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

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 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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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

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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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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 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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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

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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 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'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

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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-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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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

TECO ENERGY
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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

[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.

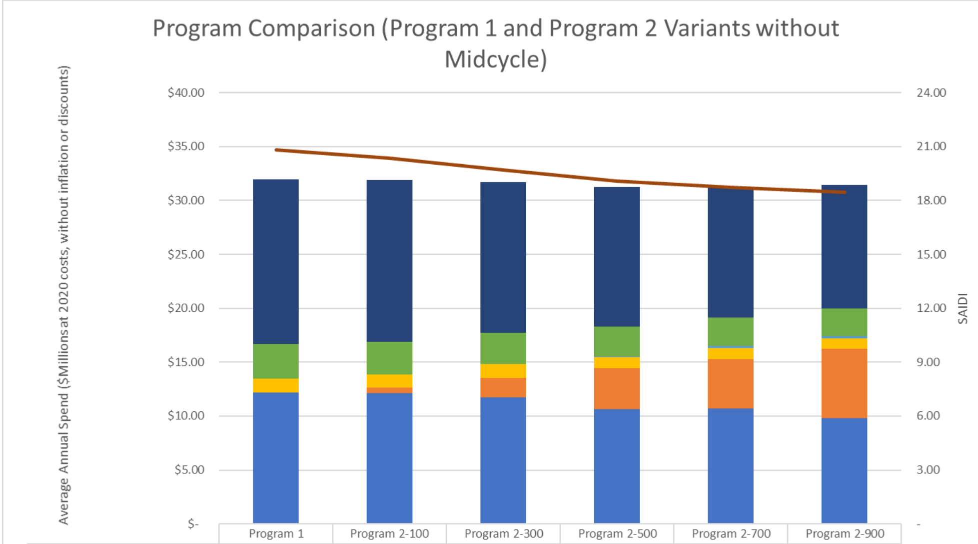
In the baseline scenario, each service area is allotted one quarter of its mileage every year, or approximately 1,562 miles in total. Central, for example, accounts for one sixth of TECO's overhead miles, and is afforded one sixth of the annual 1,562-mile budget as depicted below.

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.

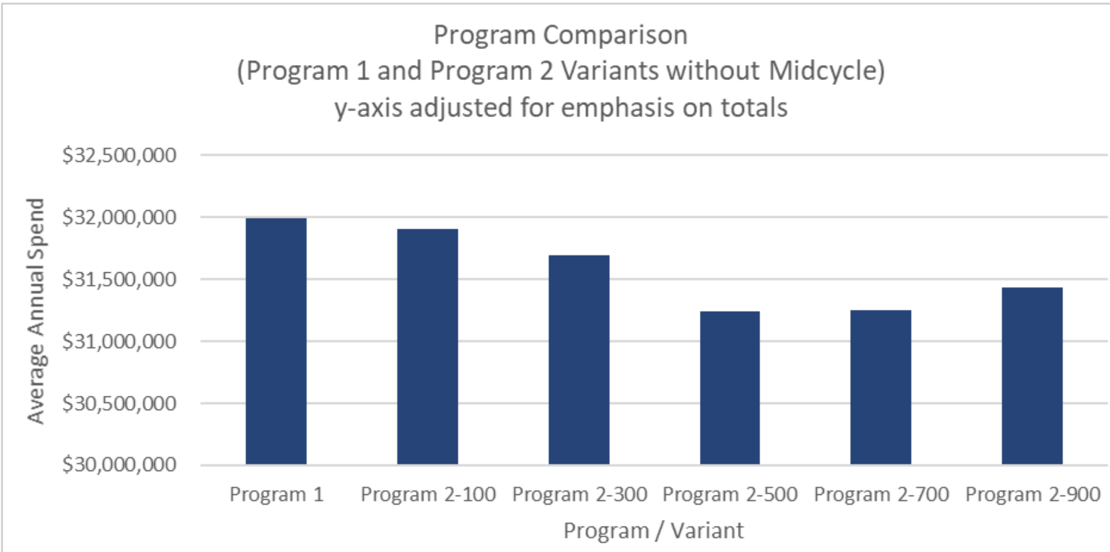


Figure 4-2: Program Comparison with Focus on Total Average Annual Spend

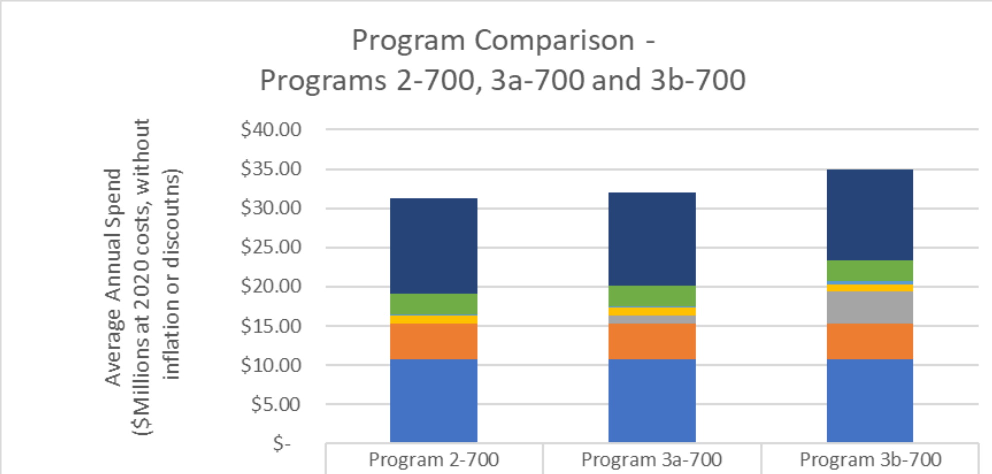
- While the 500 mile and 700-mile programs are in a virtual tie from an overall cost perspective, there is a clear advantage to the 700-mile program from the customer experience perspective. The 700-mile program drives 16 percent and 21 percent improvements in the ten-year average day-to-day and storm 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

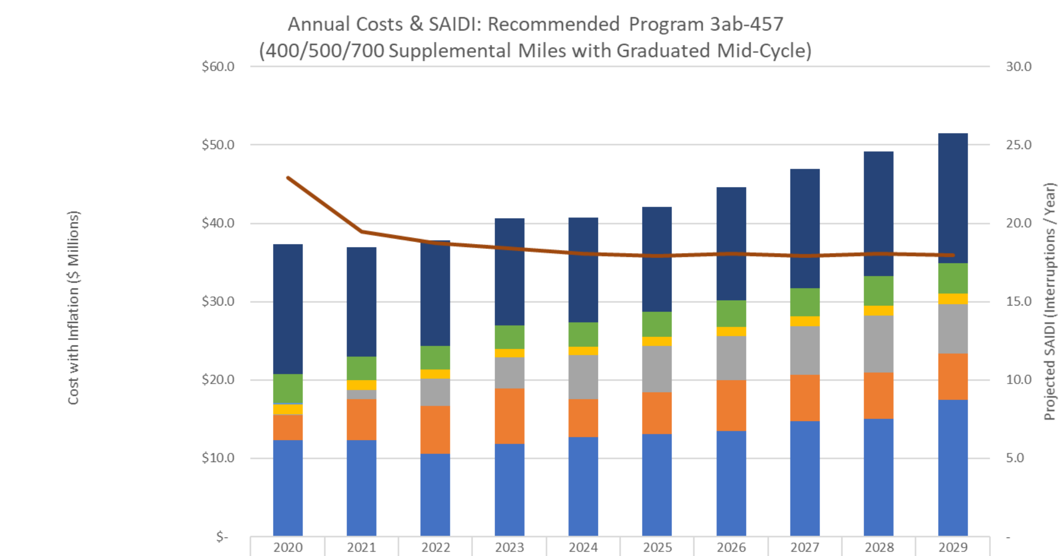
3a-700 and 3b-700 exacerbate the resource crunch. While the average annual VM budget (without inflation) for Program 2-700 (Baseline + 700 supplemental miles) is estimated at $16.4M and would require an average of 220 resources to execute, the first year VM budget would be $19.0M and require roughly 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.

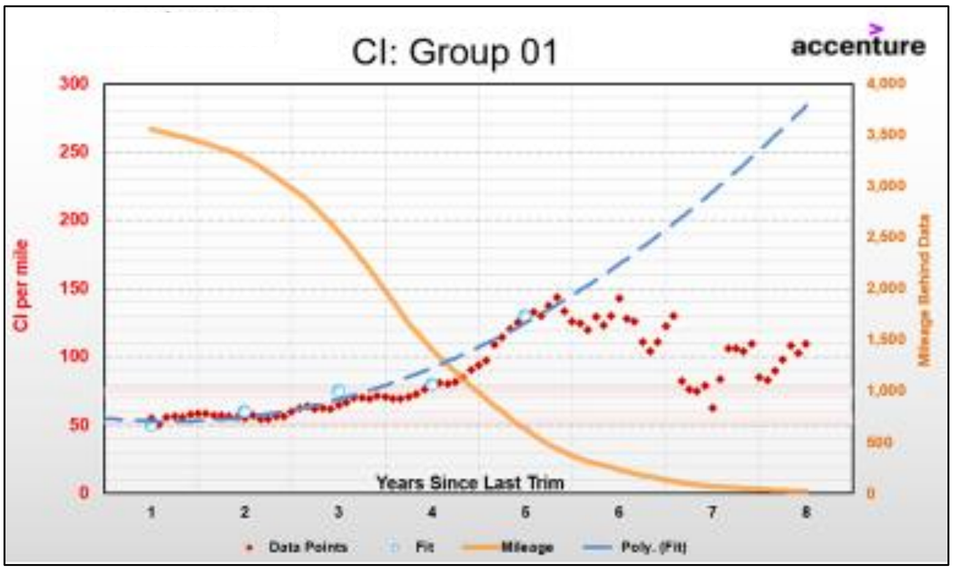


Figure 6-1: Example of Curve Fitting Analysis

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.

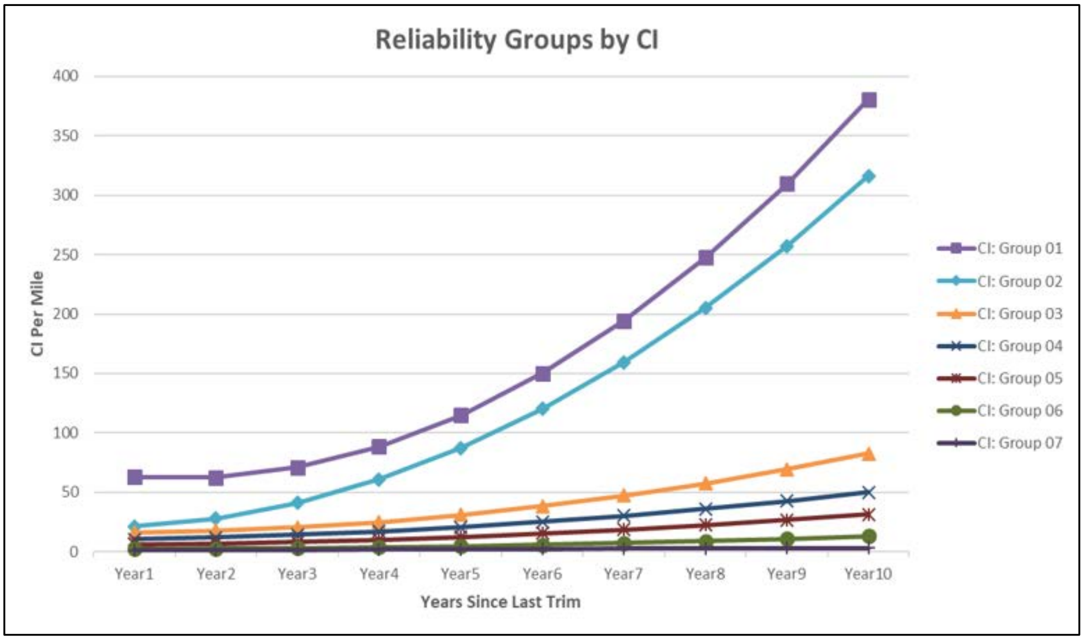


Figure 6-2: Customer Interruption (CI) Curve Groups

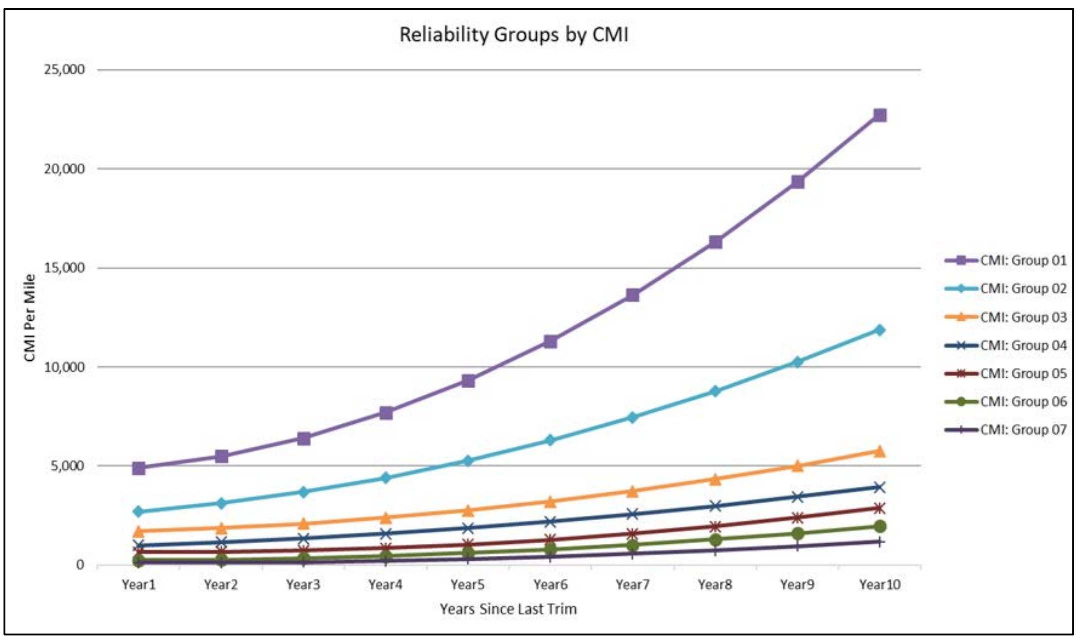


Figure 6-3: Customer Minute Interruption (CMI) Curve Groups

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.

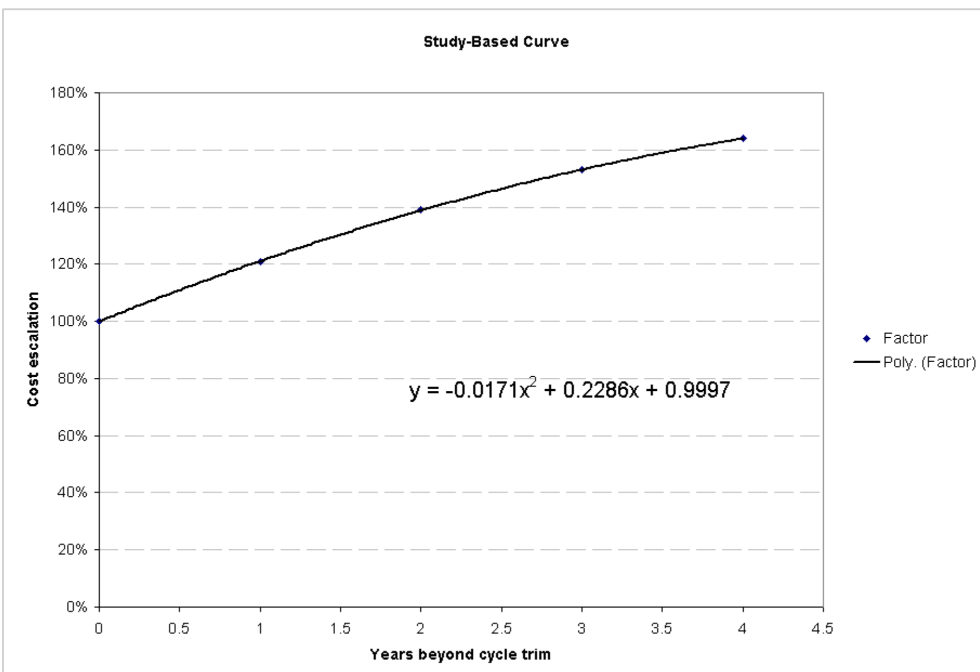


Figure 6-4: ECI Study-Based Cost Curve

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:

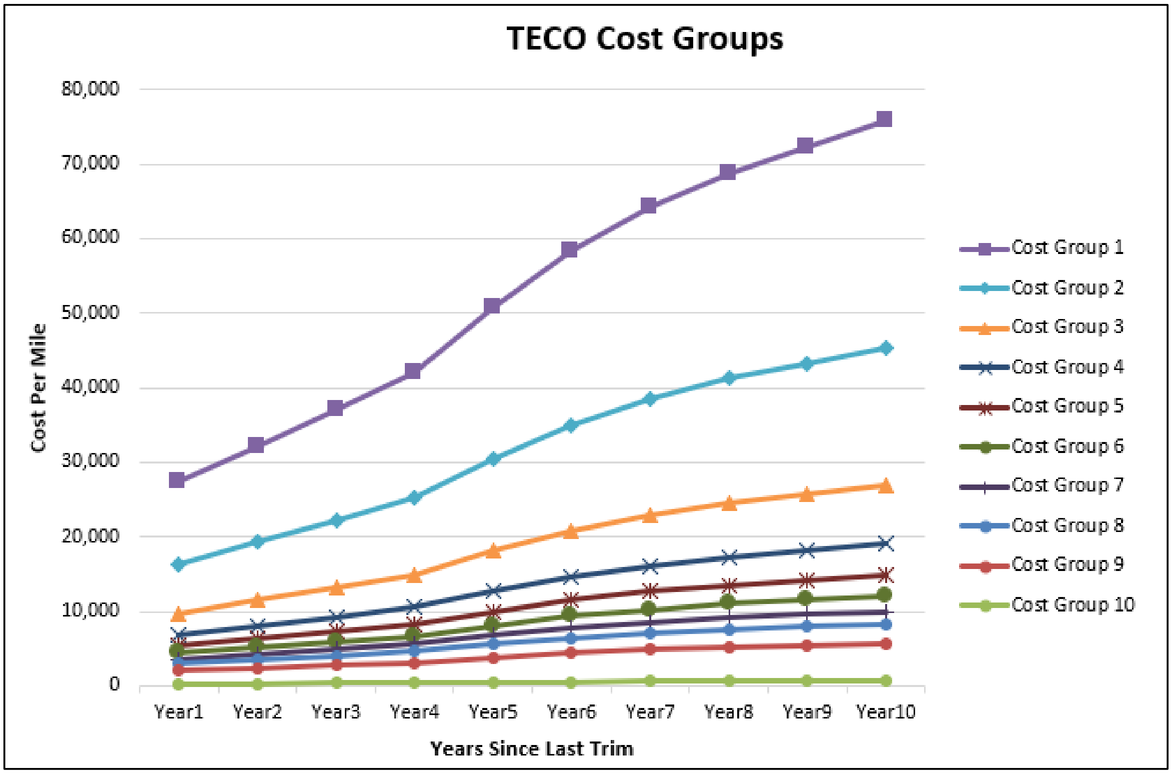


Figure 6-5: Cost Groups

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%	2.13%	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.

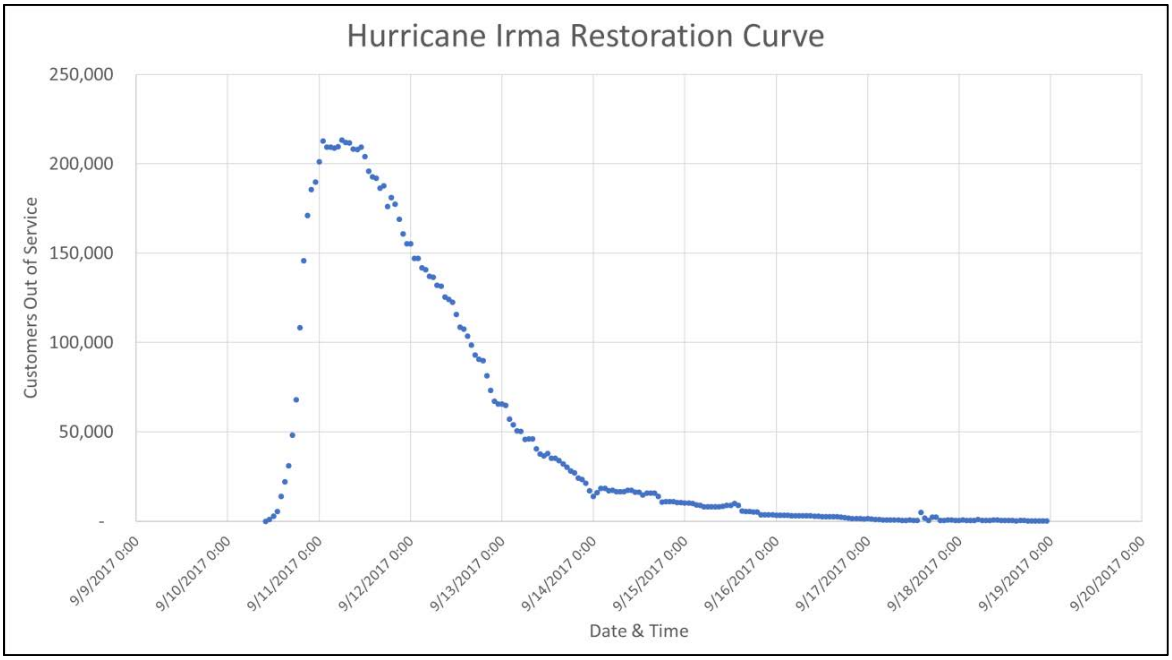


Figure 6-7: TECO Restoration Curve for Hurricane Irma

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 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.

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%

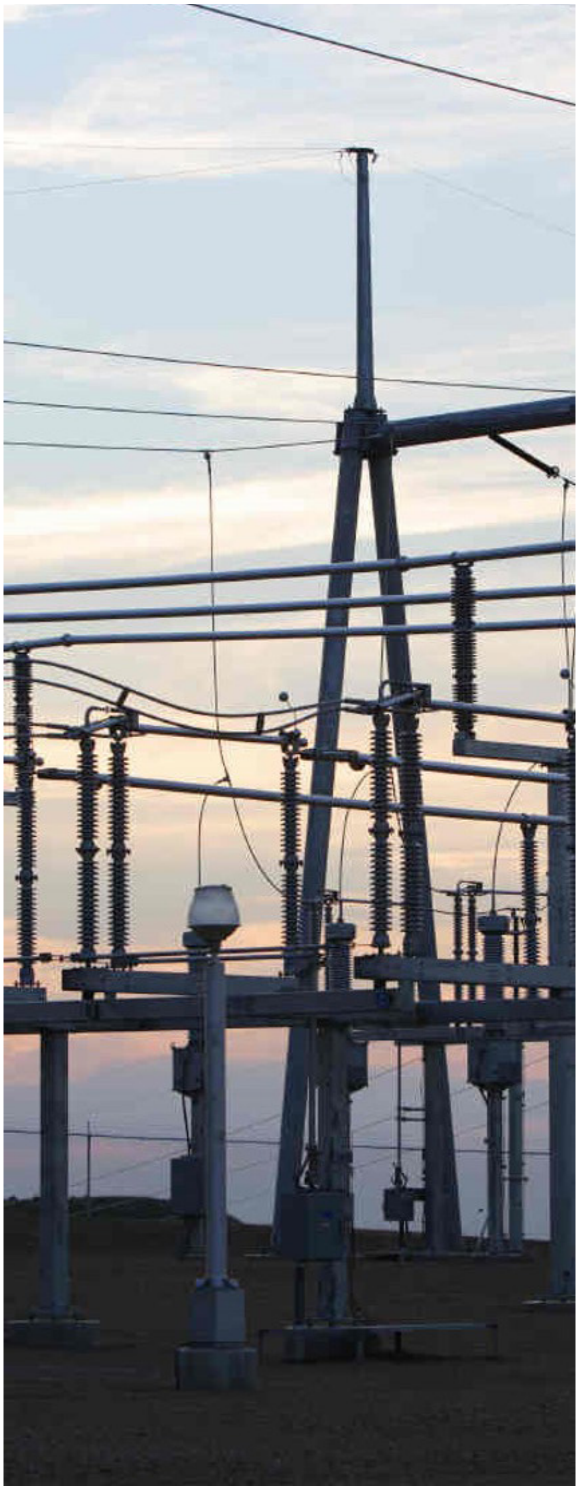
Environmental – weighted at 10% of overall score

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.

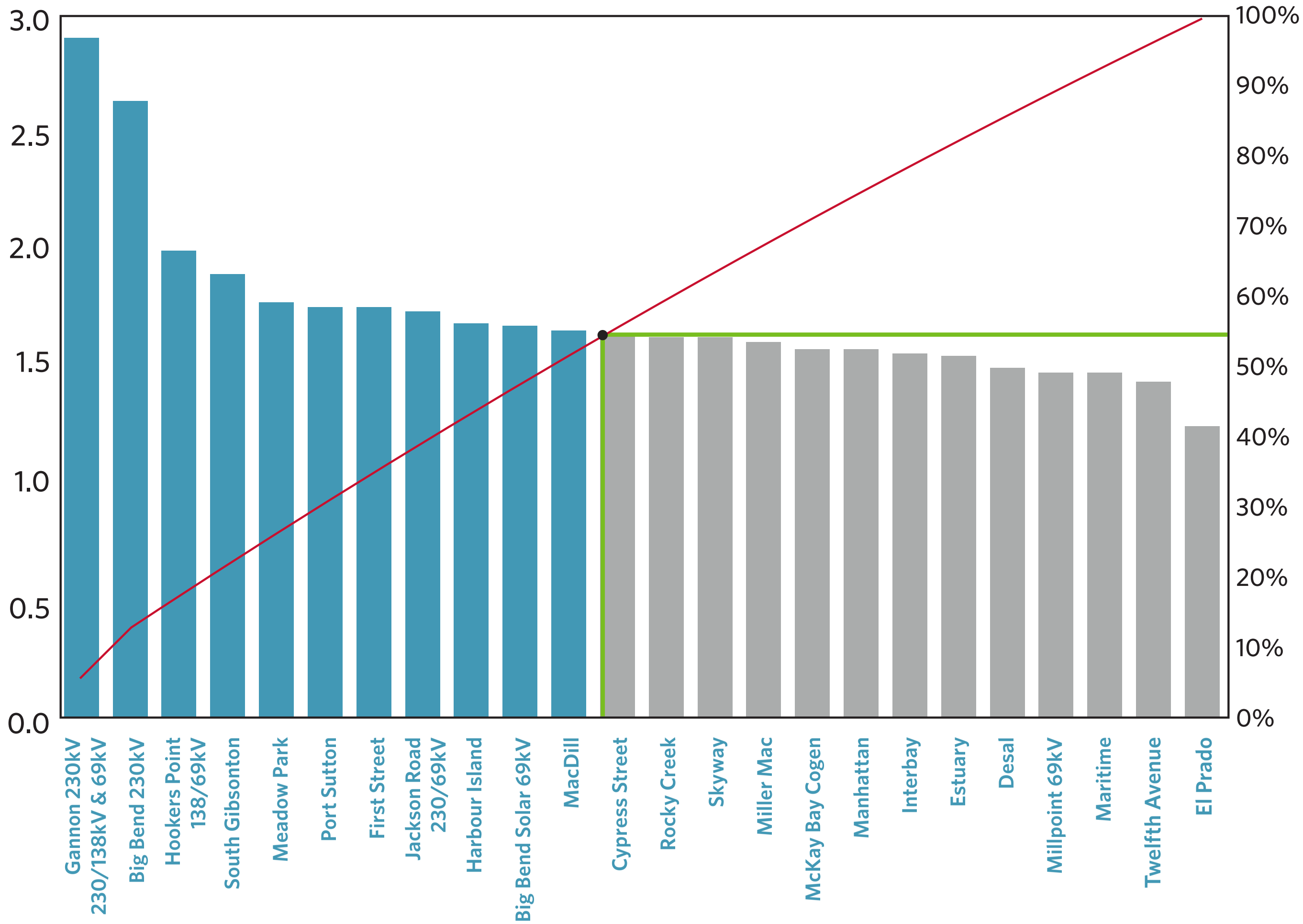
As the substation hardening projects were developed, budgetary cost estimates were created for each. These costs were turnkey – including equipment, construction, testing and commissioning. These costs were then used in a cost benefit analysis to justify the hardening project and its effectiveness in 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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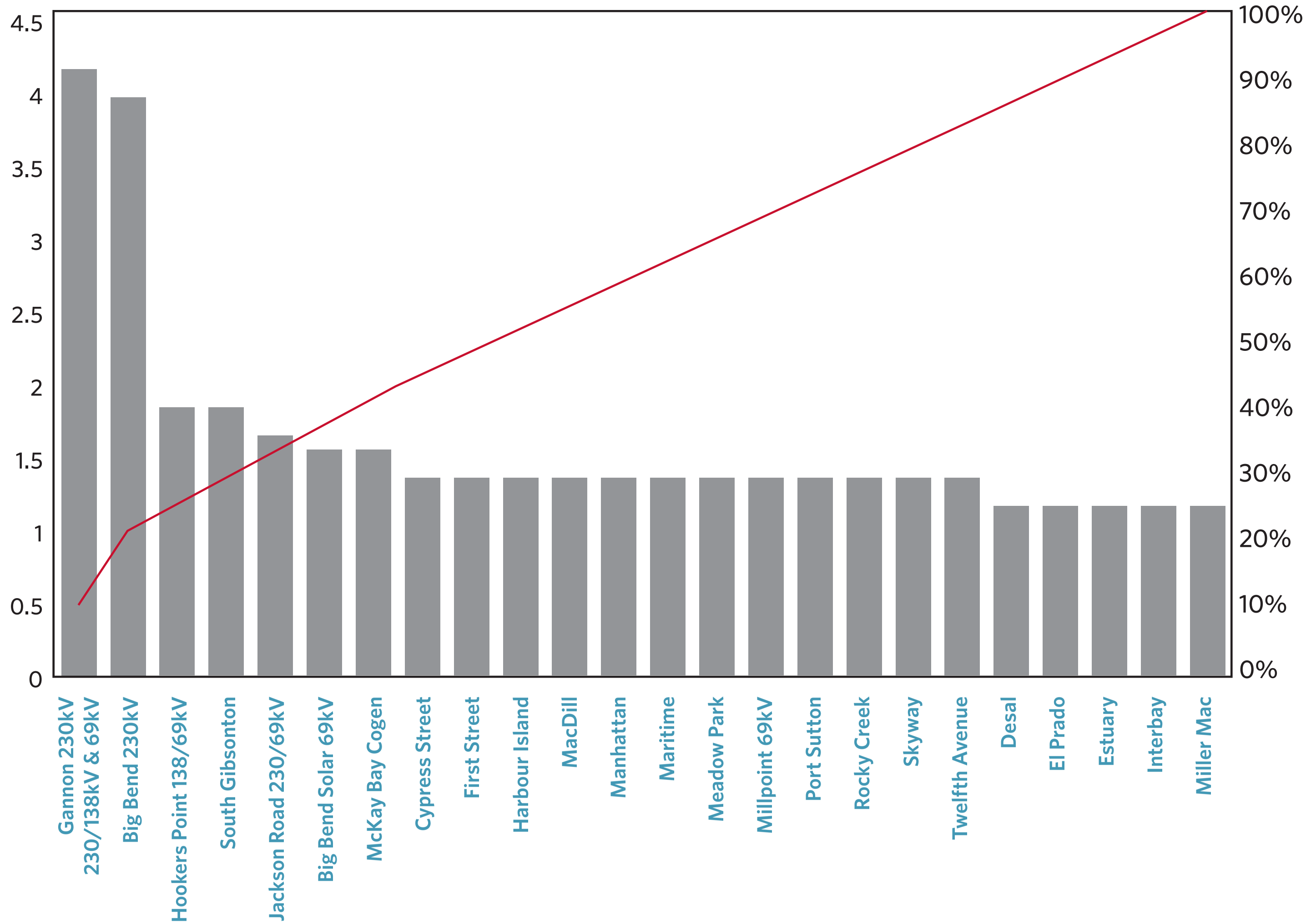
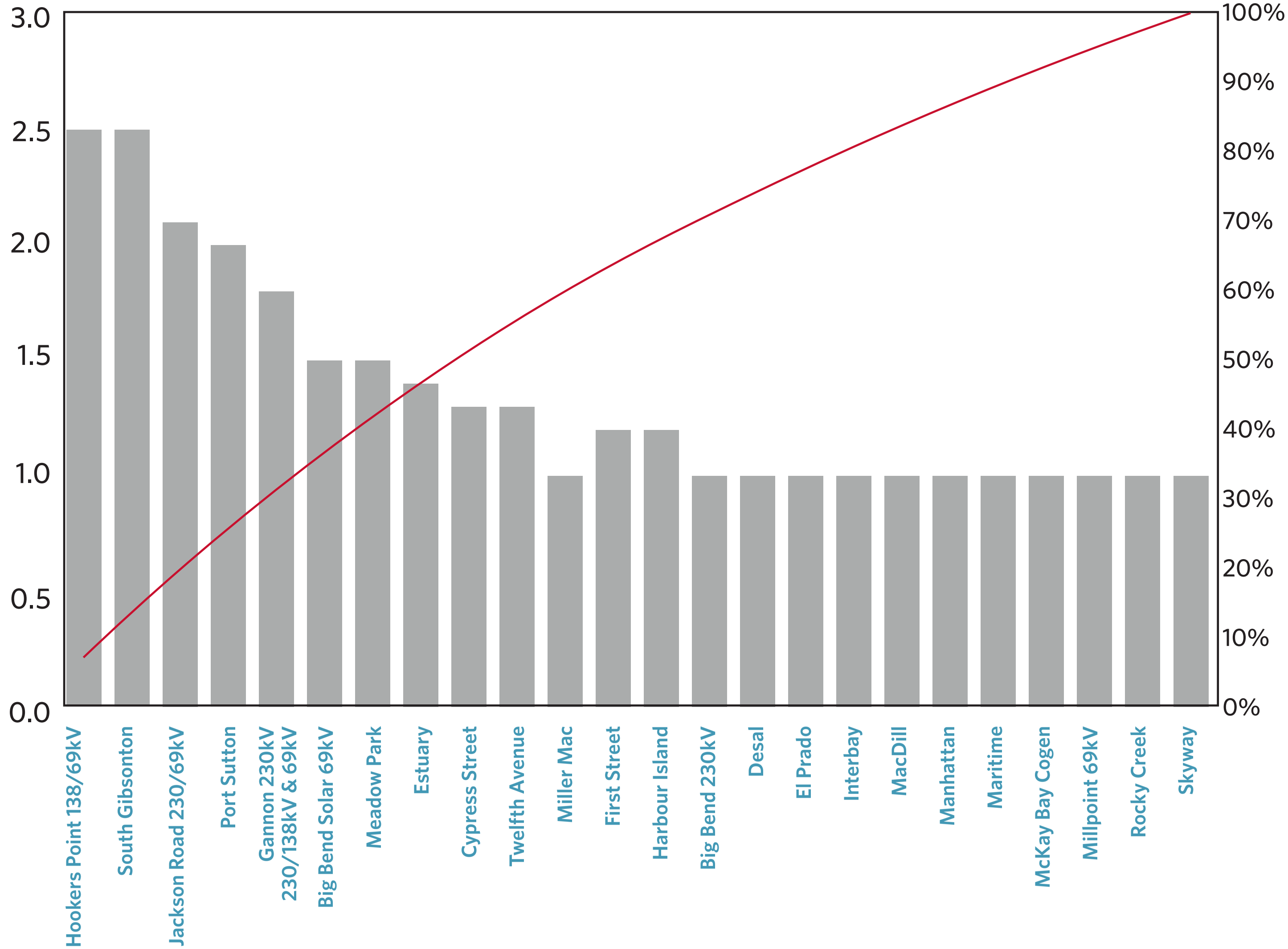
3.2 GRID STABILITY/CAPACITY

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



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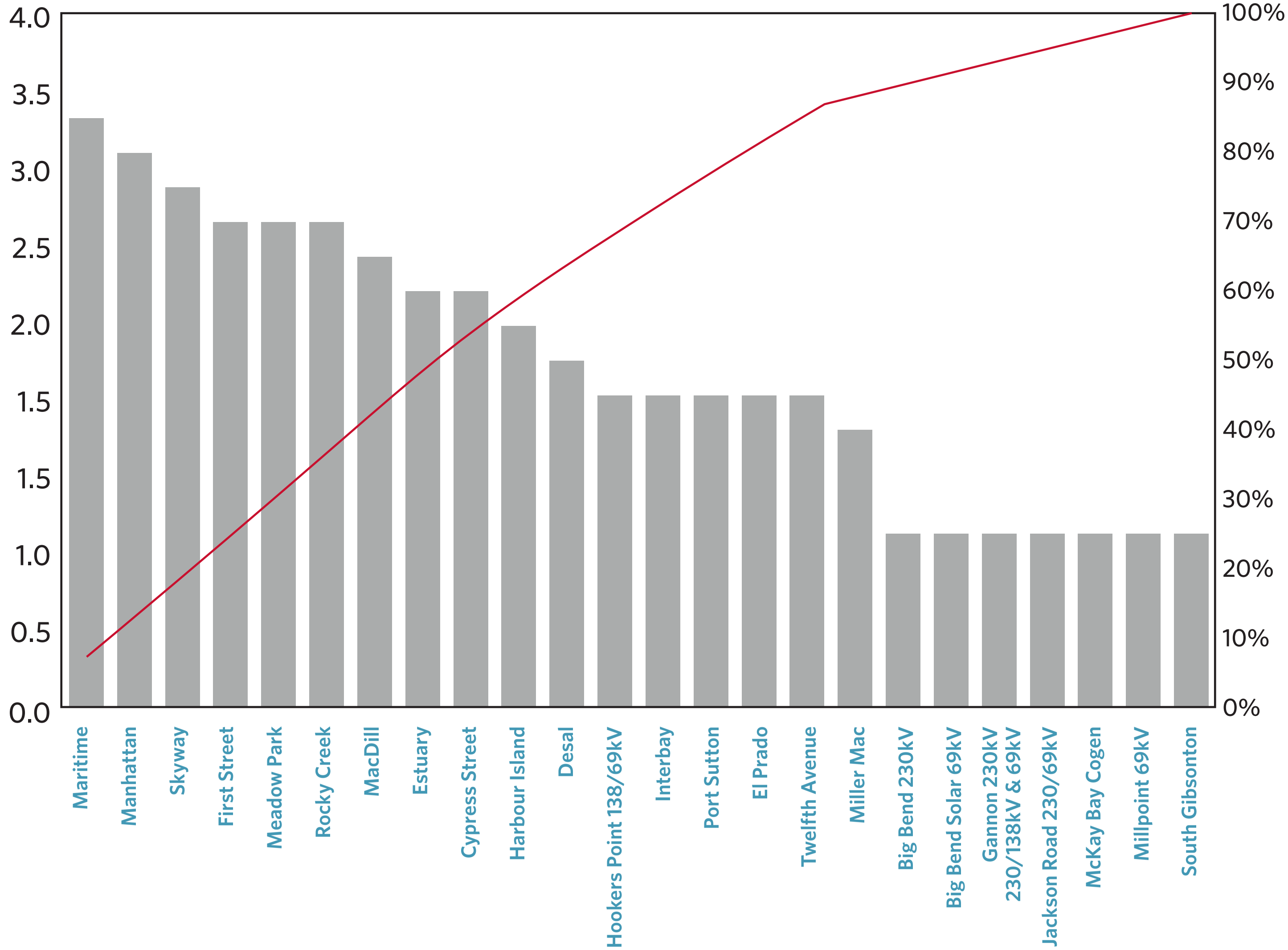
3.4 CUSTOMER SERVICE



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3.5 COST


100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
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
2.5
2.0
1.5
1.0
0.5
0.0

3.6 SAFETY

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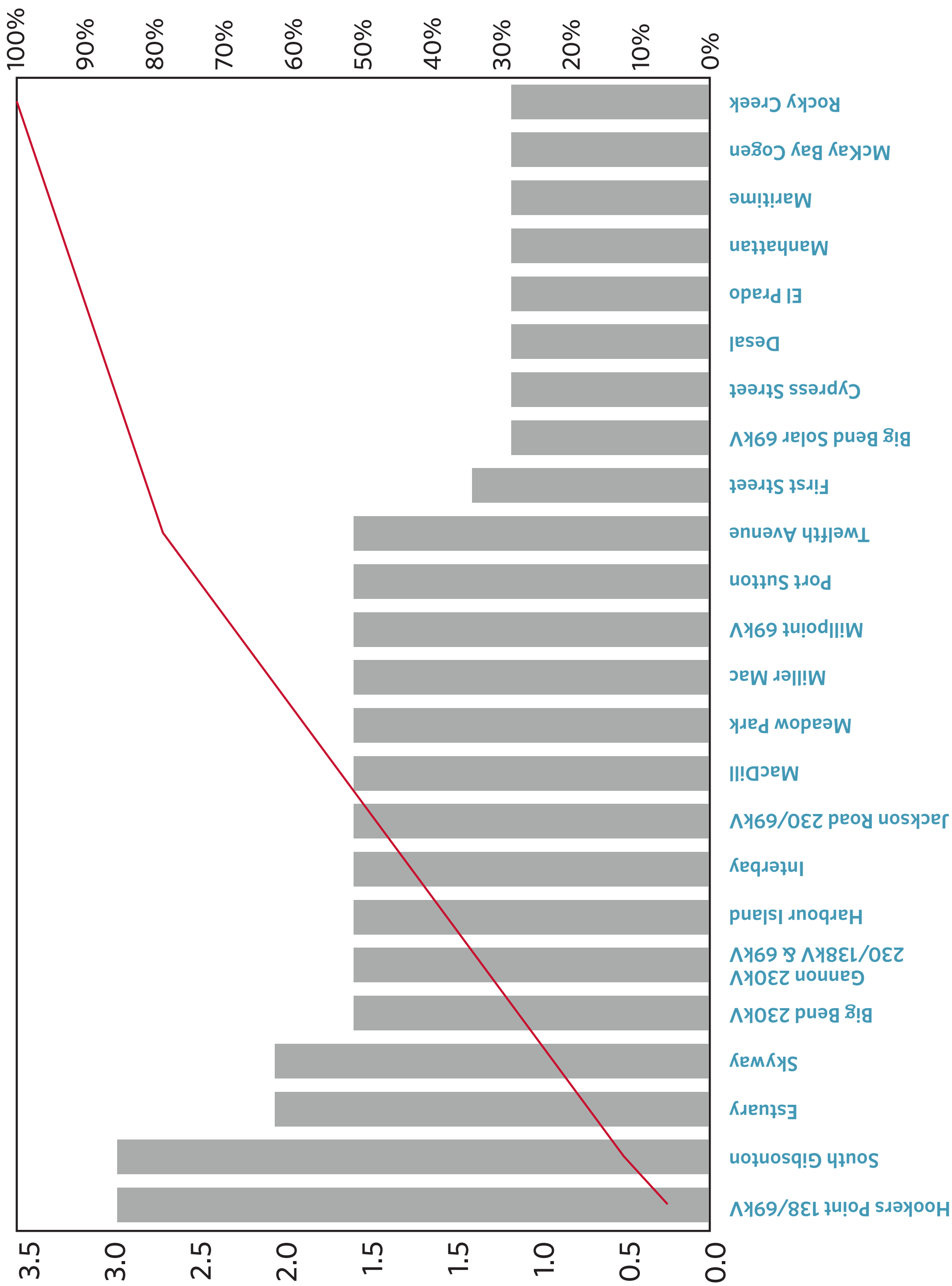
3.7 ENVIRONMENTAL



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**

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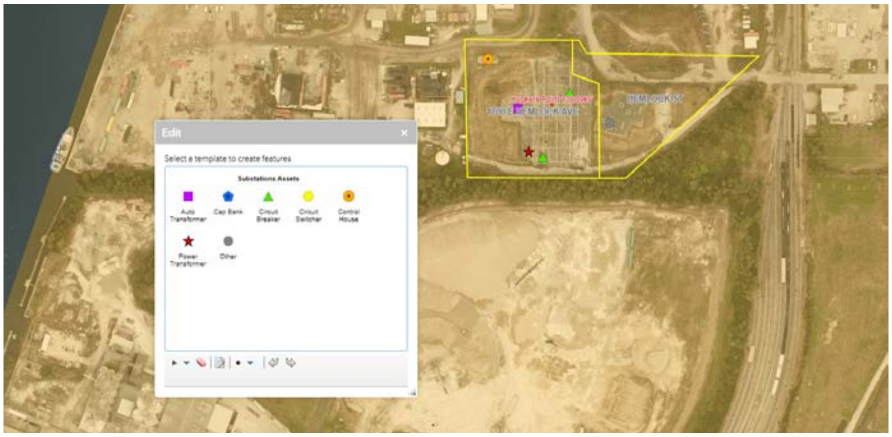


4.1 PROJECT 1

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

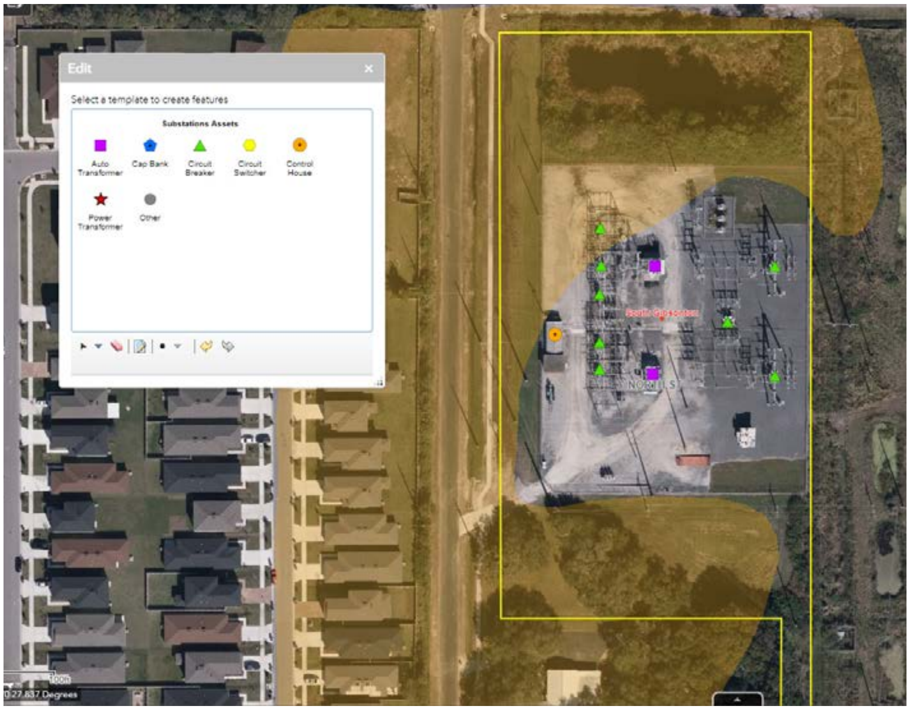
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Hookers Point project.

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

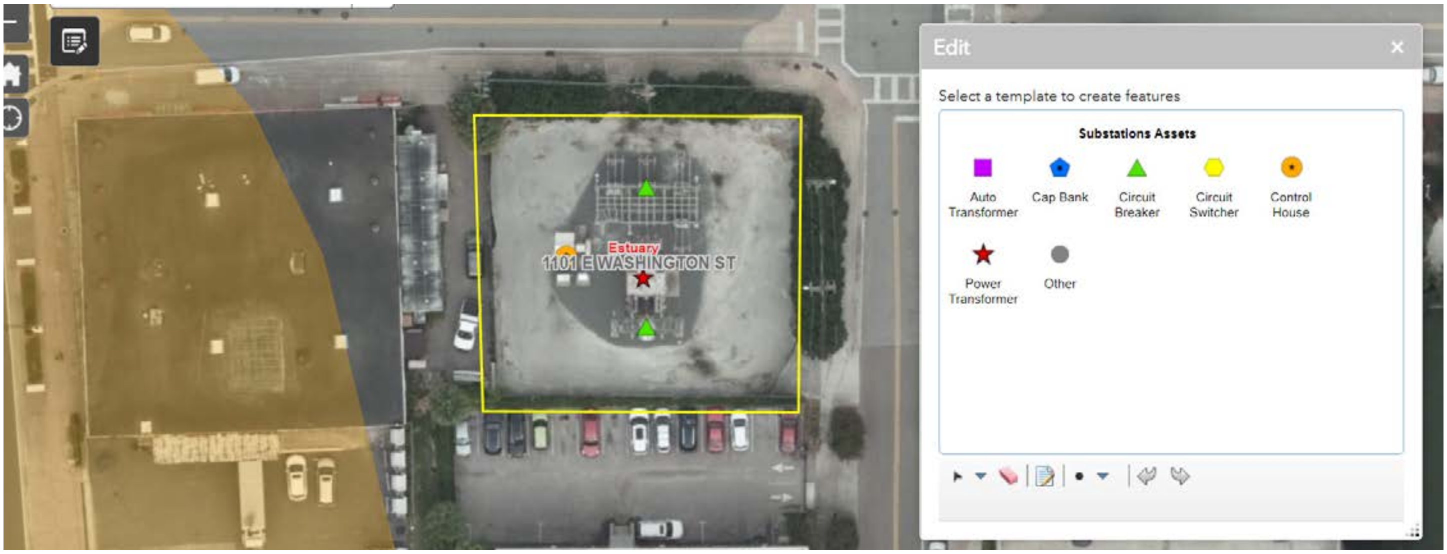
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Jackson Rd project.

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 SPPC 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

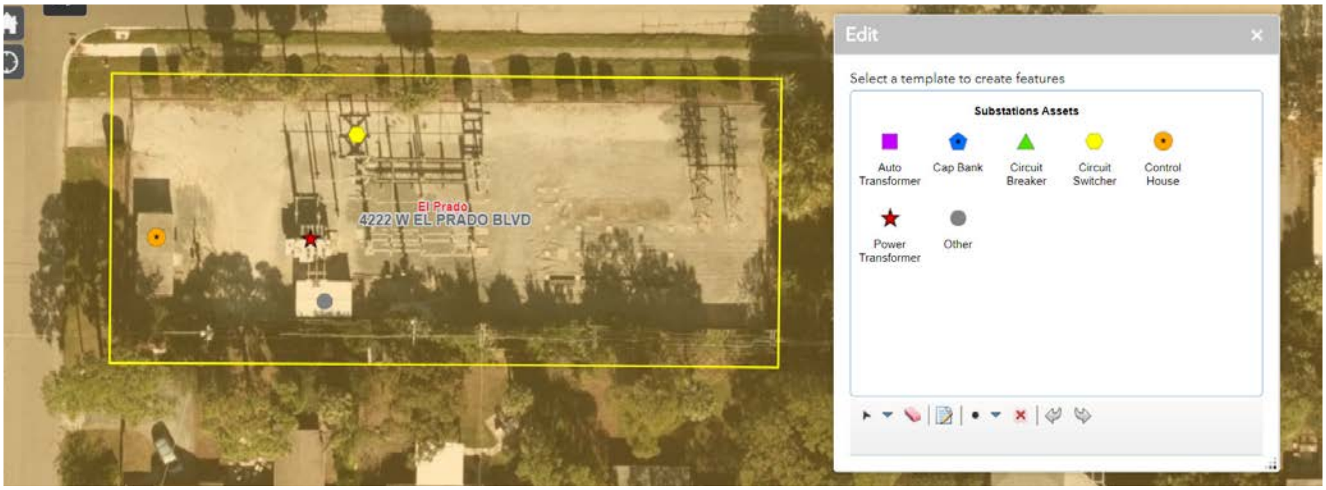
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Estuary project.

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

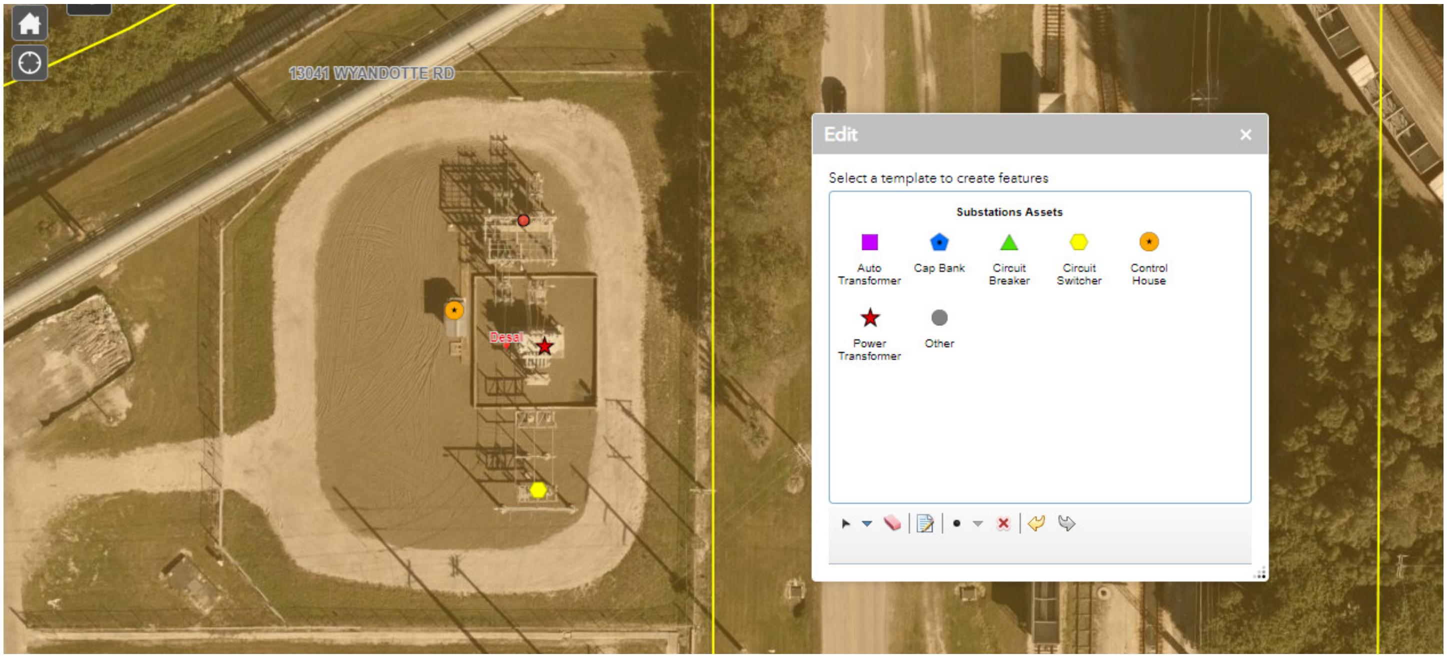
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Skyway project.

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.

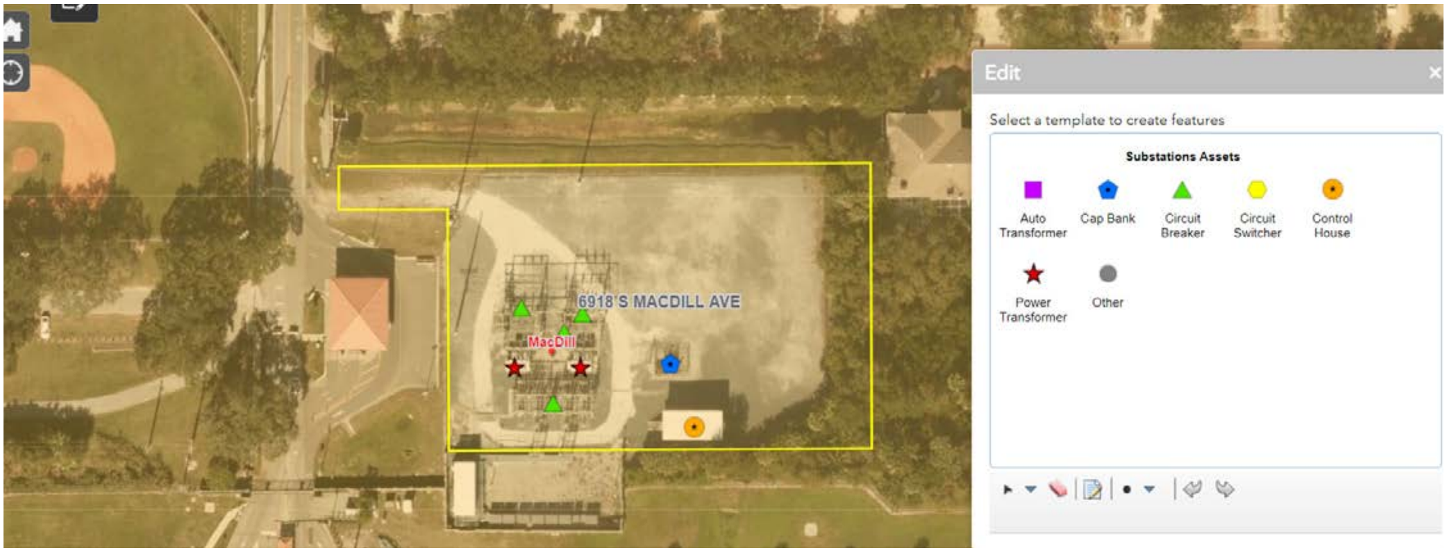
This substation project would increase the reliability of service to the Big Bend area during a storm surge event that brings flooding to the area.

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

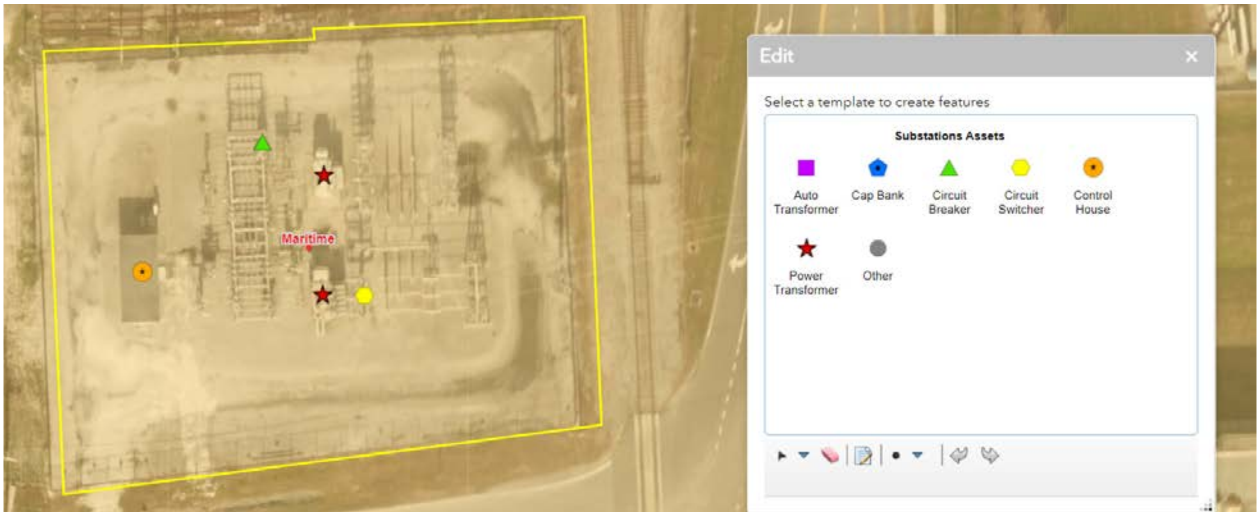
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the MacDill project.

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

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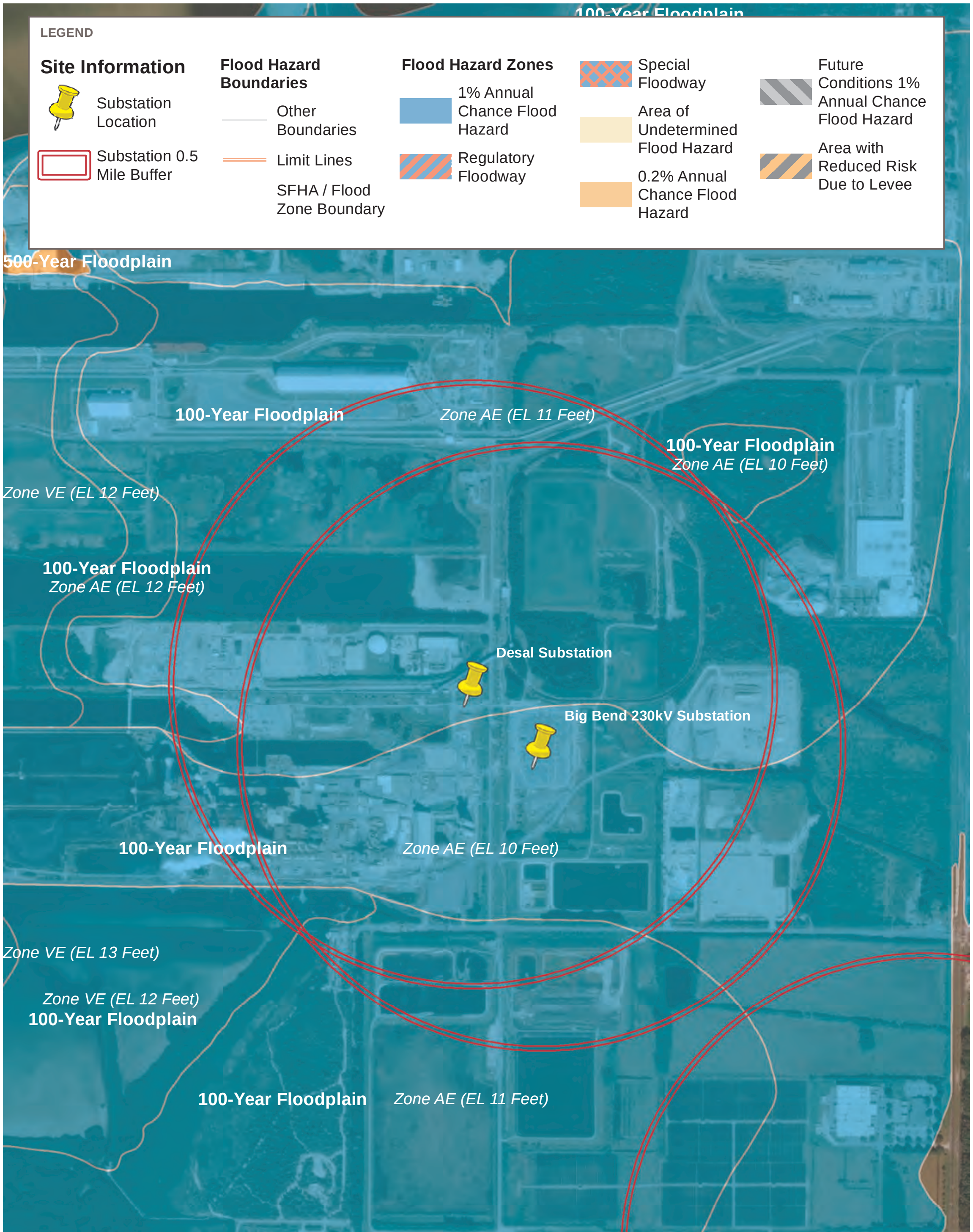

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BIG BEND 230KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 1)

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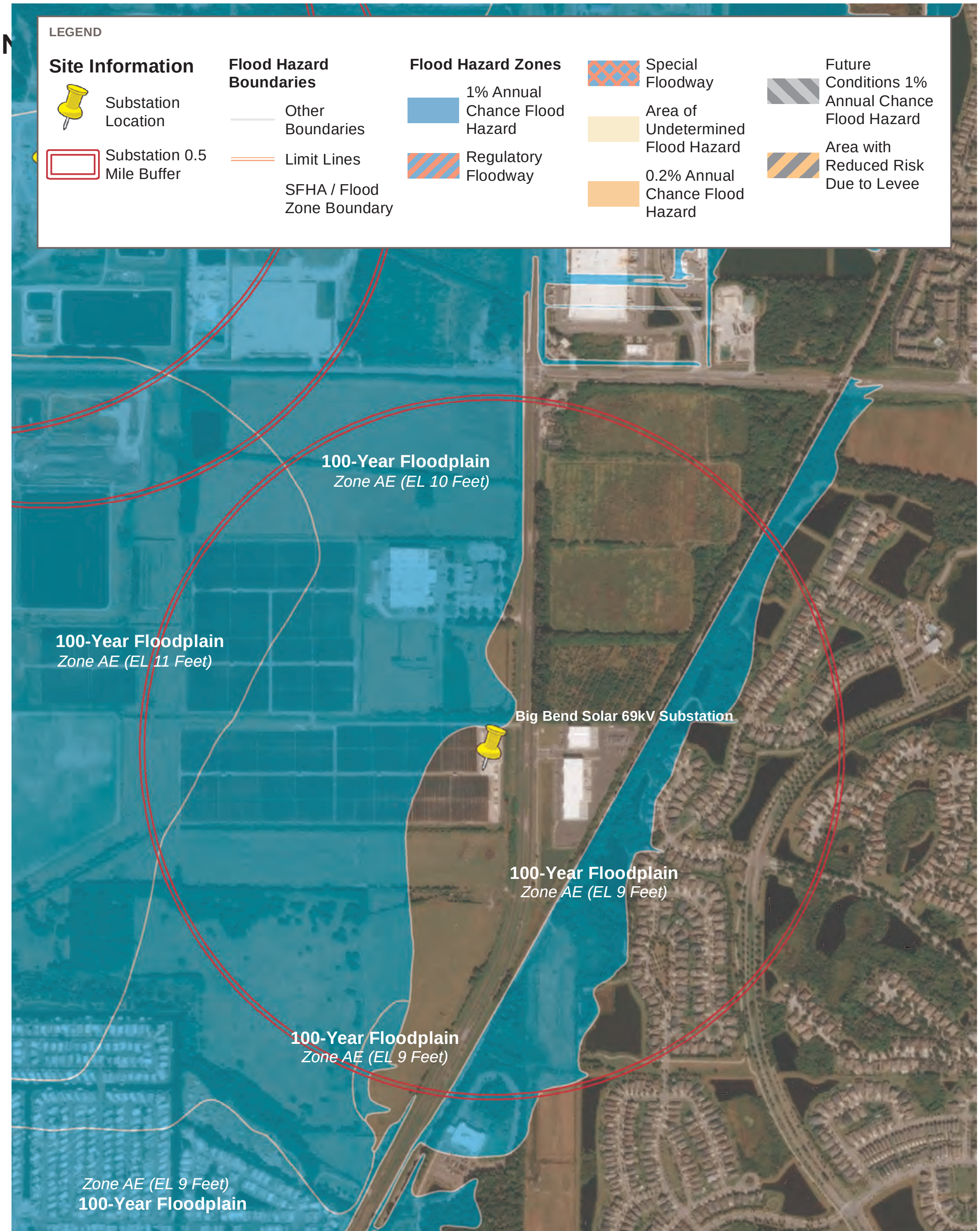

BIG BEND SOLAR 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 2)

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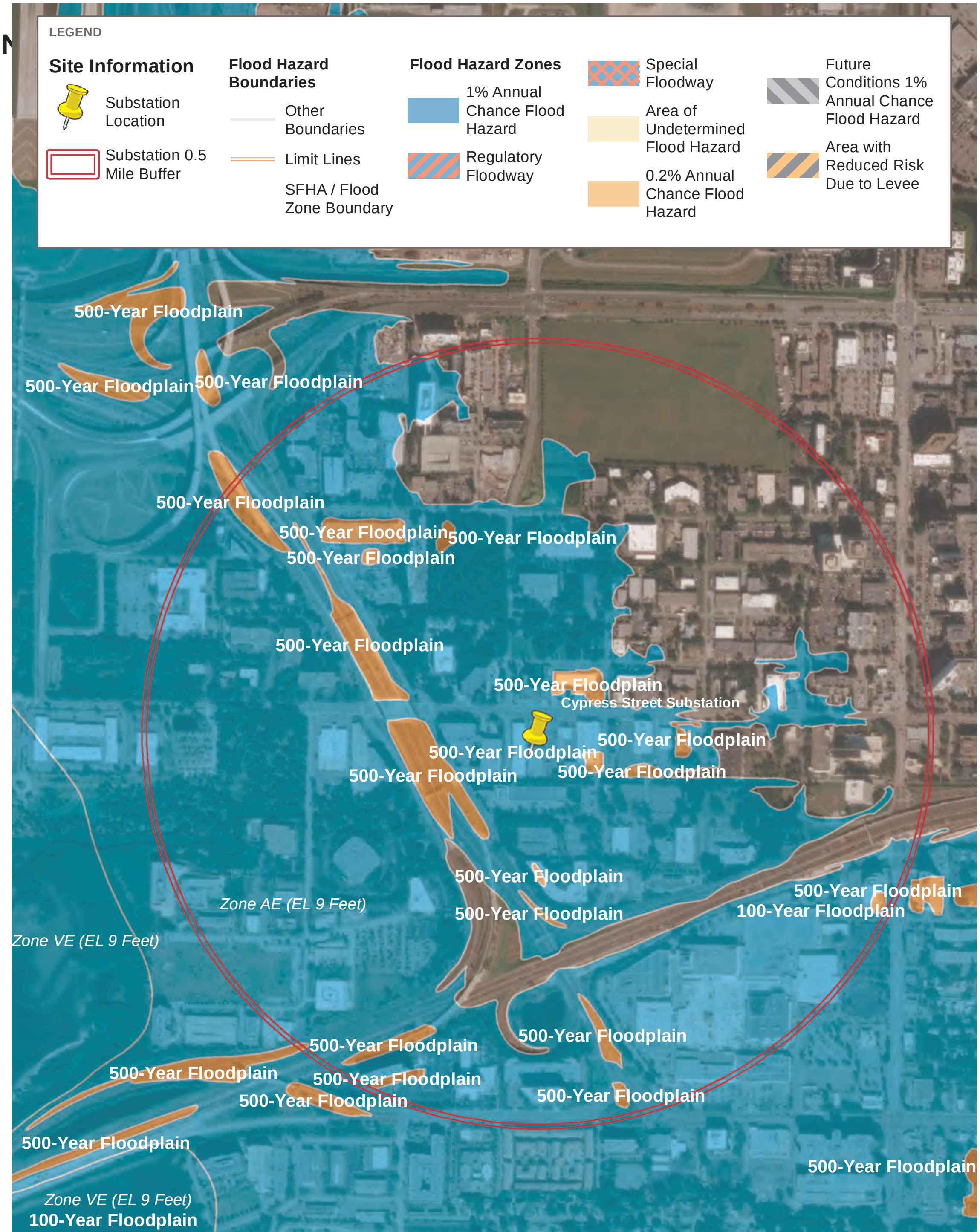

CYPRESS STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 3)

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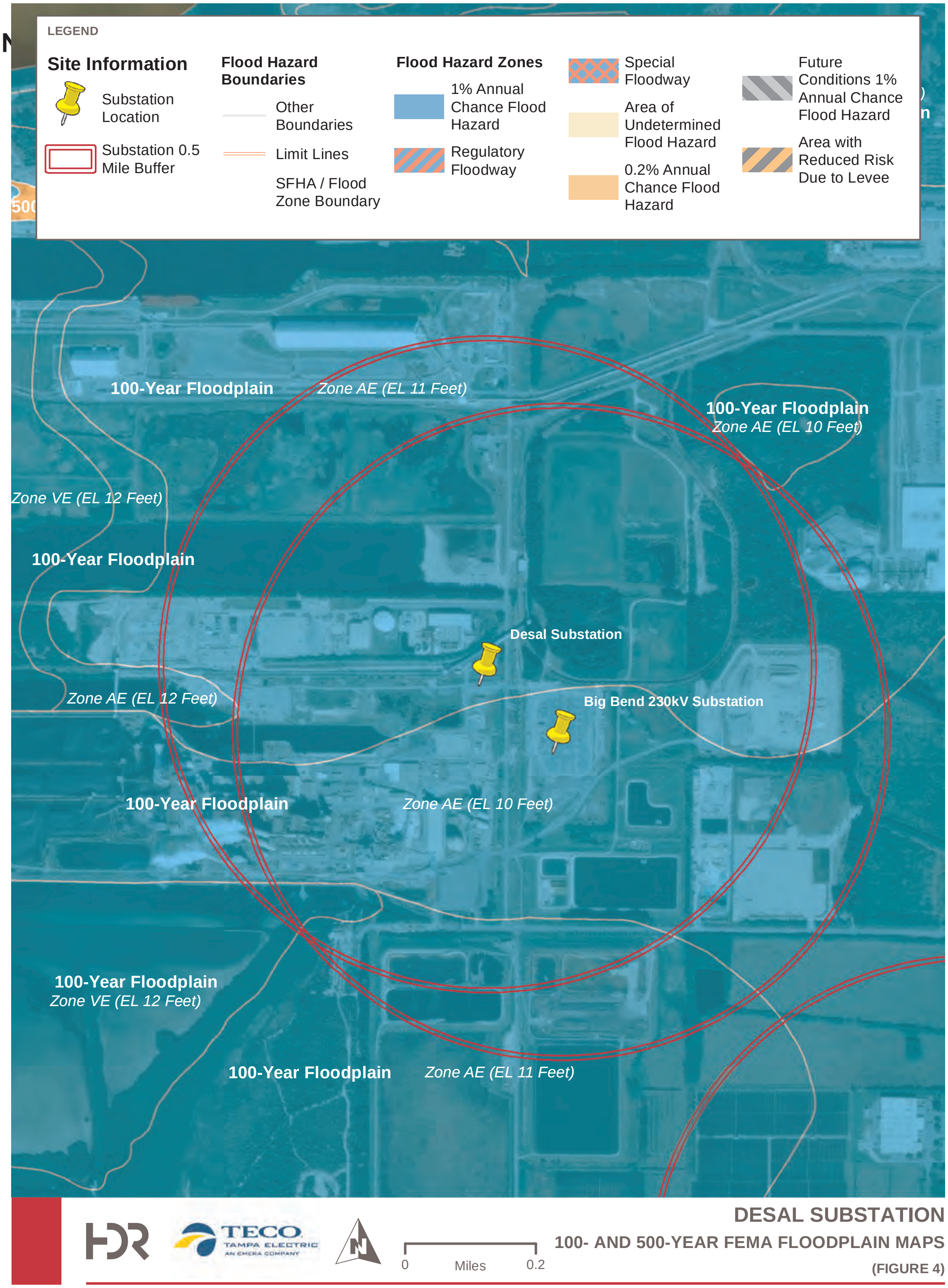

DESAL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 4)

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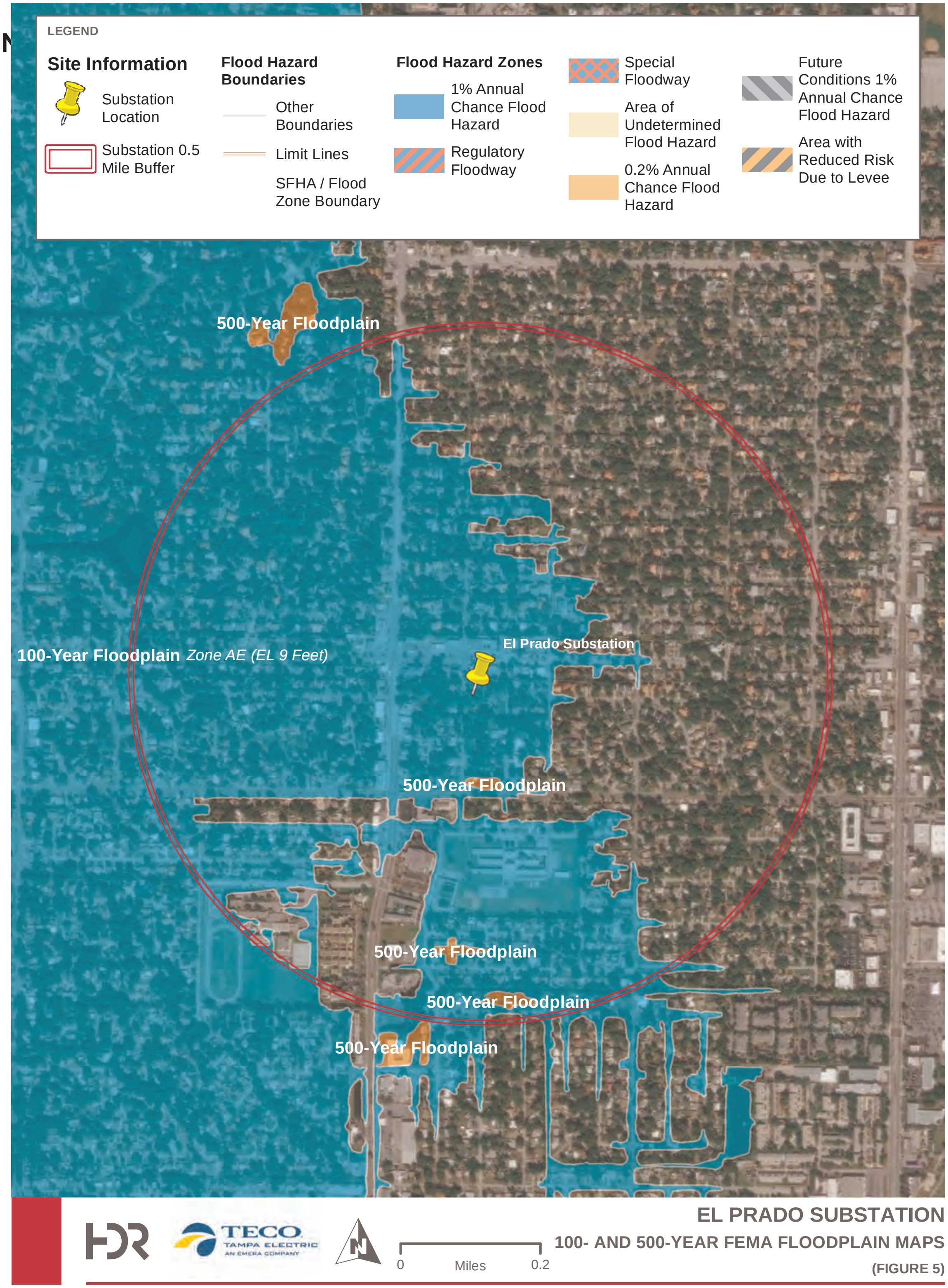

EL PRADO SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 5)

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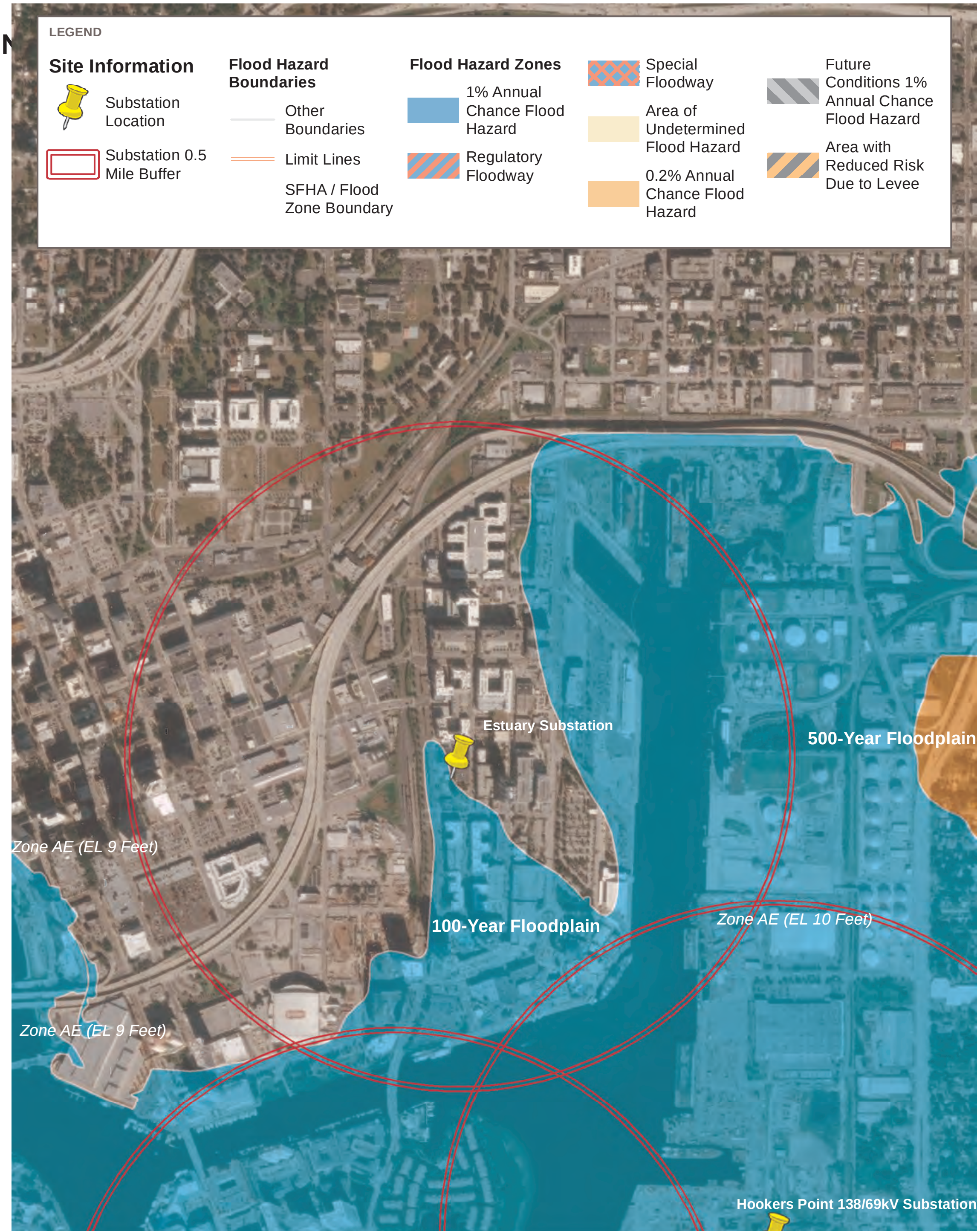

ESTUARY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 6)

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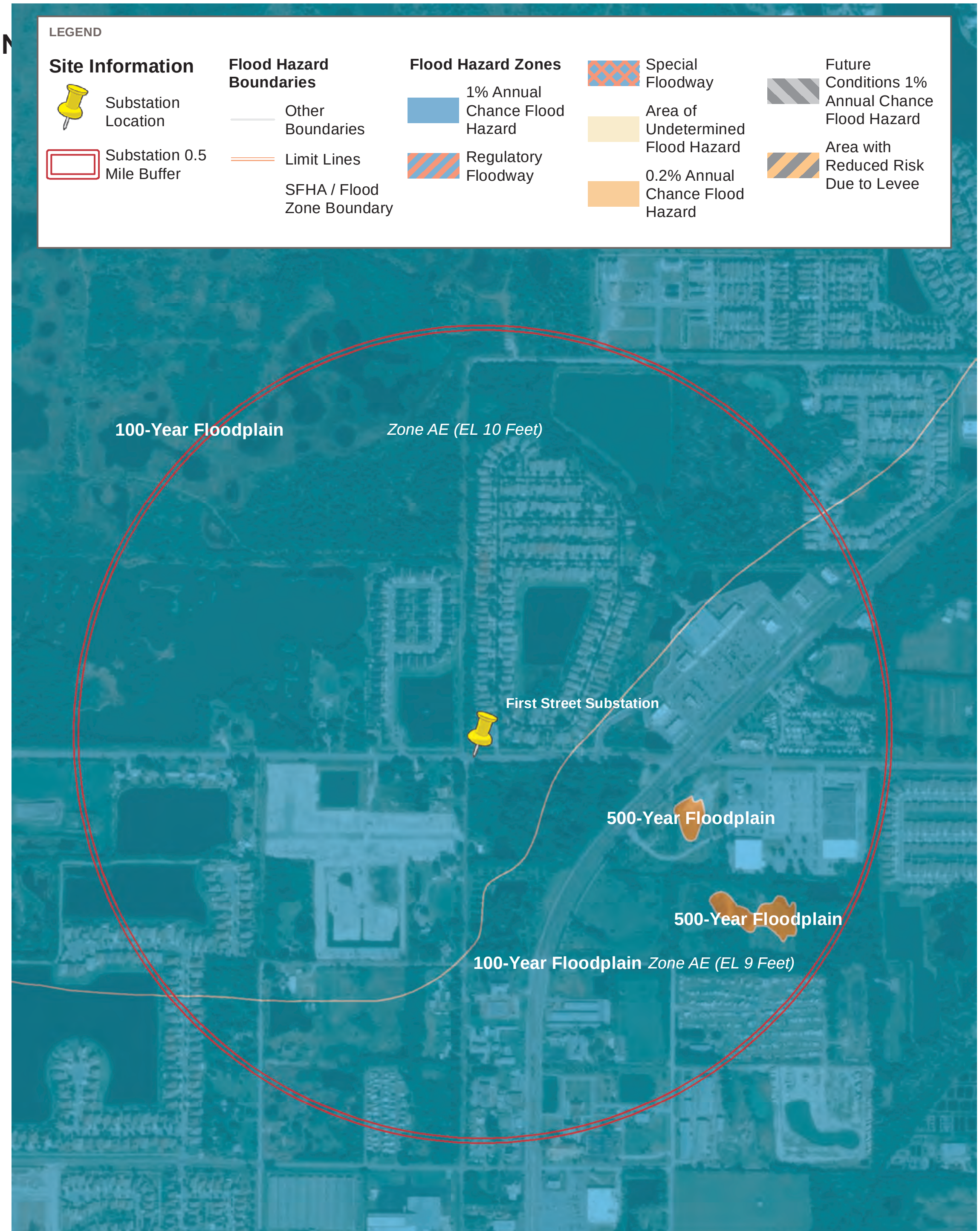

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FIRST STREET SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 7)

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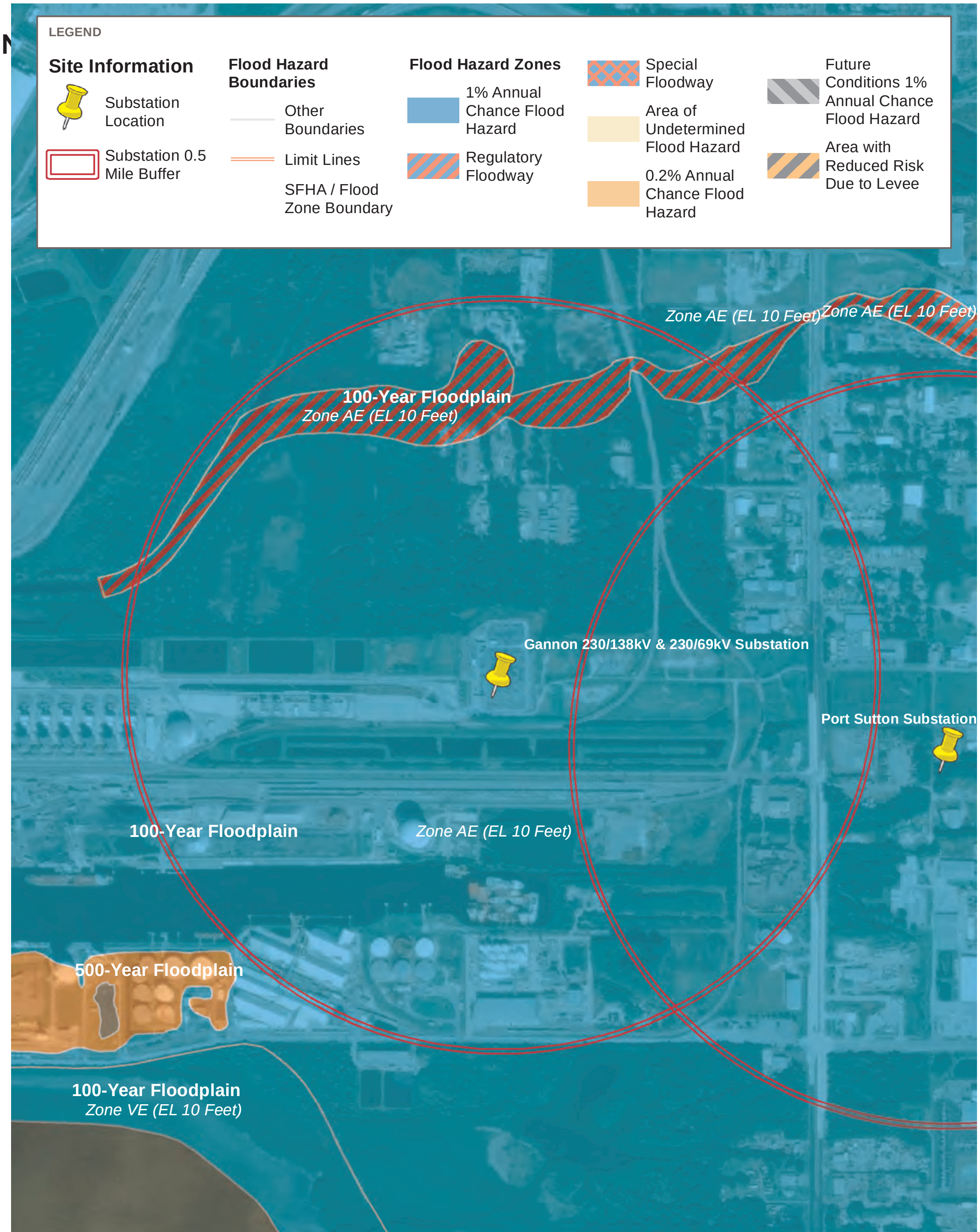

GANNON 230/138KV & 320/69KV SUBSTATIONS

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 8)

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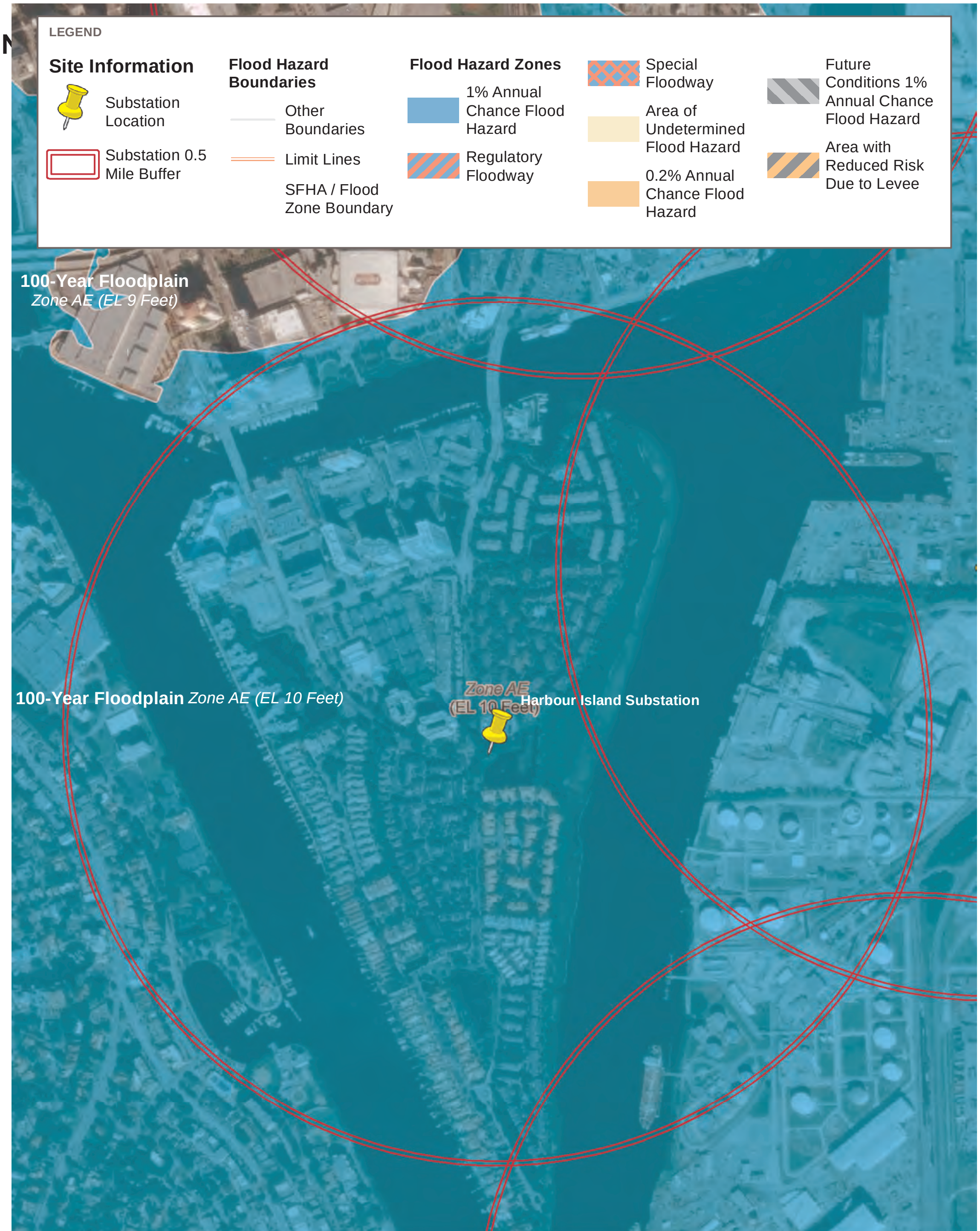

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HARBOUR ISLAND SUBSTATION

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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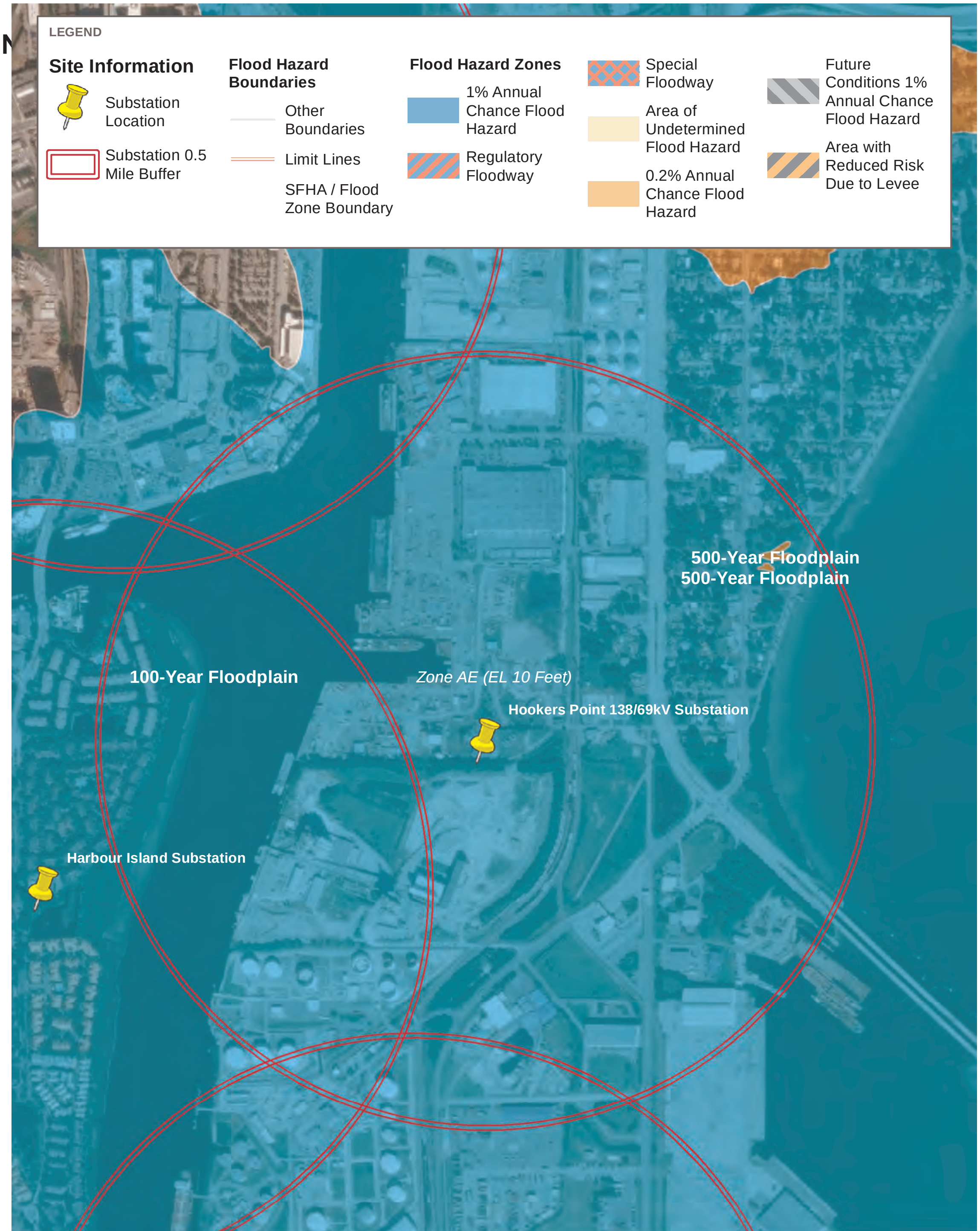

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HOOKERS POINT 138/69KV SUBSTATION

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

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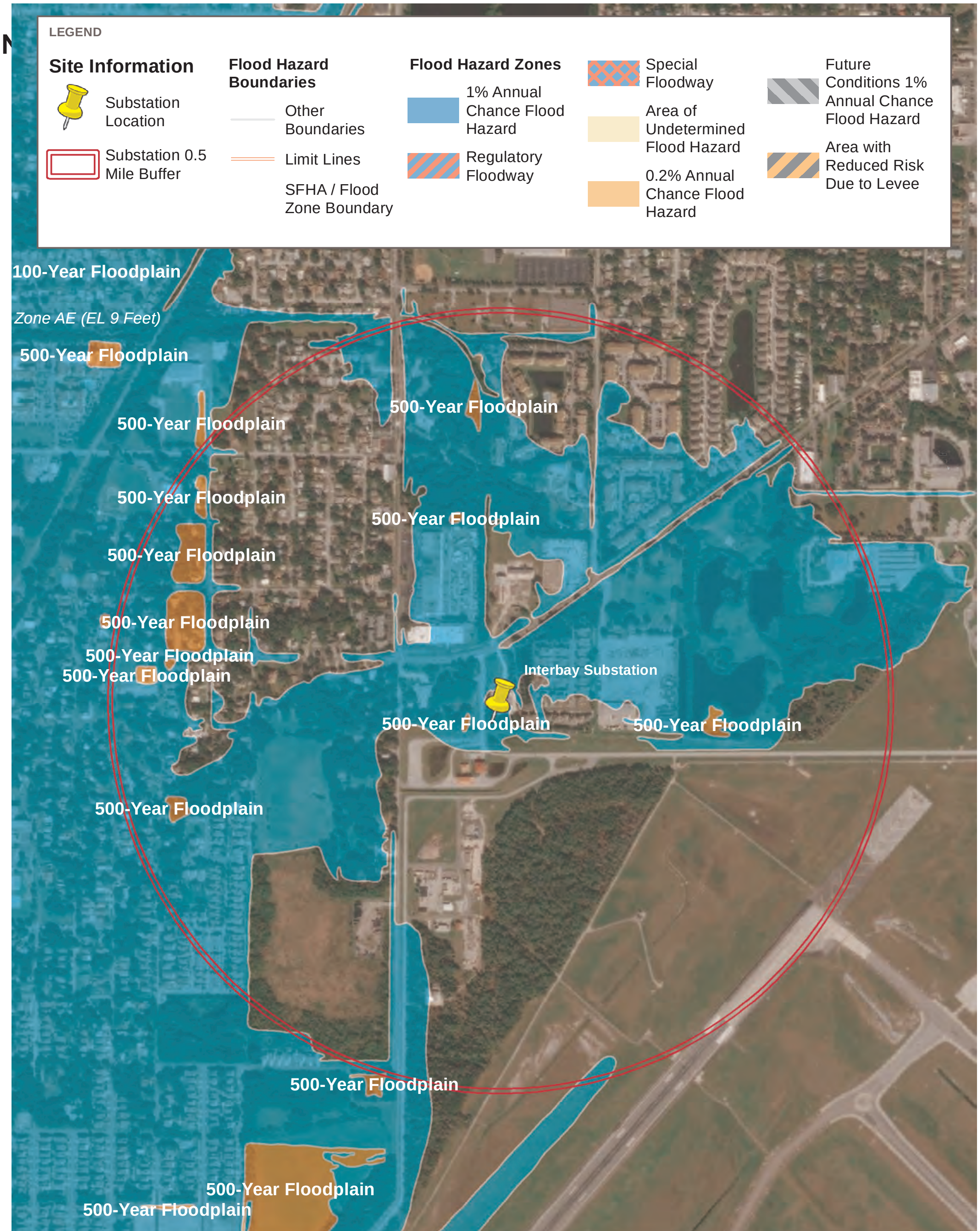

INTERBAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 11)

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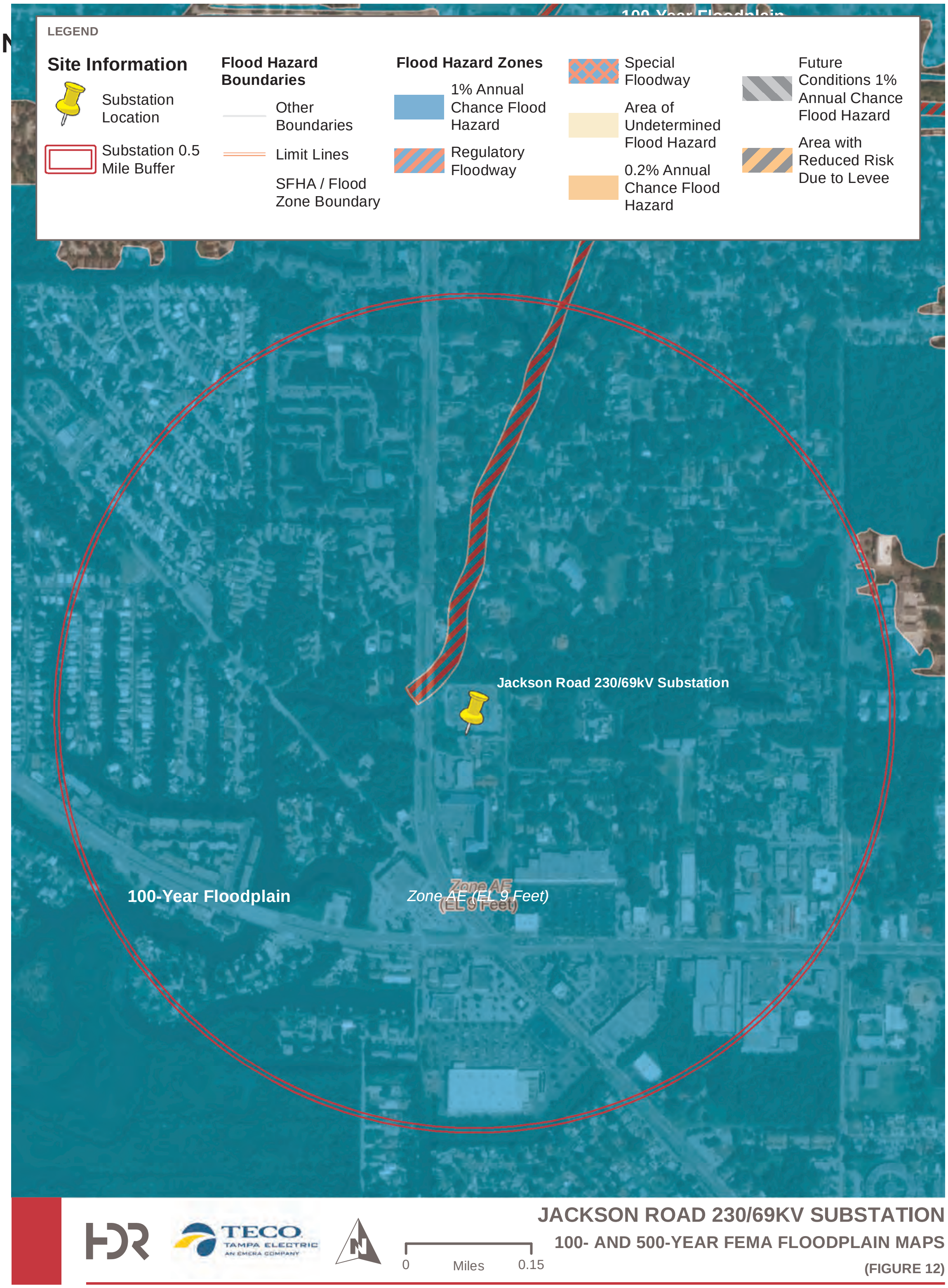

JACKSON ROAD 230/69KV SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 12)

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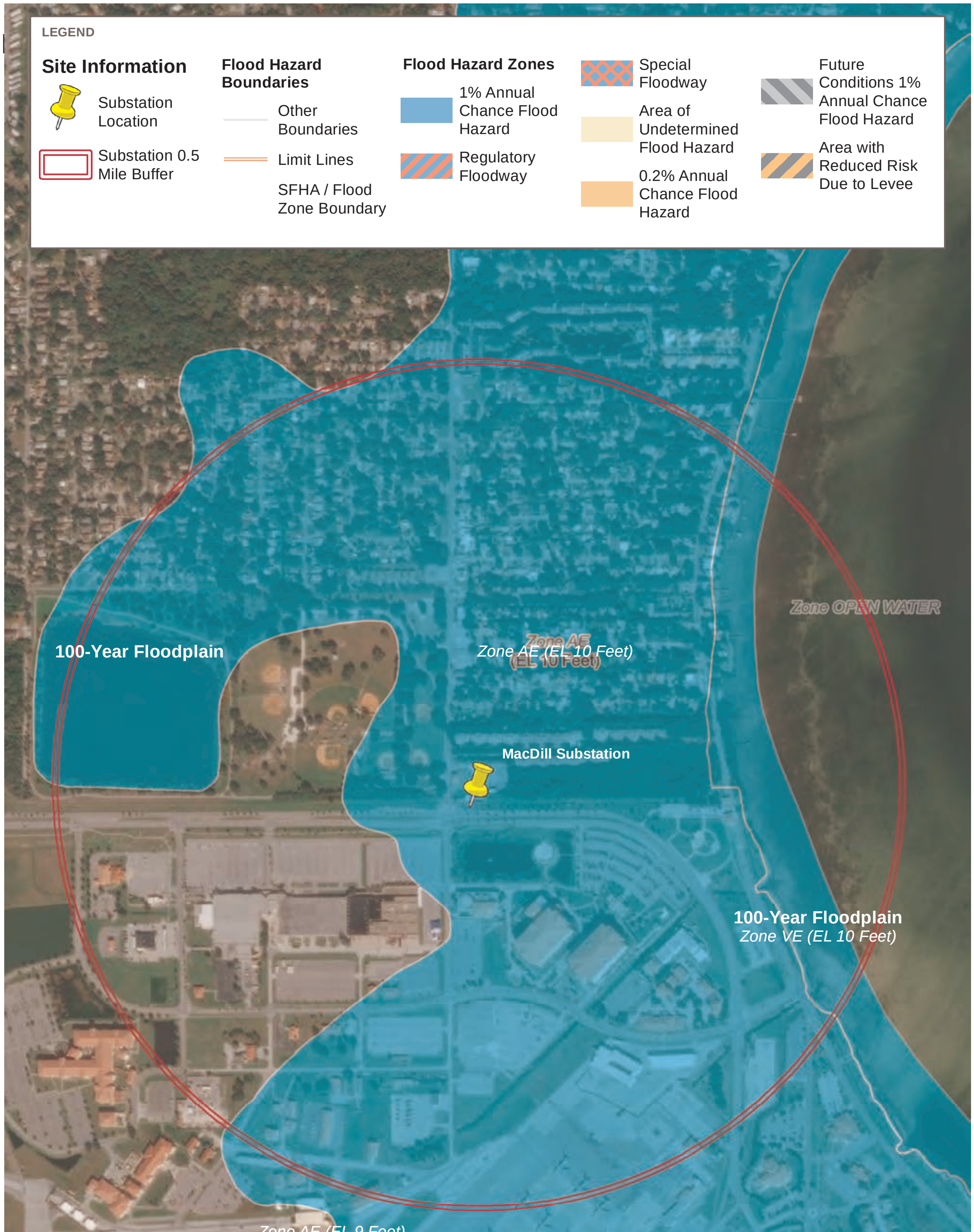

MACDILL SUBSTATION

100- AND 500-YEAR FEMA FLOODPLAIN MAPS

(FIGURE 13)

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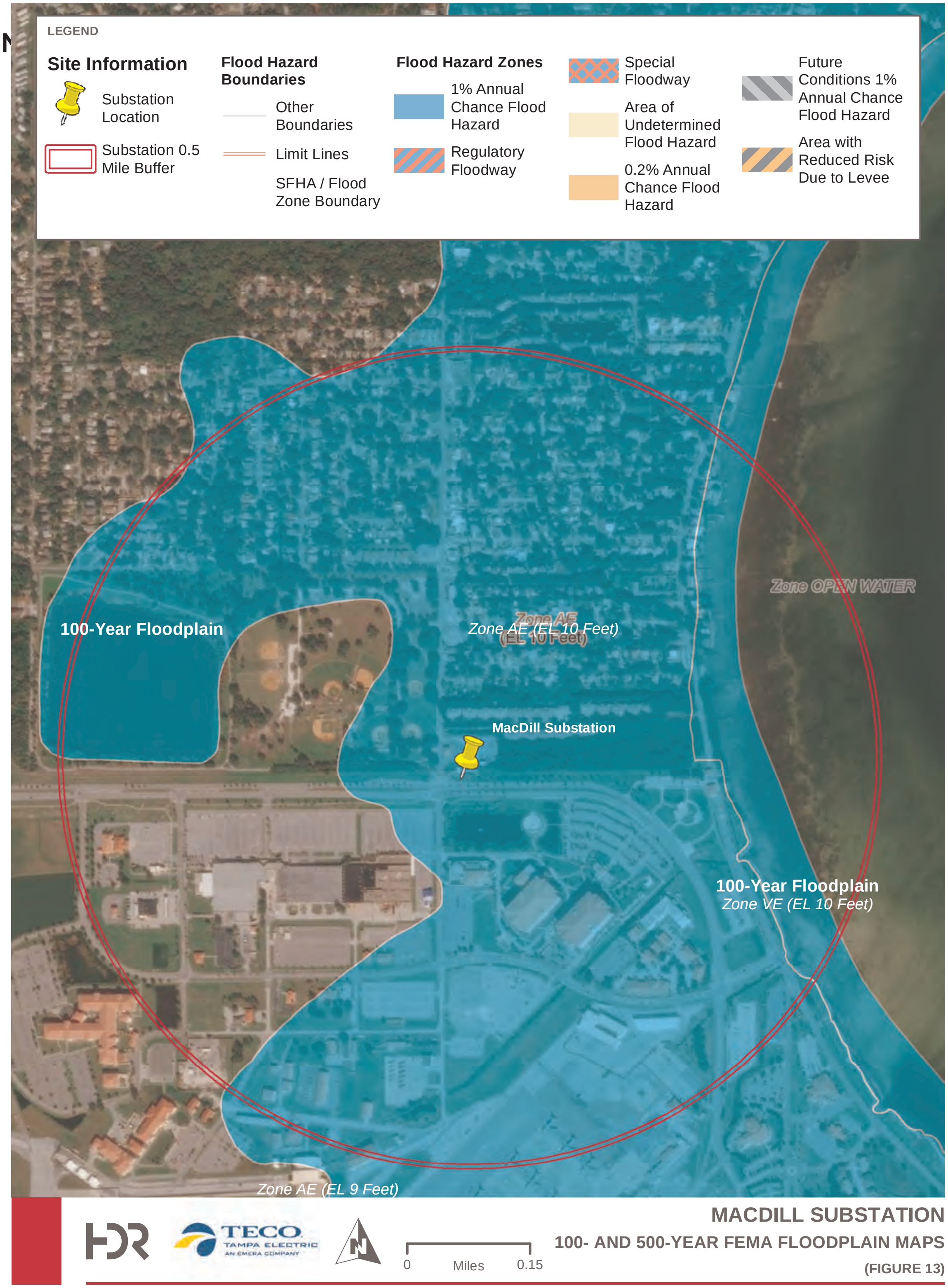

MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)

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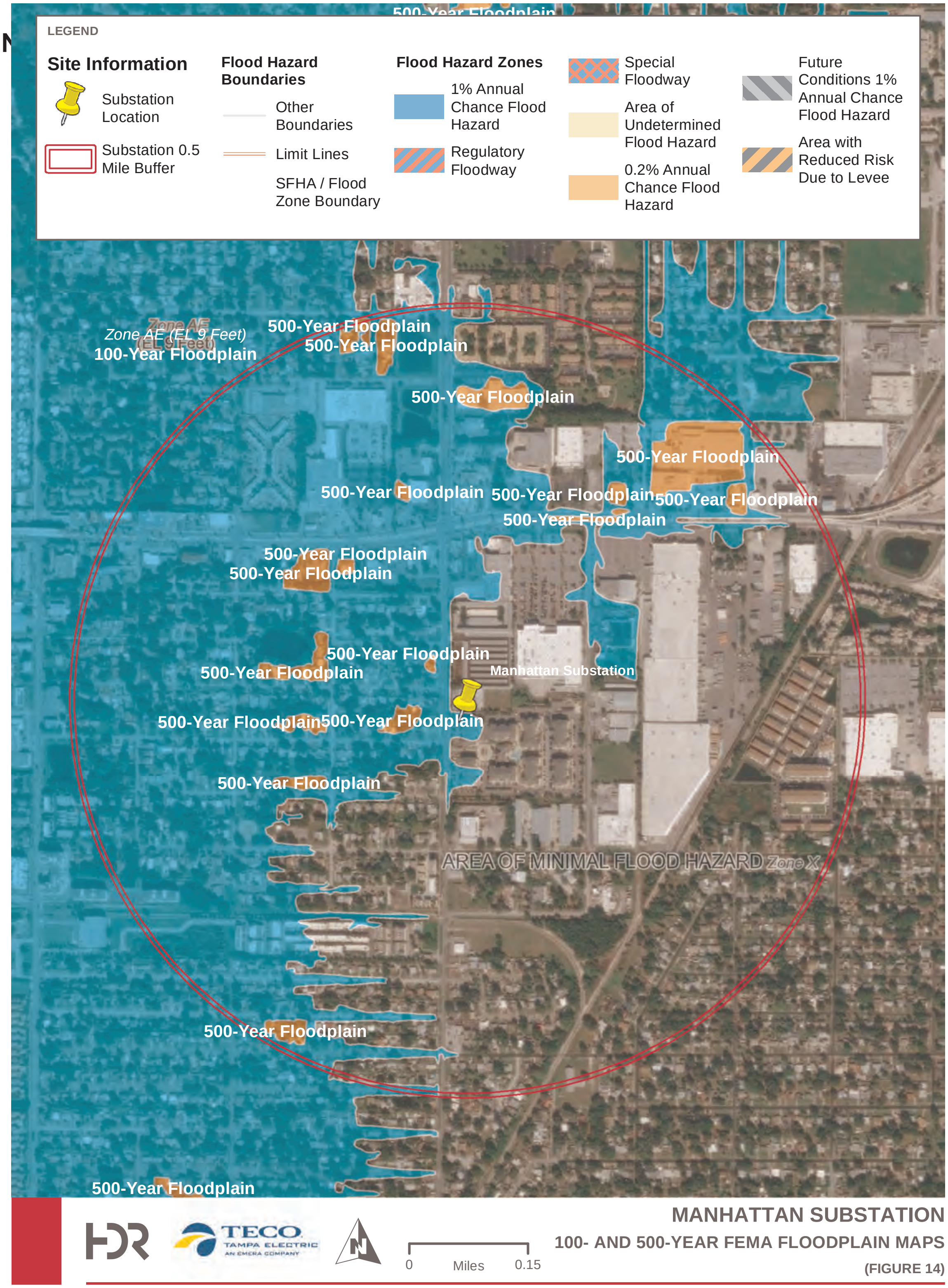

MANHATTAN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 14)

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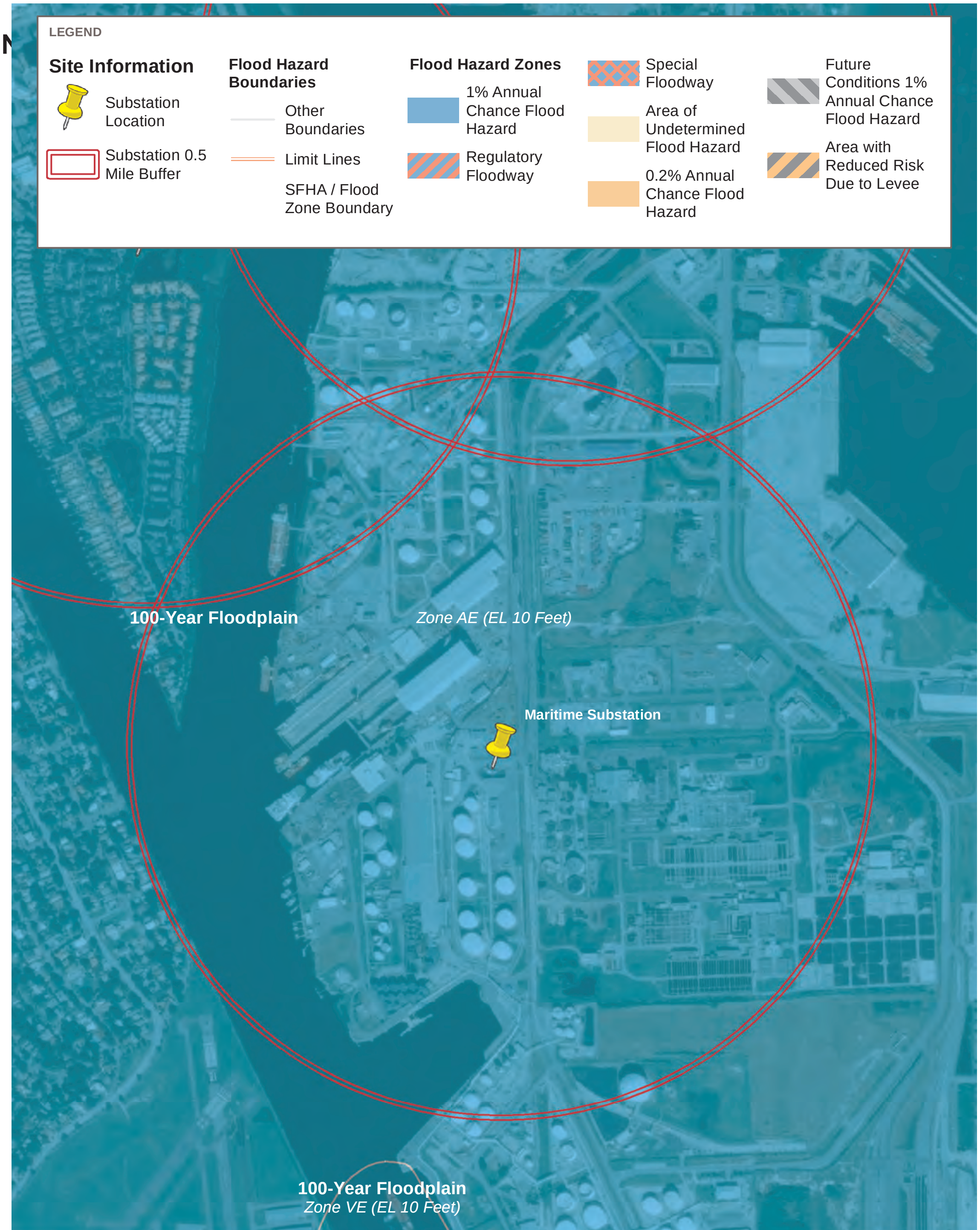

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MARITIME SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 15)

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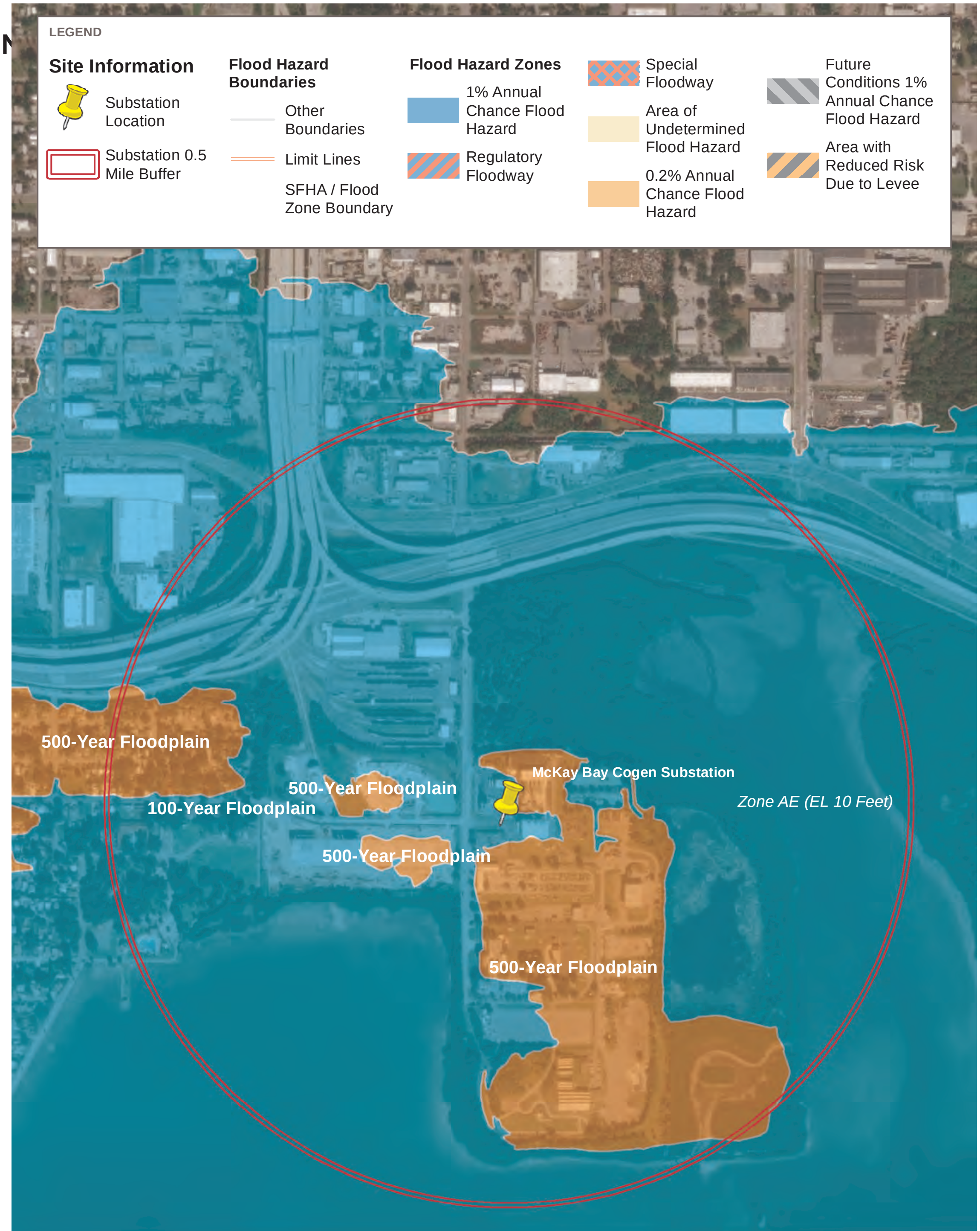

MCKAY BAY COGEN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 16)

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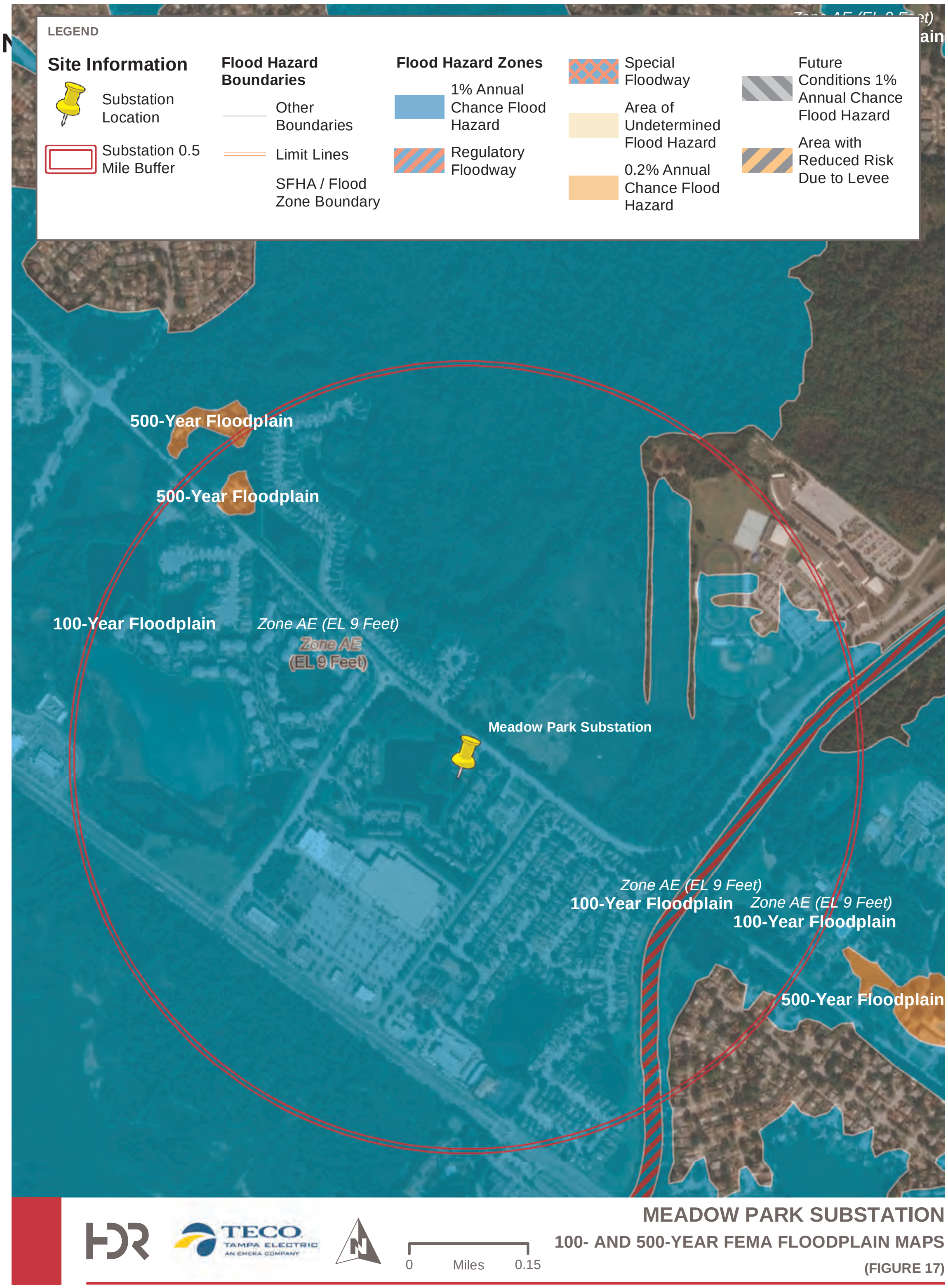

MEADOW PARK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 17)

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MILLER MAC SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 18)

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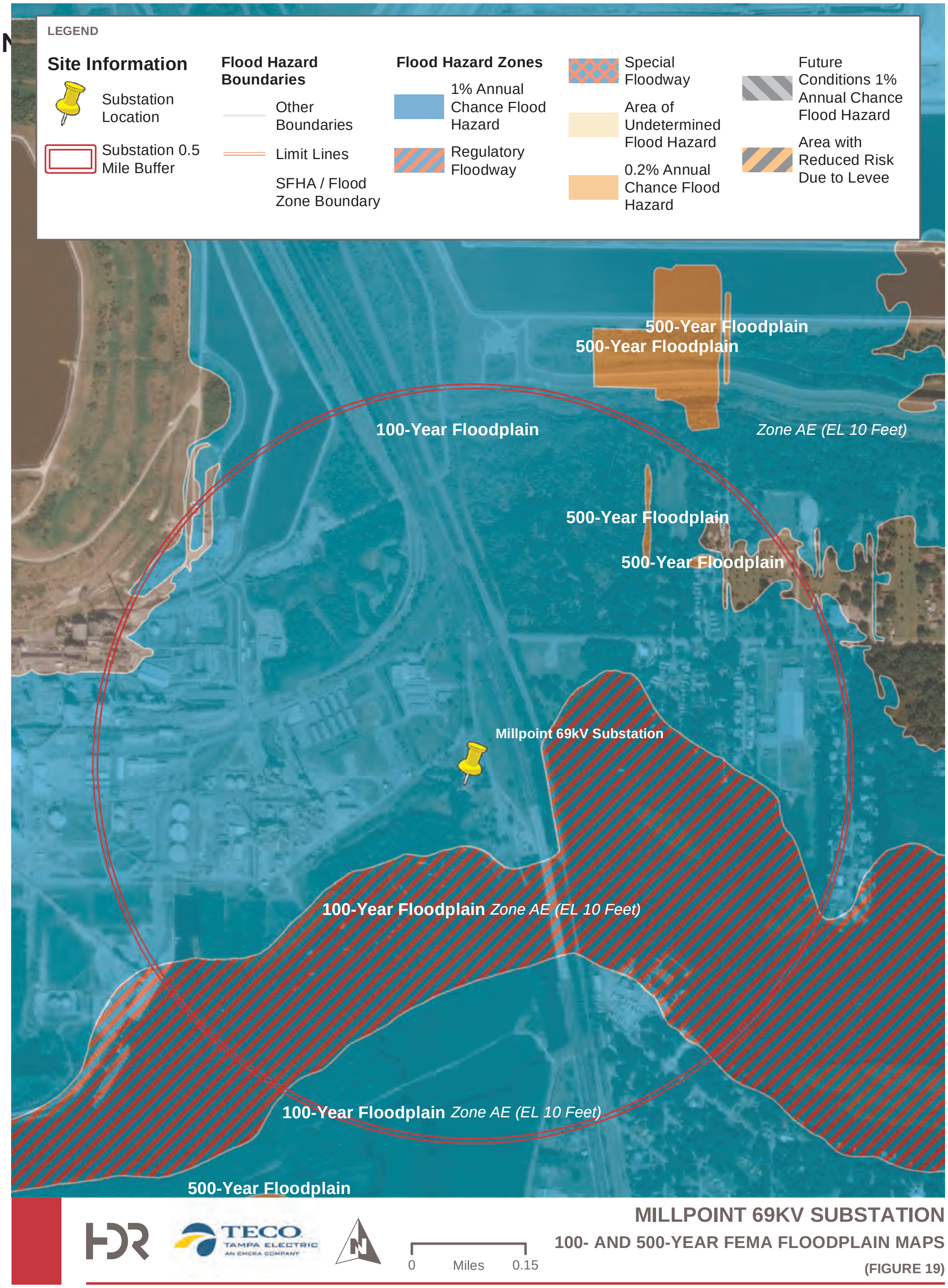

MILLPOINT 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 19)

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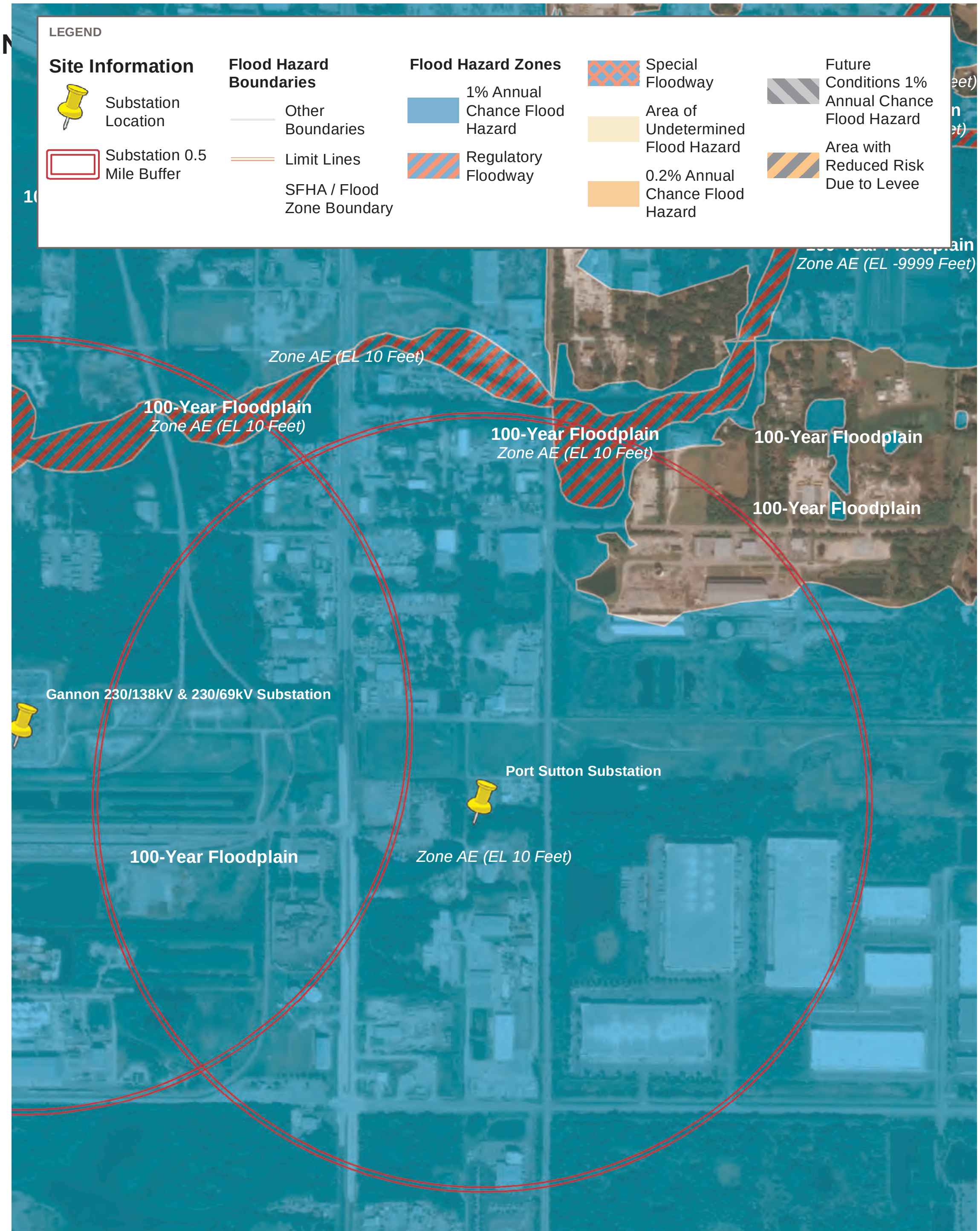

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PORT SUTTON SUBSTATION

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)

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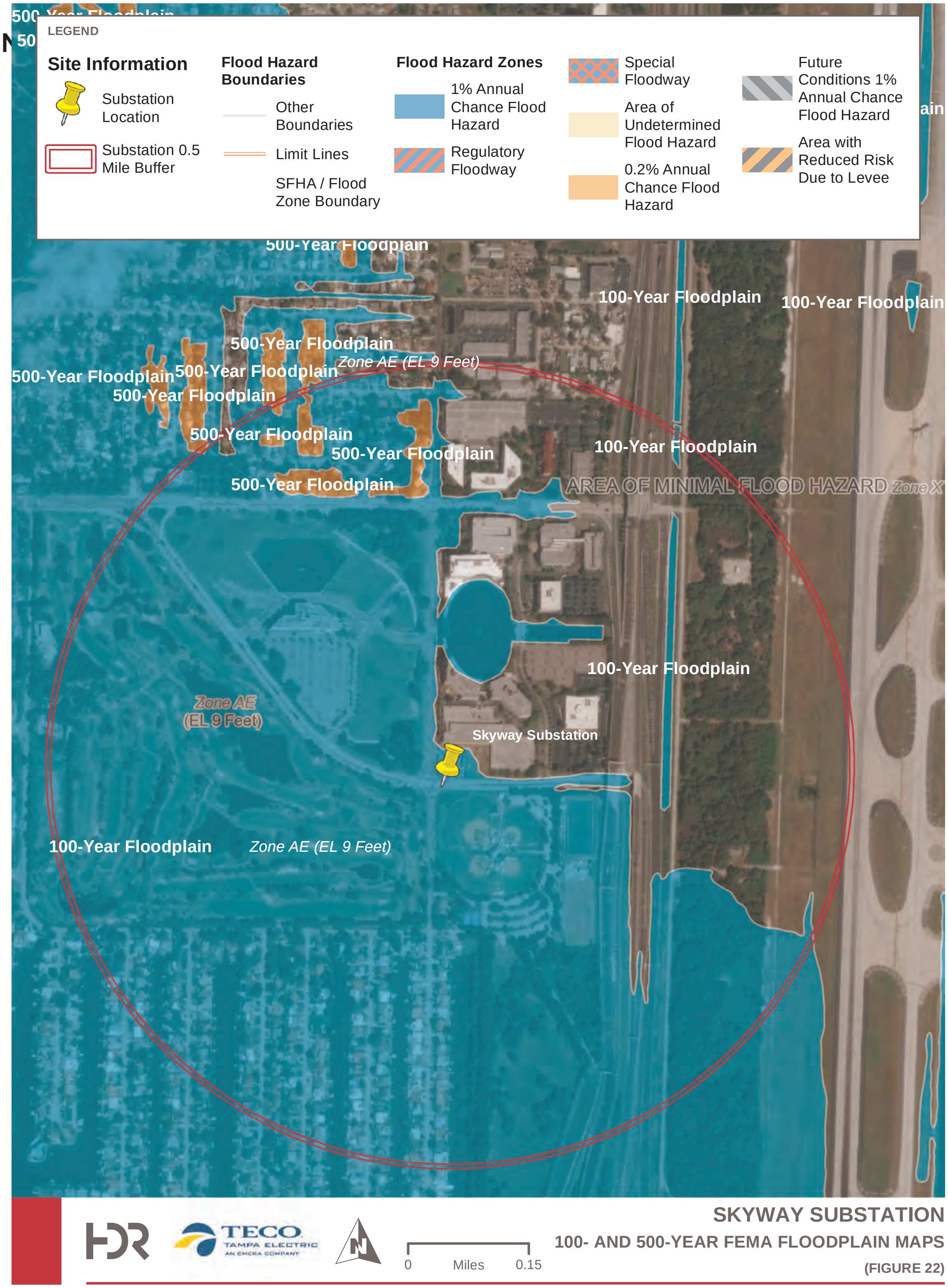
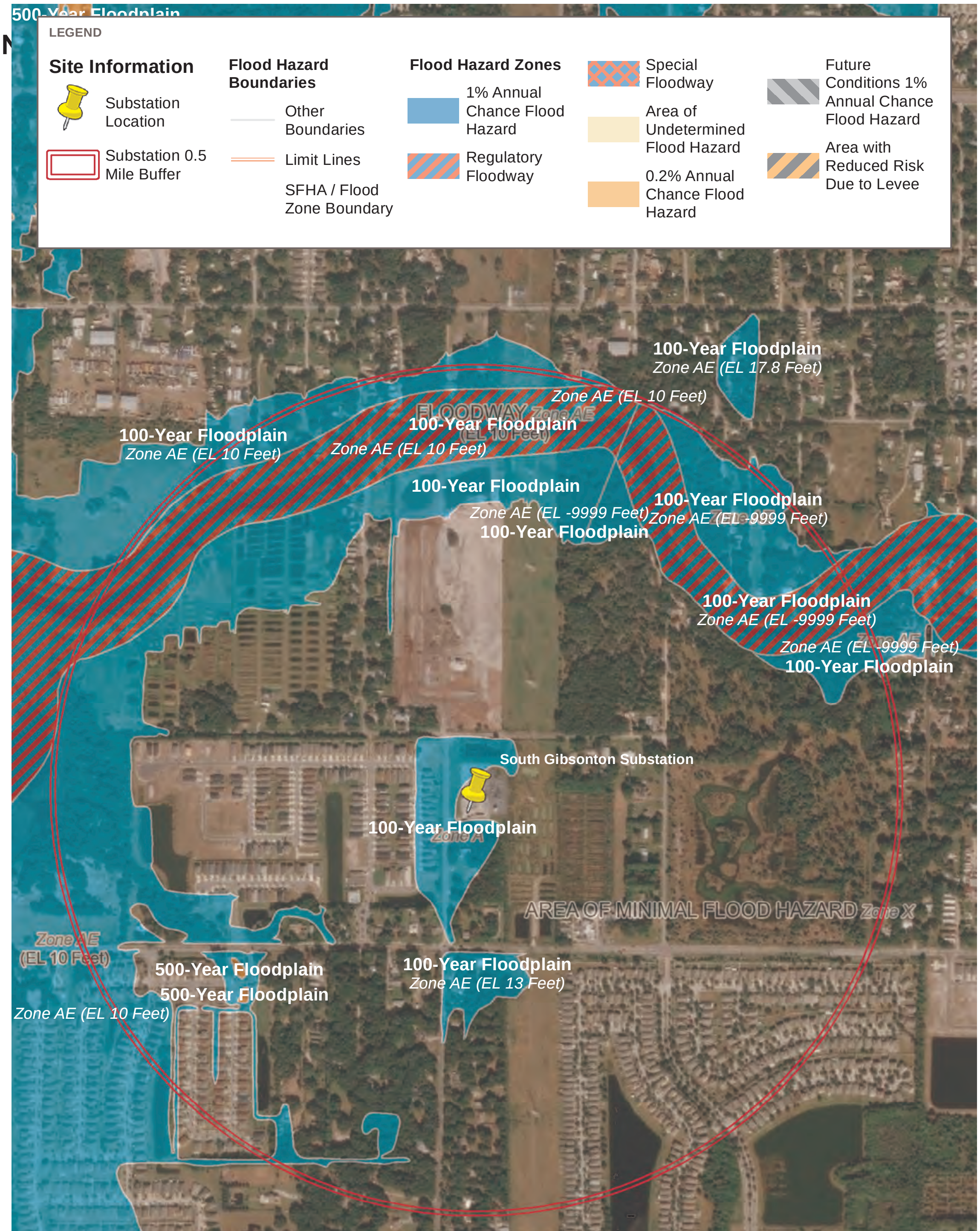


SKYWAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 22)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\SKYWAY FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



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

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