Tree\Blew into Line	305	20,060	1,219,189
Tree\Non-Prev.	9,970	811,842	68,744,420
Tree\ Prev.	9,776	740,361	66,143,332
Tree\Grew into Line	1,644	110,815	8,404,342
Tree\Vines	5,984	210,380	7,476,754
Trees (Other)	436	22,815	1,879,906
Incorporated Unknown (25%)	2,732	162,248	10,206,418
Incorporated Weather (25%)	6,190	389,703	35,775,171
Grand Total	37,037	2,468,224	199,849,532

TECO also incorporated a portion of CIs and CMIs from outages with "Unknown" and "Weather" cause codes. From experience, Accenture has found with other utilities that a significant portion of such catch-all causes is, in fact, tree-related. Therefore, after conducting an internal analysis of trends in outage counts for these cause codes in relation to explicit tree cause codes, TECO determined that 25 percent was a reasonable proportion to include in the analysis.

Finally, certain outages were excluded from this analysis irrespective of the cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

6.1.3 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; and,
- Cost to trim the entire circuit.

Similar to the performance data, the analysis included trimming data from January 1, 2006 through November 26, 2019. 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 and trim completion date (year and month of trim) of each circuit trim were incorporated in the analysis.

6.2 Reliability Performance Curve Development

6.2.1 Creating Circuit Performance Groups

Circuits were ordered according to historical performance. A total of seven groups were identified so that around 1,130 miles were represented in each group. Group 07 were the circuits that had zero tree-related outages from 2006-2019.

Table 6-2: CI Grouping Characteristics

Circuit CI Group	CI per Mile Criteria	Circuits	Miles
01	Greater than 649	164	1,117
02	Between 467 and 649	95	1,135
03	Between 277 and 467	131	1,136
04	Between 193 and 277	70	1,134
05	Between 104 and 193	101	1,132
06	Between 0.3 and 104	168	1,130
07	Less than 0.3	66	19

Table 6-3: CMI Grouping Characteristics

Circuit CI Group	CMI per Mile Criteria	Circuits	Miles
01	Greater than 55,483	159	1,130
02	Between 34,277 and 55,483	114	1,125
03	Between 22,485 and 34,277	114	1,107
04	Between 14,427 and 22,485	83	1,133
05	Between 8,340 and 14,427	87	1,152
06	Between 19.3 and 8,340	172	1,136
07	Less than 19.3	66	19

6.2.2 Circuit Performance Curve Fitting

Performance data points were derived using historical outage data, trim data, and circuit length 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.

Several conditions had to be satisfied in order 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 6-1 below 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.

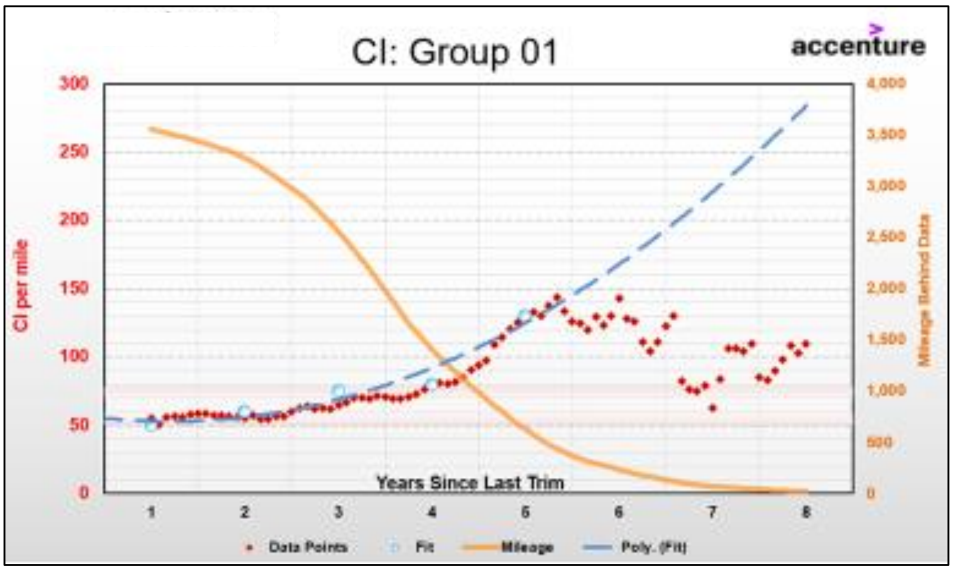


Figure 6-1: Example of Curve Fitting Analysis

A curve similar to that shown in Figure 6-1 was developed for each of the CMI groups, resulting in a total of fourteen curves, which are shown in Figure 6-2 and Figure 6-3 respectively. These curves provided the critical input required to compute the projected reliability associated with 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.

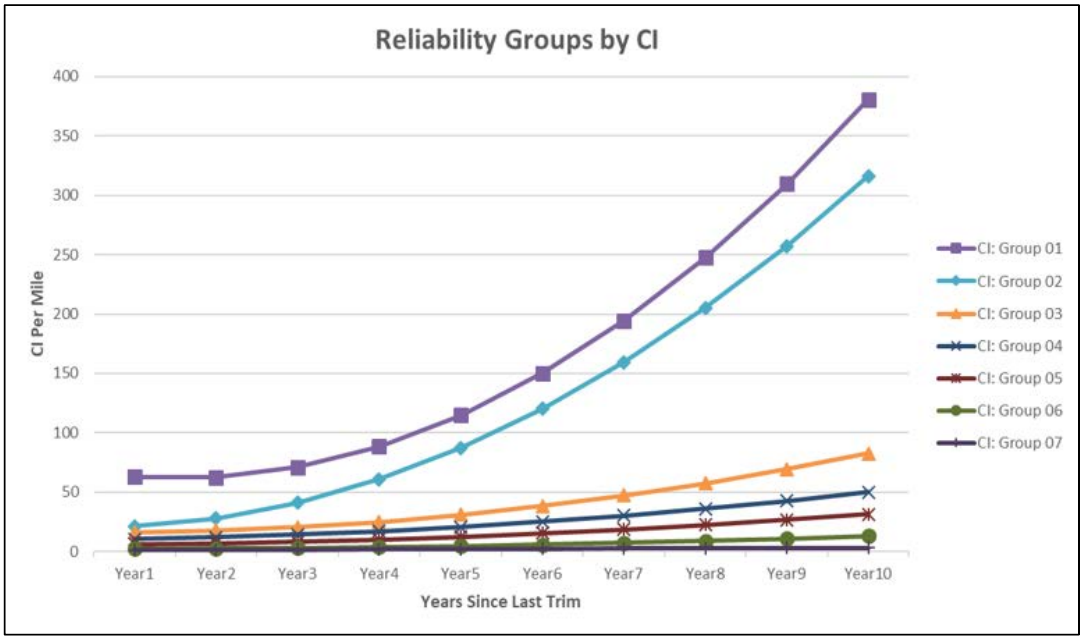


Figure 6-2: Customer Interruption (CI) Curve Groups

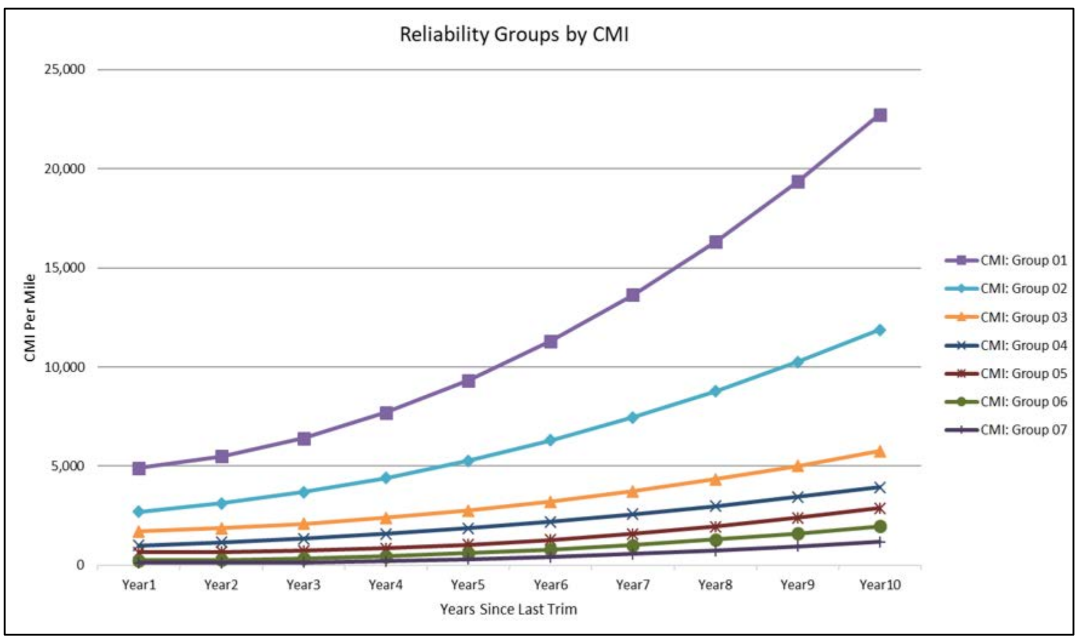


Figure 6-3: Customer Minute Interruption (CMI) Curve Groups

6.2.3 Cost Curves

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

The shapes of the cost curves were based on a proprietary study called the Economic Impacts of Deferring Electric Utility Tree Maintenance by ECI[9] 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 6-4 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20 percent. Delaying trimming by another year will further inflate costs to 40 percent 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.

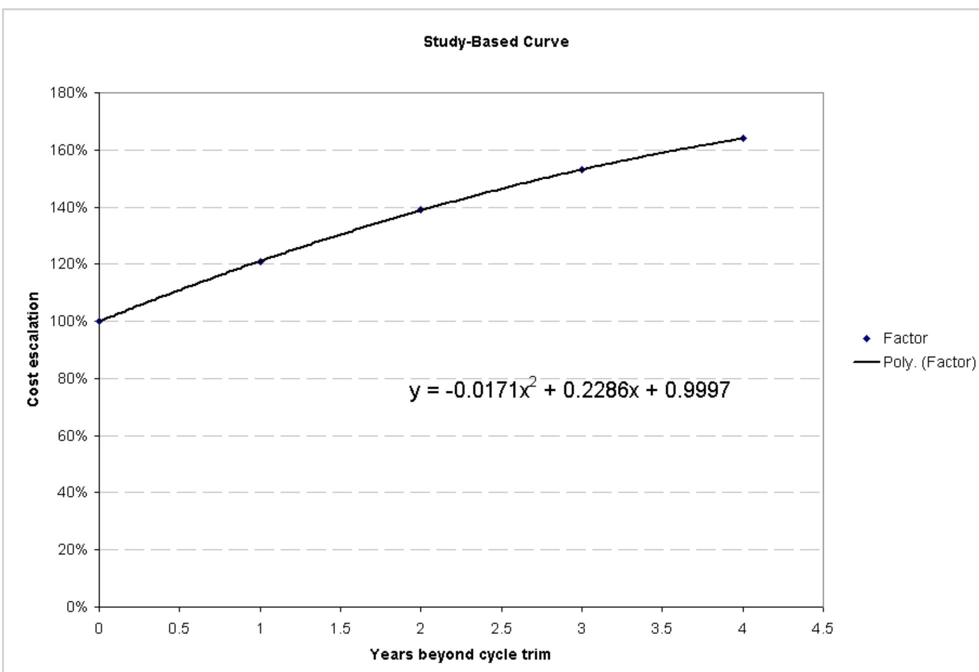


Figure 6-4: ECI Study-Based Cost Curve

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

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

Similar to how the performance groups were created, circuits were ordered according to the average cost per mile. Initially a total of six groups were identified so that each had around 1,000 miles represented in each group. Group 01 ranged from $7,600/mile to $41,000/mile and it was important to further divide it into smaller groups due to the large range between costs. Ultimately, Group 01 was divided into 4 smaller groups so that the ranges were more reasonable. The same was true on the other side of the spectrum and the lowest cost group was split into two groups. Ultimately, circuits were grouped into 10 distinct groups as shown in the following table:

Table 6-4: Cost Grouping Characteristics

Circuit Cost Group	Cost per Mile Criteria	Circuits	Miles
01	Greater than $25,000	14	79
02	Between $15,500 and $25,000	26	158
03	Between $10,000 and $15,500	42	225
04	Between $7,600 and $10,000	90	713
05	Between $6,100 and $7,600	103	1,088
06	Between $5,000 and $6,100	109	1,016
07	Between $4,100 and $5,000	91	1,037
08	Between $3,300 and $4,100	89	1,058
09	Between $1,500 and $3,300	116	896
10	Less than $1,500	25	100

With this group information a curve was created for each using the average cost per mile in each group with an additional twenty-five percent increase on each. The additional twenty-five percent was added to adjust historical trimming costs to 2019 dollars. Since TECO is on a four-year effective trim cycle each cost group is anchored on Year 4 with its respective adjusted average cost per mile. The remaining points were determined using the expertise of TECO and Accenture:

- Years 1: A 35 percent reduction in average cost if TECO would return to a circuit a year later
- Years 2-3: Linear increase in spending from Year 1 to Year 4
- Years 5-8: Follow the cost escalation described in Figure 6-5.
- Years 9-10: A 5 percent increase for each year trimming is delayed

These datapoints and assumptions were used to fit a curve for each of the cost groups shown below:

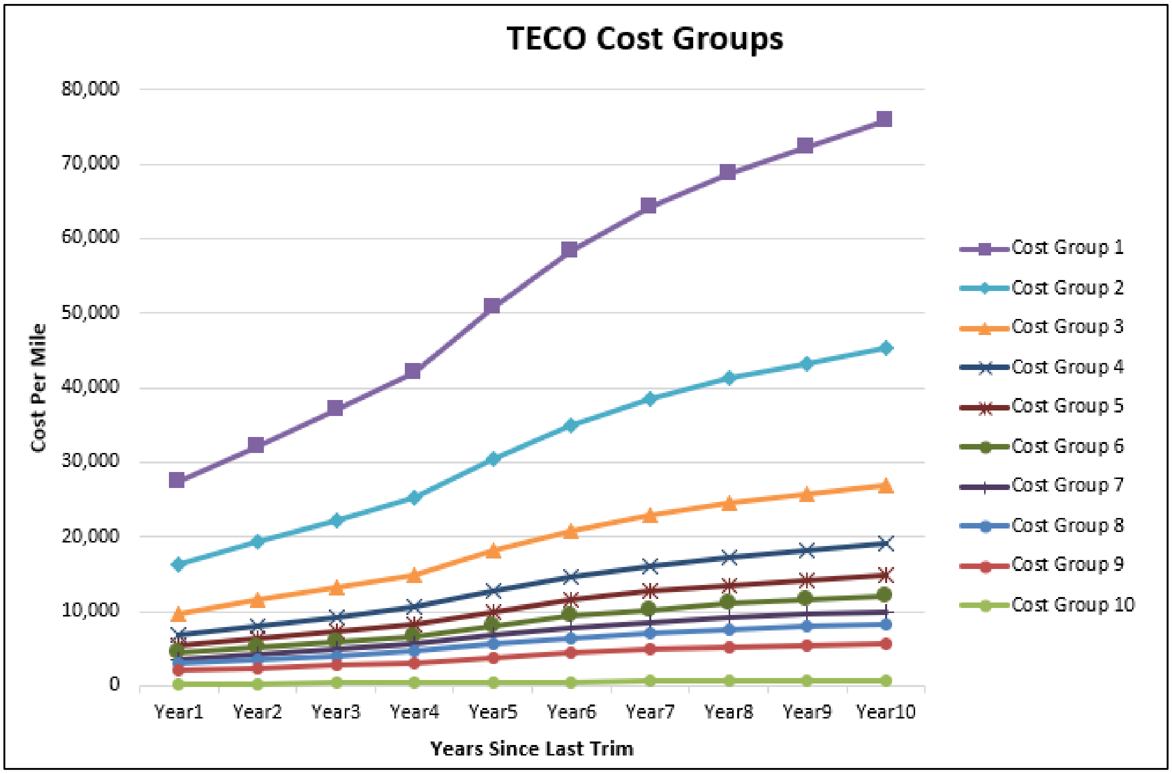


Figure 6-5: Cost Groups

TTM uses these curves to identify the estimated cost per mile to trim a circuit based on its year since last trim. These costs are in 2019 dollars and an estimated 5 percent inflation rate is used for subsequent trimming costs in future years.

6.3 Storm Module Inputs and Assumptions

Storm protection initiative cost and benefit modeling was accomplished using TTM and its associated Storm Module which have been used to prioritize trimming activities since 2006, and an Enhanced Storm Module to cover analyses not originally anticipated in the original Storm Module. The following cost implications were generated for each vegetation management activity considered:

Table 6-5: Storm Module Cost Assumptions

Cost	Cost Generator	Key Assumptions
Baseline: 4-Year Cycle Cost	TTM Core Module	• Cost curves (TTM Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across work areas
Supplemental Trimming Cost	TTM Core Module	• Cost curves (TTM Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across work areas for 25% of supplemental miles
Mid-Cycle VM Initiative Cost	TTM Enhanced Storm Module	• Cost premium for inspection and enhanced activities (SME Estimate) • Timing of mid-cycle activities (SME decision) • Proportion of circuit population targeted (SME decision – 2 scenarios) • Proportion of circuit targeted (SME decision)
Corrective Maintenance Tickets	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)
Premiums Associated with Attracting Additional Workforce	TTM Core Module	• 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)
SAIDI-Driven Restoration Costs	TTM Storm Module	• Reliability outputs from TTM Core Module • Average cost to restore a CMI (SME estimate)
Storm Restoration Costs	TTM Storm Module	• Trim list from TTM Core Module • Storm damage calculation function • FEMA HAZUS windspeed return dataset

Cost	Cost Generator	Key Assumptions
		• Average cost to restore in major event including mutual assistance (Irma Analysis, SME adjustment)

6.3.1 Baseline: 4-Year Cycle Costs

Routine cycle trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

Cycle targets are established by declaring a number of miles to trim each year. In the baseline four-year scenario, the budget was allocated such that each service area would be on its own four-year cycle.

6.3.2 Supplemental Trimming Costs

Supplemental trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

In all supplemental scenarios, each service area was guaranteed their allocation of one quarter of the supplemental miles, with the remaining three-quarters of the miles getting targeted to where they were most needed.

6.3.3 Mid-Cycle Costs

There are four key assumptions relating to mid-cycle trimming activities:

- The cost premium for inspection and targeted trimming relative to cycle activities
- The timing of mid-cycle activities
- The portions of circuits to target
- The fraction of trees which will require mid-cycle intervention

Inspection-based activities come at a premium. There is first the cost of patrolling and inspecting the lines before vegetation management activities are taken, which must then be loaded into the costs of performing the actions in question. Second, relative to regular maintenance trimming, there are cost inefficiencies 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 trimming would cost 80 percent more on a per-tree basis than routine trimming.

Mid-cycle activities are timed to promote the best possible performance out of the routine trimming initiative. Based on TECO subject matter expert input and considering the intervals between trimming in the baseline and enhanced scenarios, two years was selected as the optimal time for a mid-cycle inspection and associated vegetation management activities.

Mid-cycle activities will have similar impact in terms of overall restoration effort in a major event whether they occur on the feeder or lateral. Activities on the feeder will, however, protect more customers per tree outage avoided. With this in mind, TECO subject matter experts specified two possible scopes for Initiative 2 – feeder miles and all miles to be considered in that order.

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. TECO subject matter experts estimated up to 25 percent of trees would grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. The analysis uses this figure but presumes that additional activities may be substituted for portions of the potential trimming, such as performing removals and the like, as long as the activities fit within the stipulated budget. As the cost per tree is 180% of regular trimming cost, and only 25 percent of trees can be targeted for mid-cycle activity, this should never amount to greater than 45% (180% * 25%) of the regular 4-year cycle budget.

6.3.4 Corrective Costs

TECO responds to approximately 4,000 corrective maintenance tickets annually, of which one third are related to tree limbs growing too close to the wires. The remainder are related to various forms of capital work, moving lines to accommodate construction, and the like. In total, the corrective maintenance tickets currently amount to $1.3 million per year, with TECO trimming to a four-year cycle. In prior filings, TECO estimated that moving from a three-year to a four-year cycle would result in a 30 percent increase in corrective maintenance tickets. Conversely, moving from four years back to three years would effectively revert the current $1.3 million budget to $1.0 million, or a roughly 23 percent reduction. Postulating that all growth-related tickets (33 percent) would be eliminated in a two-year cycle, the team fit a curve and generated a set of assumptions as follows, relative to the baseline 4-year scenario:

Table-6-6: Cost Assumptions by Effective Cycle

Effective Cycle (years)	Cost Reduction	Resulting Cost
4.00	0.0%	$1.30M
3.75	7.0%	$1.21M
3.50	13.0%	$1.13M
3.25	18.5%	$1.06M
3.00	23.0%	$1.00M
2.75	26.7%	$0.95M
2.50	29.6%	$0.91M
2.25	31.7%	$0.89M
2.00	33.0%	$0.86M

6.3.5 Resource Premium Costs

Experience has shown that there is a limit to the rate at which TECO can expand its workforce without incurring some degree of premium cost. To account for this, the TTM Storm Module estimates the number of resources that would be required to do the Trimming, Mid-cycle and Corrective work 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 resources that can be added in a given year without offering overtime or a per diem premium, and the assumed productivity of new resources in their first year.

6.3.6 Day-to-Day Restoration Costs

A key output of the Tree Trimming Model 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 TTM'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. The average cost for responding to an outage is estimated at $1,300 and the calculated average number of customers interrupted per vegetation outage is 65, resulting in an estimated average cost per CI due to tree-caused outages of twenty dollars.

Annual restoration costs are estimated multiplying the SAIFI values generated by TTM by the number of customers served by TECO, and in turn multiplying that product by the estimate of $20 per customer interrupted.

6.3.7 Storm Restoration Costs

The TTM Storm Module projects storm restoration costs per year using a function which determines the fraction 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 experience with Hurricane Irma.

The TTM Storm Module'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 percent, which is taken to mean that while only 100 percent 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.

Wind Gusts (3 second sustained @10m elevation)	Years Since Last Trim 1	2	3	4	5	6
40	0.19%	0.48%	0.83%	1.21%	1.63%	2.08%
45	0.27%	0.69%	1.18%	1.73%	2.32%	2.96%
50	0.38%	0.94%	1.61%	2.37%	3.18%	4.06%
55	0.50%	1.23%	2.15%	3.15%	4.24%	5.40%
60	0.65%	1.63%	2.79%	4.09%	5.50%	7.01%
65	0.82%	2.07%	3.53%	5.20%	6.99%	8.91%
70	1.03%	2.58%	4.43%	6.49%	8.74%	11.13%
75	1.27%	3.18%	5.45%	7.99%	10.74%	13.69%
80	1.54%	3.86%	6.61%	9.69%	13.04%	16.61%
85	1.84%	4.63%	7.93%	11.63%	15.64%	19.93%
90	2.19%	5.49%	9.42%	13.80%	18.57%	23.66%
95	2.57%	6.46%	11.07%	16.23%	21.84%	27.82%
100	3.00%	7.54%	12.92%	18.93%	25.47%	32.45%
105	3.47%	8.72%	14.93%	21.92%	29.48%	37.56%
110	3.99%	10.03%	17.19%	25.20%	33.90%	43.19%
115	4.56%	11.46%	19.63%	28.79%	38.73%	49.35%
120	5.18%	13.02%	22.32%	32.71%	44.01%	56.07%
125	5.86%	14.72%	25.23%	36.98%	49.74%	63.38%
130	6.59%	16.56%	28.38%	41.59%	55.95%	71.29%
135	7.38%	18.54%	31.78%	46.58%	62.66%	79.84%
140	8.23%	20.68%	35.44%	51.95%	69.88%	89.04%
145	9.15%	22.98%	39.38%	57.72%	77.64%	98.93%
150	10.13%	25.44%	43.60%	63.90%	85.95%	109.52%
155	11.17%	28.06%	48.10%	70.50%	94.84%	120.84%
160	12.29%	30.87%	52.91%	77.55%	104.31%	132.91%

Figure 6-6: Expected Damage by Wind Gusts for a Given Year Since Last Trim

The windspeed probabilities employed by the TTM Storm Module 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 TTM Storm Module 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 calculated based on total cost per customers out at peak. As illustrated below, while TECO experienced a grand total of about 328,000 customers out from Hurricane Irma, the number of customers out simultaneously was 213,000, as many quick wins are achieved early through switching and the restoration of substation and transmission issues. Approximately two thirds of this peak value are believed to be tree-caused.

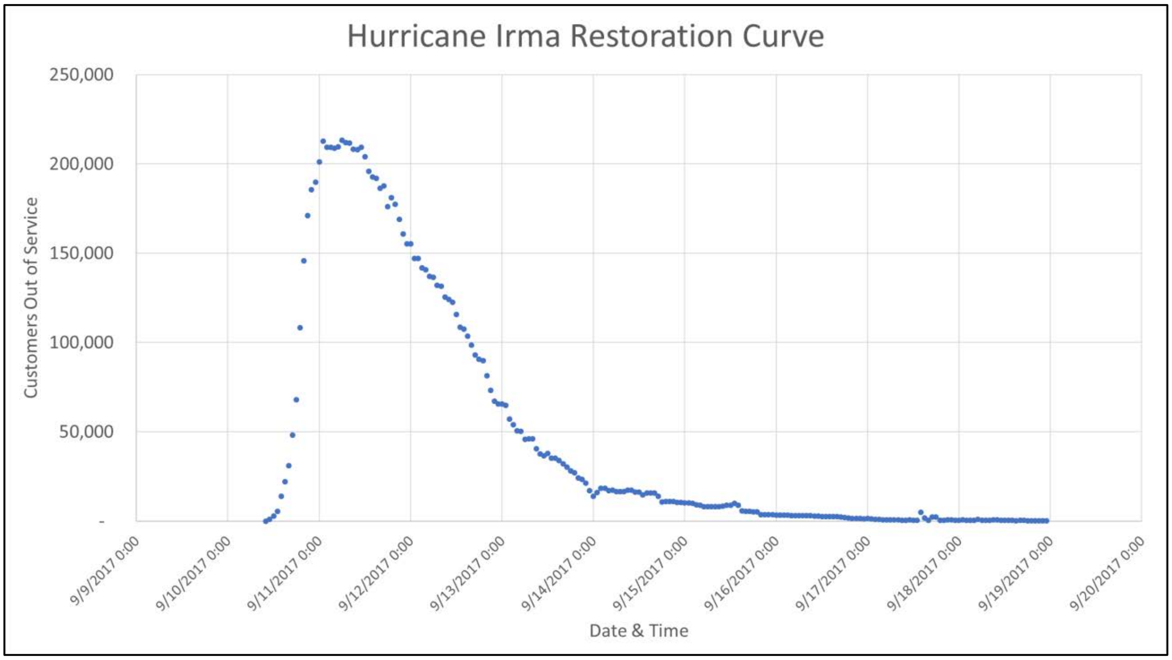


Figure 6-7: TECO Restoration Curve for Hurricane Irma

The peak number of customers out forms a more consistent denominator for cost per customer calculations, and in the case of TECO's experience with Irma this worked out to $389 per CI in line, tree, planning, logistics and other costs, which is in line with other Irma experiences in the State. Given the demand pressure on tree and line resources coming out of California's wildfire crisis, and general inflationary pressure, TECO's subject matter experts estimate that costs have risen by ten percent in the past two years, so the same restoration today would cost $424 per CI.

7 Work Plan

7.1 Baseline Summary

Work Area	2020		2021		2022		2023	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	260.3	43,997	262.1	44,336	260.0	51,889	260.1	52,612
DADE CITY	93.3	4,618	80.1	2,308	107.8	5,541	90.8	3,015
EASTERN	212.4	30,524	210.1	34,845	208.8	35,717	208.6	27,808
PLANT CITY	311.9	16,511	308.9	16,875	309.7	22,055	311.4	12,296
SOUTH HILLSBOROUGH	178.3	16,775	176.1	26,999	181.4	14,380	184.5	18,196
WESTERN	279.3	67,510	279.5	60,773	277.0	64,125	278.2	59,307
WINTER HAVEN	227.0	26,391	237.9	9,676	228.4	16,338	230.7	25,762
Total	1,562.6	206,326	1,554.6	195,812	1573.0	210,045	1,564.2	198,996

7.2 Supplemental Summary

Work Area	2020		2021		2022		2023	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	77.9	21,357	159.1	29,226	113.5	20,418	127.1	19,538
DADE CITY	99.9	5,208	6.2	484	127.6	5,578	44.9	681
EASTERN	99.8	18,598	153.3	12,341	72.9	8,794	149.8	18,918
PLANT CITY	76.7	9,702	25.2	2,443	202.2	8,347	31.1	3,579
SOUTH HILLSBOROUGH	15.3	2,264	20.5	2,427	20.2	3,236	138.9	28,399
WESTERN	15.7	3,926	82.8	13,024	112.4	20,376	155.8	27,165
WINTER HAVEN	16.8	1,277	63.1	5,063	43.2	5,784	53.2	7,950
Total	402.3	62,332	510.2	65,008	692.0	72,533	700.8	106,230

7.3 Mid-cycle Summary

Work Area	2020		2021		2022		2023	
	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers
CENTRAL	0.0	0	48.6	17,262	36.0	9,488	176.8	25,321
DADE CITY	0.0	0	2.8	1,293	5.1	904	0.0	0
EASTERN	0.0	0	17.3	4,730	34.5	12,007	115.3	16,234
PLANT CITY	0.0	0	18.0	8,234	12.0	7,191	231.0	12,380
SOUTH HILLSBOROUGH	0.0	0	51.7	16,233	23.0	13,900	82.1	3,925
WESTERN	0.0	0	58.8	27,318	53.3	19,073	171.2	27,479
WINTER HAVEN	0.0	0	45.9	20,663	32.1	14,565	241.5	7,779
Total	**0.0**	**0**	**243.1**	**95,733**	**196.0**	**77,128**	**1017.9**	**93,118**

Tampa Electric's Transmission Asset Upgrades - Year 2022 Details						
Project ID	Circuit No.	Pole Count	Project Start Month	Construction		Project Cost in 2020
				Start Month	End Month	
Transmission Upgrades-138/230 kV-230006	230006	101	9/21	11/21	4/22	$1,500,000
Transmission Upgrades-138/230 kV-230402	230402	14	3/22	8/22	12/22	$300,100
Transmission Upgrades-69 kV-66048	66048	5	12/20	4/21	4/22	$50,000
Transmission Upgrades-138/230 kV-230606	230606	28	7/21	10/21	3/22	$210,000
Transmission Upgrades-138/230 kV-230012	230012	16	7/21	10/21	3/22	$50,000
Transmission Upgrades-138/230 kV-230020	230020	61	8/22	1/23	6/23	$41,939
Transmission Upgrades-69 kV-66022	66022	50	12/20	8/21	8/22	$672,980
Transmission Upgrades-69 kV-66001	66001	70	3/21	10/21	6/22	$1,877,473
Transmission Upgrades-69 kV-66016	66016	40	11/20	6/21	6/22	$400,000
Transmission Upgrades-69 kV-66032	66032	40	2/22	1/23	8/23	$40,576
Transmission Upgrades-69 kV-66020	66020	10	7/21	3/22	8/22	$305,900
Transmission Upgrades-69 kV-66035	66035	65	8/22	1/23	8/23	$35,029
Transmission Upgrades-138/230 kV-230602	230602	112	5/21	8/21	3/22	$50,000
Transmission Upgrades-69 kV-66008	66008	9	10/21	7/21	12/21	$281,970
Transmission Upgrades-69 kV-66030	66030	50	7/21	4/22	9/22	$1,498,910
Transmission Upgrades-69 kV-66045	66045	52	9/21	5/22	12/22	$1,708,376
Transmission Upgrades-138/230 kV-230033	230033	14	6/21	3/22	6/22	$294,700
Transmission Upgrades-69 kV-66025	66025	105	3/21	8/21	8/22	$2,324,840
Transmission Upgrades-138/230 kV-230623	230623	65	10/22	1/23	7/23	$44,720
Transmission Upgrades-69 kV-66021	66021	45	2/22	6/22	3/23	$45,648
Transmission Upgrades-69 kV-66017	66017	97	2/22	7/22	6/23	$234,972
Transmission Upgrades-138/230 kV-230609	230609	5	12/21	12/21	3/22	$105,250
Transmission Upgrades-69 kV-66033	66033	26	11/20	11/21	5/22	$50,000
Transmission Upgrades-69 kV-66036	66036	31	11/20	6/21	5/22	$300,000
Transmission Upgrades-69 kV-66027	66027	17	7/21	2/22	6/22	$550,620
Transmission Upgrades-69 kV-66060	66060	6	11/20	7/21	4/22	$10,000
Transmission Upgrades-138/230 kV-230604	230604	36	10/22	2/23	7/23	$24,768
Transmission Upgrades-69 kV-66407	66407	29	12/20	5/21	5/22	$10,000
Transmission Upgrades-138/230 kV-230013	230013	20	7/21	3/22	6/22	$421,000
Transmission Upgrades-69 kV-66427	66427	7	11/20	6/21	6/22	$10,000
Transmission Upgrades-69 kV-66026	66026	83	10/21	4/22	10/22	$2,582,952
Transmission Upgrades-69 kV-66098	66098	22	9/22	1/23	6/23	$22,210
Transmission Upgrades-69 kV-66011	66011	24	9/21	5/22	12/22	$22,317
Transmission Upgrades-69 kV-66028	66028	49	9/22	1/23	6/23	$49,244
Transmission Upgrades-69 kV-66047	66047	1	2/21	4/22	6/22	$1,014
Transmission Upgrades-69 kV-66415	66415	10	12/20	3/22	8/22	$317,000
Transmission Upgrades-69 kV-66436	66436	36	8/22	2/23	8/23	$34,490

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.

TAMPA ELECTRIC COMPANY
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PAGE 1 OF 55
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SUBSTATION HARDENING STUDY

Prepared by: HDR Engineering, Inc

August 27, 2021

HDR

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Contents

EXECUTIVE SUMMARY

The Tampa Electric Company (TECO) system spans multiple counties in Florida covering a diverse area consisting of rural, urban, coastal, and inland communities. A significant part of the customer load that TECO serves, and the location of TECO's headquarters, is in Hillsborough County, Florida. This transmission network is in the Tampa Bay vicinity in low-elevation areas near the Gulf Coast. These substations are a mix of Transmission and Distribution Substations that serve as switching stations to distribute large generation resources, such as the Big Bend Substation or Gannon Substation, and distribution substations serving dense populations, such as the Manhattan Substation in south Tampa. These substations have been built and operated for many years and have served the Tampa community well. When originally developed, the substations were carefully located in geographic areas based on elevation above sea-level, proximity to customer load and access to transmission lines for interconnection to the main grid.

Over the past several years, concerns have grown over storm surge related to extreme weather events such as hurricanes or tropical storms. These concerns, coupled with rising sea levels, have drawn attention by TECO to 24 substations in Hillsborough County. In March of 2021, TECO solicited engineering firms to perform a Substation Extreme Weather Hardening Study (Substation Hardening Study) for these substations. HDR Engineering, Inc. (HDR) was selected to perform the study and began work in April of 2021.

Nine hardening projects are recommended as a result of this Substation Hardening Study.

Substation Project	Cost
Hookers Point - Re-grade Substation and Install New Control House, Autotransformer and Power Transformer	$7,600,000
South Gibsonton - Install Elevated Control House and Regrade North End of Substation	$3,100,000
Jackson Rd - Install Elevated Control House and New SPCC System for Autotransformer	$2,800,000
Estuary - Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure	$900,000
El Prado - Rebuild Substation with Open-air Distribution Circuit Breakers	$5,000,000
Skyway - Replace 13.8 kV Circuit Breakers and Elevate Control House	$3,500,000
Desal - Elevate Control Enclosure	$700,000
MacDill - Install New SPCC Systems for Power Transformers	$700,000
Maritime - Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House	$4,500,000
Total	**$28,800,000**

The substation hardening projects have an estimated cost of $28.8MM. The three (3) transmission projects at Hookers Point, South Gibsonton and Jackson will improve grid stability by maintaining the tie points between 230, 138, and 69 kV systems during a storm surge event. The six (6) distribution projects will improve reliability of service, including service to critical load, during storm surge events.

1.0 Introduction

This report outlines the study approach that HDR took in developing projects to harden the substations mentioned above against storm surge events. It outlines the data collected, based on both desktop studies and from field visits, the approach to developing scorecards to prioritize the substation susceptibility to storm surge flooding, and detailed information on the eight substation projects developed to strengthen the grid against extreme weather events.

The 24 substations included in this Substation Hardening Study are:

1. Big Bend 230 kV
2. Big Bend Solar 69 kV
3. Cypress Street 69 kV
4. Desal 69 kV
5. El Prado 69 kV
6. Estuary 69 kV
7. First Street 69 kv
8. Gannon 230 kV, 230/138 kV, 230/69 kV
9. Harbour Island 69 kv
10. Hookers Point 138/69 kV
11. Interbay 69 kV
12. Jackson Road 230/69 kV
13. MacDill 69 kV
14. Manhattan 69 kV
15. Maritime 69 kV
16. McKay Bay Cogen 69 kV
17. Meadow Park 69 kV
18. Miller Mac 69 kV
19. Millpoint 69 kV
20. Port Sutton 69 kV
21. Rocky Creek 69 kV
22. Skyway 69 kV
23. South Gibsonton 230/69 kV
24. Twelfth Avenue 69 kV

2.0
Study Approach

HDR Inc. conducted the Substation Hardening Study in three phases – Discovery, Evaluation and Recommendation. Each phase is described in the following subsections.

2.1 DISCOVERY PHASE

After being awarded the project from TECO, HDR began the process of collecting data to be used in the Substation Hardening Study. This data collection took place in the form of desktop studies, site visits in the field and the creation of a Geospatial Information Systems (GIS) database.

2.1.1 Desktop Studies

During the Discovery Phase, HDR collected data to be used in the Substation Hardening analysis. This included desktop studies and site visits to each of the 24 substations identified by TECO. The desktop studies were focused on gathering environmental existing conditions for the substations. This includes the following:

- FEMA 100- and 500-yr floodplain maps
- Evacuation Zone Categories
- Existing Wetlands within or adjacent to the substations
- Hydric soil presence

Floodplain maps

The industry standard for defining a high flood hazard area is the "100-year flood zone," which is a flood that has a 1 percent chance of occurring in a given year. This is the standard used by the Federal Emergency Management Agency (FEMA) to identify hazard areas for the National Flood Insurance Program. FEMA also identifies areas of minimal flood hazard (500-year flood zone), which is a flood that has a 0.2 percent chance of occurring in a given year.

The substation locations were overlayed upon the YEAR FEMA 100- and 500-yr floodplain maps to identify whether the substation is located within a flood hazard area. The FEMA map for each substation are located in the Appendices of this report.

Evacuation Zone Categories

Hillsborough County and the Tampa Bay Regional Council have identified evacuation zones based on potential storm tide heights and wind speed during a hurricane. The evacuation zones range from Zone A to Zone E and the potential storm tide heights vary dependent on the hurricane category, ranging from a Category 1 which can cause wind speeds of 74 to 95 miles per hour (mph) ranging to a Category 5 with wind speeds of 157 mph or greater. For example, Zone A area can experience potential storm tide heights ranging from up to 11 feet, during a Category 1 hurricane, and up to 38 feet during a Category 5 hurricane. The evacuation zone for each substation location was identified to understand potential storm tide heights during a hurricane.

Wetlands

Wetlands and other surface waters mapped by the U.S. Fish and Wildlife Service (USFWS) National Wetland Inventory (NWI) Wetland Mapper were reviewed to determine if they have been previously mapped within the substation area and adjacent to the substation area. These areas are seasonally saturated or permanently flooded and therefore can give an indication on the hydric and drainage conditions of the soil.

Hydric Soil Presence

A hydric soil is a soil that is saturated, flooded or ponded long enough during the growing season to develop anaerobic conditions in the upper part of the soil profile that favor the growth and regeneration of hydrophytic vegetation (USDA - SCS, 1991). The United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) Web Soil Survey was reviewed for near surface soil information at each substation location. The general soil types within the substation area were reviewed including hydric classification and depth to water table to have an indication of whether the substation was prone to flooding due to the near surface soil conditions.

Substation Elements

Another desktop study focused on the electric grid configuration of the substations. TECO provided HDR with the following information for each of the 24 substations.

- Single and Electrical (S&E) One Line Diagrams
- Substation Electrical Layouts
- Relaying and Control One Lines
- Property Boundaries

This information was used to identify whether the substation was used for Transmission or Distribution, the amount of generation connected (megawatts or MW), whether bulk power was connected, the number of transmission circuits connected, and the voltage level served from the substation (>100 kilovolt or kV). The data received from TECO was parsed out and saved to individual substation folders on a SharePoint drive created by HDR. This data was collected for use in the Evaluation phase for Grid Stability impact. When bulk power or multiple transmission circuits are removed from the electric grid quickly due to an outage, the system frequency can be negatively impacted and may deviate from 60 hertz (Hz). For this reason, substations with Bulk Power connected (Gannon and Big Bend 230 kV Substations) were treated with a higher level of criticality in the scorecard process during the Evaluation Phase.

Also noted in this desktop study was whether an autotransformer (230/138 or 138/69 kV) was located in the substation. This information was used to identify substations with long lead-time equipment that could impact the amount of time a substation is out of service after a storm surge event.

The last set of data collected in the desktop study concerned customer service information. This included the number of direct customers served, the number of distribution circuits at each substation, the peak load (Million Volt-Amps or MVA) and whether critical load is served from the substation.

2.1.2 Site Visits

Another critical part of the Discovery Phase was performing site visits to each of the 24 substations. Over the course of three days, an HDR senior electrical engineer and environmental engineer visited the substations along with a TECO representative. Ahead of each site visit, HDR created a substation site visit checklist with items to observe and information to be collected at each site.

The existing environmental and substation element observations made at each site were:

- Signs of recent flooding (Yes/No)?
- Substation elevation – elevated, low, or flat?
- Space to elevate control house (Y/N)?
- Relay panel condition (Old, new, or mixed)?
- Space to install berm outside substation (Y/N)?
- Space to elevate other equipment (Y/N)?
- Gopher tortoise burrows observed (Y/N)?
- Areas with standing water observed (Y/N)?
- Areas with vegetation (other than grass) observed (Y/N)?

These existing conditions were gathered to assess the substation existing environmental conditions and to develop hardening projects. Existing environmental conditions, such as whether the substation has signs of flooding and standing water and existing vegetation (i.e., water lines on the control houses, wet soils, puddles and wetlands) provided additional information on the water/soil regime and drainage conditions of the substation area and potential permitting needs for future hardening projects. The existence of Gopher tortoise burrows can also result in potential environmental restrictions and permitting needs for future hardening projects. By hardening, HDR is referring to physical design changes to the substations so they are less susceptible to damage from storm surge flooding. Industry accepted methods of substation hardening include elevating control houses to avoid flooding in storm-surge events and installing berms (temporary or permanent) to keep storm-surge flooding at bay. During the site visits, HDR staff took note of the substation layout, ownership area, and surrounding area to develop feasible hardening projects during the Recommendation Phase.

At each site visit, the HDR engineers took photographs of the substation, the equipment, and surrounding areas. These photos were taken for later references in the Evaluation and Recommendation phases of the project. This data was uploaded to the substation folders on the SharePoint drive as well as the Environmental Systems Research Institute (ESRI) Field Maps application that was developed (see section below for details).

2.1.3 ESRI Field Maps

As detailed above, a significant amount of data was collected – through both desktop studies and site visits. The SharePoint site served as a collection point and helped organize the information by substation. However, for this study, HDR needed the ability to analyze the substations geographically with overlays of information such as floodplain data and topography. To accomplish this task, the HDR engineering team worked with its GIS group to create a dashboard on ESRI Field Maps application. The first step was to enter the address of each of the 24 substations into the web-based platform. Using the mobile application during site visits, the engineering team was able to document representative assets for each individual piece of equipment such as control house, transformers, and circuit breakers. Each asset was tagged with GIS coordinates and notes from the field regarding equipment height above ground and condition were recorded. As photos of each asset were taken, including nameplates, those photos were tagged to the individual asset in the ESRI Field Maps application.

With substation assets captured and loaded into the ESRI Field Maps application, HDR was able to analyze each one in relation to floodplains and storm surge zones during the Evaluation Phase and recommend substation hardening projects during the Recommendation Phase.

2.2 EVALUATION PHASE

After the Discovery Phase was completed and HDR had sufficient information collected for each substation, the study entered the Evaluation Phase. The key part of this phase was the creation of a scorecard tool to prioritize the substations and rank them based on several criteria. Two primary elements for the scorecard included probability and impact, and secondary elements included weighting. The goal was to rank and score the 24 substations based on their criticality. ISO standards define criticality as a measure of the importance of an asset to the delivery of the organization's objectives.

The business objectives used in the scoring included:

- Grid Stability / Capacity – ability of the interconnected grid to provide adequate power and balance supply and demand
- Reliability / Availability – duration of time the system is out and not providing power to customers
- Customer Service – the number of customers and amount of load impacted by an outage
- Cost – the cost of restoring the system after it is damaged
- Safety – risk of injury, disability or death of an employee or member of the public
- Environmental – risk of not meeting environmental stewardship objectives or regulations

Input factors were used as the basis for measuring the impact on these objectives. The factors and objectives were then quantified and weighted to determine an overall criticality score for each substation.

2.2.1 Input Data

Input factors measured were based on observations made during the substation inspections. The following factors were used relative to each business objective:

Grid Stability / Capacity
- Generation connected
- Bulk Power connected
- Number of transmission circuits
- Load size >100kV

Reliability
- Hydric soil
- Signs of flooding
- Observed water
- Past flooding
- Material lead time / autotransformer

Customer Service
- Number of direct-served customers
- Number of distribution circuits
- Peak load (MVA)
- Critical Load

Cost
- Asset book value (based on age)
- Repair/replace cost factors due to autotransformers
- Repair/replace cost factors due to switchgear
- Replacement power costs

Safety
- Control house for shelter
- Evacuation zone category

Environmental
- Adjacent wetlands
- Gopher tortoise burrows
- HAZMAT

2.2.2 Scoring Levels

Input factors were scored using five levels reflecting impact to the business objectives:

1 = Negligible impact
2 = Minor impact
3 = Moderate impact
4 = Major impact
5 = Extreme impact

Impact level scores were assigned as follows:

Grid Stability / Capacity

- Generation connected:
  - 1 = 0
  - 2 = 25 MW
  - 3 = 500 MW
  - 4 = 1,000 MW
  - 5 = Greater than 1,000 MW

- Bulk Power connected
  - 1 = No
  - 4 = Yes

- Number of transmission circuits
  - 1 = 0
  - 2 = 1
  - 3 = 5
  - 4 = 10
  - 5 = More than 10

- Load size >100kV (Yes/No)
  - 1 = No
  - 4 = Yes

Reliability

- Hydric soil
  - 1 = No
  - 2 = 0 inches or unlisted
  - 3 = 3 inches

- Signs of flooding
  - 1 = No
  - 3 = Yes

- Observed water
  - 1 = No
  - 2 = Puddles
  - 3 = Yes

- Past flooding
  - 1 = No
  - 3 = Yes

- Material lead time / autotransformer
  - 1 = No
  - 3 = Yes

Customer Service

- Number of direct-served customers
  - 1 = None
  - 2 = 2,000
  - 3 = 6,000
  - 4 = 8,000
  - 5 = 10,000 or more

- Number of distribution circuits
  - 1 = None
  - 2 = 2
  - 3 = 4
  - 4 = 6
  - 5 = 8 or more

- Peak load (MVA)
  - 1 = 0
  - 2 = 20 MVA
  - 3 = 30 MVA
  - 4 = 40 MVA
  - 5 = 50 MVA or more

- Critical Load (Yes/No)
  - 1 = No
  - 3 = Yes
  - 5 = Port Load

Cost

- Asset book value / age
  - 1 = Old (i.e., fully depreciated)
  - 3 = Mixed (i.e., mid-life)
  - 5 = New

- Repair/replace cost factors due to autotransformers
  - 1 = No
  - 3 = Yes

- Repair/replace cost factors due to switchgear
  - 1 = No
  - 3 = Yes

- Replacement power costs
  - 1 = 0
  - 2 = 25 MW
  - 3 = 500 MW
  - 4 = 1,000 MW
  - 5 = Greater than 1,000 MW

Safety

- Control house
  - 1 = Yes
  - 2 = No

- Evacuation zone category
  - 2 = B
  - 3 = A

Environmental

- Adjacent wetlands
  - 1 = No
  - 3 = Yes

- Gopher tortoise burrows
  - 1 = No
  - 2 = Inconclusive
  - 3 = Yes

- HAZMAT (Yes/No)
  - 1 = No
  - 4 = Yes

2.2.3 Scoring

Impact level scores were then weighted, in consultation with TECO, and weighted-average total scores were calculated for each factor and the overall criticality score. The following weightings were used:

Grid Stability / Capacity – weighted at 40% of overall score

- Generation connected – weighted at 40%
- Bulk Power connected – weighted at 30%
- Number of transmission circuits – weighted at 20%
- Load size >100kV – weighted at 10%

Reliability – weighted at 20% of overall score

- Hydric soil – weighted at 25%
- Signs of flooding – weighted at 15%
- Observed water – weighted at 15%
- Past flooding – weighted at 30%
- Material lead time / autotransformer – weighted at 25%

Customer Service – weighted at 10% of overall score

- Number of direct-served customers – weighted at 25%
- Number of distribution circuits – weighted at 25%
- Peak load (MVA) – weighted at 25%
- Critical Load – weighted at 25%

Cost – weighted at 10% of overall score

- Asset book value / age – weighted at 50%
- Repair/replace cost factors due to autotransformers – weighted at 15%
- Repair/replace cost factors due to switchgear – weighted at 15%
- Replacement power costs – weighted at 20%

Safety – weighted at 10% of overall score

- Control house for shelter – weighted at 80%
- Evacuation zone category – weighted at 20%

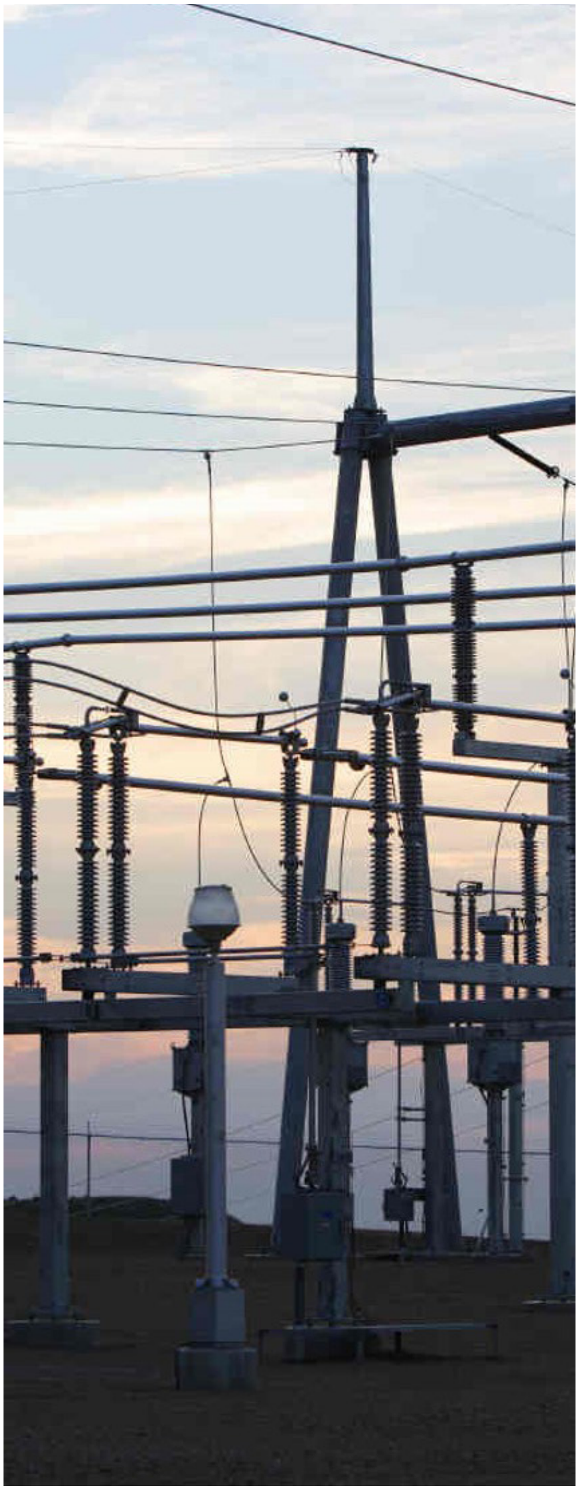
Environmental – weighted at 10% of overall score

Adjacent wetlands – weighted at 40%

- Gopher tortoise burrows – weighted at 20%
- HAZMAT – weighted at 40%

Weighting Chart

Generation Connected (40%)	Grid Stability (40%)	**Consequence Score (100%)**
Bulk Power Connected (30%)		
Number of Transmission Circuits (20%)		
Load Size > 100kV (10%)		
Hydric Soil (25%)	Reliability / Outage Duration (20%)	
Signs of Flooding (15%)		
Observed Water (15%)		
Past Flooding (20%)		
Material Lead Time (25%)		
# of Direct Served Customers (25%)	Customer Service (10%)	
# of Distribution Circuits (25%)		
Peak Load MVA (25%)		
Critical Load (25%)		
Book Value / Asset Age (50%)	Cost (10%)	
Cost Factor / Autotransformer (15%)		
Cost Factor / Switchgear (15%)		
Replacement Power Costs (20%)		
Control House (80%)	Safety (10%)	
Evacuation Zone Category (20%)		
Adjacent Wetlands (40%)	Environmental (10%)	
Gopher / Tortoise Burrows (20%)		
HAZMAT (40%)		



2.2.4 Scoring Results

Based on the scores and weightings described above, overall criticality scores and rankings for each substation were determined as shown in the chart on page 09. The blue bars show the criticality scores for each substation on Y-axis to the left. The red line shows the cumulative scores using the Y-axis on the right. For example, as shown by the green lines, 50% of the scores are due to the 10 left-most substations while the remaining 50% is due to the 14 substations to the right.

2.3 RECOMMENDATION PHASE

After the scorecard was developed, HDR reviewed the results and identified substations that were susceptible to storm surge flooding. Special attention was paid to substations where outages could impact grid stability or reliability of service and posed safety and environmental risks. For these substations HDR developed hardening projects to mitigate the risks and improve the resiliency of the substation in the event of storm surge flooding. On each scorecard substations were identified that scored high (to the left side of the charts) on the risk rankings. Hardening projects were developed to reduce those risks and drive their score down, bringing them to the right of the scorecards and in line with the other lower-risk substations.

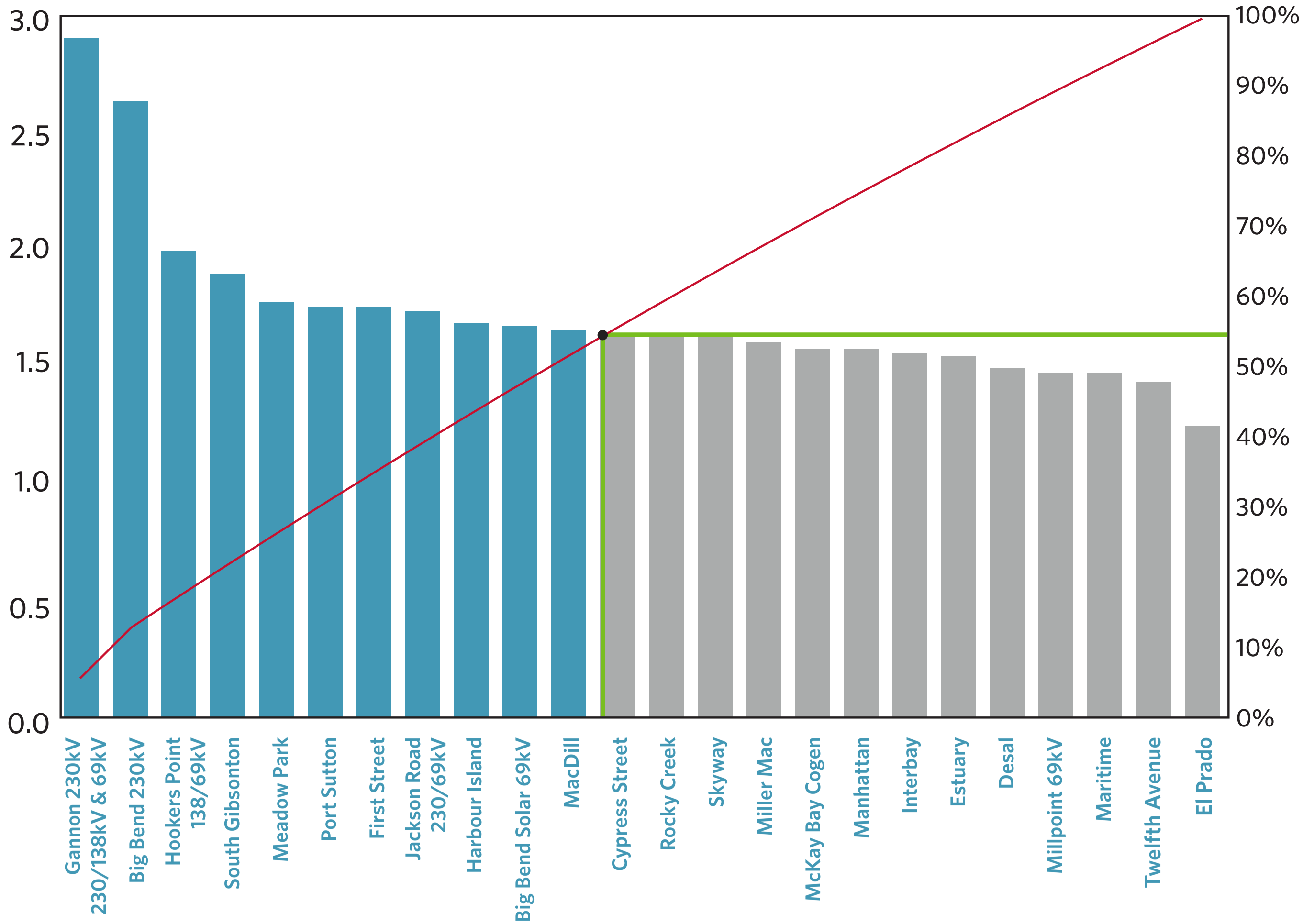
As the substation hardening projects were developed, budgetary cost estimates were created for each. These costs were turnkey – including equipment, construction, testing and commissioning. These costs were then used in a cost benefit analysis to justify the hardening project and its effectiveness in improving grid resiliency at the same time as being cost effective.

The projects developed in the Recommendation Phase are presented in Section 4.0 – Substation Hardening Projects.

3.0
Study Results - Scorecards

3.1 OVERALL SCORES

The Pareto chart below shows the consequence scores for each substation using the Y-axis on the left. The red line shows the cumulative scores using the Y-axis on the right. As shown by the two green lines, the 11 substations shown in blue to the left of the green vertical line account for approximately 55% of the overall consequence scores (based on the green horizontal line).



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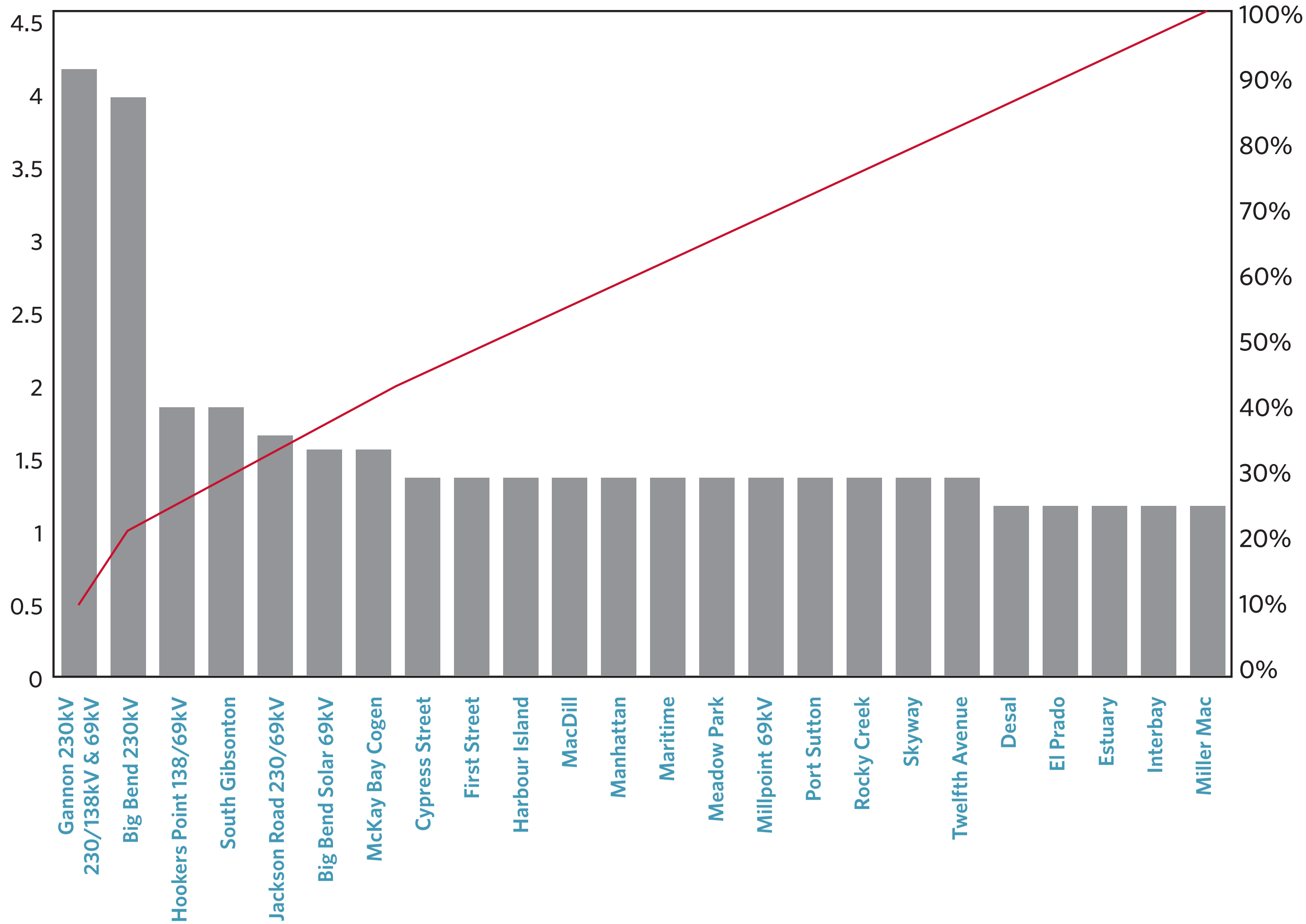
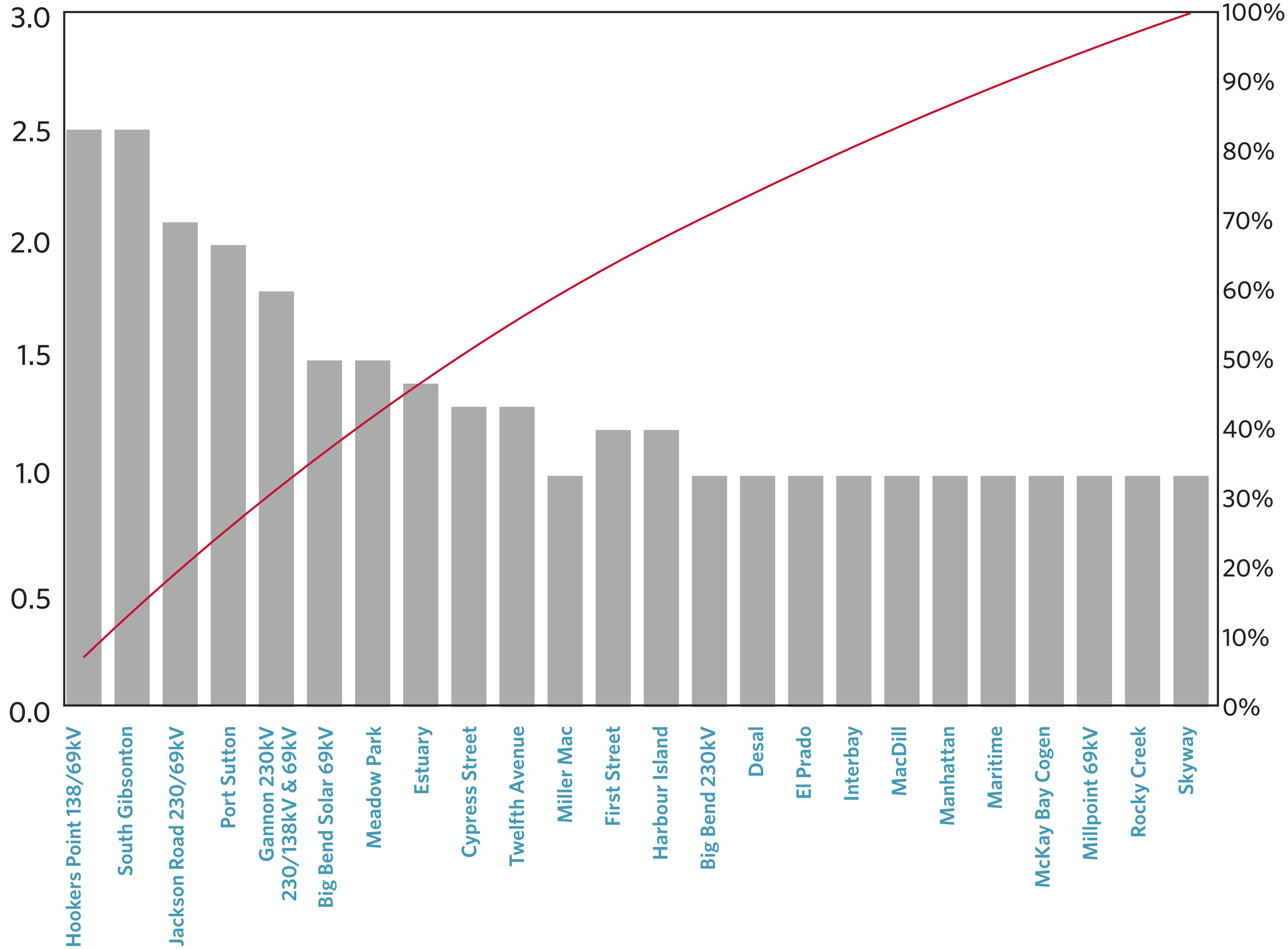
3.2 GRID STABILITY/CAPACITY

The component scores and rankings that made up the overall score are shown in the charts below and on the following pages:



3.3 RELIABILITY



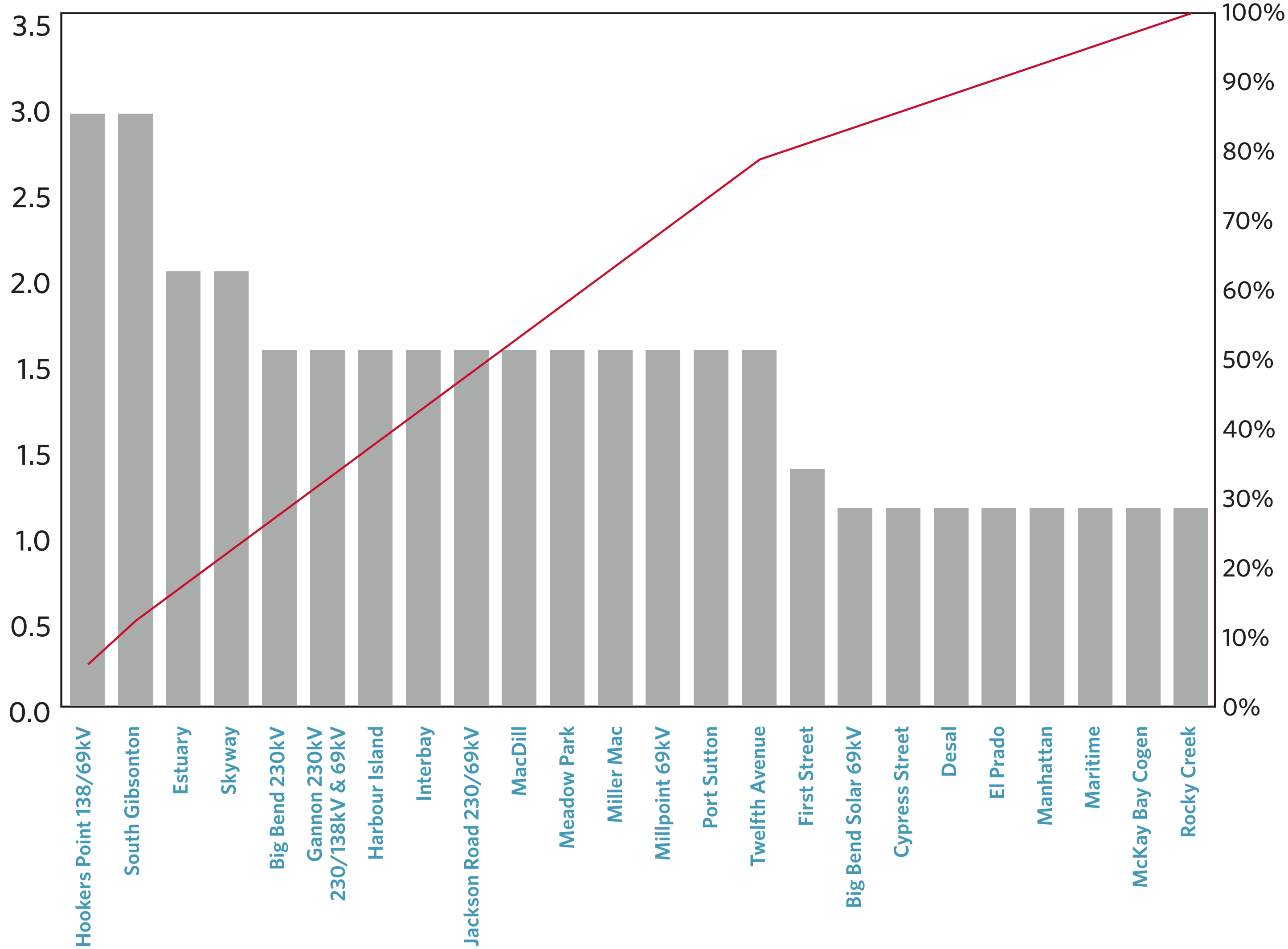
3.4 CUSTOMER SERVICE

3.5 COST


Gannon 230kV 230/138kV & 69kV
Big Bend 230kV
Harbour Island
Big Bend Solar 69kV
McKay Bay Cogen
Cypress Street
Desal
First Street
Interbay
MacDill
Miller Mac
Millpoint 69kV
Rocky Creek
Jackson Road 230/69kV
Manhattan
Maritime
Meadow Park
Port Sutton
Skyway
El Prado
Hookers Point 138/69kV
South Gibsonton
Estuary
Twelfth Avenue
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%


100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
2.5
2.0
1.5
1.0
0.5
0.0
South Gibsonton
Skyway
Twelfth Avenue
Rocky Creek
Millpoint 69kV
Maritime
Manhattan
MacDill
Jackson Road 230/69kV
Hookers Point 138/69kV
Harbour Island
Gannon 230kV 230/138kV & 69kV
El Prado
Cypress Street
Big Bend 230kV
Port Sutton
Miller Mac
Meadow Park
McKay Bay Cogen
Interbay
First Street
Estuary
Desal
Big Bend Solar 69kV

3.7 ENVIRONMENTAL



4.0 Substation Hardening Projects

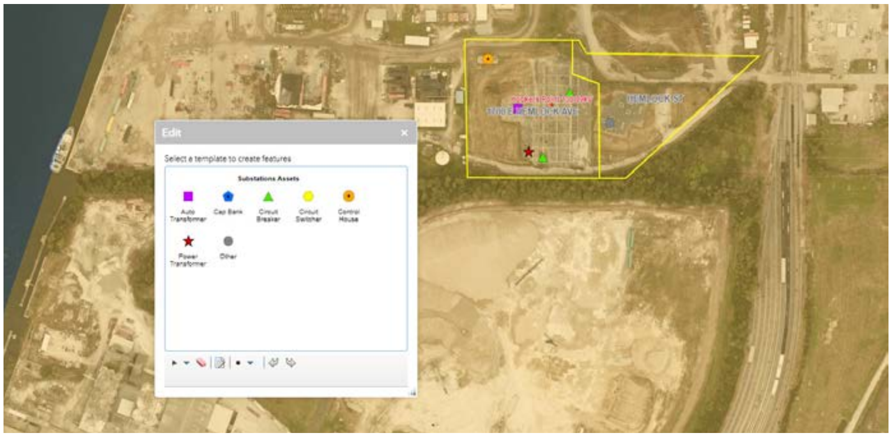
Based on the data collected in the Discovery Phase and scorecards developed in Evaluation Phase, eight (8) projects were developed to harden TECO substations against extreme weather events. Three projects at transmission substation aim to improve grid stability and five were developed to improve customer service, cost, safety, and environmental impacts of losing the substations due to flooding from storm surge.

The Big Bend 230 kV and Gannon 230/138 and 69 kV Substations scored very high in the overall consequence and Grid Stability scorecards. This is due to the large amount of generation connected to these substations and the number of transmission lines that terminate at the facility. Both substations are fairly hardened against extreme weather in their current state. Each substation has new equipment, the circuit breakers and control houses are elevated, and the substation grading is elevated around the substations. For this reason, no projects were developed to improve Big Bend and Gannon, and the project development was focused on Hookers Point, Gibsonton and Jackson Rd transmission substations.

Of the 16 distribution substations, 10 were not found to be susceptible to storm surge flooding. These substations had new and/or elevated equipment and favorable substation grading and were located on an elevated property with grading away from the substations. For these reasons no hardening projects were developed at these substations and the focus was put on the remaining six distribution substations – Estuary, El Prado, Skyway, Desal, MacDill and Maritime.

The following table shows the substation hardening projects along with the total estimated costs for each. These costs are budgetary estimates (+/- 25% accuracy). They include equipment, engineering, permitting, construction, project management, testing and commissioning costs.

Substation Project	Cost
Hookers Point - Re-grade Substation and Install New Control House, Autotransformer and Power Transformer	$7,600,000
South Gibsonton - Install Elevated Control House and Regrade North End of Substation	$3,100,000
Jackson Rd - Install Elevated Control House and New SPCC System for Autotransformer	$2,800,000
Estuary - Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure	$900,000
El Prado - Rebuild Substation with Open-air Distribution Circuit Breakers	$5,000,000
Skyway - Replace 13.8 kV Circuit Breakers and Elevate Control House	$3,500,000
Desal - Elevate Control Enclosure	$700,000
MacDill - Install New SPCC Systems for Power Transformers	$700,000
Maritime - Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House	$4,500,000
Total	**$28,800,000**



4.1 PROJECT 1

Hookers Point 138/69 kV Substation

Re-grade Substation and Install New Control House, Autotransformer and Power Transformer

Hookers Point is a 138/69 kV Substation with a 168 MVA autotransformer and seven (7) transmission circuits that terminate in the switchyard. Also installed at this substation is a power transformer that serves critical south load. The substation sits in the FEMA 100-yr floodplain and is located ~900 ft from a canal/drainage feature discharging into Tampa Bay.

Hookers Point is a critical substation because it ties the 138 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformer may trip offline and the seven 69 kV circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The autotransformer, power transformer and control house all sit in a low-lying area on the west side of the substation. There is a ~3 ft embankment that splits the substation and to the east, on higher elevation sits the 69 kV switchyard. Three of the 69 kV circuit breakers are very old, oil-filled circuit breakers that sit close to the ground.

HDR recommends decommissioning and removing the autotransformer, power transformer and control house and elevating the west side of the switchyard to match the elevation of the main switchyard. Once the grading is complete, install a new 138/69 kV autotransformer with a 3′ SPCC wall and a new power transformer to serve the customer load. HDR also recommends replacing the three older 69 kV breakers with gas insulated circuit breakers with on elevated structures, per the current TECO standard design.

This project will greatly reduce the likelihood of flooding in a storm surge event and will improve grid stability by making this critical 138/69 kV Substation more resilient.

Project Cost Estimate

In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Hookers Point project.

Cost Benefit

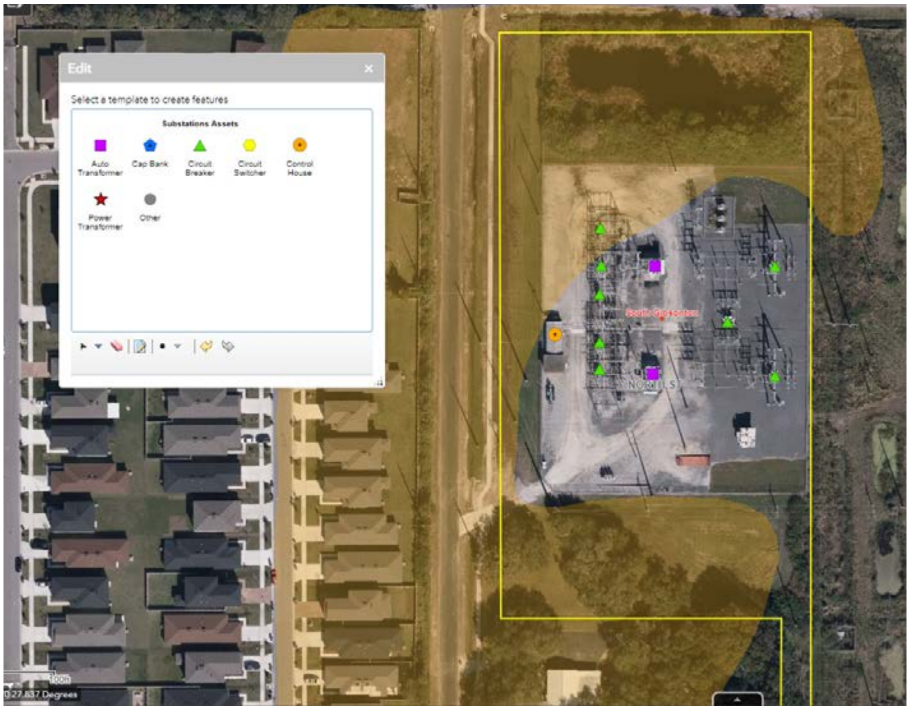
The Hookers Point project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $7.6MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 138/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency issues at those facilities.

This project improves the Grid Stability and Reliability score of Hookers Point and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

Hookers Point 138/69 kV Substation

RE-GRADE SUBSTATION AND INSTALL NEW CONTROL HOUSE, AUTOTRANSFORMER AND POWER TRANSFORMER

Item	Equipment	Engineering, Permitting, Construction, Project Management, Testing and Commissioning
Re-grade Substation	$250,000	$430,000
Elevated Control House	$2,000,000	$320,000
138/69 kV Autotransformer	$2,700,000	$320,000
69/13 kV Transformer	$900,000	$220,000
3 qty 69 kV Circuit Breakers	$300,000	$160,000
	$6,150,000	$1,450,000
Total	**$7,600,000**	



4.2 PROJECT 2

South Gibsonton 230/69 kV Substation

Install New Control House on Elevated Platform and Regrade North End of Substation

South Gibsonton is a 230/69 kV Substation with two (2) 224 MVA autotransformers and eight (8) transmission circuits that terminate in the switchyard. The substation partially sits in the FEMA 100-yr floodplain and is located ~1.5 mi from the Tampa Bay.

South Gibsonton is a critical substation because it ties the 230 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformers may trip offline and the eight circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The control house at South Gibsonton sits at ground level. HDR recommends installing a new control house on an elevated platform or concrete slab. Currently control house is located underneath incoming transmission lines. There is available property, shown in the yellow boxed area in the image above, that could be cleared, and the new control house installed.

During the site visit HDR received feedback from the operations manager onsite that flooding has occurred in the past from the small body of water to the north of the substation. HDR recommends re-grading the north end of the South Gibsonton Substation and establishing a detention pond where the existing body of water is and possibly extending it into the transmission Right-of-Way to the east of the substation. This improvement to the grading and water detention may help storm surge flooding recede more quickly out of the substation and harden the substation.

HDR also recommends replacing the oil-filled 69 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the South Gibsonton project.

Cost Benefit
The South Gibsonton project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $3.1MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 230/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency on the 230 kV bulk system.

This project improves the Grid Stability and Reliability score of South Gibsonton and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

South Gibsonton 230/69 kV Substation		
INSTALL ELEVATED CONTROL HOUSE AND REGRADE NORTH END OF SUBSTATION		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
Re-grade North End of Substation	$150,000	$480,000
69 kV Circuit Breaker	$100,000	$50,000
	$2,250,000	$850,000
Total	**$3,100,000**	

4.3 PROJECT 3

Jackson Rd 230/69 kV Substation

Install New Control House on Elevated Platform and Install New SPCC Systems for Autotransformer

Jackson Rd is a 230/69 kV Substation with one 224 MVA autotransformers and five (5) transmission circuits that terminate in the switchyard. The substation partially sits in the FEMA 100-yr floodplain and is located ~1.5 mi from the Tampa Bay. This substation has had flood events in the past due to the creek to the north flooding.

Jackson Rd is a critical substation because it ties the 230 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformer may trip offline and the seven circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The control house at Jackson Rd sits at ground level. HDR recommends installing a new control house on an elevated platform or concrete slab. There is space at the south end of the substation for this modification to be made.

HDR also recommends updating the SPCC system for the 230/69 kV Autotransformer to include a 3 ft concrete wall, like other designs on the TECO system. The 3 ft wall may protect the autotransformer in a flood event related to storm surge. This is especially important due to long lead-times for autotransformers. This modification has a twofold benefit of hardening the substation and improving environmental protection.

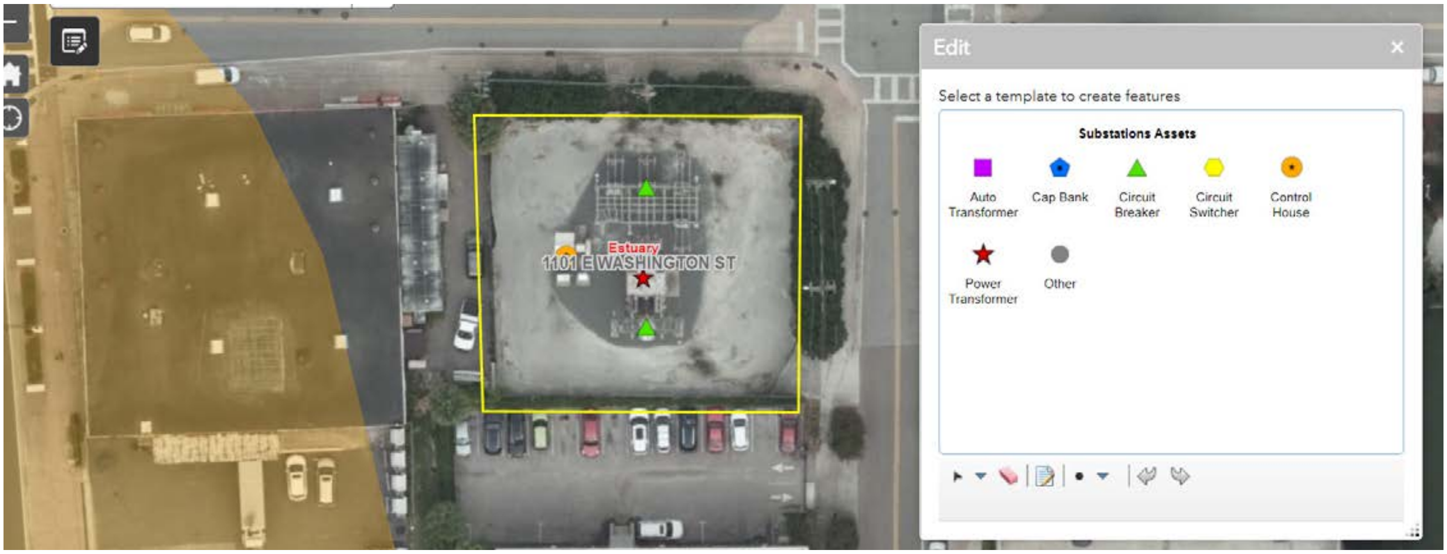
HDR also recommends replacing the oil-filled 69 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Jackson Rd project.

Cost Benefit
The Jackson Rd project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $2.8MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 230/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency on the 230 kV bulk system.

This project improves the Grid Stability and Reliability score of Jackson Rd and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

Jackson Rd 230/69 kV Substation		
INSTALL ELEVATED CONTROL HOUSE AND NEW SPCC SYSTEM FOR AUTOTRANSFORMER ITEM		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
New SPCC System for Auto	$100,000	$255,000
13 kV Circuit Breaker	$75,000	$50,000
	$2,175,000	$625,000
Total	**$2,800,000**	



4.4 PROJECT 4

Estuary 69 kV Substation

Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure

The Estuary 69 kV Substation located near downtown Tampa and serves critical downtown load. It sits just outside the FEMA 100-yr floodplain but is located ¼ mile from a canal discharging into Tampa Bay.

This substation has a power transformer, an old 69 kV oil-filled circuit breaker and four (4) distribution circuits. The 69 kV breaker is an older design that its low to the ground. The control cabinets inside the substation are not elevated and sit low to the ground as well.

To harden the Estuary 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the oil-filled 69 kV circuit breaker with a gas insulated breaker that is elevated per the TECO standard design.

HDR also recommends elevating the control cabinets like other substations. The distribution circuit breakers have older electromechanical relays and would benefit from being upgraded to SEL relays.

This substation project would increase the reliability of service to the downtown area during a storm surge event that brings flooding to the area.

Project Cost Estimate

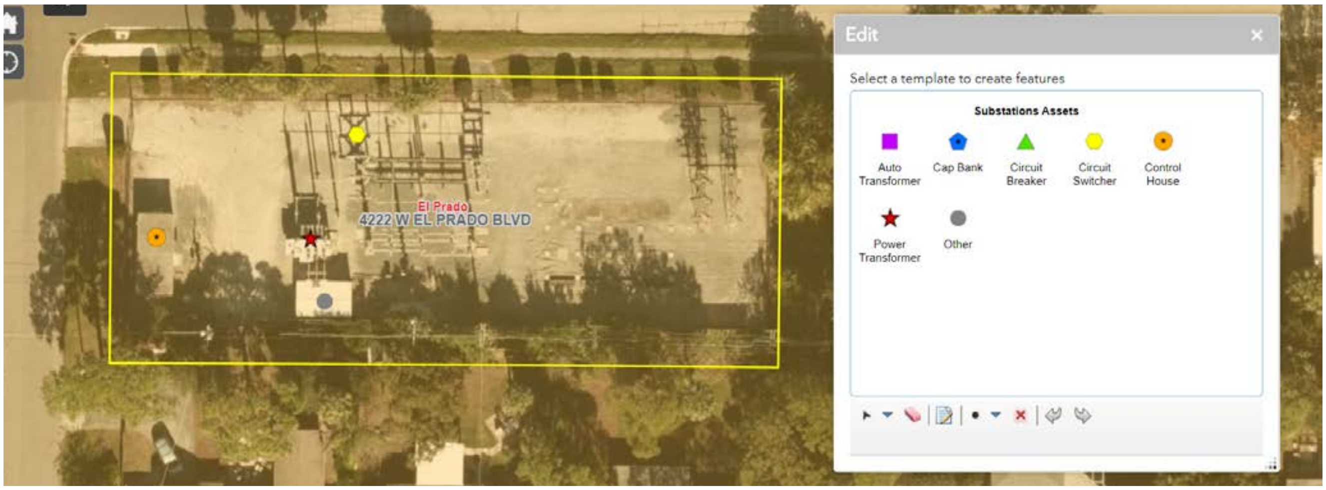
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Estuary project.

Cost Benefit

The Estuary project is a smaller capital project at $900,000 and will improve the reliability of service to TECO customers in the area, including critical downtown load. It also improves the environmental safety of the substation by removing an older 69 kV oil-filled circuit breaker and replacing it with a gas-insulted unit. The cost of replacing the circuit breaker and elevating the control enclosure at the Estuary 69 kV Substation is beneficial due to the increase in reliability and environmental safety improvements.

This project improves the Customer Service, Safety and Environmental scores of Estuary and moves the substation to the right-hand side of both scorecards into an acceptable range.

Estuary 69 kV Substation		
REPLACE 69 KV CIRCUIT BREAKER AND ELEVATE RELAY AND CONTROL ENCLOSURE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control Enclosure	$400,000	$300,000
69 kV Circuit Breaker	$100,000	$100,000
	$500,000	$400,000
Total	**$900,000**	



4.5 PROJECT 5

El Prado 69 kV Substation

Rebuild Substation with Open-air Distribution Circuit Breakers

HDR recommends rebuilding the El Prado Substation at the current site. Half of the substation site is not used and contains foundations and steel structures from decommissioned equipment. If those foundations are removed and the site re-graded, a 69 kV Circuit Switcher could be installed with a new 69/13 kV transformer and four (4) 13.8 kV package circuit breakers. This design would follow a more traditional design approach and improve switching operations and/or maintenance on the distribution breakers. An elevated control house would be installed with new relaying, and the 69 and 13.8 kV breakers and control cabinets would be elevated per the standard TECO design. An SPCC berm is also recommended for the power transformer. These steps would help harden the new substation against storm surge flooding.

Project Cost Estimate

Below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the alternative El Prado project.

Cost Benefit

Rebuilding the El Prado 69 kV Substation would be a large capitol project at a cost of $5MM. This cost would be justified by the operational and maintenance improvements. Another significant improvement would be the removal of the very old switchgear unit. If this unit failed due to storm surge flooding or during normal operation, the El Prado substation would be out of service for several months and the load would have to be back-fed by other substations. This configuration would present other operational and reliability issues. The cost of rebuilding the El Prado substation is beneficial due to the improvements in operations, maintenance, and customer service.

El Prado 69 kV Substation		
REBUILD SUBSTATION WITH OPEN-AIR DISTRIBUTION CIRCUIT BREAKERS		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Demolish and Re-grade Substation	$250,000	$500,000
Elevated Control House	$2,000,000	$320,000
69/13 kV Transformer	$900,000	$210,000
69 kV Circuit Switcher	$50,000	$80,000
Four (4) 13 kV Circuit Breakers	$100,000	$190,000
Foundations and Steel Structures	$300,000	$100,000
	$3,600,000	$1,400,000
Total	**$5,000,000**	

Alternative Project: El Prado 69 kV Substation

Replace Switchgear Unit

As an alternative to replacing the switchgear unit at El Prado, The El Prado 69 kV Substation located in south Tampa in a well established neighborhood. It sits inside the FEMA 100-yr floodplain and is located ~1 mile from the Tampa Bay.

This substation has a 69 kV circuit switcher, a power transformer, and an old 13.8 kV Switchgear unit. El Prado has four (4) distribution circuits feeding approximately 4,700 direct customers.

If flooding occurs at El Prado due to storm surge, the control house and switchgear unit could be damaged and load would not be served from this substation. The switchgear unit is a long lead-time item so the service outage could be for an extended amount of time.

HDR recommends replacing the switchgear unit with a newer design on an elevated platform similar to recent installations on the TECO system. HDR also recommends elevating the control house on a platform or concrete slab. These improvements will harden the substation against storm surge flooding and improve the reliability of service to the TECO customers in the area.

Alternative Project Cost Estimate

In the table to the right is a high-level, budgetary cost estimate (+/- 25% accuracy) for the El Prado project.

Cost Benefit

The El Prado project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $5.3MM cost is justified by the improvements to the reliability of service to customers in the area. It also replaces an older switchgear unit that is less safe to operate than the newer units installed on the TECO system. In the event of storm surge flooding, if the older switchgear at El Prado is flooded and needs to be replaced, the lead-time on the new switchgear unit could be very long and the customer load would be served from other substations which could present operational issues. The cost of replacing the switchgear unit at El Prado is beneficial due to the customer service and safety improvements.

This project improves the Customer Service and Safety scores of El Prado and moves the substation to the right-hand side of both scorecards into an acceptable range.

El Prado 69 kV Substation		
REPLACE SWITCHGEAR UNIT		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Replace Switchgear Unit	$2,500,000	$480,000
Elevated Control House	$2,000,000	$320,000
	$4,500,000	$800,000
Total	**$5,300,000**	

4.6 PROJECT 6

Skyway 69 kV Substation

Replace 13.8 kV Circuit Breakers and Elevate Control House

The Skyway 69 kV Substation is located adjacent to the Tampa International Airport and serves critical load at that facility. It sits inside the FEMA 100-yr floodplain and is located ¾ mile from the Tampa Bay.

This substation has two power transformers, 69 kV circuit breakers, seven (7) distribution circuits and a control house. Three of the distribution feeders serve the Tampa International Airport.

The control house at Skyway sits at ground level and nine (9) of the 13.8 kV circuit breakers are older, oil-filled breakers.

To harden the Skyway 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the oil-filled 13.8 kV circuit breaker with a gas insulated package breakers per the TECO standard design.

HDR also recommends installing a new control house on an elevated platform or concrete slab. There is space at the south end of the substation for this modification to be made.

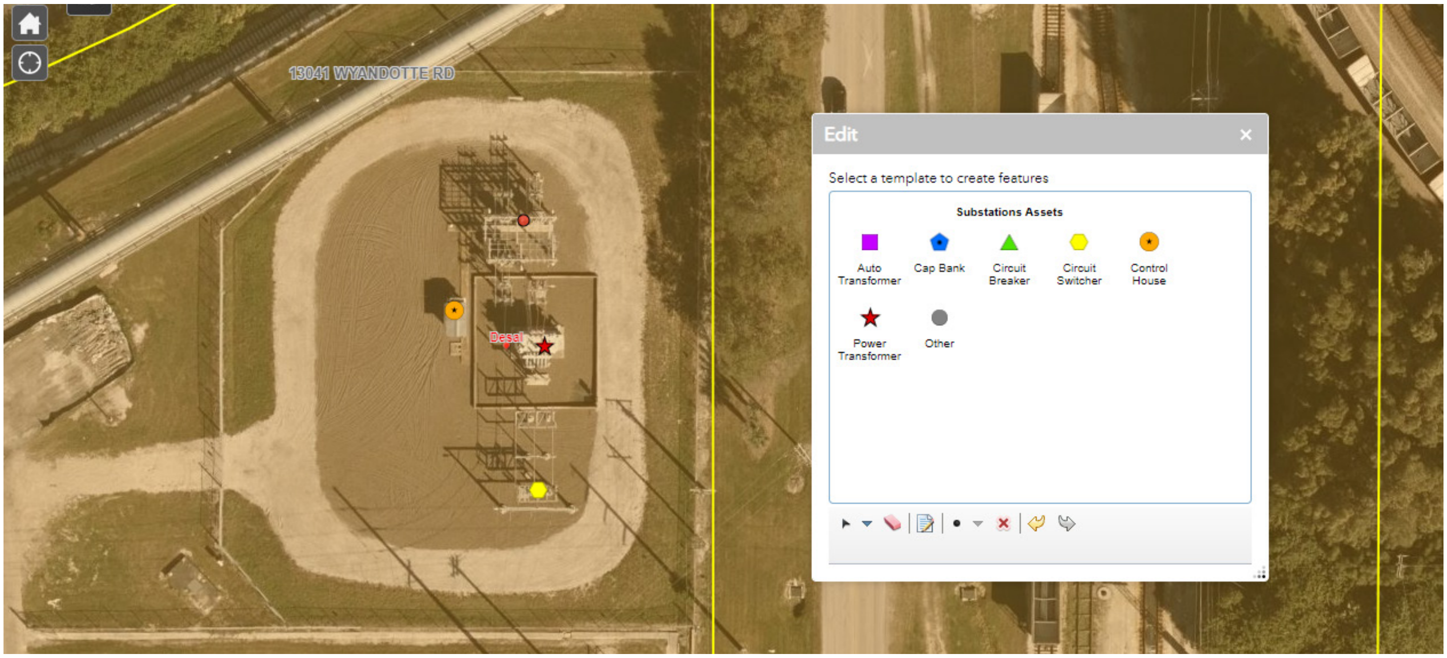
This substation project would increase the reliability of service to the airport during a storm surge event that brings flooding to the area.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Skyway project.

Cost Benefit
The Skyway project is a large capital project at $3.5MM and will improve the reliability of service to TECO customers in the area, including critical load at the airport. It also improves the environmental safety of the substation by removing older 13.8 kV oil-filled circuit breaker and replacing them with newer units. The cost of replacing the circuit breaker and elevating the control house at the Skyway 69 kV Substation is beneficial due to the increase in reliability for critical load and environmental safety improvements.

This project improves the Customer Service and Environmental scores of Skyway and moves the substation to the right-hand side of both scorecards into an acceptable range.

Skyway 69 kV Substation		
REPLACE 13.8 KV CIRCUIT BREAKERS AND ELEVATE CONTROL HOUSE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
9 qty 13.8 kV Circuit Breakers	$730,000	$450,000
	$2,730,000	$770,000
Total	**$3,500,000**	



4.7 PROJECT 7

Desal 69 kV Substation

Elevate Control Enclosure

The Desal 69 kV Substation is located adjacent to the Big Bend Generation Facility. It sits inside the FEMA 100-yr floodplain and is located approximately 1 mile from the Tampa Bay. This substation serves critical load at the Big Bend Generation facility.

This substation has a power transformer, a 69 kV circuit switcher and three (3) distribution circuits. The control cabinets inside the substation are not elevated and sit at ground level.

To harden the Desal 69 kV Substation against flooding in a storm surge event, HDR recommends replacing elevating the control cabinets.

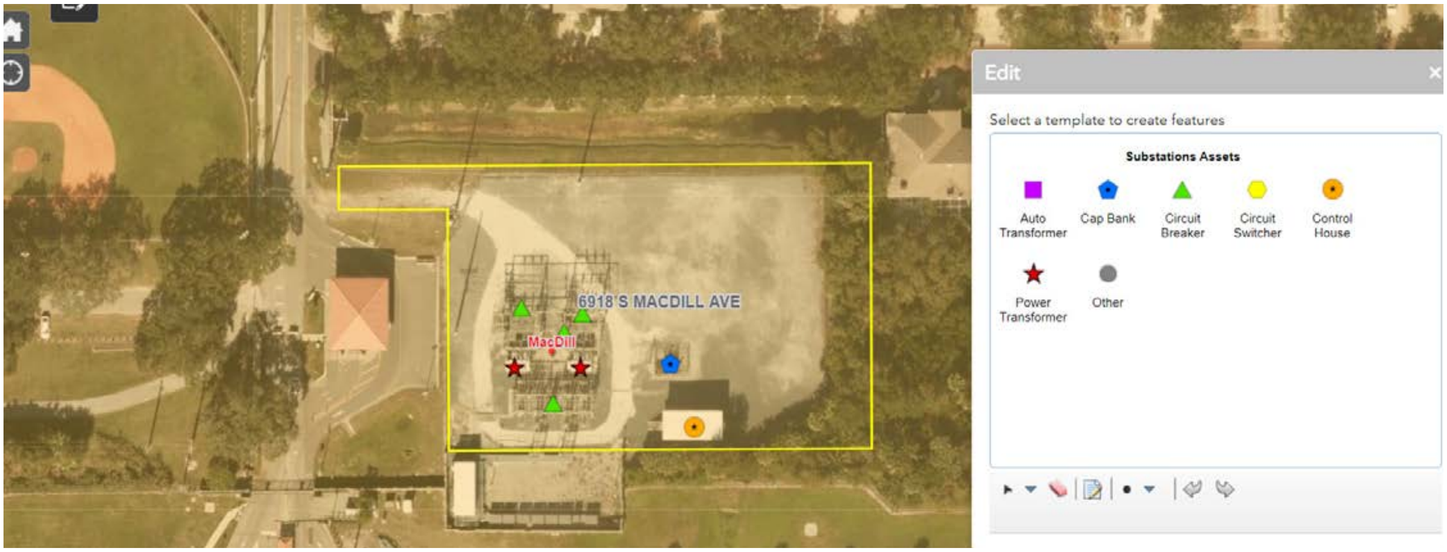
This substation project would increase the reliability of service to the Big Bend area during a storm surge event that brings flooding to the area.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Desal project.

Cost Benefit
The Desal project is a smaller capital project at $700,000 and will improve the reliability of service to TECO customers in the area, including critical load at the Big Bend Generation facility. The cost of elevating the control enclosure at the Desal 69 kV Substation is beneficial due to the increase in reliability of service to the critical load in the area.

This project improves the Safety and Cost scores of Desal moves the substation to the right-hand side of both scorecards into an acceptable range.

Desal 69 kV Substation		
ELEVATE CONTROL ENCLOSURE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control Enclosure	$400,000	$300,000
	$400,000	$300,000
Total	**$700,000**	



4.8 PROJECT 8

MacDill 69 kV Substation

Install New SPCC Systems for Power Transformers

The MacDill 69 kV Substation is located adjacent to MacDill Air Force Base and feeds critical load at that facility. It sits inside the FEMA 100-yr floodplain and is located approximately 1 mile from the Tampa Bay. This substation serves critical load at the Big Bend Generation facility.

This substation has two power transformers, 69 kV circuit breakers, two (2) distribution circuits and an elevated control house.

To harden the MacDill 69 kV Substation against flooding in a storm surge event, HDR recommends installing new SPCC systems for the two power transformers that include ~3 ft concrete walls. The 3 ft wall may protect the transformer in a flood event related to storm surge by preventing flood water intrusion into the transformer control cabinets. This modification has a twofold benefit of hardening the substation and improving environmental protection.

This substation project would increase the reliability of service to the south Tampa area during a storm surge event that brings flooding to the area.

HDR also recommends replacing the oil-filled 13 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate

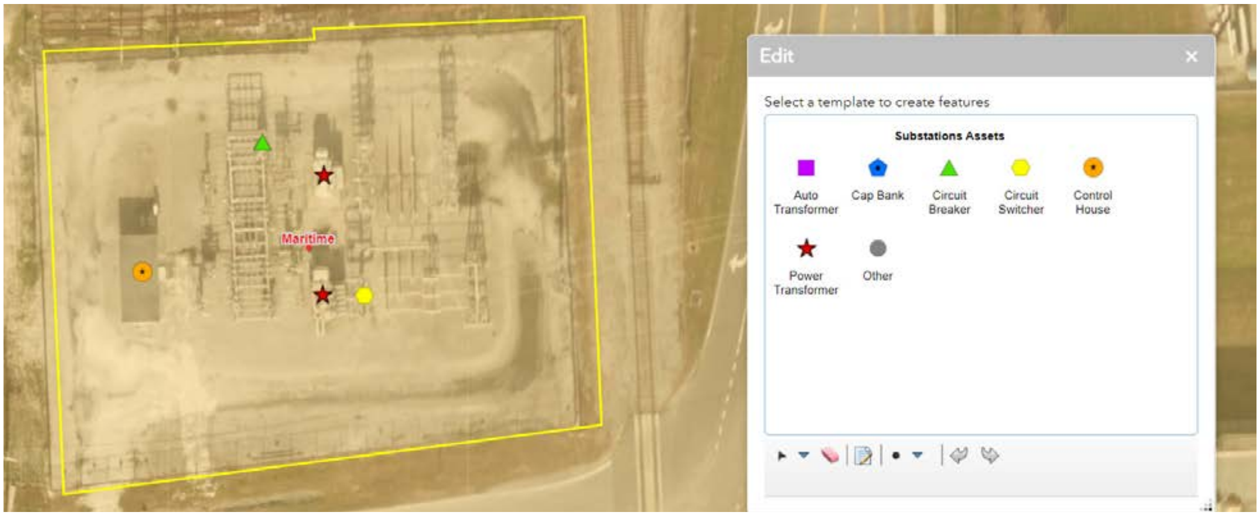
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the MacDill project.

Cost Benefit

The MacDill project is a smaller capital project at $700,000 and will improve the reliability of service to TECO customers in the area, including critical load at the MacDill AFB. The cost of installing new SPCC systems for the transformers at the MacDill 69 kV Substation is beneficial due to the increase in reliability of service to the critical load in the area as well as environmental safety improvements for capturing potential oil spills from the transformer tanks rupturing.

This project improves the Customer Service and Cost scores of MacDill and moves the substation to the right-hand side of both scorecards into an acceptable range.

MacDill 69 kV Substation		
INSTALL NEW SPCC SYSTEMS FOR POWER TRANSFORMERS		
Item	Equipment	Engineering, Permitting, Construction, Project Management, Testing and Commissioning
Install two SPPC Systems for 69/13 kV Transformers	$200,000	$375,000
13 kV Circuit Breaker	$75,000	$50,000
	$275,000	$425,000
Total	$700,000	



4.9 PROJECT 9

Maritime 69 kV Substation

Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House

The Maritime 69 kV Substation is in the FEMA 100-yr floodplain and 0.3 miles from a canal/drainage feature discharging into Tampa Bay. This substation has two power transformers, a 69 kV circuit switcher, four (4) distribution circuits and a control house. This substation feeds critical port fuel load as part of it's approximately 38 MVA of load. For this reason it scores very high on the Customer Service scorecard as seen on page 12. The control house at Maritime sits at ground level and the four (4) of the 13.8 kV circuit breakers are older and sit close to the ground as well. The two 69/13 kV transformers are older units and susceptible to failure in the event of storm surge flooding.

To harden the Maritime 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the control house with an elevated house on an elevated platform or concrete slab with new relaying, replacing the four (4) 13 kV Circuit Breakers and the two power transformers with newer units with SPCC designs with 3-foot walls that.

This substation project would increase the reliability of service to the critical port fuel load during a storm surge event that brings flooding to the area.

Project Cost Estimate

Below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Maritime project.

Cost Benefit

The Maritime project is a larger capital project at $4.5MM and will improve the reliability of service to TECO customers in the area, including critical fuel load at the port. It also improves the environmental safety of the substation by removing older oil-filled transformers and replacing them with newer units with SPCC systems that can potentially keep storm surge flooding at bay. The cost of replacing the circuit breakers, 69/13 kV transformers and elevating the control house at the Maritime 69 kV Substation is beneficial due to the increase in reliability for critical load and environmental safety improvements.

This project improves the Customer Service and Cost scores of MacDill and moves the substation to the right-hand side of both scorecards into an acceptable range.

Maritime 69 kV Substation		
REPLACE 13.8 KV CIRCUIT BREAKERS, INSTALL NEW TRANSFORMERS AND ELEVATE CONTROL HOUSE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
Two (2) 69/13 kV Transformers	$1,600,000	$290,000
Four (4) 13 kV Circuit Breakers	$100,000	$190,000
	$3,700,000	$800,000
Total	**$4,500,000**	

5.0 Conclusion

Tampa Electric Company sought out to determine the impact of storm surge flooding and for ways to harden twenty-four (24) of its substations against those flood events. HDR, Inc. performed desktop studies, site visits and built a cloud-based GIS platform to perform this analysis. After collecting this data, HDR then created a scoring methodology to rank and prioritize the substations based on several criteria. The result of this effort was a series of scorecards. These scorecards were used to develop nine (9) substation projects to harden the TECO system. The total cost for these projects is estimated to be $28.8MM and include three (3) transmission projects and six (6) distribution projects. The transmission projects are designed to harden those substations and increase grid stability by maintaining the critical tie points between the 230, 138 and 69 kV systems. The six (6) distribution projects harden the substations and improve reliability of service to the load served in the area, including critical load to south Tampa, Tampa International Airport, the Big Bend generation facility, and MacDill AFB.

The TECO system in Hillsborough County was studied for the impact of storm surge flooding and several projects were developed to harden substations in this region to improve grid stability and reliability of service.

APPENDICES

TECO SUBSTATION CONSEQUENCE SCORES

Sub #	Substation	Overall Consequence Score
34	Big Bend 230kV	2.64
464	Big Bend Solar 69kV	1.68
154	Cypress Street	1.64
422	Desal	1.50
44	El Prado	1.25
91	Estuary	1.55
226	First Street	1.76
129	Gannon 230kv 230/138kV & 230/69kV	2.91
268	Harbour Island	1.69
2	Hookers Point 138/69kV	2.00
	Interbay	1.56
80	Jackson Road 230/69kV	1.74
23	MacDill	1.66
81	Manhattan	1.58
164	Maritime	1.48
311	McKay Bay Cogen	1.58
265	Meadow Park	1.78
242	Miller Mac	1.61
39	Millpoint 69kV	1.48
75	Port Sutton	1.76
160	Rocky Creek	1.63
140	Skyway	1.63
112	South Gibsonton	1.90
159	Twelfth Avenue	1.44

TAMPA ELECTRIC COMPANY
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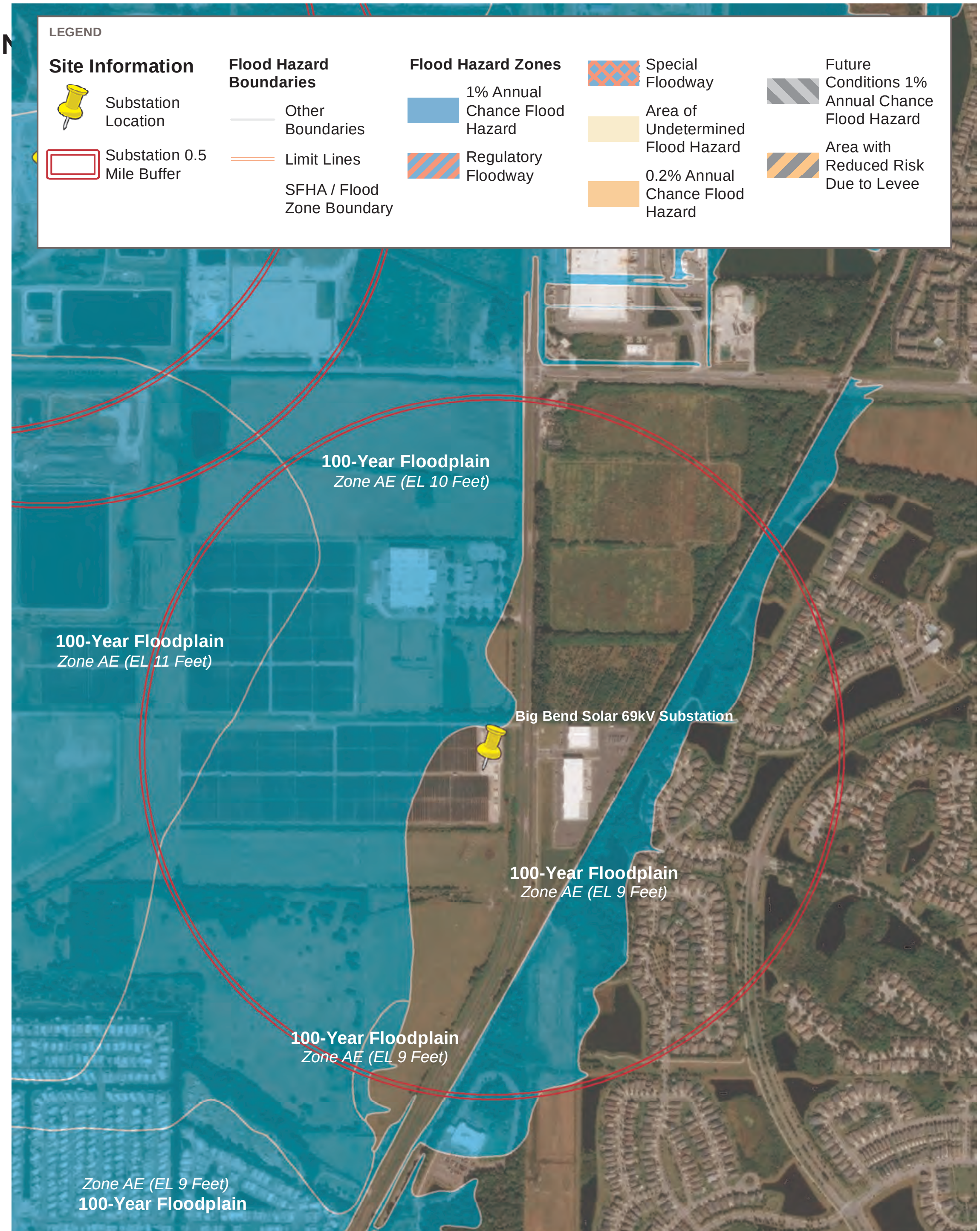
FILED: 04/11/2022

BIG BEND 230KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 1)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\BIG BEND FEMA.MXD - USER: ALMILLER - DATE: 5/20/2021



BIG BEND SOLAR 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 2)

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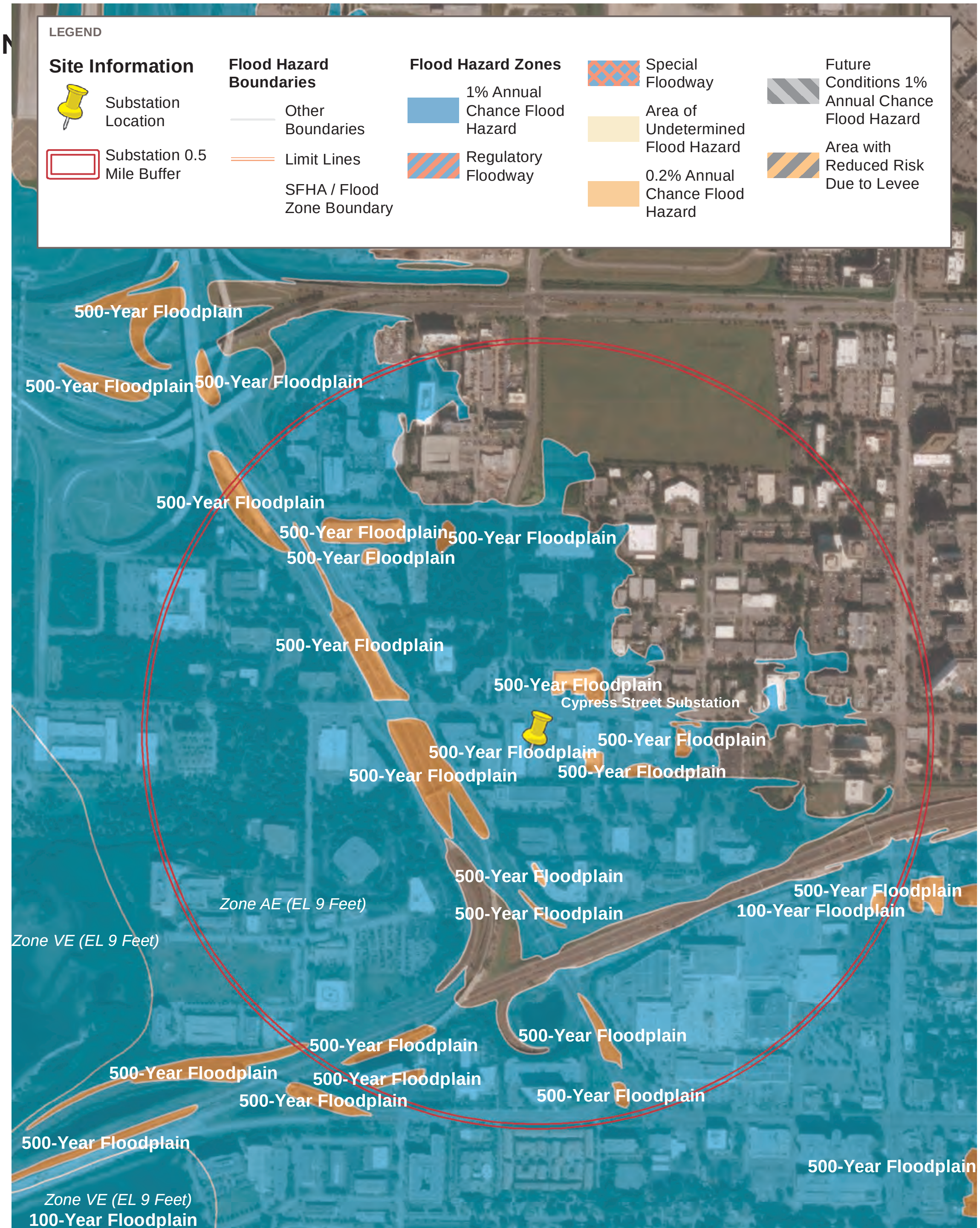

CYPRESS STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 3)

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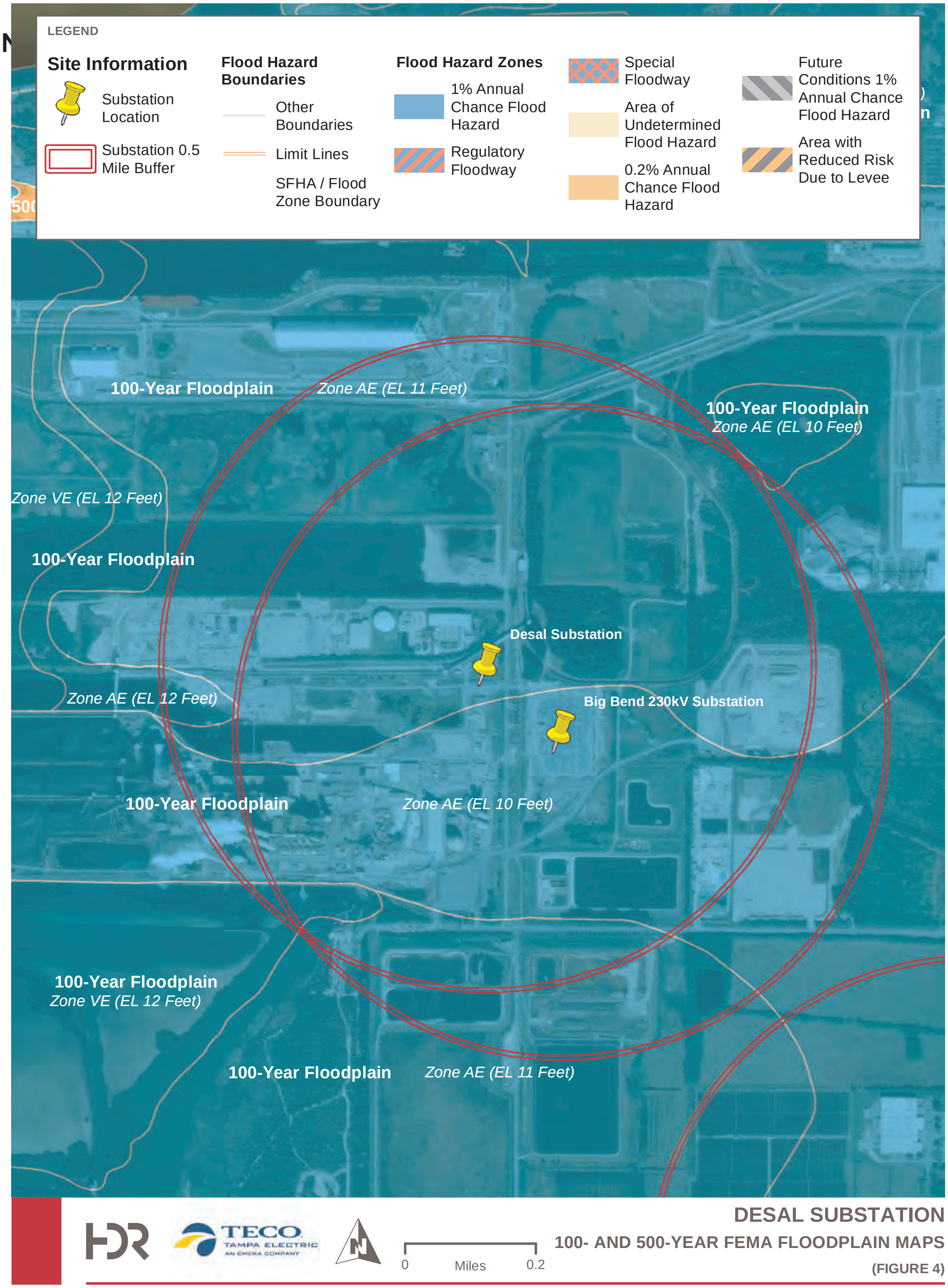

DESAL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 4)

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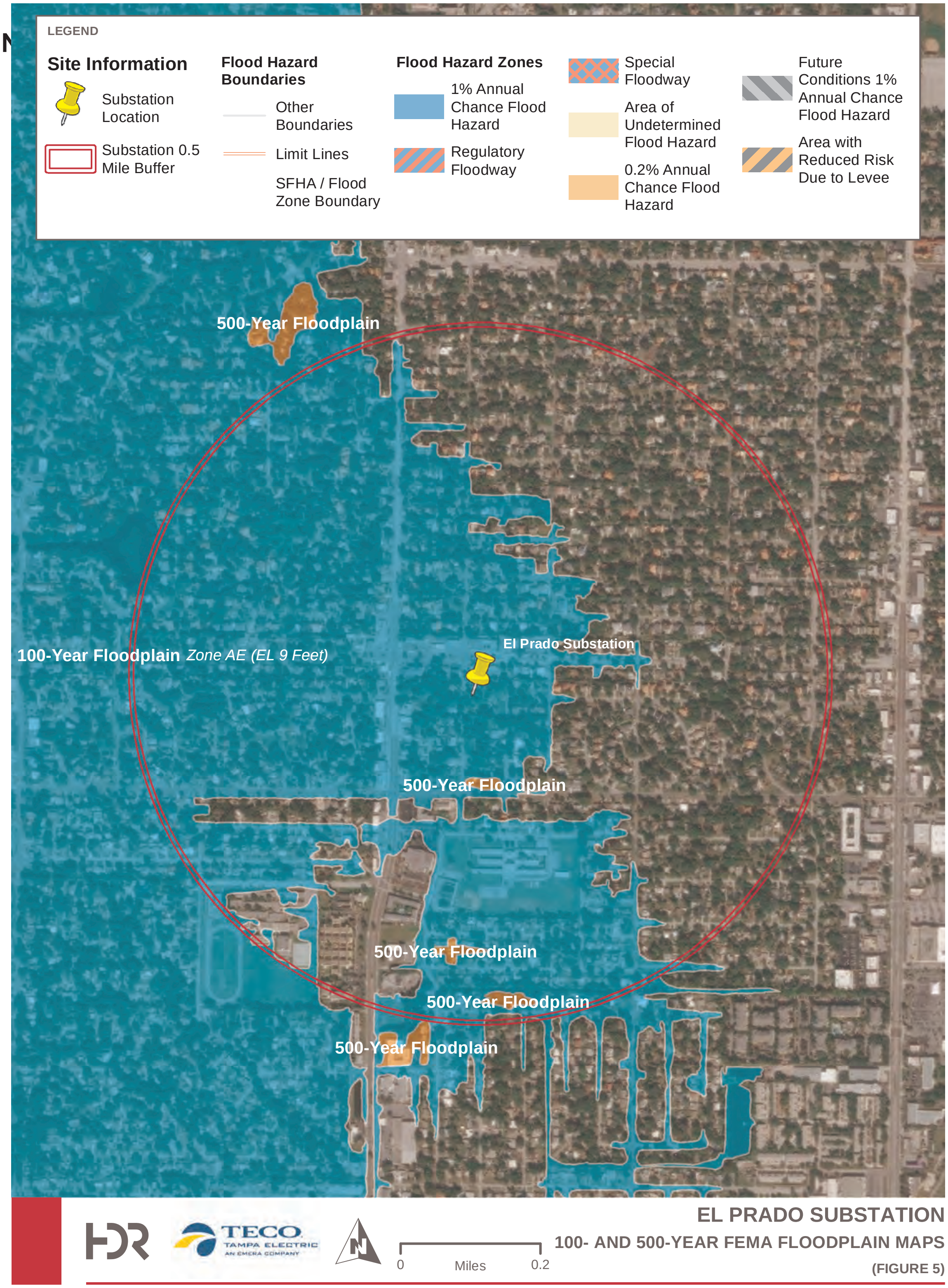

EL PRADO SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 5)

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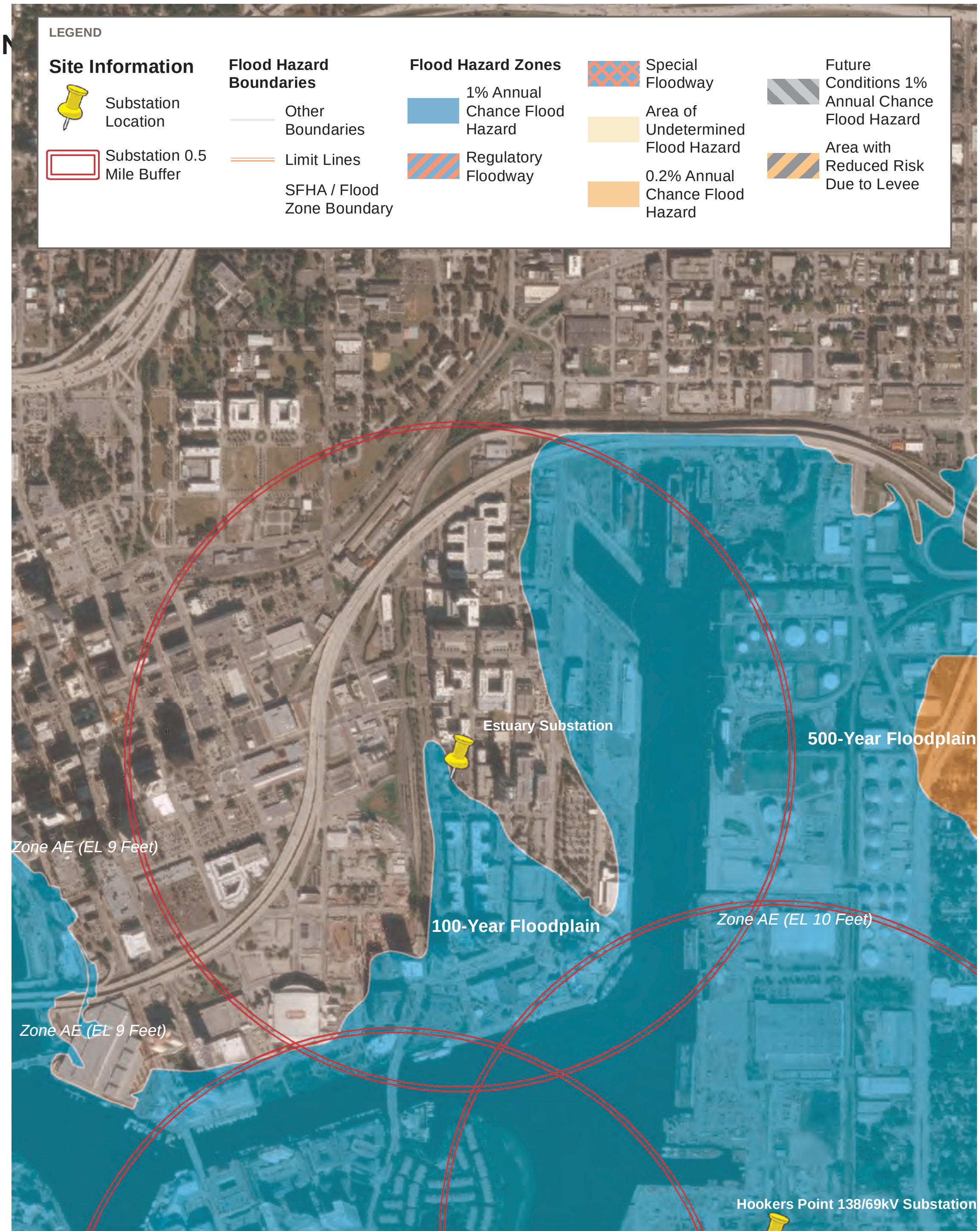

ESTUARY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 6)

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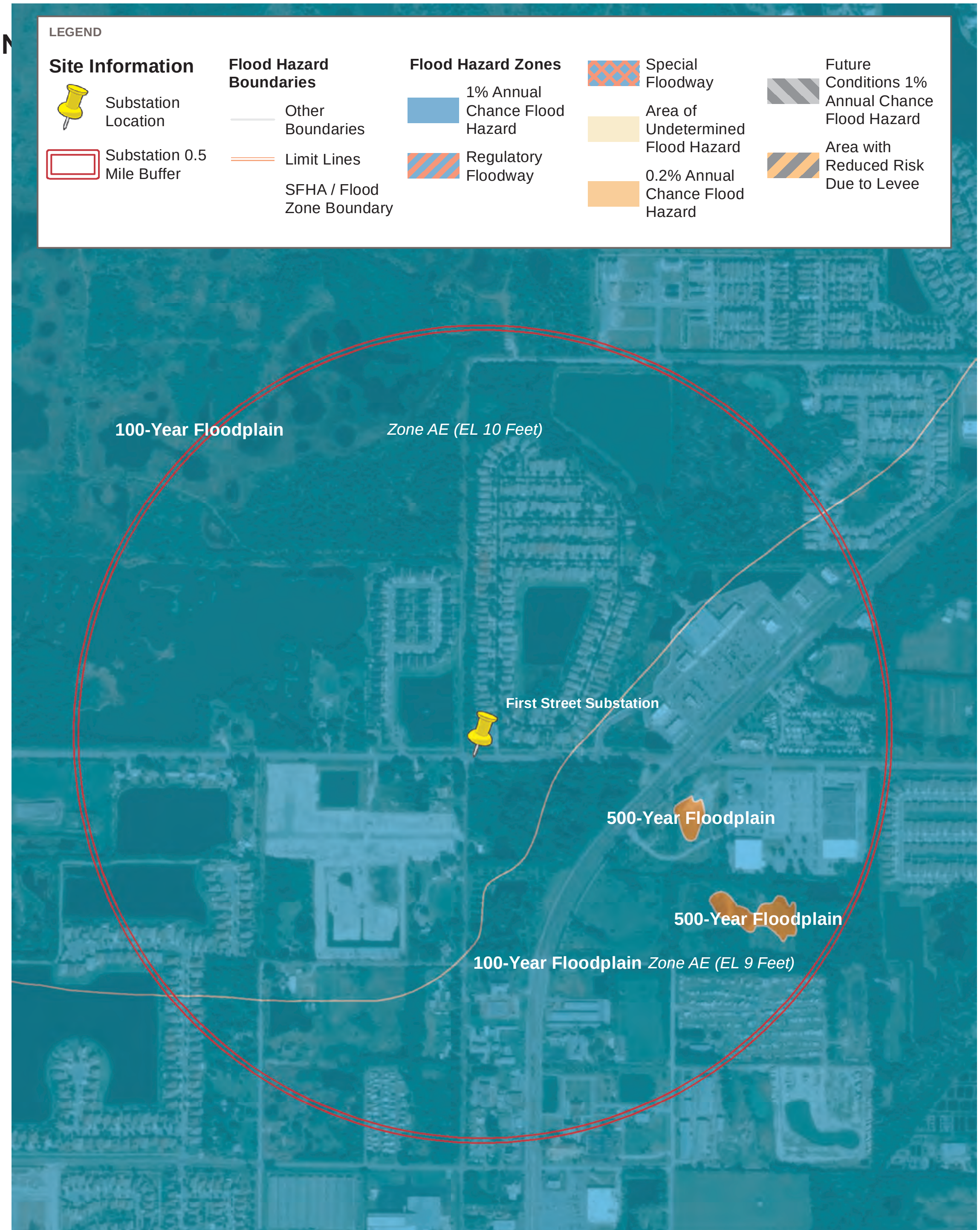

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FIRST STREET SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 7)

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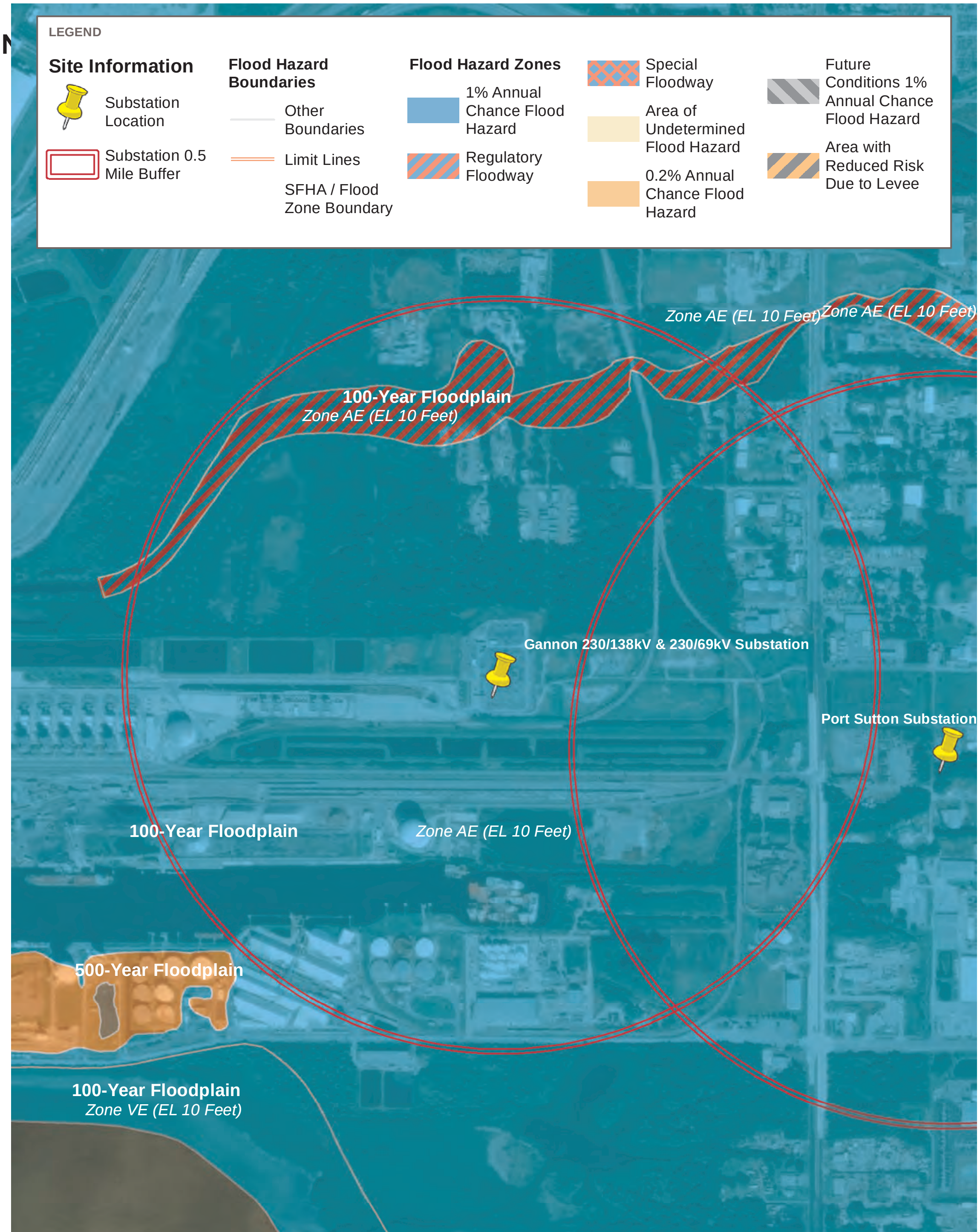
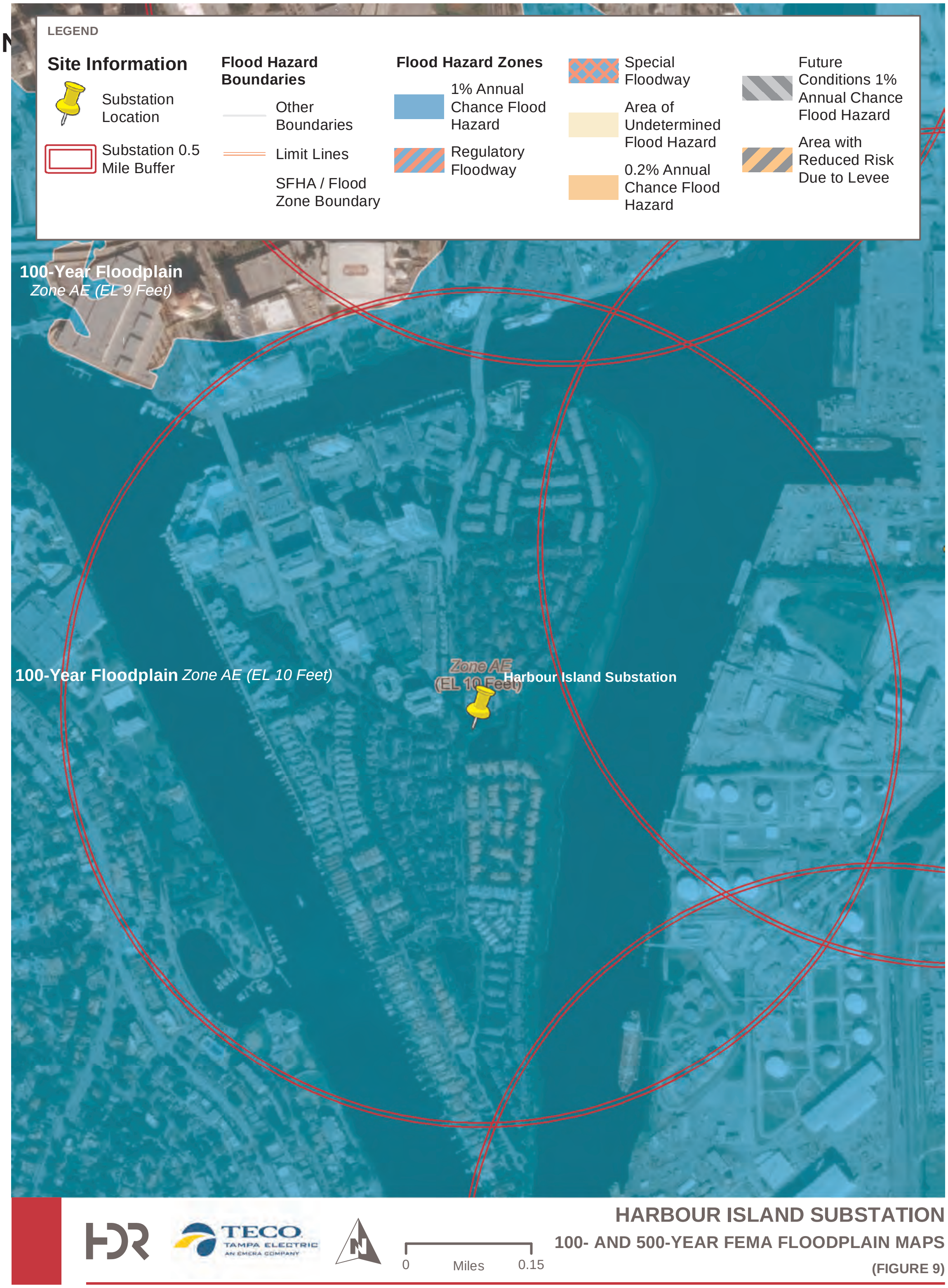


GANNON 230/138KV & 320/69KV SUBSTATIONS
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 8)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\GANNON FEMA.MXD - USER: ALMILLER - DATE: 5/20/2021



HARBOUR ISLAND SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 9)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\HARBOUR ISLAND FEMA.MXD - USER: ALMILLER - DATE: 5/20/2021

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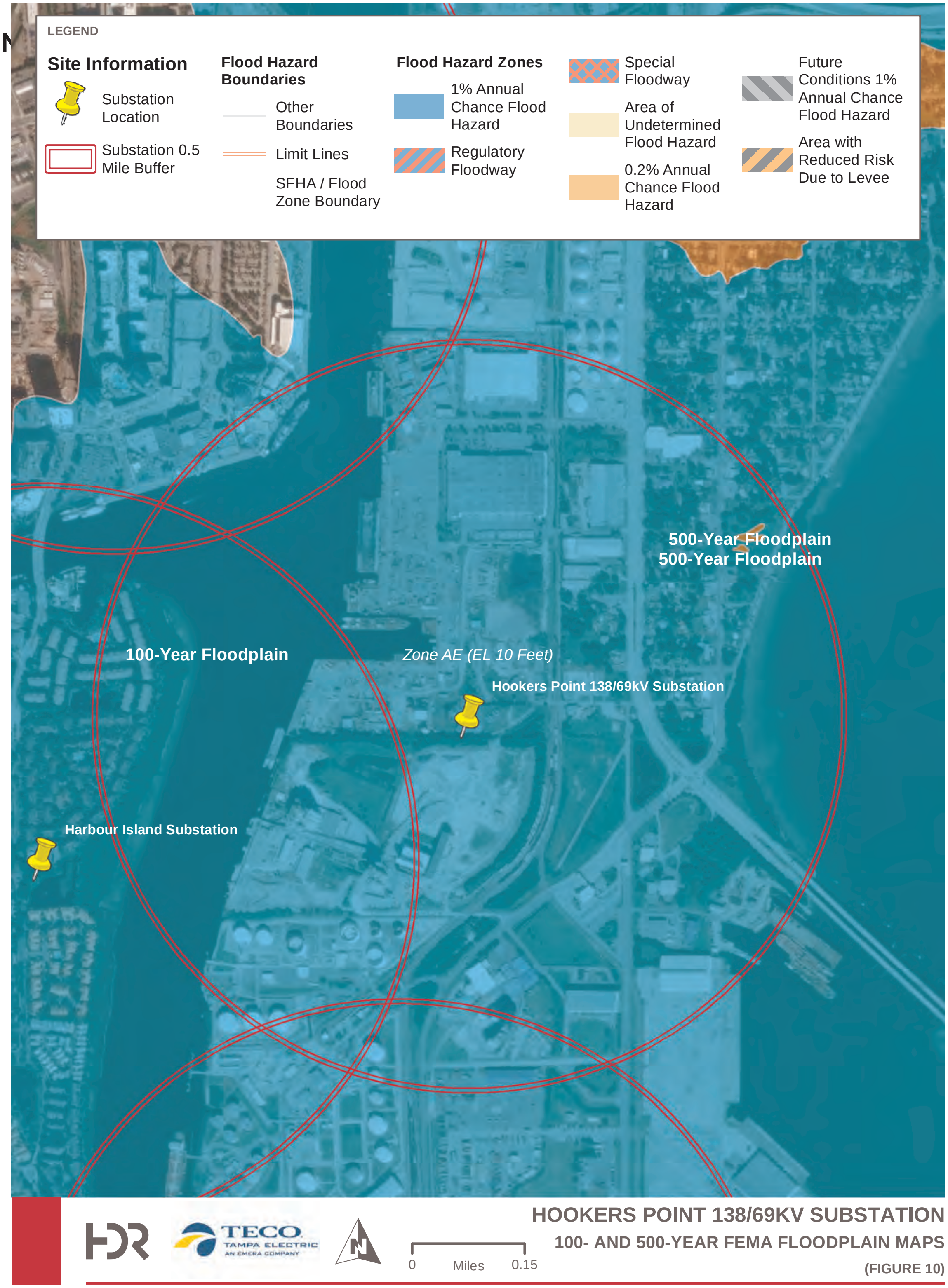
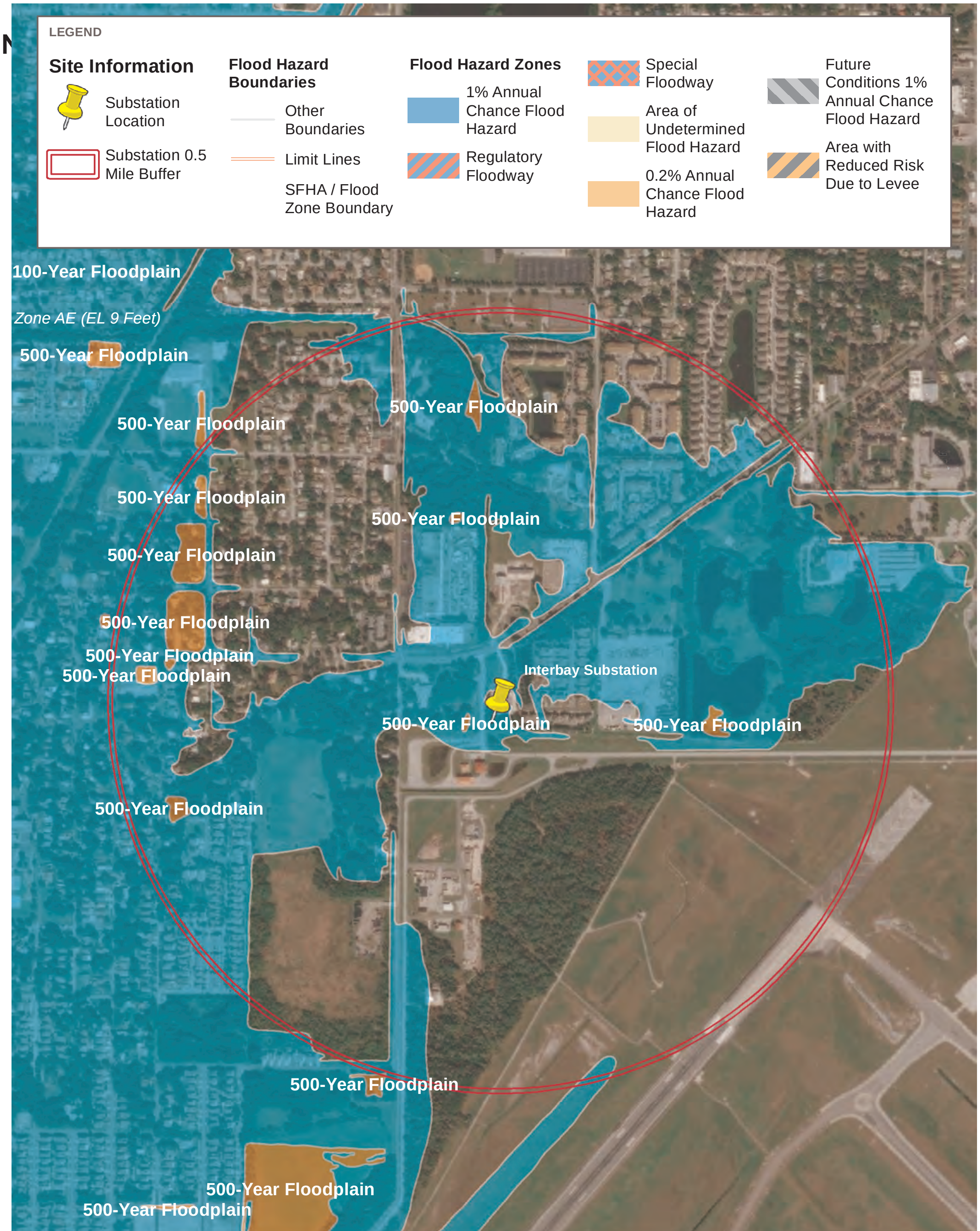


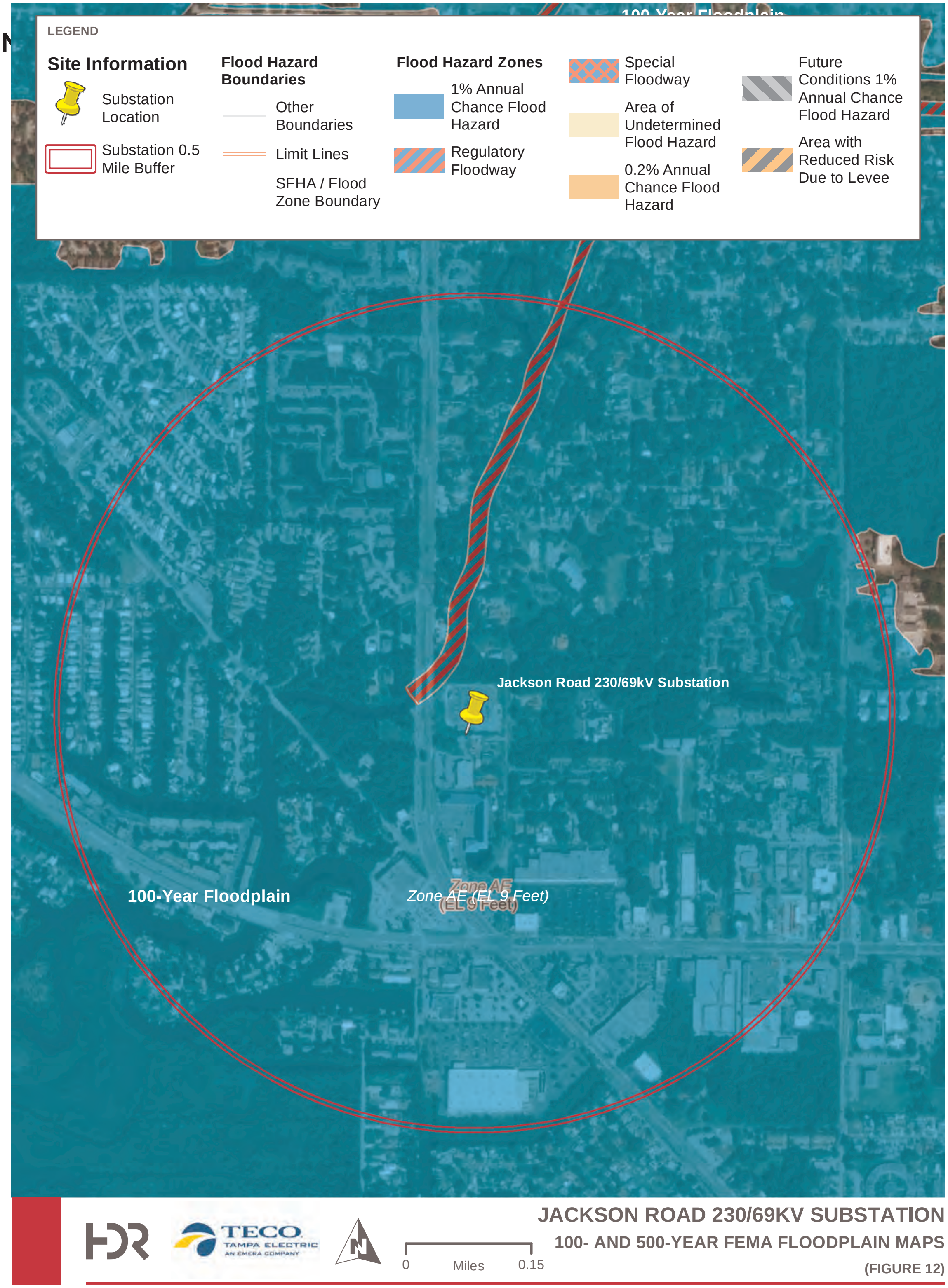
HOOKERS POINT 138/69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 10)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\HOOKERS POINT FEMA.MXD - USER: ALMILLER - DATE: 5/20/2021



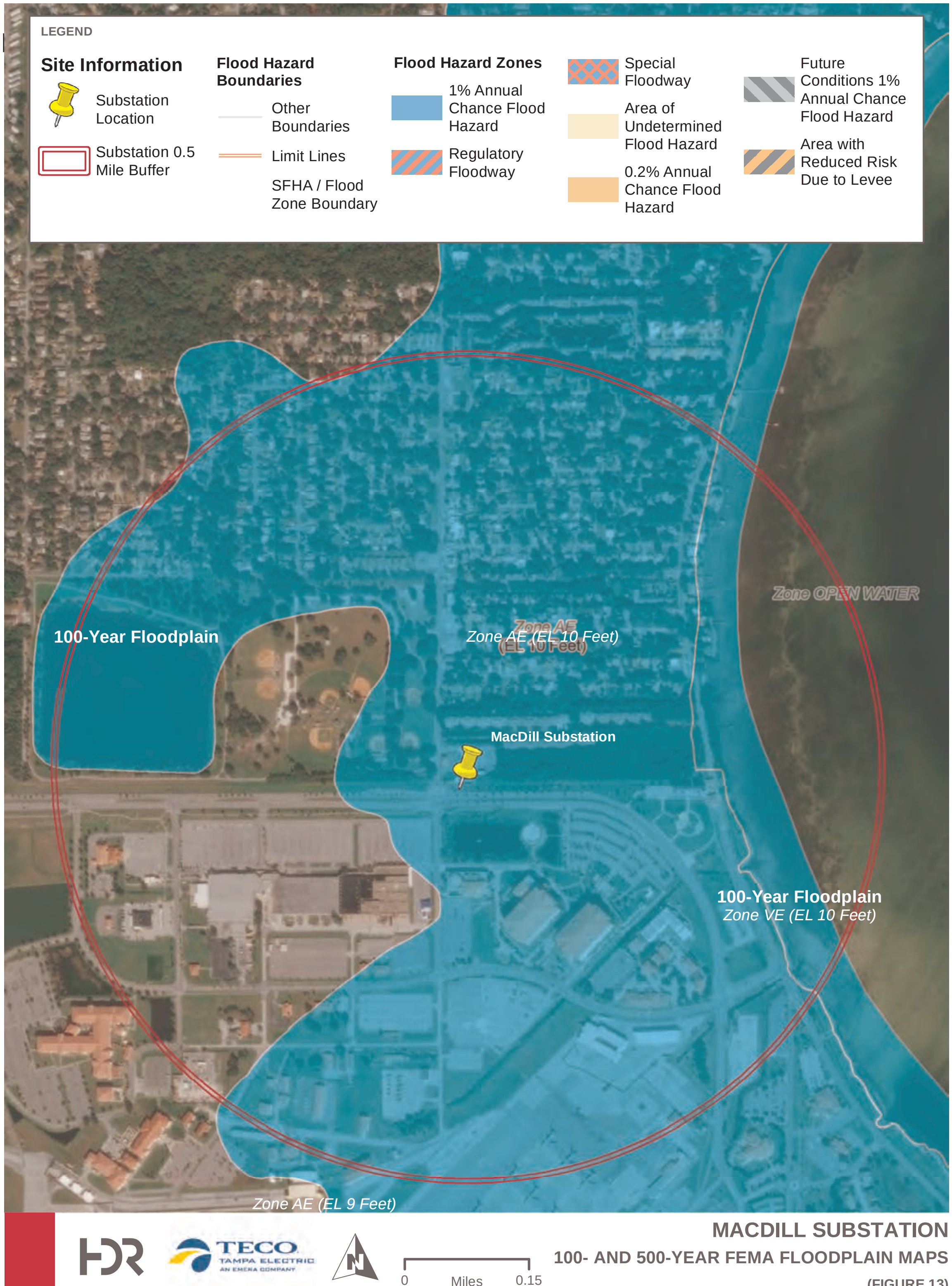
INTERBAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 11)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\INTERBAY FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



JACKSON ROAD 230/69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 12)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\JACKSON ROAD FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

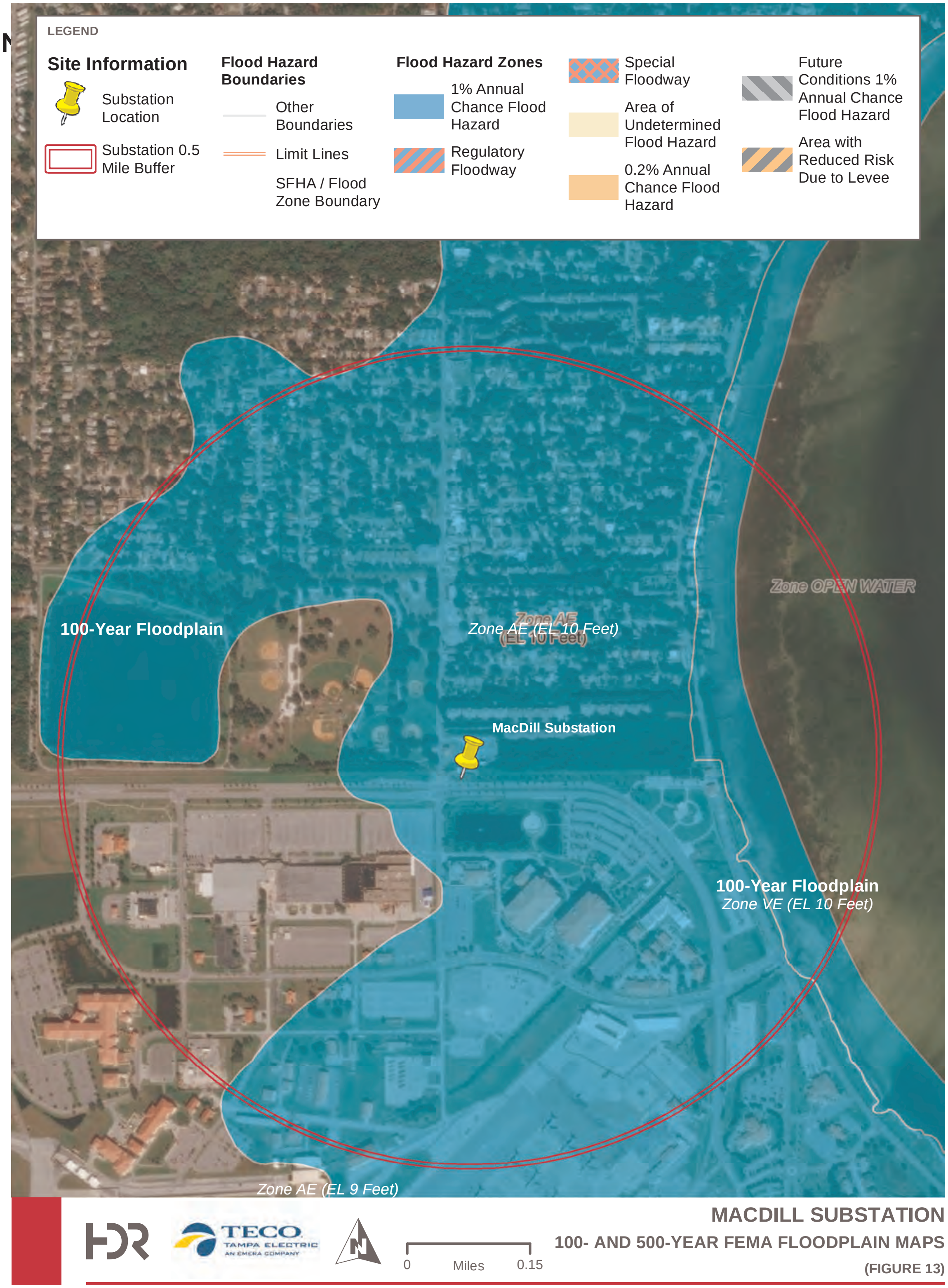


MACDILL SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 13)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MACDILL FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MACDILL FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

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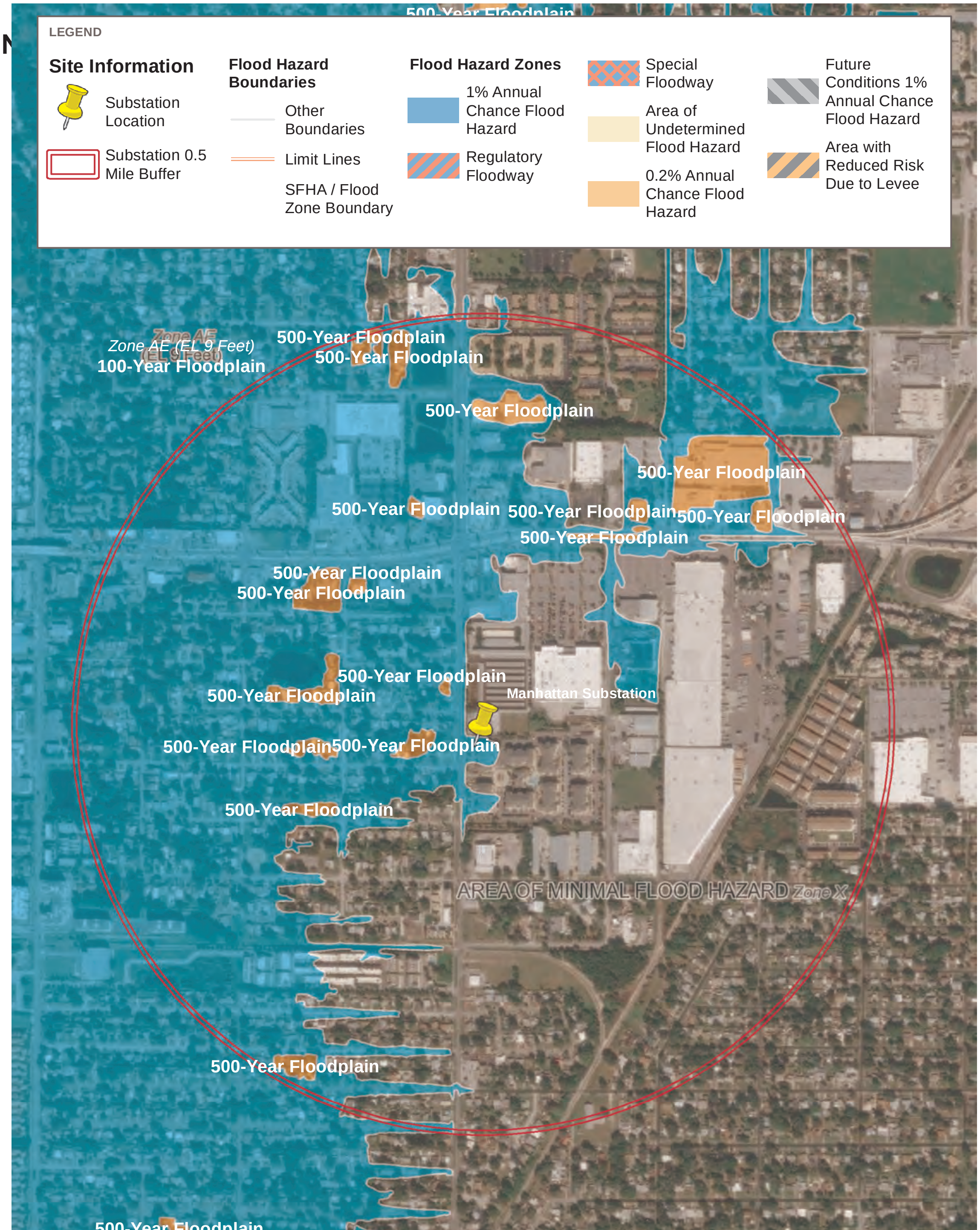

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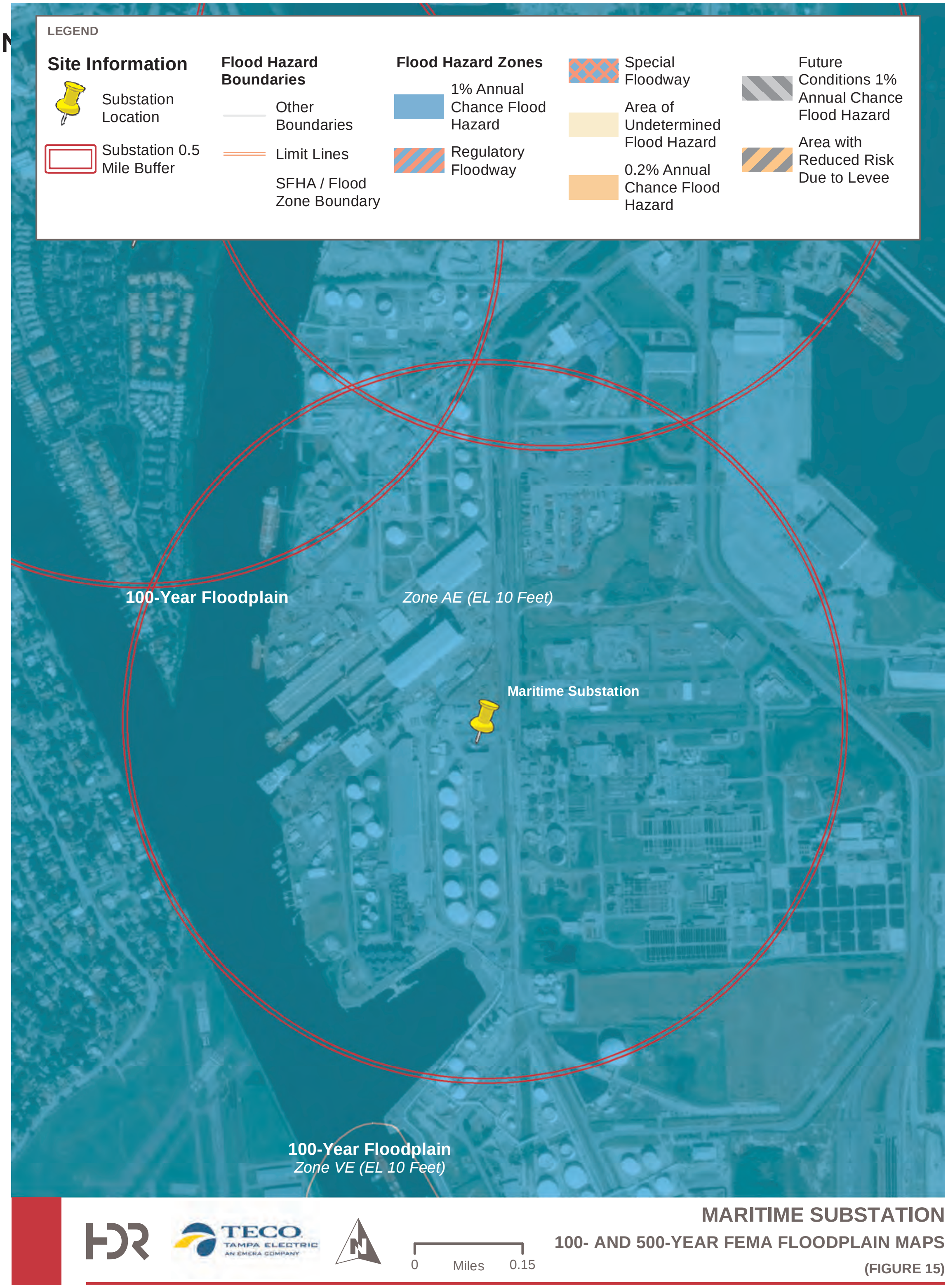
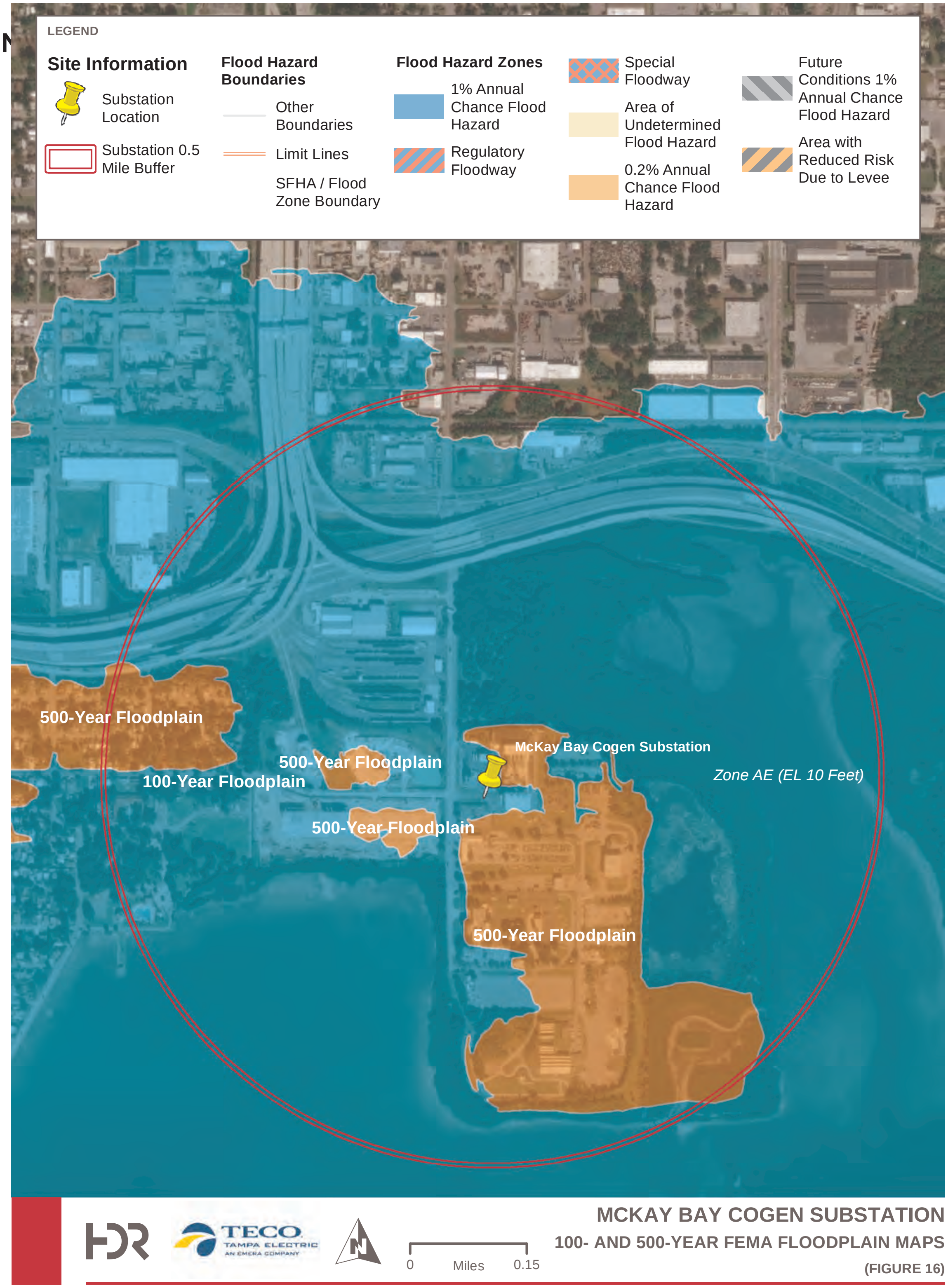
MANHATTAN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 14)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MANHATTAN FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



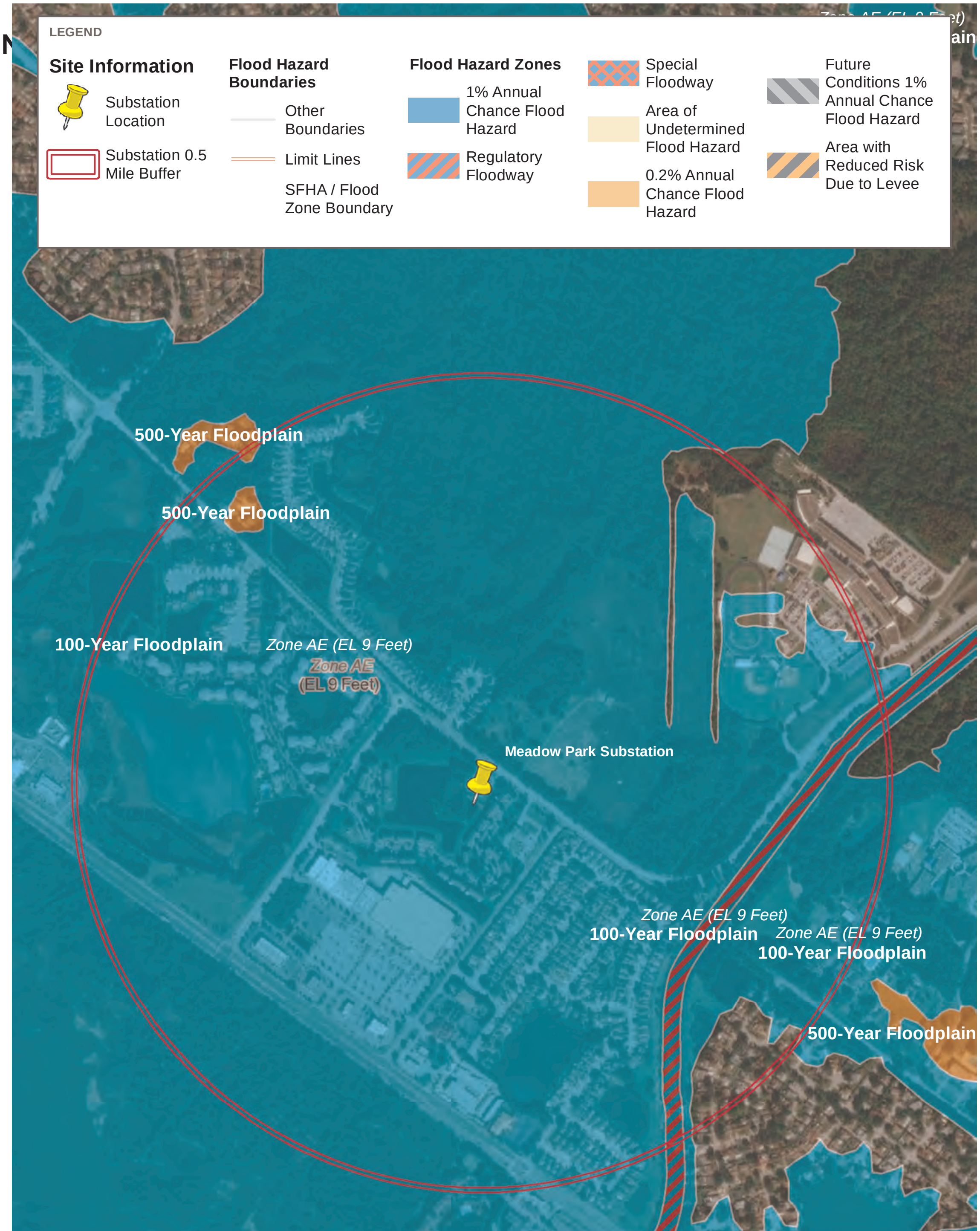
MARITIME SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 15)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MARITIME FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



MCKAY BAY COGEN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 16)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MCKAY BAY COGEN FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

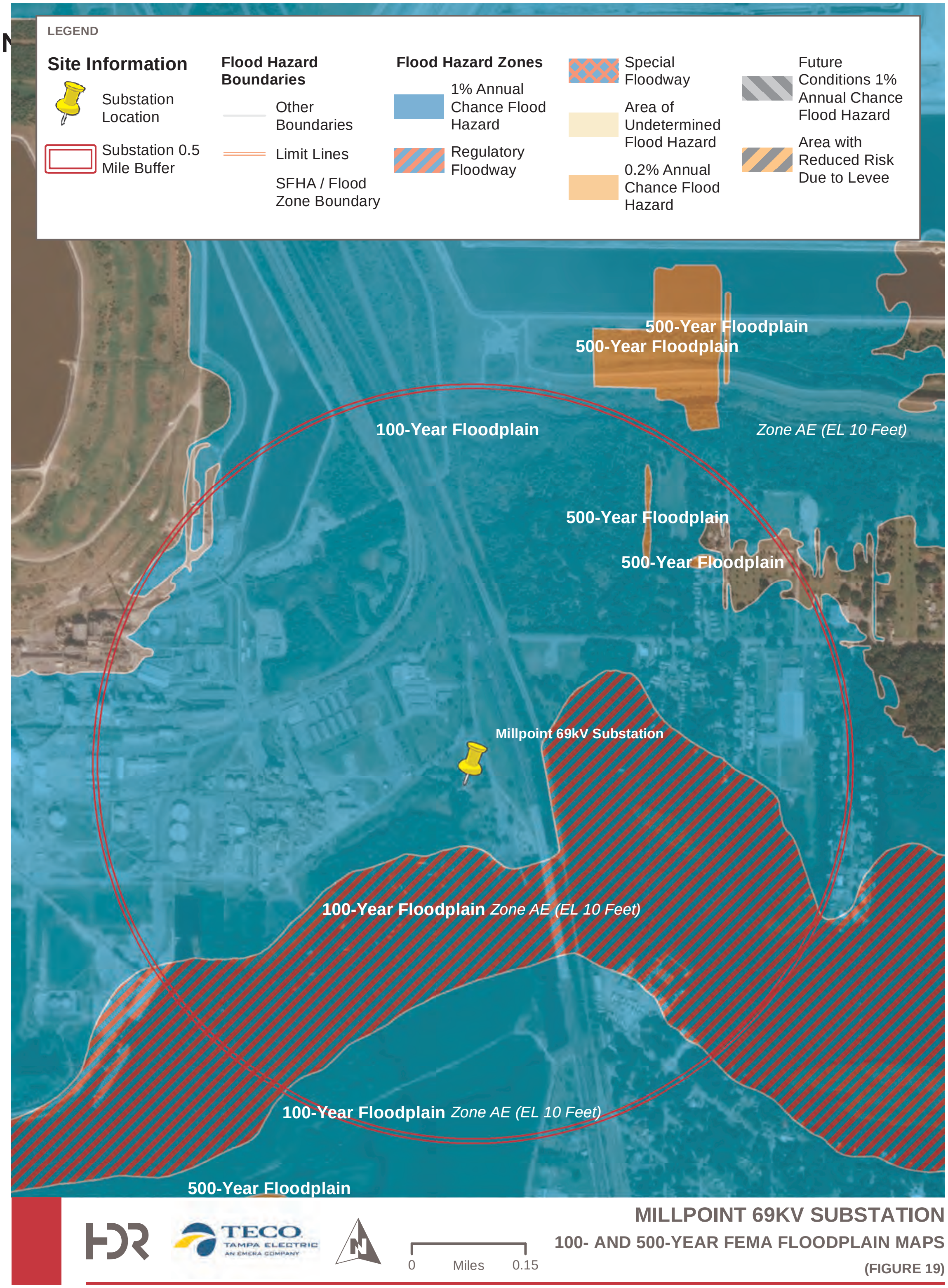


MEADOW PARK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 17)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MEADOW PARK FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

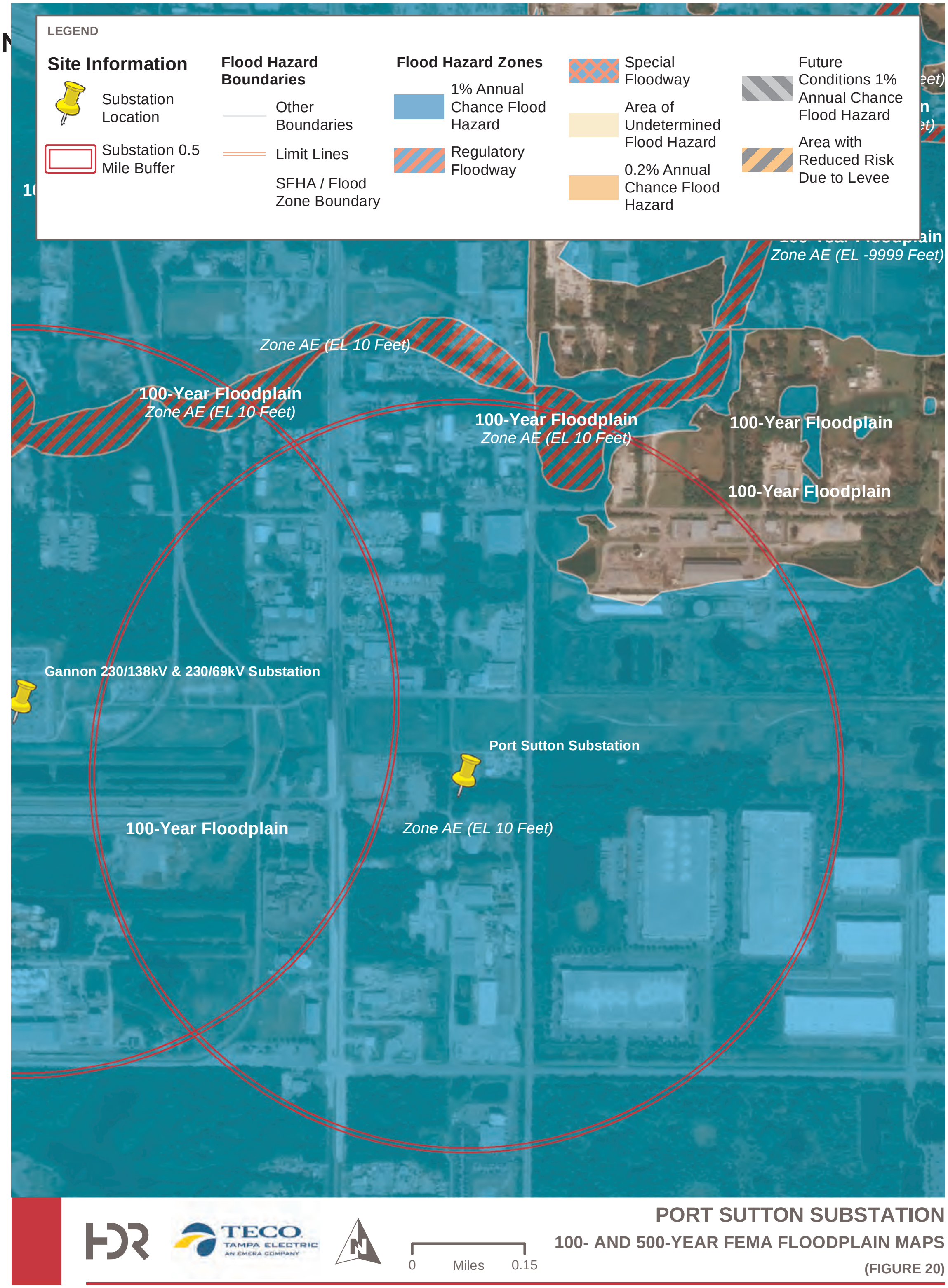
MILLER MAC SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 18)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MILLER MAC FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



MILLPOINT 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 19)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MILLPOINT FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



PORT SUTTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 20)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\PORT SUTTON FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

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ROCKY CREEK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 21)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\ROCKY CREEK FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

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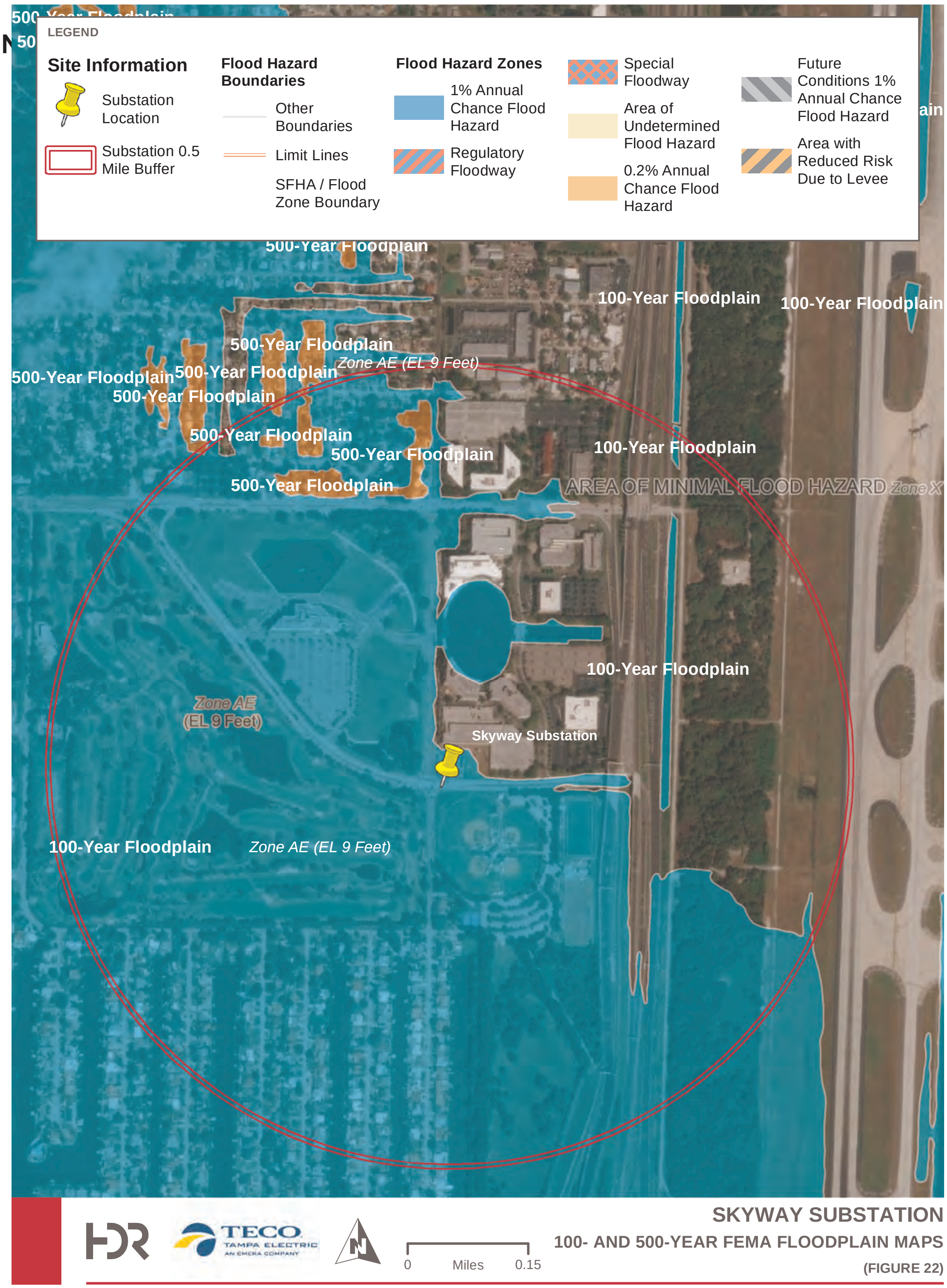

SKYWAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 22)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\SKYWAY FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

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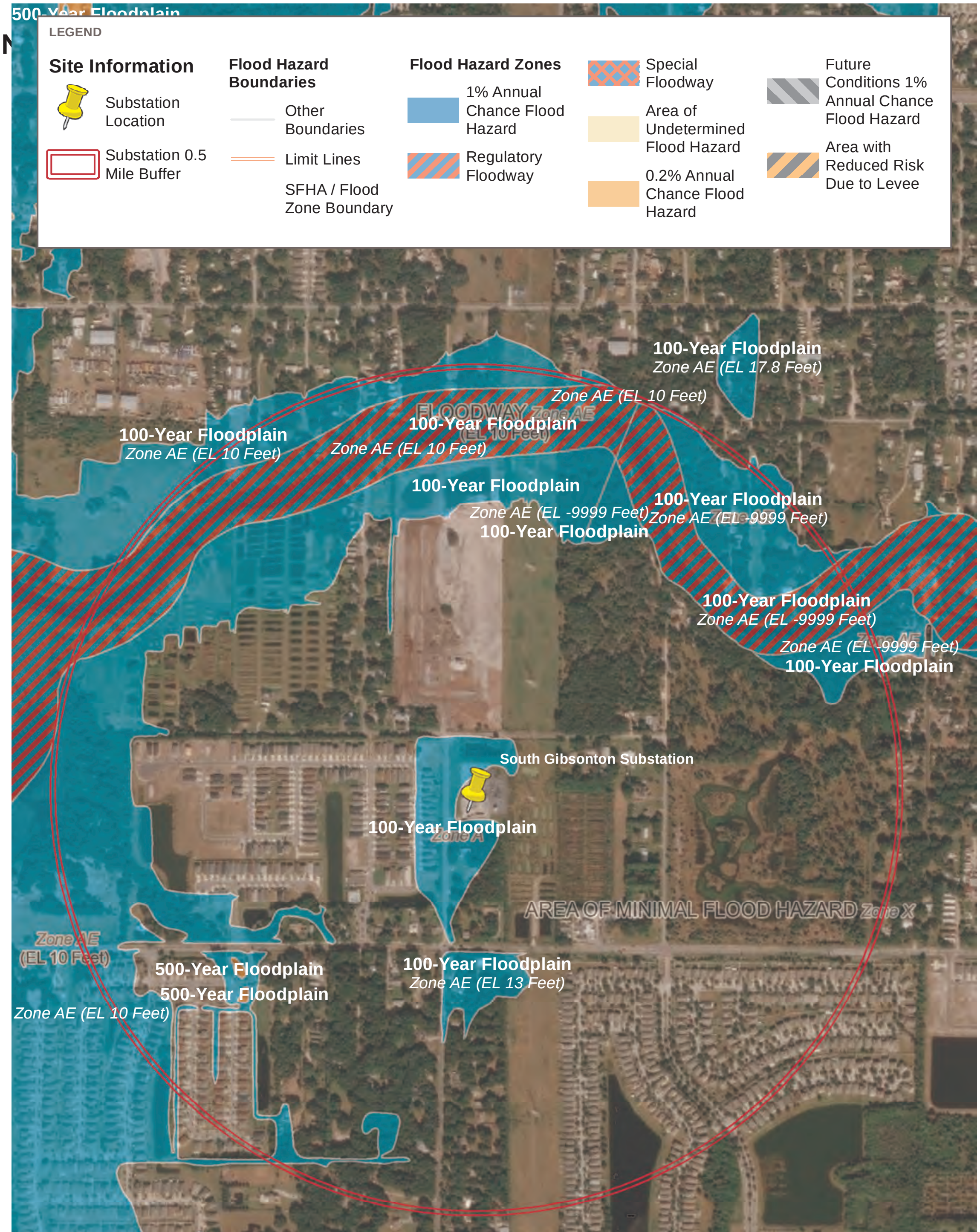

SOUTH GIBSONTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 23)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\SOUTH GIBSONTON FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

No Substation Extreme Weather Hardening Projects Planned for 2022

Reserved for Future Use

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Tampa Electric's Distribution Overhead Feeder Hardening - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2022
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
SPP FH - 13008	13008	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	249	159	25	433	0	Jul-22	Jan-23	Jun-23	$50,000
SPP FH - 13028	13028	(6) new reclosers, (43) fuses, (27) trip savers, and upgrade (52) feeder poles	3,595	242	24	3,861	35	Aug-22	Jan-23	Jun-23	$50,000
SPP FH - 13039	13039	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	299	178	24	501	29	Sep-22	Jan-23	Aug-23	$50,000
SPP FH - 13040	13040	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	992	112	51	1,155	18	Oct-22	Jan-23	Oct-23	$50,000
SPP FH - 13048	13048	(6) new reclosers, (43) fuses, (27) trip savers, and upgrade (52) feeder poles	2,720	324	81	3,125	84	Jun-22	Aug-22	Oct-22	$2,077,657
SPP FH - 13077	13077	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	105	332	48	485	15	Sep-22	Jan-23	Sep-23	$50,000
SPP FH - 13094	13094	(7) new reclosers, (50) fuses, (28) trip savers, and upgrade (100) feeder poles	1,191	375	83	1,649	15	This one we had to put it			$5,554,203
SPP FH - 13118	13118	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	1,696	199	23	1,918	3	Nov-21	Mar-22	Aug-22	$3,377,800
SPP FH - 13148	13148	(17) new reclosers, (74) fuses, (16) trip savers, and upgrade (148) feeder poles	1,393	91	16	1,500	13	Jan-22	Mar-22	Aug-22	$1,219,093
SPP FH - 13187	13187	(9) new reclosers, (37) fuses, (21) trip savers, and upgrade (77) feeder poles	1,560	191	30	1,781	30	Nov-22	Jan-23	Nov-23	$50,000
SPP FH - 13227	13227	(9) new reclosers, (37) fuses, (21) trip savers, and upgrade (77) feeder poles	1,447	159	19	1,625	46	Nov-20	Jan-21	Feb-22	$50,000
SPP FH - 13230	13230	(2) new reclosers, (54) fuses, (42) trip savers, and upgrade (107) feeder poles	572	411	22	1,005	46	Nov-22	Jan-23	Nov-23	$50,000
SPP FH - 13292	13292	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	730	33	8	771	14	Aug-22	Jan-23	Mar-23	$50,000
SPP FH - 13296	13296	(10) new reclosers, (35) fuses, (12) trip savers, and upgrade (70) feeder poles	1,430	120	14	1,564	4	Feb-22	Mar-22	Sep-22	$4,494,494
SPP FH - 13299	13299	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	729	55	18	802	2	Dec-22	Jan-23	Nov-23	$50,000
SPP FH - 13308	13308	(3) new reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles	1,220	260	36	1,516	26	Jun-20	Aug-20	Mar-22	$50,000
SPP FH - 13312	13312	(1) new reclosers, (3) fuses, (9) trip savers, and upgrade (96) feeder poles	986	351	97	1,434	4	Apr-22	Jun-22	Nov-22	$312,011
SPP FH - 13313	13313	(2) new reclosers, (18) fuses, (3) trip savers, and upgrade (62) feeder poles	196	459	74	729	25	Apr-21	Oct-21	May-22	$73,036

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Tampa Electric's Distribution Overhead Feeder Hardening - Year 2022 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2022
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
SPP FH - 13314	13314	(2) new reclosers, (97) fuses, (13) trip savers, and upgrade (61) feeder poles	683	240	85	1,008	4	Apr-21	Oct-21	May-22	$29,668
SPP FH - 13346	13346	(2) new reclosers, (74) fuses, (51) trip savers, and upgrade (148) feeder poles	1,404	238	94	1,736	12	Feb-22	Apr-22	Oct-22	$80,786
SPP FH - 13433	13433	(2) new reclosers, (111) fuses, (42) trip savers, and upgrade (101) feeder poles	339	318	69	726	61	Apr-21	Oct-21	Apr-22	$688,400
SPP FH - 13651	13651	(2) new reclosers, (70) fuses, (35) trip savers, and upgrade (139) feeder poles	2,453	63	10	2,526	50	Mar-22	May-22	Nov-22	$50,386
SPP FH - 13687	13687	(2) new reclosers, (70) fuses, (35) trip savers, and upgrade (139) feeder poles	2,054	70	2	2,126	17	Oct-22	Jan-23	Sep-23	$50,000
SPP FH - 13770	13770	(9) new reclosers, (52) fuses, (3) trip savers, and upgrade (103) feeder poles	1,769	57	5	1,831	3	Jan-22	Mar-22	Nov-22	$5,898,017
SPP FH - 13984	13984	(6) new reclosers, (37) fuses, (51) trip savers, and upgrade (73) feeder poles	1,415	114	51	1,580	51	May-22	Jul-22	Nov-22	$1,171,851
SPP FH - 13989	13989	(3) new reclosers, (27) fuses, (10) trip savers, and upgrade (54) feeder poles	2,216	53	7	2,276	26	Feb-22	Apr-22	Aug-22	$832,493
SPP FH - 14094	14094	(2) new reclosers, (12) fuses, (6) trip savers, and upgrade (23) feeder poles	2,584	256	45	2,885	6	Jun-22	Jul-22	Dec-22	$8,559
SPP FH - 14123	14123	(2) new reclosers, (54) fuses, (42) trip savers, and upgrade (107) feeder poles	1,069	59	6	1,134	13	May-22	Jun-22	Nov-22	$1,248,736
SPP FH - East Winter Haven 13309	13309	(1) new reclosers, (35) fuses, (6) trip savers, and upgrade (61) feeder poles	0	0	0	0	0	Apr-21	Oct-21	May-22	$125,468

Project ID	Project Type Road/Bridge	Project Start Qtr	Project End Qtr	Project Cost in 2022
HAMPTON SUBSTATION	Bridge	Qtr 2 2021	Qtr 4 2022	$ 622,025
WEST OF FORBES RD	Bridge	Qtr 2 2021	Qtr 4 2024	$ 92,429
EAST OF SYDNEY WASHER RD	Bridge	Qtr 2 2021	Qtr 4 2024	$ 100,525
TAMPA PALMS #1	Bridge	Qtr 2 2021	Qtr 4 2023	$ 94,755
TAMPA PALMS #2	Bridge	Qtr 2 2021	Qtr 4 2023	$ 106,899
TAMPA PALMS #3	Bridge	Qtr 2 2021	Qtr 4 2023	$ 102,851
TAMPA PALMS #4	Bridge	Qtr 2 2021	Qtr 4 2023	$ 108,249
MORRIS BRIDGE RD	Bridge	Qtr 2 2021	Qtr 4 2022	$ 434,769
COLUMBUS DRIVE #1	Bridge	Qtr 2 2021	Qtr 4 2025	$ 27,000
COLUMBUS DRIVE #2	Bridge	Qtr 2 2021	Qtr 4 2025	$ 22,000
230606	Road	Qtr 2 2021	Qtr 4 2025	$ 20,000
230020	Road	Qtr 2 2021	Qtr 4 2024	$ 219,221
230008	Road	Qtr 2 2021	Qtr 4 2022	$ 146,924
230007	Road	Qtr 2 2021	Qtr 4 2023	$ 67,399
66839	Road	Qtr 2 2021	Qtr 4 2025	$ 26,000
66046	Road	Qtr 1 2022	Qtr 4 2024	$ 90,914
66035	Road	Qtr 2 2021	Qtr 4 2025	$ 26,000
66033	Road	Qtr 1 2022	Qtr 4 2023	$ 45,072
66016	Road	Qtr 2 2021	Qtr 4 2025	$ 20,000
66007	Road	Qtr 2 2021	Qtr 4 2023	$ 21,229
66001	Road	Qtr 1 2022	Qtr 4 2023	$ 48,641

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC'S 2022-2031 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

A. SLOAN LEWIS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

A. SLOAN LEWIS

INTRODUCTION:

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

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") in the Finance Department as Director, Regulatory Accounting.

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

A. My duties and responsibilities include the accounting oversight of all cost recovery clauses and riders for Tampa Electric and Peoples Gas, the settlement of all fuel and power transactions for Tampa Electric and Peoples Gas System, and Utility Accounting and Internal Financial Reporting for Tampa Electric, Peoples Gas System, and New Mexico Gas Company.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in accounting from Florida State University in 1994 and a Master of Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 21 years have expanded my cost recovery clause responsibilities. Then in 2015, I was promoted to Manager, Regulatory Accounting with responsibilities for all the recovery clauses and riders for Tampa Electric and Peoples Gas System. I was promoted to my current role as Director, Regulatory Accounting in 2017.

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

A. The purpose of my testimony in this proceeding is to demonstrate that the company's 2022-2031 Storm Protection Plan ("2022 SPP" or "Storm Protection Plan") complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan ("SPP") Rule. Section 3(g) requires a utility to provide an estimate of the annual jurisdictional revenue requirements for each year of its SPP. Section 3(h) requires a utility to provide an estimate of rate impacts for each of the first three years of the

SPP for the utility's typical residential, commercial, and industrial customers. My testimony also explains the methodology used to calculate these estimates.

Q. Have you prepared an exhibit to accompany your direct testimony?

A. Yes. Exhibit No. ASL-1, entitled "Tampa Electric's 2022-2031 SPP Total Revenue Requirements by Program" was prepared under my direction and supervision. This exhibit shows the annual revenue requirement for the company's 2022 programs.

CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS FOR TAMPA ELECTRIC'S 2022 SPP

Q. What are the estimated annual jurisdictional revenue requirements for each year of the company's 2022 SPP?

A. The estimated annual jurisdictional revenue requirements for each year of the 2022 SPP are included in the following table. The revenue requirements of each 2022 SPP program are set out in my Exhibit No. ASL-1.

Total SPP Revenue Requirement (2022-2031)

YEAR	Revenue Requirements
2022	$47,877,941
2023	$69,433,375
2024	$87,196,252
2025	$107,222,775
2026	$127,418,631
2027	$147,273,337
2028	$167,170,904
2029	$186,443,478
2030	$205,728,771
2031	$224,897,513

Q. How were the estimated annual jurisdictional revenue requirements for the proposed plan developed?

A. The estimated annual jurisdictional revenue requirements were developed with cost estimates for each of the 2022 SPP programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the SPP Cost Recovery Clause Rule.

Q. Do these revenue requirements include any costs that are currently recovered in base rates?

A. Yes. The revenue requirement amounts shown above reflect all the investments and expenses associated with the activities in the plan without regard to whether the costs are recovered through the company's existing base rates and charges or through the company's Storm Protection Cost Recovery Clause ("SPPCRC"). The SPP statute requires utilities to submit a plan explaining the utility's "systematic approach" to storm protection, which includes existing storm hardening activities that were previously established and were not "new" or "incremental" to the new proposed storm protection activities. In the company's Commission approved "2020 Agreement" the costs of some existing storm hardening activities that were being recovered through base rates were transitioned to recovery through the SPPCRC, while others remain recovered through base rates. The existing storm hardening programs that were chosen to remain in base rates are as follows.

- Distribution Pole Replacements (Capital and O&M)
- Distribution Unplanned Vegetation Management
- Transmission Unplanned Vegetation Management
- Legacy Storm Hardening Plan Activities

The storm hardening programs that were transitioned from base rate recovery to be recovered through the SPPCRC are as follows.

- Transmission Asset Upgrades

- Distribution Planned Vegetation Management
- Transmission Planned Vegetation Management
- Distribution Infrastructure Inspections
- Transmission Infrastructure Inspections

Q. Is Tampa Electric intending to shift any of the current base rate recovered storm protection activities to recovery through the SPPCRC?

A. No.

Q. Did Tampa Electric make the agreed upon adjustments to ensure that no double recovery was occurring when it transitioned the base rate recovered activities to the SPPCRC?

A. Yes. Tampa Electric made two adjustments to ensure that all SPP costs that would be recovered through the SPPCRC were incremental and that no double recovery was occurring. First, the company reduced the filed amount of SPPCRC cost recovery in 2020 by $10.4 million dollars. This adjustment ensured that when Tampa Electric started the company's SPPCRC, those base rate activities would be removed from the total SPPCRC costs. The second adjustment was made by lowering base rates by $15 million dollars as of January 1, 2021 to recognize these activities would be removed on an ongoing basis from base rates and only be recovered through the SPPCRC.

Q. Do the estimated annual jurisdictional revenue requirements include the annual depreciation expense on SPP capital expenditures?

A. Yes. Rule 25-6.031 states that the annual depreciation expense is a cost that may be recovered through the SPPCRC. As a result, the estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures, *i.e.*, those initiated after April 10, 2020, using the depreciation rates from Tampa Electric's most current depreciation study, approved by Order No. PSC-2021-0423-S-EI issued on November 10, 2021.

Q. Was the depreciation savings on the retirement of assets removed from service during the SPP capital projects considered in the development of the revenue requirement?

A. Yes. In the development of the revenue requirements, depreciation expense from the SPP capital asset additions has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital projects.

Q. Do the estimated annual jurisdictional revenue requirements include a return on the undepreciated balance of the SPP assets?

A. Yes. Rule 25-6.031 6(c) states that the utility may recover a return on the undepreciated balance of the asset costs through the SPPCRC. As a result, this return was included in the estimated annual jurisdictional revenue requirement. In accordance with the FPSC Order No. PSC-2021-0423-S-EI, which approved 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 of 9.5 percent included in the 2021 Stipulation and Settlement Agreement.

Q. In the calculation of the estimated annual jurisdictional revenue requirements did the company include Allowance for Funds Used During Construction (“AFUDC”)?

A. No. Per Rule 25-6.0141, F.A.C, in order for projects to be eligible for AFUDC, they must involve “gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101, Electric Plant in Service, and Account 106, Completed Construction not Classified, at the time the project commences and are expected to be completed in excess of one year after commencement of construction.” None of the projects proposed in Tampa Electric’s 2022 SPP meet the criteria for AFUDC eligibility.

Q. Does Tampa Electric intend to continue to seek recovery of the appropriate estimated SPP costs through the SPPCRC, in accordance with Rule 25-6.031, F.A.C.?

A. Yes, Tampa Electric will continue to file for cost recovery of the estimated SPP costs through the SPPCRC.

CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2022-2024 OF THE STORM PROTECTION PLAN

Q. Please provide an estimate of rate impacts for each of the first three years of the proposed 2022 SPP for typical Tampa Electric residential, commercial, and industrial customers.

A. Tampa Electric prepared estimated rate impacts of the SPP for 2022, 2023, and 2024. The estimated rate impacts for each of the first three years of the 2022 SPP for a typical residential, commercial, and industrial Tampa Electric customer are listed in the table below.

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2022	2.70%	2.70%	1.17%	1.08%
2023	4.13%	4.13%	1.28%	1.19%
2024	5.31%	5.31%	1.37%	1.29%

Q. How were the estimated rate impacts for each of the first three years of the proposed SPP for a typical residential, commercial, and industrial customer determined?

A. For each year, the programs were itemized and identified as either substation, transmission, or distribution costs. Each of those functionalized costs was then allocated to rate class using the allocation factors for that function. The company used the allocation factors from the Tampa Electric 2021 Cost of Service Study that was approved with the company’s 2021 settlement agreement in Docket No. 20210034-EI. Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the rates were determined in the same manner. For residential customers, the charge is a per-kWh charge. For commercial and industrial customers, the charge is a per-kW charge. The estimated charges were derived by dividing the rate class allocated SPP revenue requirements by the 2022 energy billing determinants for residential customers and by the 2022 demand billing determinants for commercial and industrial customers. Those charges were then applied to the billing determinants associated with typical bills for each group to calculate the impact on those bills. This was done using the costs for each year 2022, 2023, and 2024.

Q. Will the rates established through the SPPCRC differ from those presented in the rate impact calculations in the SPP?

A. Yes. The rate impacts presented above reflect the “all-in” costs of the company’s SPP without regard to whether the costs are or will be recovered through the SPPCRC or through the company’s base rates and charges.

In addition, when it makes its SPPCRC filing, the company will use more recent billing determinants based on the most current load forecast.

The company will also continue to take steps to prevent double recovery of any costs through base rates and the

SPPCRC.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony and exhibit demonstrate that Tampa Electric's estimated annual jurisdictional revenue requirements for each of the 10 years of the 2022 SPP and rate impacts for each of the first three years of the 2022 SPP for the utility's typical residential, commercial, and industrial customers comply with Rule 25-6.030(3)(g)-(h). These calculations were performed in accordance with the requirements of Section 366.96, Florida Statutes, and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

A.SLOAN LEWIS

Tampa Electric's 2022-2031 Storm Protection Plan Total Revenue Requirements by Program (in Millions)

Capital	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Distribution Lateral Undergrounding	$9.22	$19.87	$30.81	$42.16	$53.87	$65.44	$76.79	$87.93	$99.25	$110.71	$596.06
Transmission Asset Upgrades	$2.90	$4.99	$6.72	$8.43	$10.26	$12.04	$13.71	$15.35	$16.33	$16.28	$107.01
Distribution - Substation Extreme Weather Protection	$0.00	$0.02	$0.15	$0.34	$0.54	$0.72	$0.93	$1.11	$1.34	$1.56	$6.70
Transmission - Substation Extreme Weather Protection	$0.00	$0.00	$0.08	$0.23	$0.40	$0.55	$0.74	$0.90	$1.10	$1.29	$5.27
Distribution Overhead Feeder Hardening	$3.31	$7.36	$10.61	$13.82	$17.37	$20.84	$24.21	$27.48	$30.93	$34.69	$190.62
Transmission Access Enhancements	$0.15	$0.42	$0.71	$1.03	$1.39	$1.73	$2.05	$2.34	$2.58	$2.86	$15.27
Distribution Pole Replacements	$1.59	$3.14	$4.69	$6.26	$7.57	$8.53	$9.48	$10.42	$11.45	$12.57	$75.70
O&M	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Distribution Lateral Undergrounding	$0.18	$0.18	$0.18	$0.15	$0.19	$0.20	$0.20	$0.21	$0.21	$0.33	$2.02
Distribution Vegetation Management - planned	$21.16	$24.00	$24.22	$25.65	$26.77	$27.99	$29.52	$30.94	$32.50	$34.27	$277.02
Distribution Vegetation Management - unplanned	$1.40	$1.40	$1.40	$1.30	$1.30	$1.30	$1.40	$1.40	$1.30	$1.30	$13.50
Transmission Vegetation Management - planned	$3.37	$3.41	$2.83	$2.92	$3.01	$3.08	$3.15	$3.22	$3.39	$3.55	$31.94
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	$0.46	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$5.23
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	$0.56	$0.62	$0.67	$0.72	$0.77	$0.82	$0.87	$0.92	$0.97	$1.02	$7.94
Transmission Access Enhancements	$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	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$1.20	$1.22	$11.17
Transmission Infrastructure Inspections	$0.54	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$0.58	$0.59	$5.49
SPP Planning & Common	$0.92	$0.87	$0.88	$0.90	$0.92	$0.94	$0.96	$0.98	$1.00	$1.02	$9.37
Other Legacy Storm Hardening Plan Items	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$0.34	$0.34	$3.14
Distribution Pole Replacements	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$0.71	$0.72	$7.23

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC'S STORM PROTECTION PLAN

VERIFIED DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF

TAMPA ELECTRIC COMPANY

VERIFIED DIRECT TESTIMONY OF JASON D. DE STIGTER

ON BEHALF OF

TAMPA ELECTRIC COMPANY

1. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. By whom are you employed and in what capacity?

A2. A2. I am employed by 1898 & Co. as a Director and I lead the Utility Investment Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 250 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 8,300 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. Briefly describe your educational background and certifications.

A3. I received a Bachelor of Science Degree in Engineering and a Bachelor's in Business Administration from Dordt College, now called Dordt University. I am also a registered Professional Engineer in the state of Kansas.

Q4. Please briefly describe your professional experience and duties at 1898 & Co.

A4. I am a professional engineer with 14 years of experience providing consulting services to electric utilities. I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients. These studies have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a project manager, I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside their Asset Management Practice performing similar studies to the effort performed for Tampa Electric Company ("Tampa Electric").

Q5. Have you previously testified before the Florida Public Service Commission or other state commissions?

A5. Yes, I provided written and rebuttal testimony on behalf of Tampa Electric Company for the 2020-2029 Storm Protection Plan before the Florida Public Service Commission, docket no 20200067-EI. I have also provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light before the Indiana Utility Regulatory Commission and written testimony on behalf of Oklahoma Gas and Electric. Additionally, I have supported many other regulatory filings. I have also testified in front of the Alaska Senate Resources Committee.

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my testimony is to summarize the results and methodology developed using 1898 & Co.'s Storm Resilience Model, with the following objectives:

1. Calculate the customer benefit of hardening projects through 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 an overall investment level that maximizes customers' benefit while not exceeding Tampa Electric's technical execution constraints.

Through my testimony I will describe the major elements of the Storm Resilience Model, which includes a Major

Storms Event Database, Storm Impact Model, Resilience Benefit Module, and Budget Optimization & Project Prioritization. Specifically, I will define resilience, review historical major storm events to impact Tampa Electric's service territory, describe the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explain how to understand the resilience benefit results. Additionally, I will outline the key updates to the Storm Resilience Model for the 2022-2031 Storm Protection Plan. Throughout my testimony I will describe both how the assessment was performed and why it was performed as such. Finally, I will describe the calculations and results of the Storm Resilience Model.

Q7. Are you sponsoring any attachments in support of your testimony?

A7. Yes, I am sponsoring the 1898 & Co., Tampa Electric's 2022-2031 Storm Protection Plan Resilience Benefits Report that is being included as Appendix F in Tampa Electric's 2022-2031 Storm Protection Plan.

Q8. Were your testimony and the attachment identified above prepared or assembled by you or under your direction or

supervision?

A8. Yes.

Q9. Are you also submitting workpapers?

A9. No.

Q10. What was the extent of your involvement in the preparation of the Storm Protection Plan?

A10. I served as the 1898 & Co. project director on Tampa Electric's 2022-2031 Storm Protection Plan Assessments and Benefits Assessment. The evaluation utilized a Storm Resilience Model to calculate benefits. I worked directly with Tampa Electric's Team involved in the resilience-based planning approach. I was responsible for the overall project and was directly involved in the development of the Storm Resilience Model, the assessment and results, as well as being the main author of the report.

2. RESILIENCE-BASED PLANNING OVERVIEW

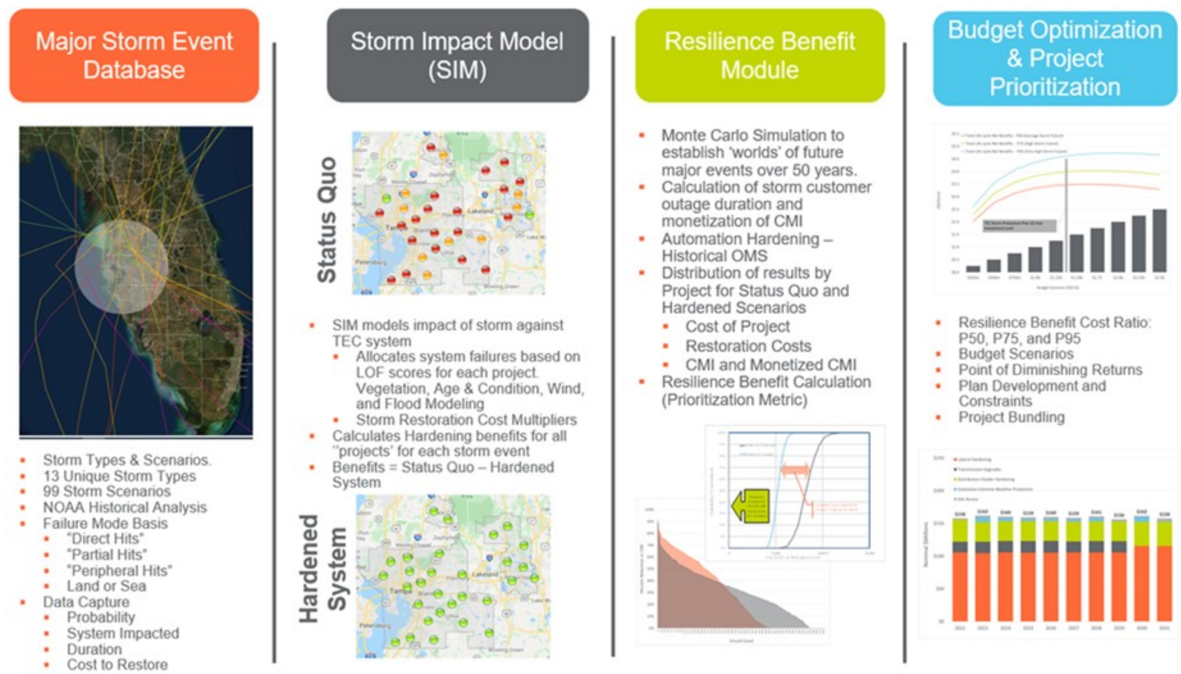
Q11. Please describe the analysis 1898 & Co. conducted for Tampa Electric.

A11. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in Tampa Electric’s T&D system utilizing a Storm Resilience Model. The Storm Resilience Model consistently models the benefits of all potential hardening projects for an ‘apples to apples’ comparison across the system. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, project, and program level. The results of the Storm Resilience Model are:

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

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit. Figure 1 below provides an overview of the Storm Resilience Model used to calculate the project benefit and prioritize projects.

Figure 1: Storm Resilience Model Overview



The storms database includes the future 'universe' of potential storm events to impact Tampa Electric's service territory. 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.

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 Likelihood of Failure ("LOF") is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone the asset is in. The Storm Impact Model also estimates the restoration costs and CMI for each of the projects. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per Tampa Electric's hardening standards. The CMI benefit is 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 employs stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types of storm events to impact Tampa Electric's service territory over the next 50 years. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience weighted benefit for each project in dollars. Feeder Automation Hardening 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 prioritizes the projects based on the highest resilience benefit cost ratio. The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates Tampa Electric's technical and operational realities (Transmission outages) in scheduling the projects.

This resilience-based prioritization facilitates the identification of the critical 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 get the "biggest bang for the buck."

Q12. Which of the Storm Protection Plan programs are evaluated within the Storm Resilience Model?

A12. The Storm Resilience Model includes project benefits results, budget optimization, and project prioritization for the following Storm Protection Plan programs:

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

Q13. Please outline the key updates that were made to the Storm Resilience Model from the 2020-2029 to the 2022-2031 Storm Protection Plan assessment.

A13. The Storm Resilience Model was used in the development of the 2020-2029 Storm Protection Plan as well as the 2022-2031 Storm Protection Plan. The following are the key updates from the 2020-2029 to the 2022-2031 Storm Resilience Model:

1. **General** – these updates include shifting of the time horizon, adding another year of storms to the historical analysis, and accounting for 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. **Substation Projects Development** – Tampa Electric

completed a technical evaluation of substation hardening alternatives since the 2020-2029 Storm Protection Plan filing. The results of that evaluation, including specific substation hardening activities and their cost were included in the model.

4. **Site Access Project Development** – Tampa Electric performed additional evaluation of transmission site access and updated the projects and associated costs.

5. **Automation Hardening Capital Costs** – 1898 & Co. performed detailed analysis on 300 circuits to identify more specific scope and cost. Based on lessons learned from the 2020 projects, the cost to deploy automation had a wide range given the uncertainty in circuit reconductoring and substation upgrades needed to not overload and burn down circuits. With improved cost estimates for the 300 circuits the prioritization of projects in the Storm Resilience Model is improved. This increases the overall benefit by decreasing major outage events for customers.

6. **Lateral Undergrounding 'Branching' Approach** – Based on a lessons learned evaluation, the project definition for lateral projects was adjusted to

include a collection of electrically connected protection zones, or 'branches'. Tampa Electric's undergrounding design standard includes looping for added resilience. Based on the 2020 project execution, it was identified that some of the projects included higher costs to achieve the full loop. By undergrounding all the electrically connected protection zones off a circuit feeder / mainline the higher costs will be mitigated since it can be designed more thoughtfully to minimize the number of new underground miles.

Q14. How is resilience defined?

A14. There are many definitions for resilience, I gravitate to the one used by the National Infrastructure Advisory Council ("NIAC"). Their definition of 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."

This definition can be broken down into four phases of resilience described below with applicable definitions for the grid:

- **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)**

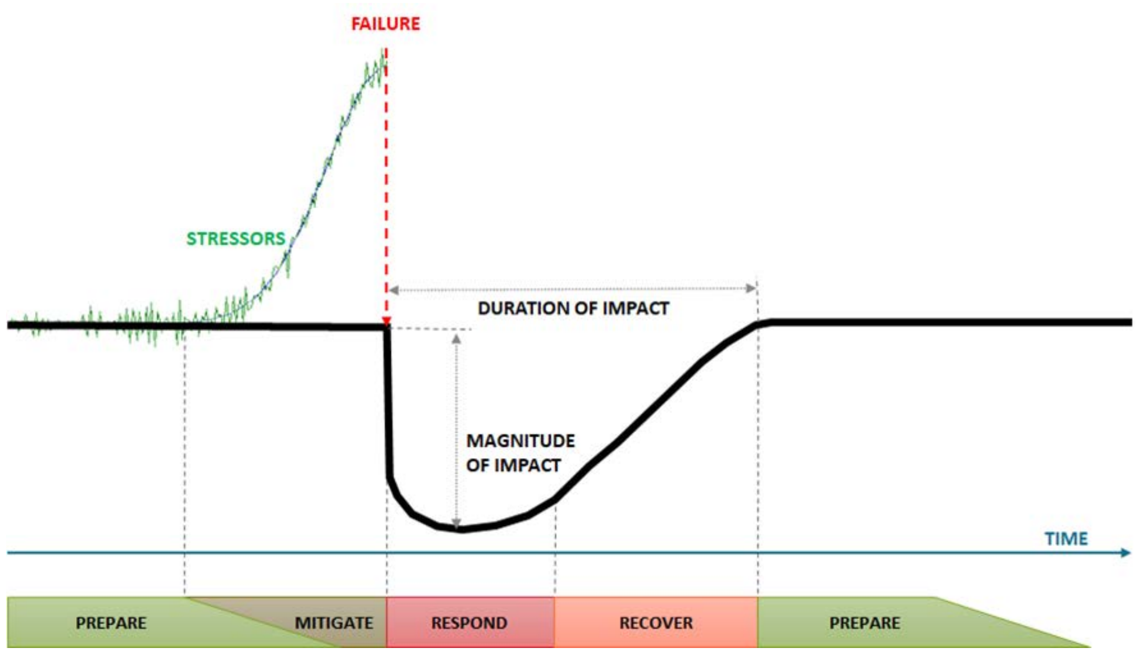
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).

- **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.

This is depicted graphically in Figure 2 below as a conceptual view of understanding resilience and how to mitigate the impact of events. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on the system in terms of the magnitude of impact (vertical) and the duration (horizontal).

Figure 2: Phases of Resilience



Q15. How does the Storm Resilience Model incorporate this definition?

A15. The Storm Resilience Model utilizes a resilience-based planning approach to calculate hardening project benefits and prioritize projects. The model includes a 'universe' of major storm events as stressors on the Tampa Electric system. The database includes the probability of these events occurring as well as the magnitude of impact, in terms of the percentage of the sub-systems (e.g. substations, transmission lines, feeders, laterals), and duration to restore the system. The database also includes the restoration cost to return the system back to normal operation after each of the storm events.

The Storm Resilience Model also identifies, on a probability weighted basis, which specific portions of the Tampa Electric system would be impacted and their contribution to the overall restoration costs. The model also evaluates the storms impact for each portion of the system based on current status of the system and if that part of the system is hardened. For example, the Storm Resilience Model calculates the magnitude and duration of a storm event on a distribution circuit given its current state and after it has been hardened.

Q16. Please outline the type and count of hardening projects evaluated in the Storm Resilience Model.

A16. Table 1 below contains the list of potential hardening projects by program evaluated in the Storm Resilience Model.

Table 1: Potential Hardening Project Count

Program	Project Count
Distribution Lateral Undergrounding	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

Q17. How were these potential hardening projects identified?

A17. The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of Tampa Electric's system during major storm events. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. Additionally, hardening approaches for parts of the system were based on the balance of the resilience benefit they provide with the overall costs. I discuss this more below. Table 2 below shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

Table 2: Tampa Electric's Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**9**
Site Access	**[count]**	**44**
Roads	[count]	25
Bridges	[count]	19

All of the assets that benefit from hardening are strategically grouped into potential hardening projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. The main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures. Therefore, 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 the physical hardening and automation hardening provides significant resilience benefit for feeders. The 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 that of laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate impacts from vegetation outside the trim zone and other types of outages. The combination of the physical and automation hardening provides a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is the preferred approach for lateral hardening while overhead physical hardening combined with automation hardening is the preferred approach for feeders.

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

Tampa Electric identified 44 separate transmission access, road, and bridge projects based on field inspections of the system.

Tampa Electric 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 Tampa Electric's more detailed assessment, nine (9) substations were identified that included flooding risk to the level that could require mitigation.

Q18. Why is this approach to hardening project identification important?

A18. This approach to hardening project identification is important for several reasons.

1. The approach is comprehensive. As Table 2 shows, the approach evaluates nearly all of Tampa Electric's transmission and distribution ("T&D") system. By considering and evaluating the entire system on a consistent basis, the results of the hardening plan provide confidence that portions of Tampa Electric's system are not overlooked for potential resilience benefit.
2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and industrial, and priority customers. 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.

3. The granularity at the asset and project levels allows Tampa Electric to invest in portions of the system that provide the most value to customers from a restoration cost reduction, customers impacted ("CI"), and customer minutes interrupted ("CMI") perspective. For example, a circuit may have 10 laterals that come off a feeder and the Storm Resilience Model may determine that only 3 out of the 10 should be hardened. Without this granularity, over-investment in hardening is a concern. The adopted approach provides confidence that the overall plan is investing in the parts of the system that provide the most value for customers.

4. The types of hardening projects include the mitigation measures over all the four phases of resilience providing a diverse investment plan.

Since storm events cannot be fully eliminated, the diversification allows Tampa Electric to provide a higher level of system resilience.

5. The approach balances the use of robust data sets with Tampa Electric's experience with storm events to develop storm hardening projects. Data-only approaches may provide decisions that don't match reality, while people-driven only solutions can be filled with bias. The approach balances the two to better identify types of hardening projects.

Q19. Why is it necessary to model storm hardening projects benefits using this resilience-based planning approach and Storm Resilience Model?

A19. The Storm Resilience Model was architected and designed for the purpose of calculating storm hardening project benefit in terms of reduced restoration costs and customer minutes interrupted to build a Storm Protection Plan with the right level of investment that provides the most benefit for customer. It was necessary to model storm hardening projects using the resilience-based planning approach shown in Figure 2 for the following reasons:

1. The benefits of hardening projects are wholly

dependent on the number, type, and overall impact of future storms to impact Tampa Electric's service territory. Different storms have dramatically different impact to Tampa Electric's system, for instance, in review of Tampa Electric's historical storm reports, it was observed that tropical storm events even 100 to 150 miles away from Tampa Electric's service territory from the Gulf side have greater impact in terms of restoration costs than larger storms 100 to 150 miles away on the Florida or Atlantic side. This is mainly caused by the energy that exists in the storm bands when they reach Tampa Electric's service territory. For this reason, the resilience-based planning approach includes the 'universe' of potential major events that could impact Tampa Electric over the next 50 years, this is the Major Storms Event Database. In relation to the conceptual model showing the phases of resilience (Figure 2), I will discuss how the probabilities and system impacts of storm events were developed later in my testimony.

2. Major events cause assets to fail. Assets collectively serve customers. It only takes one asset failure to cause customer outages. The cost

to restore the failed assets is dependent on the extent of the damage and resources used to fix the system. The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. It may only take 4 hours to fix the failed equipment, but customers could be without service for 4 days if crews are busy fixing other parts of the system for 3 days and 20 hours. All of this is dependent on the type of storm to impact the system. Modeling this series of events, the phases of resilience from Figure 2, for the entire system at the asset and project level for both a Status Quo and Hardened scenarios is needed to accurately model hardening project benefits. Therefore, the resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 99 storm events for both scenarios. I discuss core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan in further detail below in my testimony.

3. The output of the Storms Impact Model is the resilience benefit of each project for each of the 99 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm, and the mix of storm events to occur over the life of the hardening projects. A project’s resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life-cycle of the assets. A future ‘world’ of major storm events could include a higher frequency of category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of category 1 type storms with high impact and a high frequency of tropical storms with lower impacts. The number of storm combination scenarios is significant given there are 13 unique types of storm events. To model this range of combinations, the Storm Restoration Model employs stochastic modeling, or Monte Carlo Simulation, to randomly select from the 99 storm events to create a future ‘world’ of the 13 unique storm events to hit Tampa Electric’s service territory. The Monte Carlo

Simulation creates a 1,000-future storm “worlds”. From this, the life-cycle resilience benefit of each hardening project can be calculated in the Resilience Benefit Module, I discuss this in more detail below in my Testimony.

4. To answer the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include a Budget Optimization and Scheduling Model within the Storm Resilience Model. The Budget Optimization algorithm develops the project plan and associated benefits over a range of budget levels to identify a point of diminishing returns where additional investment provides very little return. The Project Scheduling component uses the preferred budget level and develops an executable plan by prioritizing projects that provide the most benefit while balancing Tampa Electric’s technical constraints. I outline this in more detail below.

3. MAJOR STORMS EVENT DATABASE

Q20. Please provide an overview of the Major Storms Event Database and how it was developed.

A20. The Major Storms Event Database includes the 'universe' of storm events that could impact Tampa Electric's service territory over the next 50 years. The database describes the phases of resilience (Figure 2) for Tampa Electric's high-level system perspective for a range of storm stressors. It was developed collaboratively between Tampa Electric and 1898 & Co. It utilizes information from the National Oceanic and Atmospheric Administration ("NOAA") database of major storm events, Tampa Electric's historical storm reports, available information on the impact of major storms to other utilities, and Tampa Electric's experience in storm recovery. From that information, 13 unique storm types were observed to impact Tampa Electric's service territory. For each of the storm types, various storm scenarios were developed to capture the range of probabilities and impacts of each storm type. In total, 99 storms scenarios were developed to capture the 'universe' of storm events to impact Tampa Electric's service territory. Table 3 below provides a summary of the Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration of the event.

Table 3: Major Storms Event Database Overview

Storm Type No.	Scenario Name	Annual Probability (Percent)	Restoration Costs (Millions)	System Impact (Laterals) (Percent)	Total Duration (Days)
1	Cat 3 Direct Hit-Gulf	1.0 - 2.0	306.0 - 1,224.0	60.0 - 70.0	17.4 - 34.5
2	Cat 1&2 Direct Hit-Florida	5.0 - 8.0	76.5 - 153.0	35.0 - 55.0	6.0 - 8.8
3	Cat 1&2 Direct Hit-Gulf	2.0 - 4.0	153.0 - 306.0	45.0 - 60.0	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	14.5	5.1 - 15.3	6.3 - 15.6	2.0 - 3.6
6	Localized Event Direct Hit	50.0	0.5 - 1.5	1.3 - 3.1	0.3 - 0.6
7	Cat 3 Partial Hit	3.0 - 4.0	91.8 - 184.0	36.0 - 48.0	6.4 - 9.2
8	Cat 1&2 Partial hit	7.0	15.3 - 91.8	8.5 - 28.0	2.3 - 6.9
9	TS Partial Hit	17.0 - 18.0	11.5 - 30.6	8.0 - 15.0	2.0 - 3.6
10	TD Partial Hit	12.0 - 15.0	0.4 - 3.1	2.0 - 3.8	1.5 - 2.7
11	Cat 3 Peripheral Hit	2.0 - 3.0	0.8 - 22.2	1.2 - 14.1	1.0 - 3.0
12	Cat 1&2 Peripheral Hit	10.0 - 11.0	0.6 - 8.9	0.9 - 6.5	0.9 - 2.3
13	TS Peripheral Hit	11.0 - 12.0	0.5 - 3.8	0.7 - 3.4	0.9 - 1.3

Q21. What does the NOAA data show on the number and types of major storm events to impact Tampa Electric's service territory?

A21. The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 169 years, beginning in 1852. The NOAA major events database was mined for all major event types up to 150 miles from Tampa Electric's 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 Tampa Electric's service territory. Additionally, the database was mined for the category of the storm as it hit Tampa Electric's 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 Tampa Electric's 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 Tampa Electric's 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, minimizing damage relative to a 'direct hit'. For large category

storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' 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 4 below includes the summary results from the NOAA database of storms to hit or nearly hit Tampa Electric's service territory since 1852.

Table 4: Historical Storm Summary from NOAA

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	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	12	20	32	30	29	91
Tropical Depression	10	8	18	17	N/A	35
Total	32	37	69	68	50	187

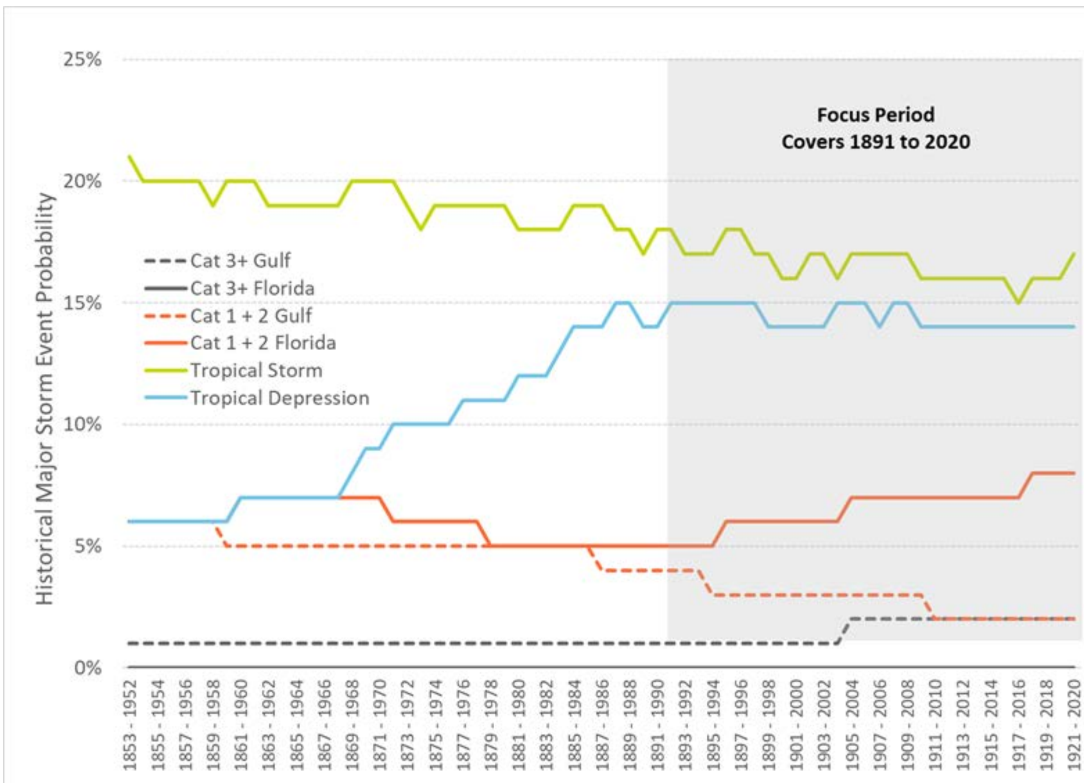
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Table 4 shows a total of 187 storms to hit the Tampa area since 1852. A total of 69 were direct hits within 50 miles, 68 were partial hits in the 51 to 100-mile radius, and 50 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 187, with one 'Direct Hit'. While there are 10 Category 3 type storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida.

Q22. What analysis of this historical storm information was done to determine the storm probability ranges?

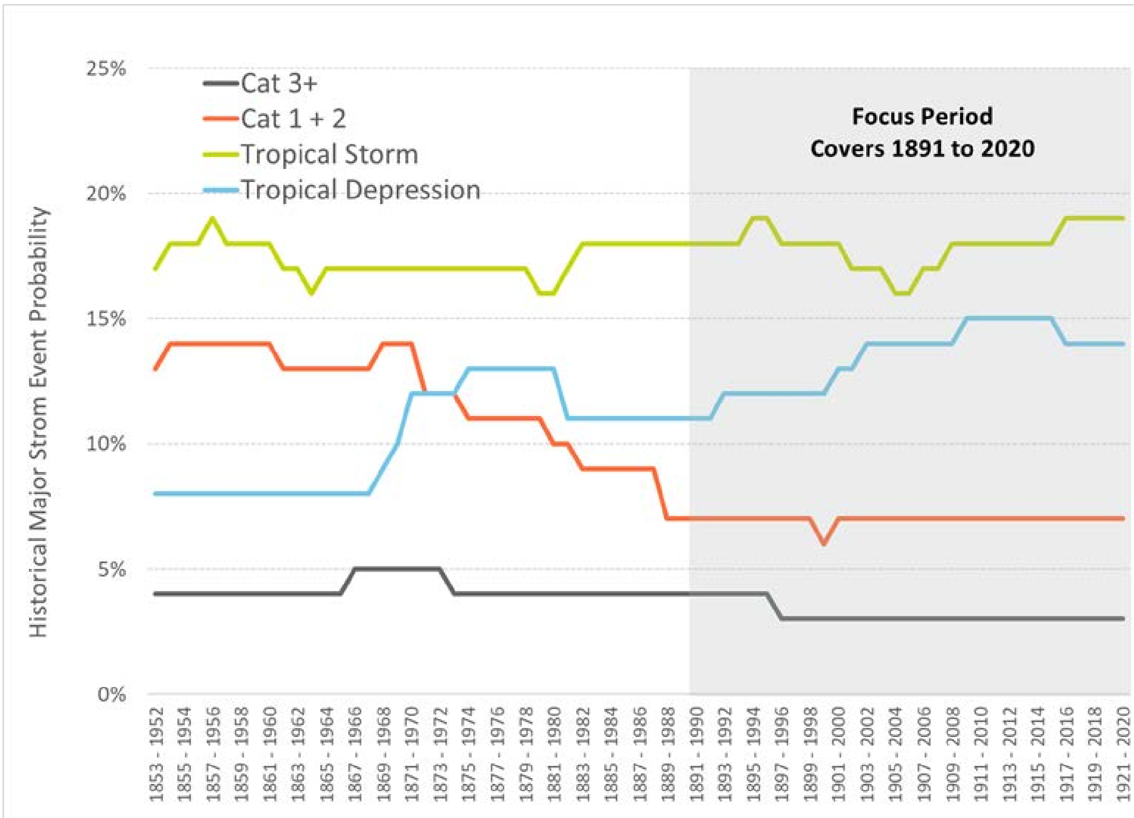
A22. 1898 & Co. converted the storm information from Table 4 above to show the total storm count for 100-year rolling average starting with the period of 1852 to 1951 ending with the period 1920 to 2020. This provides 70 distinct 100 year periods. This was done for each of the 13 unique storm events. The counts of each 100-year period for each storm type were then converted to probabilities. Starting on the page below, Figure 3, Figure 4, and Figure 5 show the 100-year rolling storm probability for "direct hits" (50 miles), "partial hits" (51 to 100 miles), and "peripheral hits" (101 – 150 miles), respectively.

Figure 3: "Direct Hits" (50 Miles) 100 Year Rolling Probability



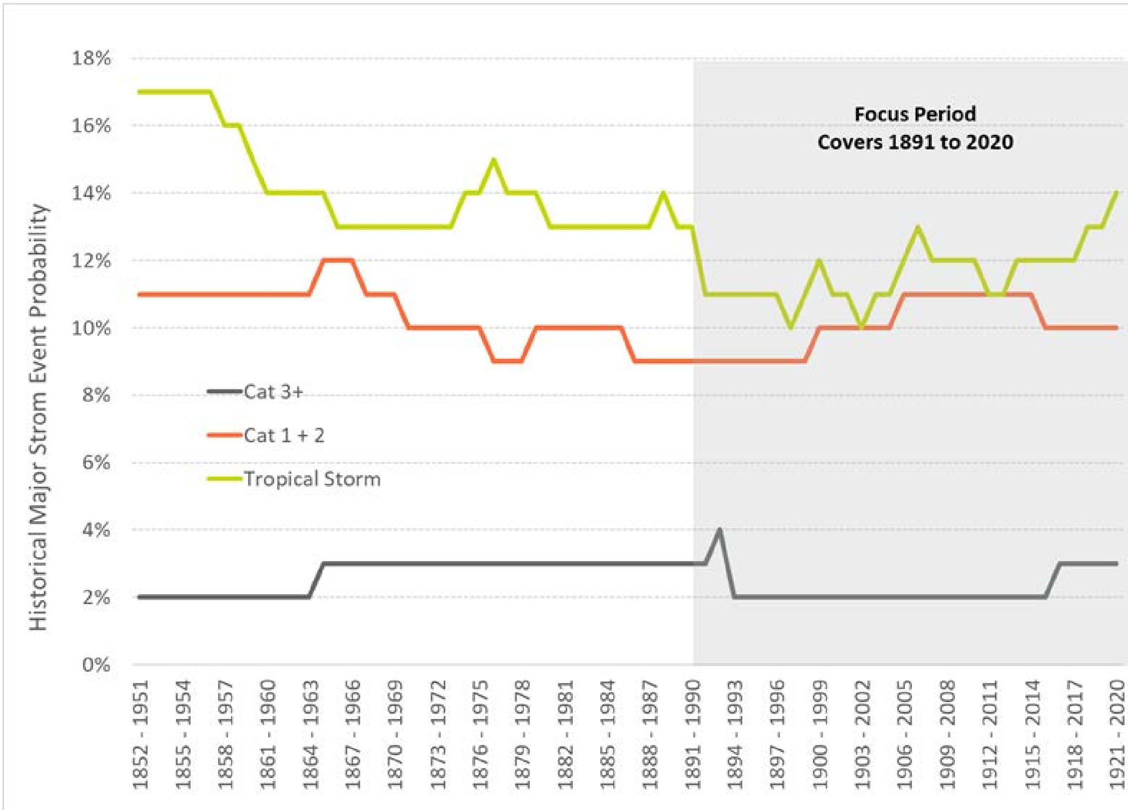
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 4: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability



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

Figure 5: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability



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

Each of the figures show a relative stability in the 100-year probability levels for the last 30 periods corresponding to storm events from 1891 through 2020. This time horizon served as the basis for developing the probability ranges for the 13 unique storm events.

Q23. How were the storm impact ranges developed?

A23. The range of system impacts for each storm scenario were developed based on historical storm reports from Tampa Electric and augmented by Tampa Electric's team experience with historical storm events. The database includes events that have not recently impacted Tampa Electric's service territory. The approach followed an iterative process of filling out more known impact information from recent events and developing impacts for those events without impact data based on their relative storm strength to the more known events.

4. STORM IMPACT MODEL

Q24. Please provide an overview of the Storm Impact Model.

A24. The Storm Impact Model describes the phases of resilience, Figure 2, for each potential hardening project on Tampa Electric's T&D system for each storm stressor scenario from the Major Storms Event Database. 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 the 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, CMI, and monetized CMI perspective.

Q25. You have mentioned that the Storm Resilience Model employs a data-driven decision-making methodology. Please describe what core data sets that are in the model and how they are used in the resilience benefit calculation.

A25. The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms at a very granular system level to model the benefits of each hardening project for each storm scenario. Tampa Electric's data systems include a connectivity model that allows for the linkage of three foundational data sets used in the Storm Impact Model – the Geographical Information System ("GIS"), the Outage Management System ("OMS"), and Customer Count/Customer Type.

GIS - The GIS provides the list of assets in Tampa

Electric’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 Storm Protection Plan. The strategic assignment of assets to projects and the value of the approach is discussed above.

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, lightening, 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.

Customer - The third foundational data set is customer count and customer type information that featured connectivity to the GIS and OMS systems. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project’s assets. This customer information is included for every distribution asset in Tampa Electric’s system. The customer information is used within the Storm Impact Model to calculate each storm’s CMI (customers affected * outage duration) for each lateral or feeder project.

Vegetation Density - 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 Tampa Electric. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor (approximately 240,000 spans) utilizing tree canopy data and geospatial analytics.

Wood Pole Condition - 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 1898 & Co.’s asset health algorithm to calculate an Asset Health

Index ("AHI") and 'effective' age for each pole.

Wind Zones - 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 higher closer to the coast and lower further inland. 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.

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. The Storm Impact Model performs a geospatial analysis of each structure to identify if there is road access or if the asset is in a deep right-of-way ("ROW").

Flood Modeling - The model also includes 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 Tampa Electric's 255 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. Tampa Electric performed a more detailed assessment of the 59 substation and identified nine (9) for hardening improvement.

Q26. What were the results of the vegetation density algorithm?

A26. Figure 6 and Figure 7 below show the range of vegetation density for overhead ("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 OH Primary and Transmission Conductor have near zero tree canopy coverage, while approximately 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 6: Vegetation Density on Primary Conductor

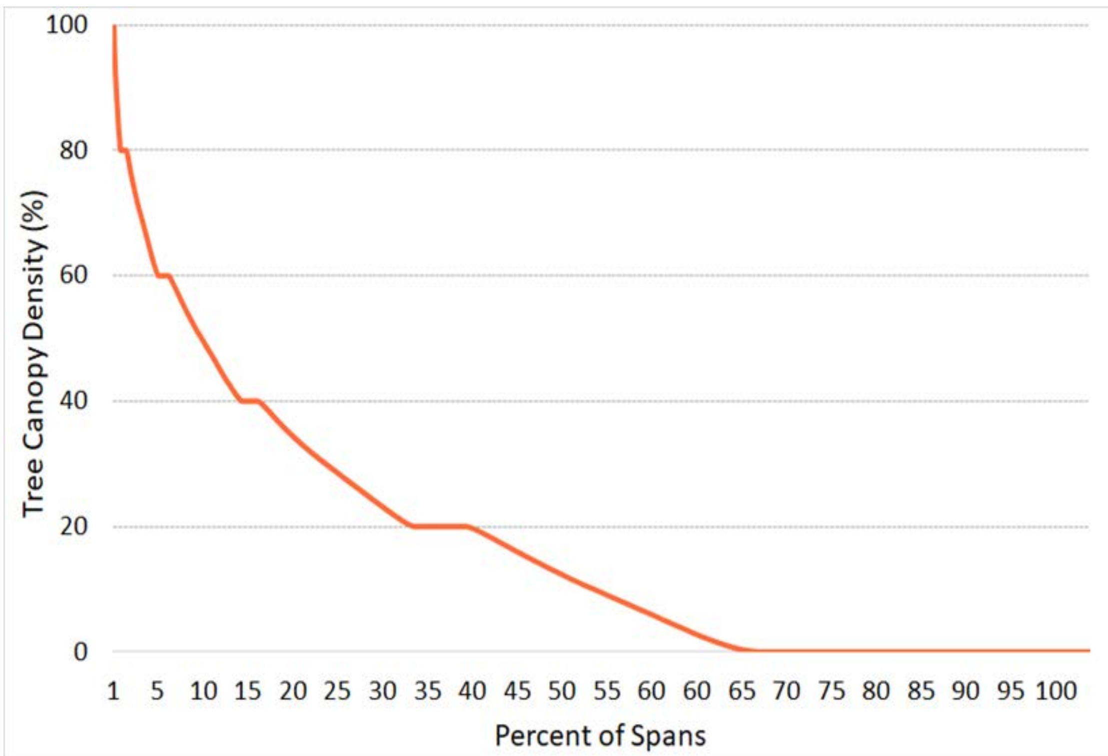
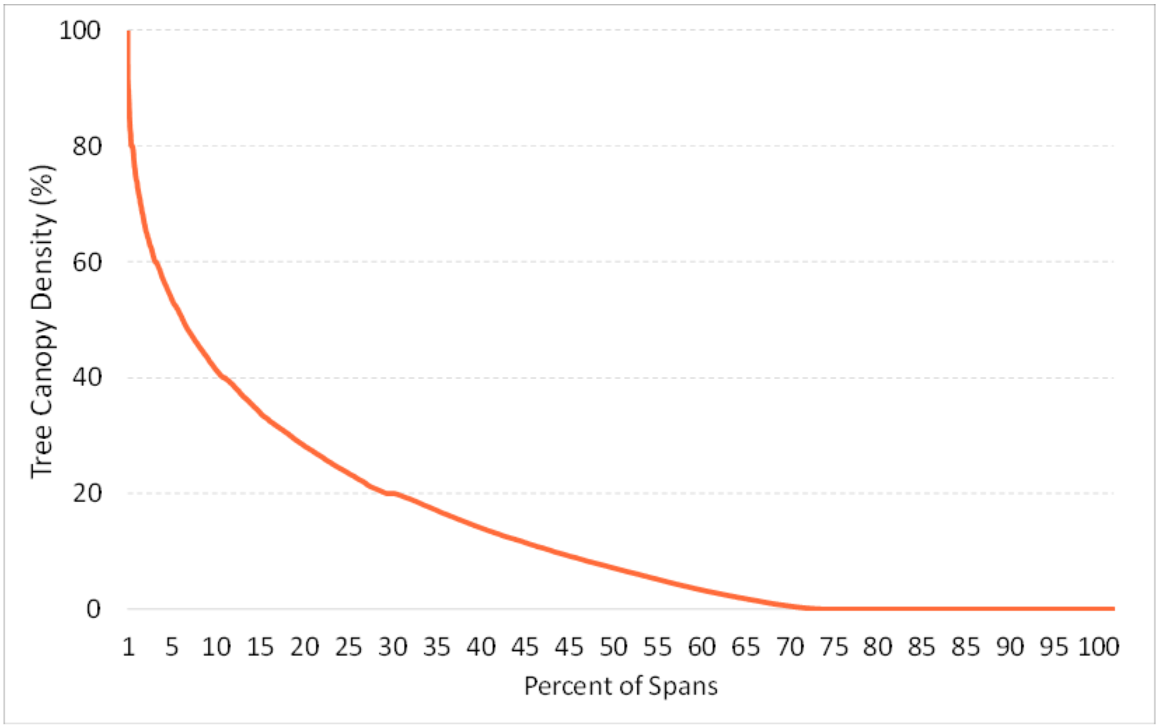


Figure 7: Vegetation Density on Transmission Conductor



Q27. How are asset and system failures during major storm events identified in the Storm Impact Model hardening projects?

A27. The Storm Impact Model identifies system failures based on the primary failure mode of the asset base. The model identifies the parts of the system that are likely to fail given the specific storm event from the Major Storms Event Database.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing 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 utilizes expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. 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 each project against each other to identify the likely lateral, backbone, or transmission circuits 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. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF is equal to the total LOF of the circuits it provides access to.

Q28. How are restoration costs allocated to the asset base for each major storm events?

A28. 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 based on storm restoration cost multipliers above planned replacement costs. These multipliers were developed by Tampa Electric and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF and the overall restoration costs outlined in the Major Storms Event Database.

Q29. How are customer outage durations calculated in the model for each major storm event?

A29. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset and project 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 are also monetized.

Q30. Why were CMI benefits monetized?

A30. The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed. Since CMI is in minutes and restoration costs is in dollars, the resilience-based planning approach monetized CMI. The monetized CMI benefit is combined with the restoration cost benefit for each project to calculate a total resilience benefit in dollars.

Q31. How was the CMI benefit monetized?

A31. CMI was monetized using DOE’s ICE Calculator. The ICE Calculator is an electric outage 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 or resilience improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (“DOE”). The ICE calculator incudes the cost of an outage for different types of customers. The calculator was extrapolated for the longer outage durations associated with 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.

Q32. How are the storm specific resilience benefits calculated for each project by major storm event?

A32. 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.

5. RESILIENCE BENEFIT MODULE

Q33. Please provide an overview of the Resilience Benefit Calculation Module

A33. 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 stochastic modeling, or 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 feeder automation 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.

Q34. What economic assumptions are used in the life-cycle Resilience Benefit Module?

A34. The resilience net benefit calculation includes the following economic assumptions.

- 50 year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years.
- Two (2) percent escalation rate
- Six (6) percent discount rate

Q35. How were hardening project costs determined?

A35. Project costs were estimated for approximately 14,000 projects in the Storm Resilience Model. Some of the project costs were provided by Tampa Electric while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that were then multiplied by unit cost estimates to calculate the project costs.

Distribution Lateral Undergrounding – The GIS and accessibility algorithm calculated the following scope items for each of the lateral undergrounding projects:

- Miles of overhead conductor for 1, 2, and 3 phase laterals

- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

Tampa Electric provided unit costs 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.

Transmission Asset Upgrades - 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. Tampa Electric 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.

Substation Extreme Weather Hardening - The project costs for the Substation Extreme Weather Hardening program are based on a report done by a third-party for Tampa Electric to evaluate substation hardening initiatives, such as raising control houses.

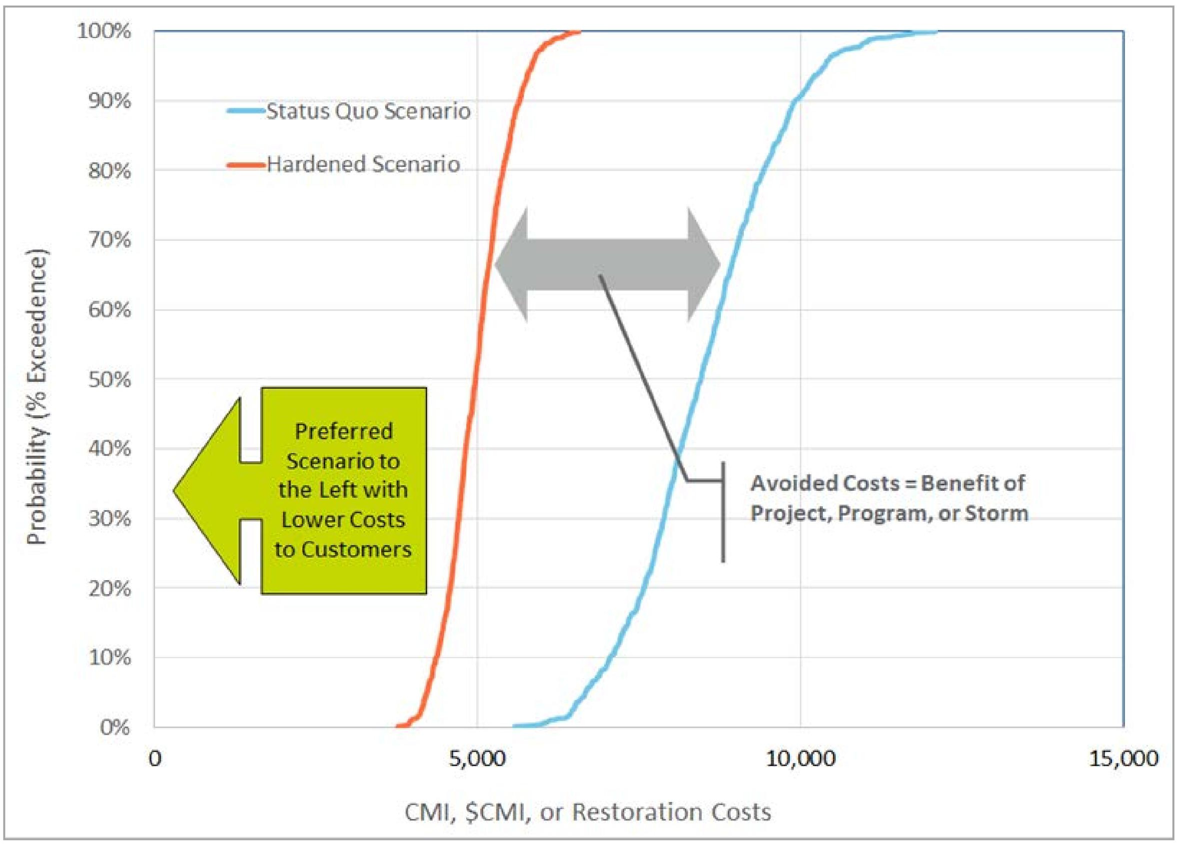
Distribution Overhead Feeder Hardening - The distribution overhead feeder hardening project costs are based on the number of wood poles that don’t meet current design standards for storm hardening and the cost to include automation. Tampa Electric provided unit replacement costs based on the accessibility of the pole as well as the cost to add automation to each circuit. Automation hardening cost estimates include the cost to add reclosers, pole replacements, re-conductor portions of the line, and substation upgrades that may be needed to handle load transfer. The remaining circuits costs were based on the average of these values.

Transmission Access Enhancements – Tampa Electric provided all the project costs for the Transmission Access Enhancements as developed by a third-party.

Q36. How are the resilience results of the Monte Carlo Simulation displayed and how should they be interpreted?

A36. The results of the 1,000 iterations are graphed in a cumulative density function, also known as an ‘S-Curve’. In layman’s terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 8 below shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 8: Status Quo and Hardened Results Distribution Example



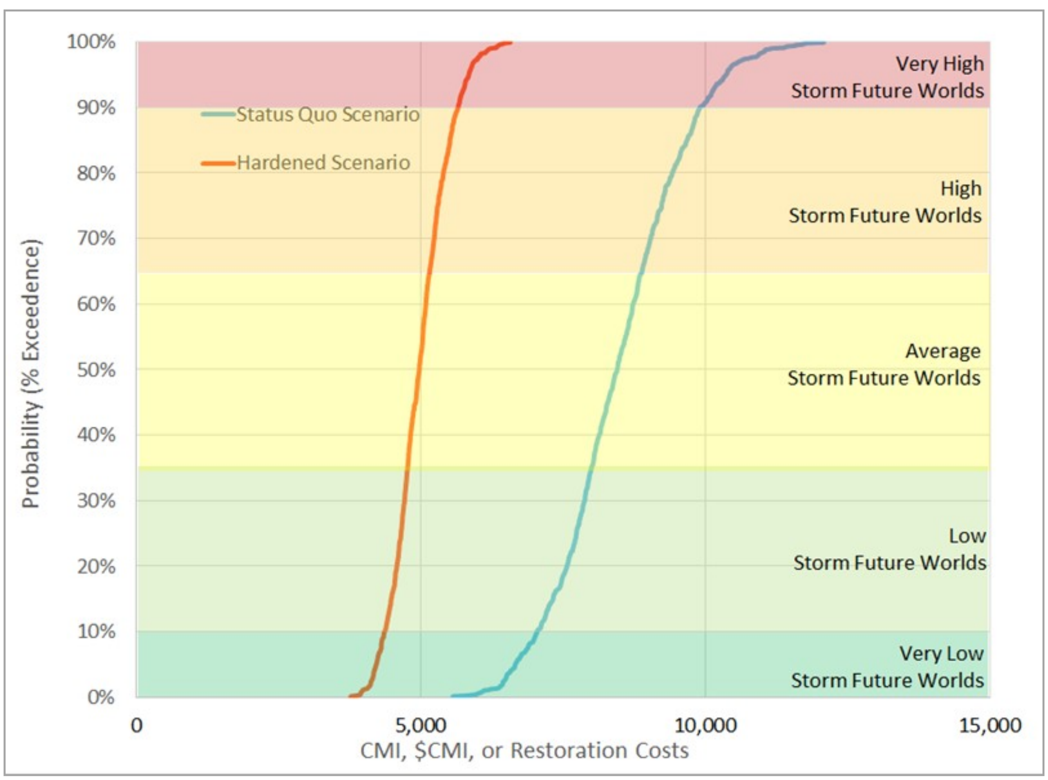
Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear 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.

Q37. How do S-Curves map to potential Future Storm Worlds?

A37. Figure 9 below provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

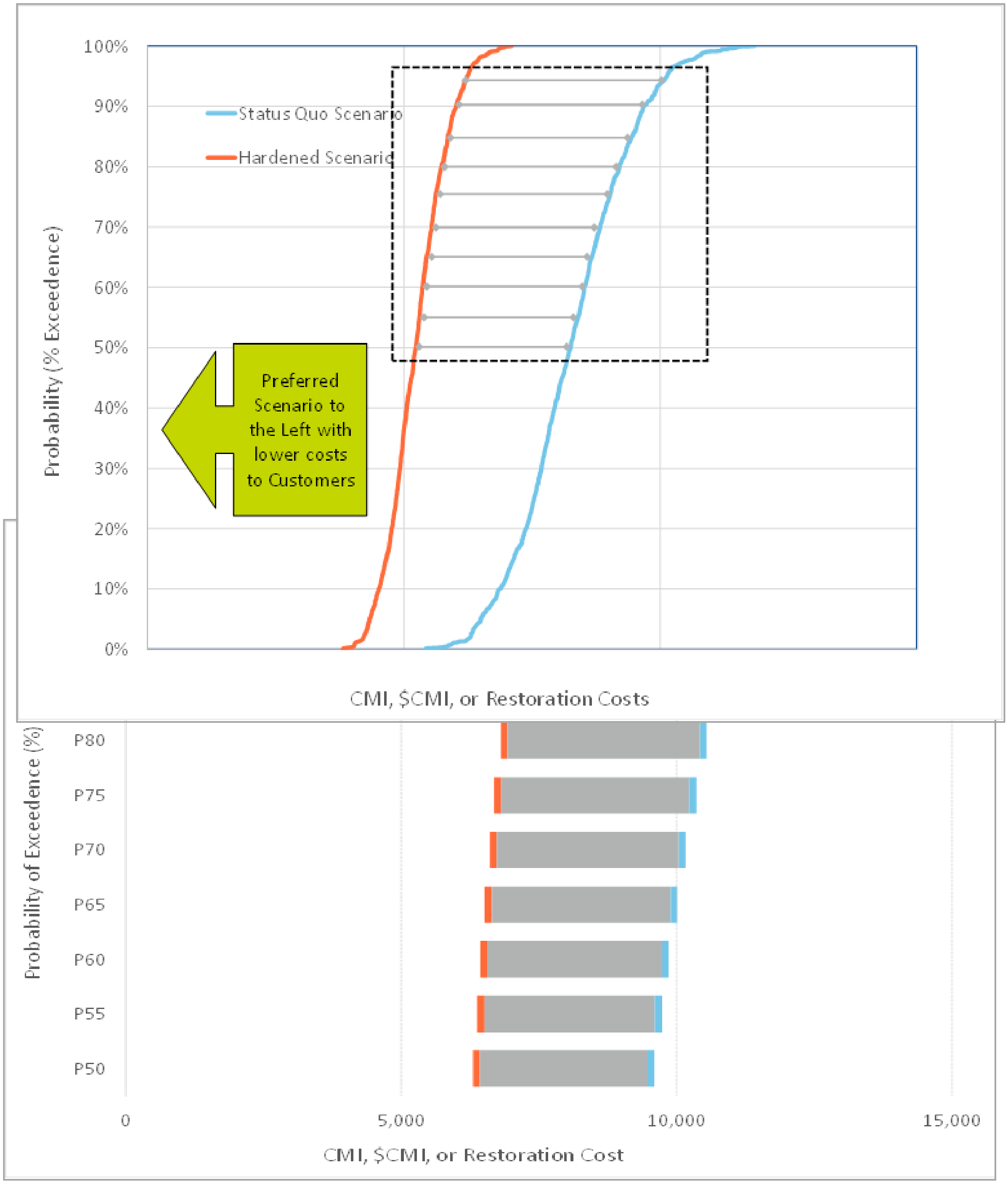
Figure 9: S-Curves and Future Storms



Q38. How are the S-Curves used to display the resilience benefit results?

A38. 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. Rather than show the entire S-curve, the resilience results will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 10 below illustrates this concept of looking at the top part of the S-curves and showing the P-values.

Figure 10: S-Curves and Resilience Focus



Q39. Please describe the analysis to calculate resilience benefit for automation hardening projects.

A39. 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 'pit' of the resilience conceptual model described in Figure 2.

The resilience benefit for feeder automation was estimated using historical Major Event Day ("MED") outage data from the OMS. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days. Tampa Electric has outage records going back 20 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 20 years.

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. The Storm Resilience Model extrapolates the 20 years of benefit calculation to 50 years to match the time horizon of the other projects. Additionally, the CMI was monetized and discounted over the 50-year time horizon to calculate the net present value ("NPV"). The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Q40. Please provide an example of this calculation.

A40. A historical outage may include a down pole from a storm event, causing the substation breaker to lock out resulting in a four-hour outage for 1,500 customers, or 360,000 CMI (4*1500*60). 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.

Q41. What are the benefit results of this analysis for the automation hardening projects?

A41. Figure 11 and Figure 12 below show the percent decrease in CMI and monetized CMI for all circuits ranked from highest to lowest from left to right. The figures also include the benefits to all outages.

Figure 11: Automation Hardening Percent CMI Decrease

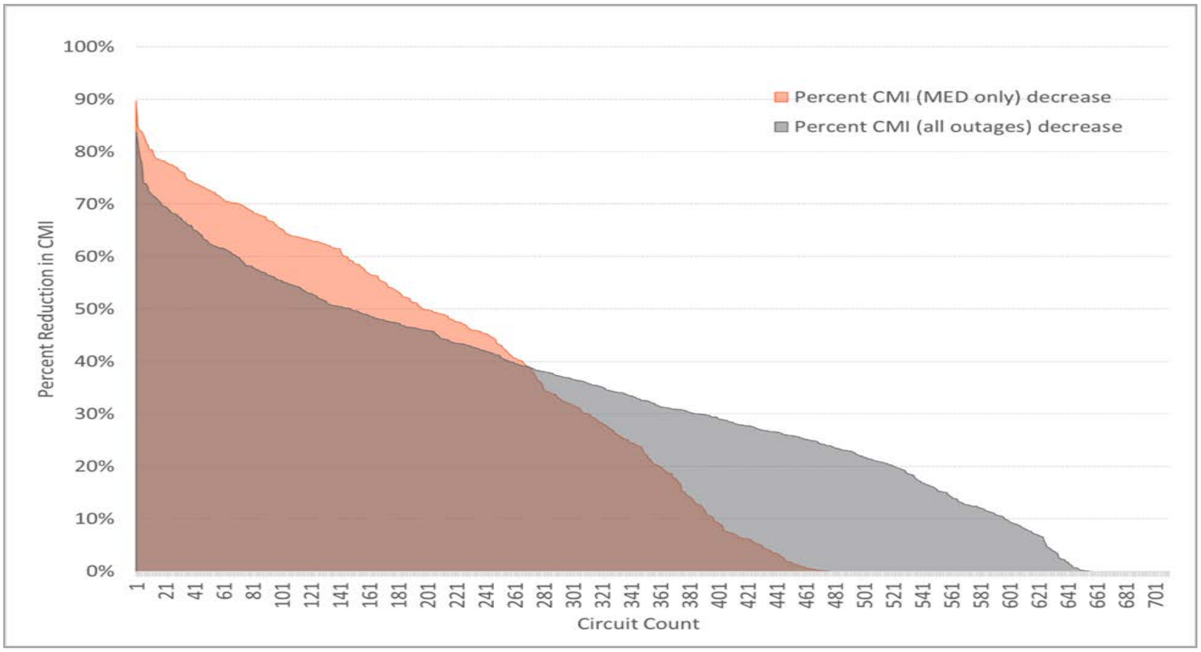
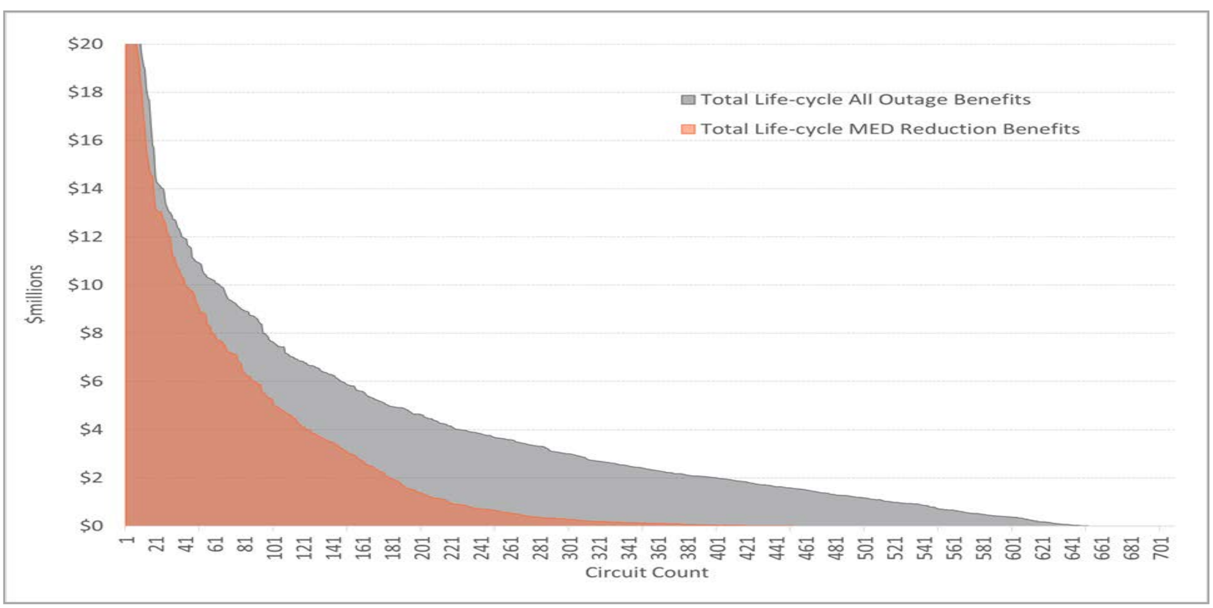


Figure 12: Automation Hardening Monetization of CMI Decrease



Q42. What are the specific outputs from the Resilience Benefit

module?

A42. The Resilience Benefit Module includes the following values for each project:

- 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-based strategy, the approach focuses on the P50 and above values, specifically considering:

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

6. BUDGET OPTIMIZATION AND PROJECT SCHEDULEING

Q43. How were hardening projects prioritized?

A43. All the projects are evaluated and prioritized using the same criteria allowing all 13,855 projects to 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 (P50, P75, and P95) as well as a weighted value.

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. Tampa Electric and 1898 & Co. settled on a weighting on the three values for 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.

Q44. How and why was the budget optimization performed?

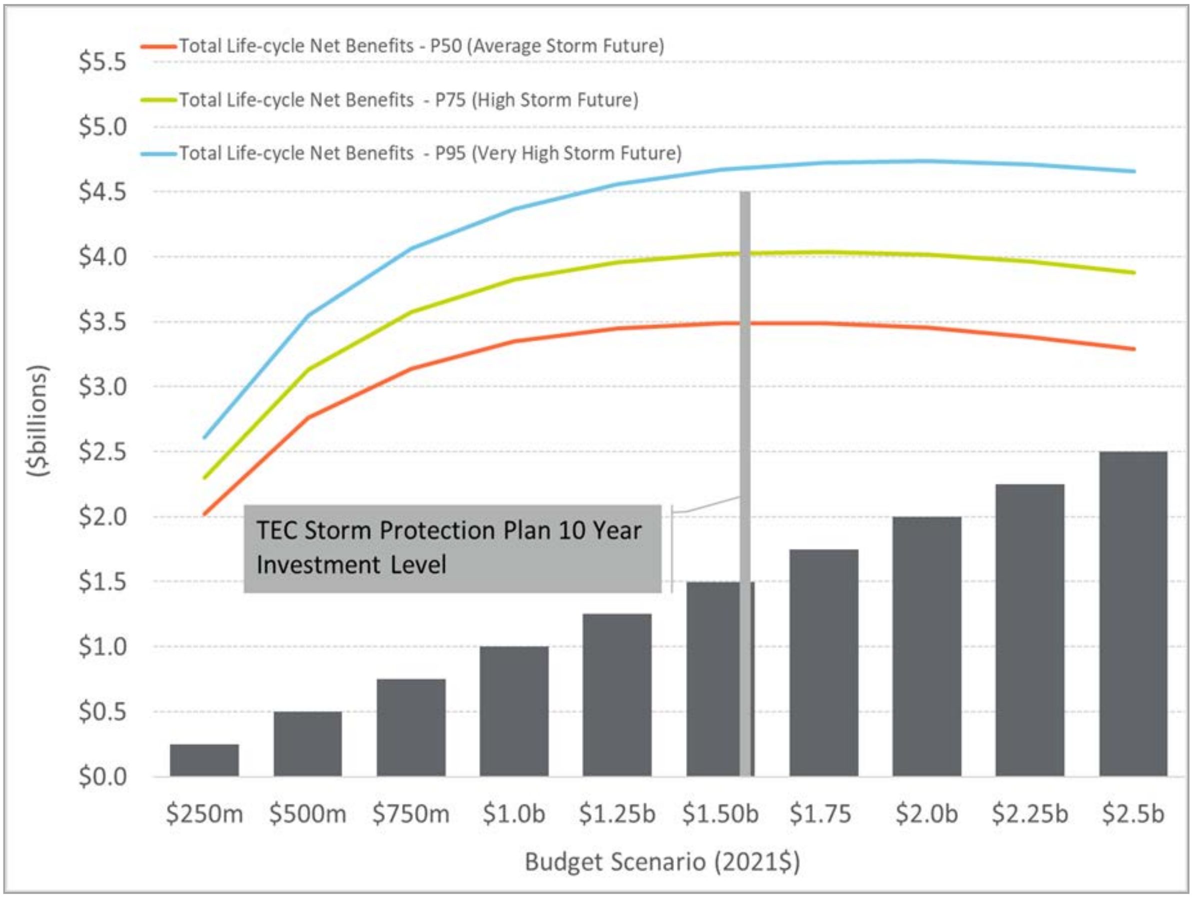
A44. The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment.

The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. For each budget level, the optimization model selects the projects with the highest benefit cost ratio to hardening in the next 10 years. The model then strategically groups projects by type of program and circuit. For instance, all the selected laterals on a circuit are scheduled for undergrounding in the same year. This allows Tampa Electric to gain capital deployment efficiencies by deploying resources to the same geographical area at one time.

Q45. What were the results of the budget optimization analysis?

A45. Figure 13 below shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 13: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.25 billion with the benefit level flattening from $1.25 billion to $1.75 billion and decreasing from $1.75 billion to $2.5 billion.

Q46. What conclusions can be made from the results of the budget optimization analysis?

A46. The budget optimization results show that Tampa Electric’s overall investment level is right before the point of diminishing returns showing that Tampa Electric’s plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

Q47. How was the overall investment level set and projects selected?

A47. Tampa Electric and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. 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 robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing Tampa Electric’s Storm Protection Plan project identification and schedule, the Tampa Electric 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 (i.e., project A before project B, project Y and project Z at the same time)

7. RESILIENCE BENEFIT RESULTS

Q48. What is the investment profile of the Storm Protection Plan?

A48. Table 5 below shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.59 billion. Distribution Lateral Undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Overhead Feeder Hardening is second, accounting for 20.0 percent. Transmission Asset Upgrades makes up approximately 8.8 percent of the total, with Substation Extreme Weather Hardening and Transmission Access Enhancement site access making up 1.7 percent and 2.0 percent, respectively.

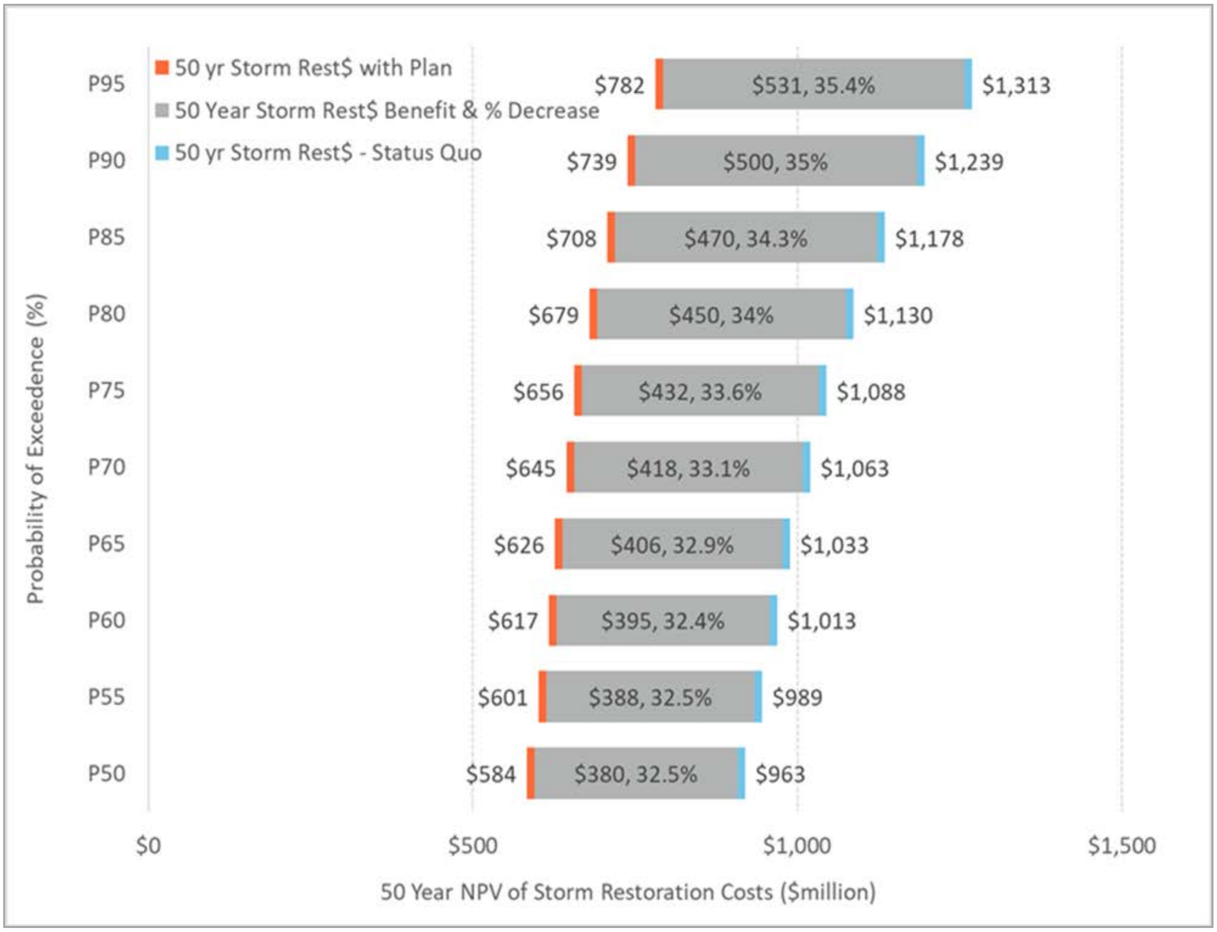
Table 5: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Distribution Lateral Undergrounding	Transmission Asset Upgrades	Substation Extreme Weather Hardening	Overhead Feeder Hardening	Transmission Access Enhancement	Total
2022	$105,600	$16,500	$0	$33,300	$2,400	$157,800
2023	$104,500	$17,500	$700	$29,900	$3,000	$155,600
2024	$105,700	$17,500	$4,300	$30,000	$3,000	$160,500
2025	$105,100	$17,900	$2,700	$30,000	$3,700	$159,400
2026	$105,000	$18,200	$3,300	$30,000	$3,400	$159,900
2027	$105,600	$16,900	$2,900	$30,000	$3,400	$158,800
2028	$105,600	$17,300	$4,800	$30,000	$3,100	$160,800
2029	$105,600	$17,200	$700	$30,000	$2,800	$156,300
2030	$115,400	$0	$7,200	$37,000	$2,000	$161,600
2031	$115,400	$0	$900	$37,000	$4,400	$157,700
Total	$1,073,500	$139,000	$27,500	$317,200	$31,200	$1,588,400

Q49. What are the restoration cost benefits of the plan?

A49. Figure 14 below shows the range in restoration cost reduction at various probability of exceedance levels. 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, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

Figure 14: Storm Protection Plan Restoration Cost Benefit

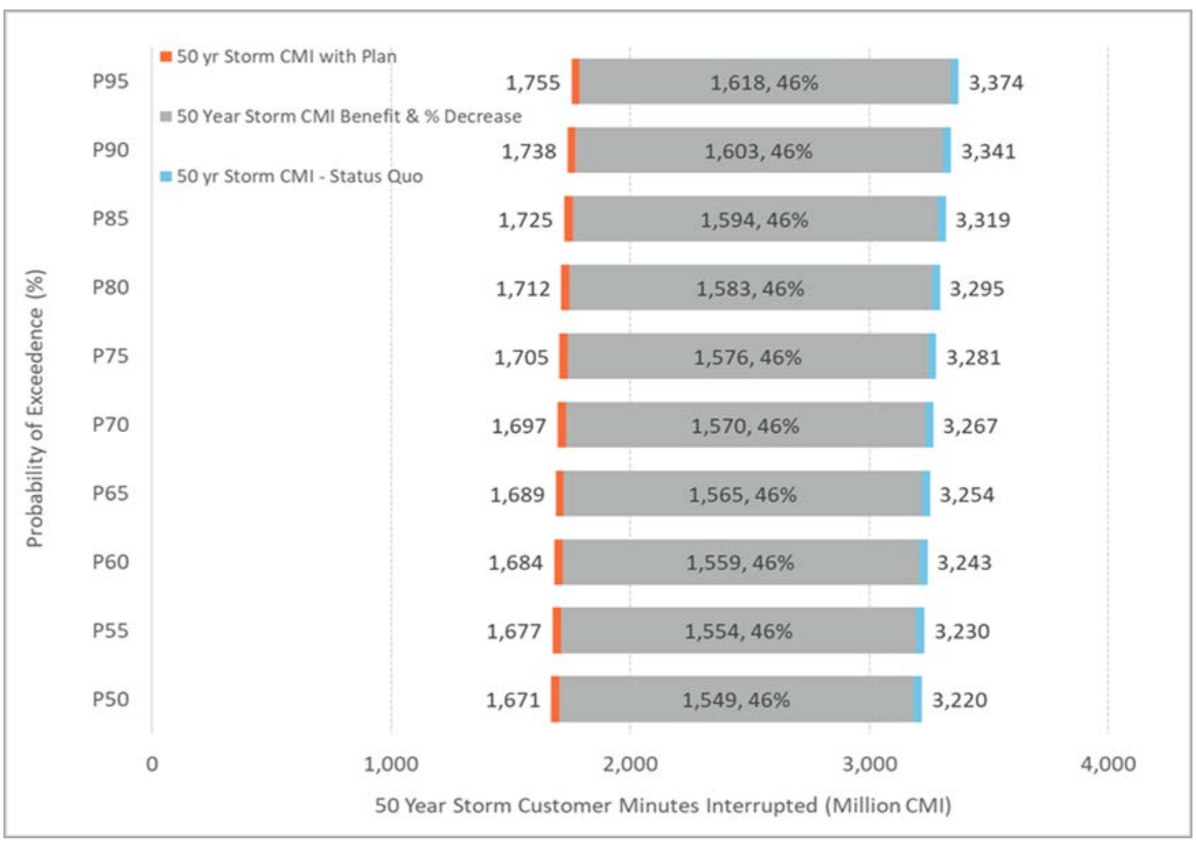


The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration costs decrease benefit is approximately 24 to 33 percent of the project costs.

Q50. What are the customer outage benefits of the plan?

A50. Figure 15 below shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 46 percent decrease in the storm CMI over the next 50 years.

Figure 15: Storm Protection Plan Customer Benefit



Q51. What are the key take-aways from how resilience-based

planning assessment was performed?

A51. The follow are the key take-aways from how the resilience-based planning assessment was performed in the Storm Resilience Model:

- **Customer and Asset Centric:** The model is foundationally customer and asset centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset weak links that serve customers shows that the Storm Resilience Model is directly aligned with the intent of the statute to identify hardening projects that provide the most benefit to customers. Additionally, with this customer and asset centric approach, the specific benefits required by the statute can be calculated, restoration cost saving and impact to customers in terms of CMI, more accurately.
- **Comprehensive:** The comprehensive nature of the assessment is best practice; by considering and evaluating nearly the entire T&D system the results of the hardening plan provide confidence that portions of Tampa Electric's system are not

overlooked for potential resilience benefit.

- **Consistency:** The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits calculation between asset types. For example, the model can compare a substation hardening project to a lateral undergrounding project. This is a significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this capability, the assessment would not have been able to identify a point of diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis for the entire plan.
- **Rooted in Cause of Failure:** The Storm Resilience Model is rooted in the causes of asset and system failure from two perspectives. Firstly, the Major Storms Event Database outlines the range of storm stressors and the high level impact to the system. Secondly, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail, mainly vegetation density, asset condition, wind zone, and flood modeling. With this basis, hardening investment identification and prioritization provides a robust assessment to focus

investment on the portions of the system that are more likely to fail in the major storm.

- **Drives Prudency:** The assessment and modeling approach drive prudency for the Storm Protection Plan on two main levels. Firstly, the granularity of potential hardening projects, over 20,000, allows Tampa Electric to invest in the portions of the system that provide the model value to customers. Without granularity, there is risk that parts of the system "ride the coat-tails" of needed investment causing efficient allocation of limited capital resources. Secondly, the budget optimization allows for the identification of the point of diminishing returns so that over investment in storm hardening is less likely.
- **Balanced:** Hardening projects include mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows Tampa Electric to provide a higher level of system resilience for customers.

Q52. What conclusions can be made from the results of the resilience analysis?

A52. The following include the conclusions of Tampa Electric's

Storm Protection Plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.59 billion for Tampa Electric's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 13) shows the investment level is right before the point of diminishing returns.
- Tampa Electric's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 46 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to

pay’ customer surveys.

- Tampa Electric’s mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact/low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional ‘blue sky’ benefits to customers not factored into this report.

8. CONCLUSION

Q53. Does this conclude your prepared verified direct testimony?

A53. Yes.