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April 10, 2020

<u>VIA: ELECTRONIC FILING</u>

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

Re: Tampa Electric Company's Petition for Approval of Storm Protection Plan
         Dkt. 20200067-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Petition for Approval of Storm Protection Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

MNM/bmp
Attachment

cc: J.R. Kelly (w/o attachment)
        Mireille Fall-Fry (w/o attachment)
        TECO Regulatory Department

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Review of 2020-2029 Storm Protection	)	DOCKET NO. 20200067-EI
Plan pursuant to Rule 25-6.030, F.A.C.,	)	
Tampa Electric Company	)	FILED: April 10, 2020

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

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Section 366.96, Florida Statutes and Rule 25-6.030, Florida Administrative Code, petitions for Commission approval of its 2020-2029 Transmission and Distribution Storm Protection Plan ("SPP"). In support of this petition, the company states:

I.   Preliminary Information

1.   The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

2.   Any pleading, motion, notice, order or other document required to be served upon

Tampa Electric or filed by any party to this proceeding shall be served upon the following individuals:

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

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

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

II. Plan Filing Requirement and Review Criteria

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

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

> (a)   The extent to which the plan is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability, including whether the plan prioritizes areas of lower reliability performance.
>
> (b)   The extent to which storm protection of transmission and distribution infrastructure is feasible, reasonable, or practical in certain areas of the utility's service territory, including, but not limited to, flood zones and rural areas.
>
> (c)   The estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan.

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

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

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

III. Statement on Disputed Issues of Material Fact

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

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

11.   Tampa Electric's SPP is the result of a rigorous and comprehensive analysis of potential storm protection activities, including their potential costs and benefits. The company's SPP is attached as Exhibit 1 to this Petition.

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

13.   As explained further in the attached SPP, and in the testimony of Gerry R. Chasse, Regan B. Haines, John H. Webster, A. Sloan Lewis, and Jason D. De Stigter filed

contemporaneously with this petition, these Programs and Projects are the most cost-effective method of achieving the goals of Section 366.96 of the Florida Statutes.

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

- Distribution Lateral Undergrounding

- Vegetation Management

- Transmission Asset Upgrades

- Substation Extreme Weather Hardening

- Distribution Overhead Feeder Hardening

- Transmission Access Enhancement

- Infrastructure Inspections

- Legacy Storm Hardening Plan Initiatives

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

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

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

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

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

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

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

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

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

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

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

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

17.   Gerry R. Chasse's testimony introduces Tampa Electric's 2020-2029 SPP and explains how the implementation of the SPP will strengthen the company's infrastructure to withstand extreme weather conditions. His testimony also provides an overview of the company's service area and describes the process that the company used to develop the Plan, as well as a description of how the Plan's implementing Programs were selected and prioritized.

18.   Regan B. Haines' testimony presents the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Infrastructure Inspection and Legacy Storm Hardening Initiatives Programs in Tampa Electric's 2020-2029 SPP. His testimony provides a description and explanation of how each Program will ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

19.   John H. Webster's testimony presents the Vegetation Management and Transmission Access Storm Protection Programs in Tampa Electric's 2020-2029 SPP. His testimony provides a description and explanation of how each Program will ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

20.   A. Sloan Lewis' testimony demonstrates that the company's 2020-2029 Storm Protection Plan complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan Rule, by providing an estimate of the annual jurisdictional revenue requirements for each year of the SPP. Her testimony also provides an estimate of rate impacts for each of the first three years of the SPP for the company's typical residential, commercial, and industrial customers.

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

V. Relief Requested

22.   Tampa Electric respectfully requests that the Commission find that it is in the public interest to approve the Company's SPP without modification.

WHEREFORE, Tampa Electric Company respectfully urges the Commission to find that it is in the public interest to approve the Company's 2020-2029 Transmission and Distribution Storm Protection Plan without modification.

DATED this 10th day of April 2020

Respectfully submitted,

(signature)

_____
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Ausley McMullen
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Tampa Electric's

2020–2029

Storm Protection Plan

Filed: April 10, 2020

Tampa Electric's
2020-2029 Storm Protection Plan Summary

Tampa Electric's 2020-2029 Storm Protection Plan describes the company's comprehensive approach to protect and strengthen its electric utility infrastructure to withstand extreme weather conditions as well as to reduce restoration costs and outage times in a prudent, practical and cost-effective manner. Protecting and strengthening Tampa Electric's transmission and distribution electric utility infrastructure against extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

Tampa Electric's 2020-2029 Storm Protection Plan will be its first ten-year protection plan filed in response to Rule 25-6.030, Storm Protection Plan. That Rule, which became effective on February 18, 2020, requires utilities to file storm protection plans. Tampa Electric has developed this Plan to comply with the Rule. This Plan contains a description of the company's Storm Protection Programs, the specific supporting Projects to these Programs and required detail as prescribed by Rule 25-6.030. This Plan also incorporates the continuation of legacy Storm Hardening Plan Initiatives that have been in place since 2006 and wood pole inspections.

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1 Tampa Electric's Service Area:

Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties as shown in the figure below. The company's service area is divided into seven "service areas" for operational and administrative purposes. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.

Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including 25,416 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,250 circuit miles of overhead facilities and 414,000 poles. The company currently has approximately 5,550 circuit miles of underground distribution

facilities. The company currently has 216 substations. Tampa Electric also has approximately 322,000 authorized joint user attachments on the company's transmission and distribution poles.

Tampa Electric developed the proposed 2020-2029 Storm Protection Plan and its supporting Programs and initiatives by examining the entire company's service area for the most cost-effective enhancement opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness or practicality concerns.

2 References:

The following resources are referenced in this Plan:

a) 2017 National Electrical Safety Code

b) National Hurricane Center Database

c) Florida State Building Code

d) Hillsborough County Wind Maps

e) Tampa Electric's prior Storm Implementation Plans

f) Tampa Electric's Distribution Engineering Technical Manual

g) Tampa Electric's Standard Electrical Service Requirements

h) Tampa Electric's General Rules and Specifications-Overhead

i) Tampa Electric's General Rules and Specifications-Underground

j) Tampa Electric's Approved Materials Catalog

k) Hillsborough County Flood Hazard Maps

3 Storm Protection Plan Overview

Tampa Electric's Storm Protection Plan ("Plan" or "SPP") sets out a systematic and comprehensive approach to storm protection focused on those Programs and Projects that provide the highest level of reliability and resiliency benefits for the lowest relative cost. The company believes that these activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" in a cost-efficient manner.

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

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

In response to the new requirement to develop a comprehensive

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SPP, Tampa Electric evaluated its existing Storm Hardening Plan activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions.

First, Tampa Electric engaged Accenture, LLP ("Accenture") to evaluate its existing vegetation management ("VM") activities and determine what types of incremental vegetation trimming would reduce storm-related outage times and restoration costs. Tampa Electric's Line Clearance Department and Accenture developed and finalized the SPP spending plan described in the VM section. Spending levels were evaluated for each of the initiatives, using multiple activities, and ultimately resulted in the proposed list of VM initiatives and spending levels. A complete copy of Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report is included as Appendix "G".

Second, Tampa Electric engaged 1898 & Co. to perform Project prioritization and benefits calculations for several of the company's proposed Storm Protection Programs, including:
- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

Tampa Electric and 1898 & Co. used a resilience-based planning approach to identify hardening Projects and prioritize investment in the transmission and distribution (T&D) system using 1898 & Co's Storm Resilience Model. The Storm Resilience

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Model consistently models the benefits of all potential hardening Projects for an accurate comparison across the system. The resilience-based planning approach calculates the benefits of storm hardening Projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, Project, and Program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as Customer Minutes of Interruption("CMI")

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

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

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

The Budget Optimization and Project Scheduling model prioritized the Projects based on the highest resilience benefit cost ratio. The model prioritized each Project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the Project cost. This was done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric's technical and operational (transmission outages) in scheduling the Projects.

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

Early iterations of the modeling tool allowed the company to understand the Storm Protection Programs and the benefits that could be expected. In addition, Tampa Electric personnel

factored the legacy Program Storm Hardening Plan Initiatives into these evaluations. Also, real-world considerations were included that examined practical realities of multi-year implementation, such as growing and sustaining an external workforce, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the modeling tool to develop the final set of Programs, Program funding and ultimately individual Project selection. A complete copy of Tampa Electric's Storm Protection Plan Resilience Benefits Report is included as Appendix "F".

Third, Tampa Electric engaged Power Engineers, Incorporated, to perform an automation analysis for the (22) prioritized distribution circuits for the 2020-2022 Overhead Feeder Hardening Program. The analysis determined the number and placement of reclosers, conductor upgrades, substation transformer capacity increases, relay upgrades and in some instances circuit extensions, to meet the company's criteria to reduce customer exposure, impact and count for unplanned outages. These proposed system enhancements were also used as input to the broader 1898 & Co. analysis described below.

Finally, the company used the analyses provided by these consultants as a basis for establishing the spending levels in the proposed 2020-2029 SPP. This information was used in conjunction with technical and operational constraints to select Storm Protection Programs, Program funding levels and Project selection and prioritization. The company's 2020-2029 SPP is thus comprised of both the company's legacy Storm Hardening Plan activities, as well as those incremental activities that emerged from this rigorous analysis process to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission.

4 Experience with Major Storm Events

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

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

Table 1: Named Storms Affecting Tampa Electric Service Area since 1960			
Year	Storm Name	Size [1]	Wind Speed [2]
1960	Donna	Cat 3	115
1995	Erin	TS	57
2004	Charley	Cat 2	86
2004	Francis	Cat 1	63
2004	Jeanne	Cat 1	63
2005	Dennis	TS	43

2005	Wilma	TS	44
2006	Alberto	TS	45
2007	Barry	TS	31
2012	Debby	TS	53
2012	Isaac	TS	36
2013	Andrea	TS	47
2015	Erika	TS	<39
2016	Colin	TS	<39
2016	Hermine	Cat 1	37
2016	Matthew	TS	20
2017	Emily	TS	<39
2017	Irma	Cat 1	90
2018	Alberto	TS	29
2019	Nestor	TS	26

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

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

5 Construction Standards, Policies, Practices and Procedures

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

5.1 National Electrical Safety Code Compliance

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

5.2 Wind Loading Standards

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

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loading criteria must be applied when constructing facilities less than 60 feet in height when crossing railroads, bridges and highways.

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

5.2.1 Extreme Wind Loading Criteria

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

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

5.3 Distribution

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

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

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

5.3.1 Design Philosophy

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

5.3.2 Overhead System

5.3.2.1 Voltage

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

5.3.2.2 Clearances

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

5.3.2.3 Pole Loading

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

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

5.3.2.4 Materials

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

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

5.3.2.5 Construction Types

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

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

5.3.2.6 Pole Loading Compliance

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

5.3.3 Underground Facilities

5.3.3.1 Standard Design

Tampa Electric's standard underground distribution system consists of normally looped circuits operating at 13.2kV three-

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

5.3.3.2 Network Service

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

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

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

5.3.4 Construction Standards in Coastal Areas

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

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

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

5.3.5 Location of Facilities

Tampa Electric's policy as stated in the DETM is to ensure that the route for new lines is located within the Public ROW or an

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

5.3.6 Critical Infrastructure

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

5.4 Transmission

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

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5.4.1 Design Criteria

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

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

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

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

5.4.2 Transmission Structures

5.4.2.1 Voltage levels

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

5.4.2.2 Material types

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

5.4.2.3 Configuration Types

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

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

- Number of circuits

- Conductor size

- Structure strength

- Span length

- Soil conditions

- ROW width

- Potential permitting requirements

- Utilization of adjacent land

- Environmental impacts

- Electric and magnetic field criteria

- Aesthetics

- Economics and cost-effectiveness

- Community input

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

5.4.3 Foundations

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

When a structure location requires it, Tampa Electric uses an industry accepted program for foundation design. Soil borings

are collected, or standard penetration tests are conducted to compile the appropriate soil data for foundation analysis.

5.5 Substation

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

Tampa Electric designs, constructs and maintains transmission and distribution substations and switchyards ranging from 13.2kV to 230kV. This includes performing siting studies, physical design, grading and drainage, foundation design, layout and design of control buildings, structure design and analysis, protection and control systems, and preparation of complete specifications for material, equipment and construction. The company currently has 216 substations.

5.5.1 Design Philosophy

5.5.1.1 Wind Strength Requirements

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

The design standards summarized above meet the NESC loading criteria for extreme wind, Grade B construction. As previously

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stated, Tampa Electric's service area is within the 100 mph to 120 mph extreme wind contours referenced in the NESC.

5.5.1.2 Equipment Elevations

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

5.5.1.3 Protection

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

5.5.1.4 Flood Zones

The company carefully evaluates flood zones when building on existing sites or when selecting future sites. The company will continue to review existing sites in the Flood Zone 1 designated area. The major focus will be on the elevation and water resistance of control cabinets and related equipment. Prudent modifications will be made. Consideration will be given to

whether there will be load to be served in the area of the substation immediately after a storm and if any load can be served from adjacent substations that are outside the flooded area.

5.5.1.5 Other

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

5.5.2 Construction Standards

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

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

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Electric has determined that this fencing standard is most effective in blocking debris and exceeds county codes.

5.6 Deployment Strategy

Tampa Electric's 2020-2029 Storm Protection Plan's deployment strategy will reduce storm restoration costs and customer outage duration following major storm events and enhance system reliability through the continuation of several core components of the company's Storm Hardening Plans. The deployment strategy includes the continuation of legacy Storm Hardening Plan Initiatives and the implementation of new and expanded Storm Protection Plan Programs.

6 Storm Protection Plan Programs

Tampa Electric's proposed 2020-2029 SPP includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis previously described. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described in this section. These Programs will achieve the goals, objectives and requirements of the Florida Legislature and the Commission.

6.1 Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding Program aims to strategically underground existing overhead lateral primary, lateral secondary and service lines. The expected benefits from this Program are:

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

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

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

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

- Total Circuit Miles: 11,800
- Total Overhead Miles: 6,251 (53 percent)
- Total Underground Miles: 5,549 (47 percent)
- Total Overhead Lateral Miles: 4,471
- Total Overhead Feeder Miles: 1,780
- Total Underground Lateral Miles: 4,949
- Total Underground Feeder Miles: 600
- Customers served off Laterals: 88 percent
- Customers served off Feeders: 12 percent

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

	Tampa Electric's Distribution System Overhead versus Underground Outage Comparison (in Percent)			
	Distribution System	Day-to-Day Outages	Major Event Day Outages	Irma Repair/Replace
Overhead	53	81	91	99.60
Underground	47	19	9	0.40

These metrics show that the underground system proves to be much stronger and more resilient during extreme weather events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years. This SPP Program is also expected to provide similar reliability improvements and restoration benefits (time and costs) during normal day-to-day operations and summer thunderstorm events.

As previously discussed, Tampa Electric used the 1898 & Co.

modeling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. Initial model runs provided the optimal 10-year SPP spending levels and demonstrated that this Program's undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. Tampa Electric relied on the model output to confirm appropriate funding levels in alignment with the need to attract and sustain external workforces capable of executing a large-scale Distribution Lateral Undergrounding Program for the duration of the 2020-2029 SPP. The company also relied on the model output to identify the 2020-2021 Projects, selecting Projects that would allow it to most rapidly grow the Program, execute at small scale initially and develop operationally sound, sustainable and efficient processes. The individual Projects, the prioritization of these Projects and the annual Program funding levels are supported by the model. For operational efficiencies, laterals on the same feeder circuit were grouped and scheduled together in the same time frame. Laterals were then selected based on their ease of execution (e.g. fewer joint use attachers, fewer rear lot spans, and no major road or railroad crossings) balanced against their customer benefits. Strategically and operationally, these Projects are intended to allow the company to most rapidly complete projects to learn, adapt and enhance its processes to ensure the Program is sustainable, efficient and cost-effective. The 2020 activity will largely consist of designing, permitting, obtaining easements and attempting to coordinate with joint users on the identified Projects in detail included in Appendix "A". While this currently reflects a construction quarter end date of "Q4 2020" for these Projects, the Projects can be completed only if all permitting and required easements are obtained. The company anticipates the permits and easements will be obtained, however if they cannot be, the company will begin the process by accelerating future planned Projects into

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2020.

For the SPP years 2022 to 2029, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The table below shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	24	$8.0
2021	281	$79.5
2022	316	$108.1

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

6.2 Vegetation Management
Tampa Electric's Vegetation Management Program ("VMP") combines a continuation of its existing filed and approved distribution and transmission VMP activities with three additional strategic VM initiatives.

6.2.1 Existing Vegetation Management Activities
Tampa Electric currently trims the company's distribution system on a four-year cycle. This approach was approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012. The four-year cycle is flexible enough to allow the company to change circuit prioritization

utilizing the company's reliability-based methodology. Since 2007, Tampa Electric has partnered with a third-party consultant and used their proprietary vegetation management software application. The software analyzes multi-year circuit performance data, trim cycles, and corrective and restoration costs to generate a priority list for circuit trimming for the four-year distribution trimming cycle. The software optimizes circuit selection in terms of both reliability and cost-effectiveness.

The company also adheres to a comprehensive vegetation management strategy for its transmission system. The company operates three categories of transmission lines 230kV, 138kV, and 69kV. For the circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4. This standard imposes performance-based, risk-based, and competency-based requirements for vegetation management on these circuits. The company imposes a two-year vegetation management cycle for 138kV circuits, and a three-year cycle for 69kV circuits. The company's vegetation management strategy for its transmission system includes the maintenance of the transmission ROWs.

6.2.2 New VMP Initiatives

In addition to continuing its existing VMP plans, Tampa Electric partnered with Accenture to analyze various VMP strategies to further enhance the transmission and distribution facilities while reducing outage times and restoration costs due to extreme weather conditions. Accenture updated its existing vegetation management software to include the most recent outage, cost, and trim data, and to add functionality to estimate the value derived from activities that address only part of a circuit at a time. Tampa Electric and Accenture then analyzed and compared full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather

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events, as well as overall service reliability. Based on this
analysis, Tampa Electric is proposing two additional
distribution VM initiatives and one additional transmission VM
initiative. The purpose of these additional VM initiatives is
to enhance the company's current cycles, specifically for the
purpose of system storm hardening. These additional VM
initiatives are:

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

6.2.2.1 Initiative 1: Supplemental Distribution Circuit VM

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

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

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and customers is detailed below:

Supplemental Vegetation Management Project Schedule by Service Area						
	2020		2021		2022	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	77.9	21,357	159.1	29,226	113.5	20,418
Dade City	99.9	5,208	6.2	484	127.6	5,578
Eastern	99.8	18,598	153.3	12,341	72.9	8,794
Plant City	76.7	9,702	25.2	2,443	202.2	8,347
South Hillsborough	15.3	2,264	20.5	2,427	20.2	3,236
Western	15.7	3,926	82.8	13,024	112.4	20,376
Winter Haven	16.8	1,277	63.1	5,063	43.2	5,784
Total	402.3	62,332	510.2	65,008	692	72,533

The total Supplemental Circuit VM initiative costs are detailed below for the 2020-2029 SPP:

Supplemental Vegetation Management Project Costs (in thousands)	
2020	$3,200
2021	$5,200
2022	$6,100
2023	$7,100
2024	$4,800
2025	$5,300
2026	$6,500
2027	$5,900
2028	$5,900
2029	$5,900

6.2.2.2 Initiative 2: Mid-Cycle Distribution VM

Tampa Electric's experience with existing VM activities is that some trees cannot be effectively maintained within the four-year distribution VM cycle because of their rapid growth rate. For instance, the company estimates that up to twenty-five percent of trees grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. Additionally, some trees develop into a threat to distribution facilities due to an

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evident defect or hazard trees. The current four-year cycle has limited tree removal potential. Fall-in trees were determined to be a major damage factor in recent storms.

The Mid-Cycle VM initiative is inspection-based and designed to identify and selectively mitigate these trees. Tampa Electric and Accenture's analysis showed that this initiative will lead to reductions in both extreme weather outages and restoration costs as well as day-to-day outage costs. For the first three years of the Storm Protection Plan, the company will inspect feeders that have not been trimmed in the last two years and then prescribe additional VM work based on the inspection findings. After the first three years, the company plans to expand the initiative to include laterals. The Mid-Cycle VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed below:

Mid-Cycle Vegetation Management Project Schedule by Service Area						
	2020		2021		2022	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	0	0	48.6	17,262	36	9,488
Dade City	0	0	2.8	1,293	5.1	904
Eastern	0	0	17.3	4,730	34.5	12,007
Plant City	0	0	18	8,234	12	7,191
South Hillsborough	0	0	51.7	16,233	23	13,900
Western	0	0	58.8	27,318	53.3	19,073
Winter Haven	0	0	45.9	20,663	32.1	14,565
Total	0	0	243.1	95,733	196	77,128

The total Mid-Cycle VM Project costs are detailed below. The 2020 costs are associated with the initial inspections.

Mid-Cycle Vegetation Management Project Costs (in thousands)	
2020	$100
2021	$1,200
2022	$3,500
2023	$4,000
2024	$5,600
2025	$6,000
2026	$5,700
2027	$6,200
2028	$7,300
2029	$6,300

6.2.2.3 Initiative 3: 69kV VM Reclamation

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

An additional benefit to the Project is improved access. One of the VM lessons learned from recent storm recovery efforts is

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that unobstructed access to transmission facilities is critical to minimizing restoration times. Clearing these vegetation-obstructed areas will reduce outage potential, allow for faster restoration times, and lower restoration costs due to the following:

- Improving vegetation to conductor clearances will reduce blow-in outages;

- Removing hazard trees will reduce fall-in outages;

- Removing vegetation overgrowth will allow the ground to dry faster, promoting deeper tree roots and improving accessibility, reducing the need for access matting;

- Outage locations can be identified much easier, up to 200 percent faster;

- Damage assessment can be completed more accurately;

- Safer work sites reduce the number of personnel and equipment needed to restore; and

- Normal line and vegetation inspection and maintenance costs will be reduced by the improved clearances and unobstructed access.

The time to restore transmission outages is dependent on several factors, such as voltage, switching, design, and other facility impacts, but the key factor to restoration is accessibility. Outages that occur in areas obstructed by vegetation, on average, take up to 75 percent longer to restore. Tampa Electric has identified areas along the 69kV system where these vegetative conflicts and obstructions exist and mapped them to determine Project scope, cost, and schedule. The entire 69kV Vegetation Reclamation Initiative is a short-term initiative planned for four years beginning in 2020 and concluding in 2023. The Project scope and cost detail for the 69kV Vegetation Reclamation Initiative is listed below.

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

6.2.3 Estimated Costs – VMP

Tampa Electric and Accenture estimate that, in total, approximately 270 VM contract trimmers and six contract forestry inspectors will be needed for all distribution VM activities once the new initiatives are scaled up to their future steady state. The 69kV Reclamation Initiative will require approximately 40 VM total contract trimmers to complete.

6.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of this initial ten-year SPP. Tampa Electric has over 25,400 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 20 percent are supported with wood poles. Historically, the company's transmission hardening Program focused on replacing existing wood transmission poles with non-wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2019, the company hardened 8,971 wood transmission structures with non-wood material as a part of the existing Storm Hardening Plan. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood

transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

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

access issues to be addressed.

The table below shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	21	$5.6
2021	35	$15.2
2022	28	$15.0

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

6.4 Substation Extreme Weather Hardening

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

Tampa Electric engaged 1898 & Co. to perform preliminary analysis and prioritization of the company's 216 substations. The SLOSH model, described in the 1898 & Co. report included as

Appendix "F", identified 59 of these 216 substations with some level of flooding risk and the height of a wall needed to mitigate that risk. The 59 substations were evaluated and prioritized in the model using only the single solution of building a flood wall around the perimeter of each substation. Using this methodology, the model identified 11 substations that were prioritized to be hardened within the 2020-2029 SPP.

Tampa Electric will begin this Program in early 2021 by engaging an additional third-party consultant that specializes in substation engineering and asset management to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled. This study will include the 11 identified substations, as well as others that Tampa Electric subject matter experts determine have potential vulnerability to extreme weather. The study, to be completed by the end of 2021, will examine the potential for flooding for each substation, flood mitigation options, and provide an engineering recommendation for station flood protection or mitigation, if applicable. The study is estimated to cost $250,000 and will also include:

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

The Company expects the 2021 study and analysis to identify the proper hardening solution for each of the substations, with cost estimates that are more reflective of the unique characteristics of each substation. Once the study is complete, Tampa Electric will determine a final prioritized list of Substation Extreme Weather Protection Projects. The required Project-level information will be provided at the appropriate filing

opportunity in the Storm Protection Plan Cost Recovery Clause
Docket.

The table below shows the Substation Extreme Weather Hardening
Program's Projects by year and projected costs for the first
three years of the 2020-2029 SPP:

Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	0	$0.0
2021	1 (Note 1)	$0.3
2022	0	$0.0

Note 1: The Project identified in 2021 is the further
study of potential substation solutions as described
above.

6.5 **Distribution Overhead Feeder Hardening**

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

6.5.1 Distribution Feeder Strengthening

These enhancements will incorporate changes to the Company's distribution design standards to focus on the physical strength of Tampa Electric's distribution infrastructure. The company plans to harden selected feeders to meet NESC construction Grade B criteria with the Rule 250C (Extreme Wind) loading and strength criteria applied. This will involve the evaluation of the feeder, including a thorough review of the poles, conductor and equipment to determine the upgrades necessary to ensure the feeder meets new hardened design and construction standards.

6.5.2 Distribution Feeder Sectionalizing and Automation

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

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

Upgraded conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgraded additional transformer capacity at strategic substations will ensure maximum load restoration capacity.

Combined, these design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Tampa Electric has approximately 800 distribution circuits, which were prioritized based on their reliability performance and priority customer count to identify the target circuits for the 2020-2022 timeframe. Reliability performance was considered for both extreme weather and blue-sky days with a higher weighting factor assigned to circuit reliability under extreme weather conditions.

With a list of (22) circuits targeted for an OH distribution investment, Tampa Electric identified improvements on each circuit that would result in increased sectionalizing of the system with the following measures:

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

For 2020 implementation, the company identified circuits for improvement that require minimal engineering, minimal lead-time on material and do not require permits. Circuit improvements that require complex engineering, longer lead-times for materials and could result in local and state permits and approval have been scheduled for 2021 and 2022 in-service dates. The remainder of the SPP years (2023-2029) were prioritized by the model.

The table below shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	5	$6.5
2021	18	$15.4
2022	13	$29.6

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

6.6 Transmission Access Enhancement

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

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

management Program for all high voltage circuits, 200kV and above. These routes are necessary to ensure compliance.

The company has identified a total of 70 potential Access Road Projects, subdivided by circuit. In many cases, more than one circuit benefits from the installation or repair of the road. While engineering will determine the exact scope and cost of the road, company subject matter experts developed a preliminary cost estimate for each Project that was used in the 1898 & Co. model for cost-benefit prioritization. The costs were based on the number of road miles and construction type. The total Access Roads initiative costs are detailed below for the 20 Access Road Projects proposed in the 2020-2029 SPP:

Access Road Projects Costs (in thousands)	
2020	$0
2021	$604
2022	$391
2023	$0
2024	$810
2025	$978
2026	$0
2027	$3,325
2028	$1,982
2029	$1,065

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

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

The company currently maintains a total of 24 bridges, with three of these bridges being recently installed in a transmission upgrade Project. In addition to the 21 current bridges identified for replacement, the company identified an additional five bridges for a net total of 26 potential bridge Projects. The total Access Bridges initiative costs are detailed below for the 17 Access Bridge Projects proposed in the 2020-2029 SPP:

Access Bridge Project Costs (in thousands)	
2020	$0
2021	$780
2022	$1,118
2023	$1,606
2024	$853
2025	$360
2026	$354
2027	$0
2028	$0
2029	$601

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

Tampa Electric used 1898 & Co.'s resilience-based modeling described in Appendix "F" to evaluate the cost-benefit expectation for each of the 96 Access Enhancement Projects. Since permitting is the primary driver of the schedule, it was assumed that Access Projects could not begin until 2021. The model then developed a prioritization of these Projects based on the cost-benefit expectations. This SPP Plan reflects the completion of 37 Access Enhancement Projects over the ten-year SPP.

The table below shows the Transmission Access Enhancements Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

	Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	0	$0.0
2021	8	$1.4
2022	6	$1.5

6.7 Infrastructure Inspections

Tampa Electric's Infrastructure Inspection Program is a comprehensive inspection Program that combines the existing Commission approved Storm Hardening Plan Initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

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

Tampa Electric has not historically attempted to quantify the benefits of these inspection activities because they were required by Commission Order. In those Orders, the Commission found that these activities offered significant storm resiliency benefits. For instance, the Commission found that wood pole inspections and corrective maintenance "can reduce the impact of hurricanes and tropical storms upon utilities' transmission and distribution systems." Order No. PSC-06-0144-PAA-EI. The Commission also found that wood pole inspections reduce

restoration times because, in the named storms in Florida in 2004 and 2005, "the number of failed poles resulting from a storm [were] correlated with the number of days required to restore service to customers." Order No. PSC-06-0144-PAA-EI. The Commission later found that a transmission structure inspection program would offer similar benefits. Order No. PSC-06-0351-PAA-EI. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because "[u]tility poles that are overloaded or approaching overloading are subject to failure in extreme weather." Order No. PSC-06-0351-PAA-EI. Tampa Electric believes that infrastructure inspection activities still offer these benefits.

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

6.7.1 Wood Pole Inspections

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

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission and distribution

poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair, reinforcement or replacement to meet strength requirements of the NESC.

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

Tampa Electric estimates that this initiative will cost approximately $1,000,000 annually over the ten-year horizon of this SPP.

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

6.7.2 Transmission Inspections

Tampa Electric will continue to conduct the multi-pronged inspection approach the company has historically applied to the system which has led to the transmission system having a history of strong reliability performance. This approach includes the eight-year above ground structure inspection cycle, eight-year ground line wood inspection cycle, annual ground patrol, annual aerial infrared patrol, annual substation inspection cycle and the pre-climb inspection requirement. Tampa Electric will continue these inspections and will also continue the company's ongoing efforts to monitor and evaluate the appropriateness of its transmission structure inspection program to ensure that any

cost-effective storm hardening or reliability opportunities found are taken advantage of.

Tampa Electric estimates the annual cost of this initiative is approximately $360,000 over the ten-year Plan horizon. Tampa Electric believes this cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

6.7.2.1 Groundline Inspections

Tampa Electric conducts groundline inspections in compliance with the Commission's order requiring groundline inspection of wooden transmission structures. A groundline inspection includes excavation, sounding and boring wood poles. Excavation requires removing earth at the base of the pole around the entire circumference to a minimum depth of 18 inches below groundline. All poles passing the excavation inspection will then be sounded with a hammer. If sounding provides evidence of possible interior voids or rot, at least one boring shall be made where the void is indicated. If rot or voids are detected, enough boring shall be made so that the extent can be determined. Poles set in concrete, or otherwise inaccessible below groundline, shall be bored at least twice at groundline at a 45-degree downward direction. All bored holes shall be plugged with treated dowels. Groundline inspections are performed on an eight-year cycle. Each year approximately 12.5 percent of all wooden transmission structures are scheduled for inspection. For 2020 through 2022, the company plans to perform approximately 1,750 groundline inspections over the three-year period.

6.7.2.2 Ground Patrol

The ground patrol is a visual inspection for deficiencies including poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware and

encroachment. The ground patrol will include identification of vegetation encroachment as well as all circuit deficiencies. All transmission circuits are patrolled by ground at least once each year.

6.7.2.3 Aerial Infrared Patrol

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

6.7.2.4 Above Ground Inspections

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

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UAS has allowed the company to complete the Above Ground Inspections in conjunction with the Ground Patrol utilizing the UAS for an aerial view of the structures identified for the comprehensive inspection.

For 2020 through 2022, annual above ground inspections are planned on approximately 10,500 structures. This is in line with the company's petition that changed the above ground inspection cycle from a six-year cycle to an eight-year cycle which was approved in Docket 20140122-EI, Order No. PSC-14-0684-PAA-EI and confirmed by Consummating Order No. PSC-15-0017-CO-EI.

6.7.2.5 Substation Inspections

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

Tampa Electric estimates that the annual cost of these inspections is approximately $150,000 over the ten-year horizon of the SPP.

6.7.2.6 Pre-Climb Inspections

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

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

6.7.3 Joint Use Pole Attachments Audit

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

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

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

There is no incremental cost of this initiative as each audit is ultimately paid for by the joint attacher.

6.7.4 Infrastructure Inspections Summary

The Infrastructure Inspection Program has no estimated completion date because the inspection activities are continuous and ongoing. The infrastructure inspection activities are either part of an ongoing cycle – such as wood pole and transmission structure inspections – or only occur when triggered by a specific event – such as pre-climb and joint use inspections. Given the nature of this Program, Tampa Electric concluded that it was not practical or feasible to identify specific Storm Protection Projects under this Program. Instead, the table below shows the number of infrastructure inspections the company is projecting over the 2020-2022 storm Protection Plan period.

Projected Number of Infrastructure Inspections			
	2020	2021	2022
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	22,500	22,500	35,625
Groundline Inspections	13,275	13,275	21,018
Transmission			
Wood Pole/Groundline Inspections	702	367	707
Above Ground Inspections	2,949	3,895	3,396
Aerial Infrared Patrols	Annually	Annually	Annually
Ground Patrols	Annually	Annually	Annually
Substation Inspections	Annually	Annually	Annually

Note 1: Tampa Electric completed its most recent Joint Use Pole Attachment Audit in the first quarter of 2020.

The table below provides the annual O&M expenses for each of the inspection programs for the 2020-2022 period.

Projected Costs of Infrastructure Inspections (in thousands)			
	2020	2021	2022
Distribution			
Wood Pole/Groundline Inspections	$708	$1,000	$1,020
Transmission			
Wood Pole/Groundline Inspections	$60	$61	$62
Above Ground Inspections	$10	$10	$10
Aerial Infrared Patrols	$110	$112	$114
Ground Patrols	$145	$148	$151
Substation Inspections	$140	$143	$146

6.8 Legacy Storm Hardening Plan Initiatives

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

project. In this internal analysis, the company would project the costs and estimate the benefits that should be realized. Tampa Electric recognizes that assigning a monetary value to customer benefits is challenging due to the lack of specific information about the financial impacts of outages, and because assigning value to public safety and health may skew the project's benefit analysis.

6.8.1 Geographic Information System

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. All new computing technology requests and new initiatives are evaluated with a goal to eliminate redundant, exclusive and difficult to update databases as well as to place emphasis on full integration with Tampa Electric's business processes. These evaluations further cement GIS as the foundational database for Tampa Electric's facilities.

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

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is $0 because the company's GIS system is an integral system used by the company to maintain its transmission and distribution asset information. Tampa Electric

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will continue to update and make improvements/enhancements to its GIS as needed.

6.8.2 Post-Storm Data Collection

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

- Pole/Structure – type of damage, size and type of pole, and likely cause of damage;
- Conductor – type of damage, conductor type and size, and likely cause of damage;
- Equipment – type of damage, overhead or underground, size, and likely cause of damage; and
- Hardware – type of damage, size and likely cause of damage.

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

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

The incremental cost of this initiative is estimated to be approximately $113,000 per storm and will depend on the severity of the storm and extent of system damage.

6.8.3 Outage Data - Overhead and Underground Systems

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

- Centralized capture of outage related data;
- Analysis and clean-up of outage-related data;
- Maintenance and adjustment to distribution outage database data;
- Automatic Generation and distribution of canned reliability reports; and
- Generating ad hoc operational and managerial reports.

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

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

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underground systems are correctly assessed.

The company does not propose any specific DOD Projects because there will only be DOD activity when there are storm related outages, and the company cannot predict when storm-related outages will occur during the ten-year planning horizon.

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

6.8.4 Increase Coordination with Local Governments

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

The company does not propose any specific local government coordination Projects because these activities occur intermittently and often on an unplanned basis before, during, and after severe weather events.

There are no incremental costs associated with this activity.

6.8.5 Collaborative Research

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

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

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

6.8.6 Disaster Preparedness and Recovery Plan

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

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

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

Tampa Electric will also continue to plan, participate in, and conduct internal and external preparedness exercises, collaborating with government emergency management agencies, at the local, state and federal levels. Internal company exercises focus on testing lessons learned from prior exercises/activations, new procedures, and educating new team members on roles and responsibilities in the areas of incident command, operations, logistics, planning and finance. The scope and type of internal exercises vary from year to year based on exercise objectives defined by a cross-functional exercise design team, following the Homeland Security Exercise and Evaluation Program ("HSEEP"). External preparedness exercises are coordinated by local, state and federal governmental emergency management agencies. Tampa Electric personnel participate in these exercises to test the company's internal emergency response plans, including coordination with Emergency Support Functions ("ESF") to maintain key business relationships at local Emergency Operation Centers ("EOC"). Like Tampa Electric, the exercise type (tabletop, functional or full-scale) and scope varies from year to year, and

depending upon the emergency management agencies' exercise objectives, Tampa Electric participants may not be included.

Annually, Tampa Electric participates in the State of Florida's hurricane exercise with the FPSC, which often coincides with exercises conducted by Hillsborough, Pasco, Pinellas and Polk counties. In addition, municipalities within Tampa Electric's service area (Oldsmar, Plant City, Tampa and Temple Terrace) may also host exercises and/or pre-storm season briefings. For example, in 2019, Tampa Electric participated in exercises and/or pre-storm briefings hosted by the State of Florida (in conjunction with FPSC), Hillsborough and Pinellas counties, as well as the cities of Oldsmar, Tampa and Temple Terrace. However, in 2020, Tampa Electric has been advised that the State of Florida will not conduct an annual hurricane exercise. As a result, some counties and municipalities are following the State's lead.

Tampa Electric has been incorporating Lessons Learned from Hurricane Irma and the company's experience supporting the restoration for Hurricane Michael into the company's Emergency Response plans. While the updates cover a broad category or processes, a focus has been on insuring the plan can scale up to handle major storms (Cat 3, 4, 5), in Logistics (life support) and the ability to restore internal communications in the event public networks are negatively impacted (Internet, cellular and satellite).

Tampa Electric will implement a Damage Assessment tool as an integrated part of its Advanced Distribution Management System ("ADMS") scheduled for implementation in 2021.

The total cost to support all Emergency Management activities and initiatives is estimated to be $300,000 annually.

6.8.7 Distribution Pole Replacements

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

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

Tampa Electric estimates the annual capital and O&M costs of this initiative is approximately $13,300,000 over the ten-year Plan horizon.

6.8.8 Legacy Storm Hardening Plan Initiatives Costs

The table below shows the projected costs for the first three years of the 2020-2029 SPP for the Legacy Storm Hardening Plan Initiatives:

Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)		
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2020	$0.3	$9.9
2021	$0.3	$11.8
2022	$0.3	$15.5

Tampa Electric developed the projected 2020-2029 SPP costs by examining the time, the scope of work, and reasonably expected costs for each of the SPP Programs. To develop the company's estimations of costs, Tampa Electric relied upon the following key underlying assumptions:

1. Initially, the company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This initially was determined to be between 100 to 200 million dollars on an annual basis, based upon work constraints.

2. Recognizing the sustained amount of work it would take for external resource companies to physically build or obtain a work force that could support several ongoing Storm Protection Programs.

3. Recognizing that there will be some competition for resources between utilities which could push costs upward.

4. Identification of the range of work necessary for each Storm Protection Program and the feasibility of success with external resources.

5. The costs would be made up of new incremental capital and O&M costs for each of the proposed Storm Protection Programs and their associated Projects.

6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2020-2029 spend at approximately $1.5 billion over the ten-year Plan.

7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be between 100 to 200 million on an annual basis.

8. Actual historical costs would be used where the company has significant history and recent experience in developing the cost for each type of Project. Costs were also analyzed for impacts for potential competition and

future contractor capacity impacts.

9. Costs were validated for reasonableness and range by a variety of means, either in discussions amongst internal team members with this experience, discussions with Accenture LLP and 1898 & Co., or discussions with neighboring utilities.

10. Costs were used to complete SPP programs within the designated proposed timeline as described in the Transmission Asset Upgrade Program and the 69kV Reclamation initiative within the Vegetation Management Program.

11. Recognizing costs were projected based upon single solution modeling for the Substation Extreme Weather Hardening Program. The company needs to evaluate other potential solutions and opportunities before committing to an appropriate cost-effective solution for Tampa Electric's substations.

12. The company will continue the components of the Commission's legacy Storm Hardening Plan and will seek recovery of the costs associated with these activities through the SPPCRC, with the exception of the Geographical Information System, Post-Storm Data Collection, Increased Coordination with Local Governments, Disaster Preparedness and Recovery Plan, Distribution Pole Replacements, and unplanned (reactive) vegetation management.

13. The company would show with transparency the total costs for the proposed 2020-2029 SPP, the total revenue requirements for the proposed 2020-2029 SPP, and the total revenue requirements which would be recoverable through the Storm Protection Plan Cost Recovery Clause.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total costs (capital and O&M) by Programs:

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Tampa Electric's 2020-2029 Storm Protection Plan Total Costs by Program (in Millions)

Capital	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Lateral Undergrounding	$8.00	$79.45	$108.08	$101.44	$107.00	$110.78	$113.96	$111.42	$115.52	$121.17	$976.81
Transmission Asset Upgrades	$5.50	$15.21	$14.98	$16.51	$11.99	$19.04	$17.92	$16.28	$19.56	$12.11	$149.12
Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$7.34	$5.54	$4.67	$6.71	$5.24	$2.88	$32.37
Distribution Overhead Feeder Hardening	$6.50	$15.38	$29.58	$33.39	$32.49	$33.19	$33.82	$32.76	$36.36	$36.25	$289.73
Transmission Access Enhancements	$0.00	$1.38	$1.52	$1.56	$1.66	$1.40	$0.54	$3.17	$1.93	$1.57	$14.73
Distribution Pole Replacements	$9.42	$11.18	$14.72	$15.16	$15.62	$16.09	$10.64	$10.86	$11.07	$11.29	$126.05

O&M	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Vegetation Management - planned	$16.49	$19.76	$21.18	$24.00	$24.22	$25.55	$26.77	$27.99	$29.42	$30.94	$246.31
Distribution Vegetation Management - unplanned	$1.30	$1.30	$1.20	$1.10	$1.10	$1.10	$1.20	$1.20	$1.30	$1.30	$12.10
Transmission Vegetation Management - planned	$2.63	$3.53	$3.59	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$32.95
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.11	$0.30	$0.30	$0.33	$0.24	$0.38	$0.36	$0.33	$0.39	$0.24	$2.98
Distribution Overhead Feeder Hardening	$0.21	$0.38	$0.40	$0.79	$0.82	$1.02	$1.06	$1.17	$1.42	$1.64	$8.92
Distribution Infrastructure Inspections	$0.71	$1.00	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$10.46
Transmission Infrastructure Inspections	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.56	$5.09
SPP Planning & Common	$0.99	$0.39	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$3.10
Other Legacy Storm Hardening Plan Items	$0.28	$0.28	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$3.01
Distribution Pole Replacements	$0.52	$0.62	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$6.93

Tampa Electric developed the 2020-2029 SPP projected costs and benefits for each of the proposed SPP Programs through the thorough and comprehensive analysis the company performed with Accenture LLP and 1898 & Co. Accenture, as described above, modeled the current VM Program against the proposed SPP initiatives during extreme weather. For the other SPP Programs, Tampa Electric worked with 1898 & Co. to evaluate the benefits of the 10-year Programs against a status quo scenario. Both the reduction in restoration costs and the reduction in customer minutes of interruption show the percentage improvement expected during major event days from the SPP Programs when compared to the status quo.

Tampa Electric - Proposed 2020-2029 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	$976.8	$0.0	33	44	Q2 2020	After 2029
Vegetation Management	$0.0	$279.3	21	22 to 29	Q2 2020	After 2029
Transmission Asset Upgrades	$148.9	$3.0	90	13	Q2 2020	2029
Substation Extreme Weather	$32.4	$0.0	70 to 80	50 to 65	Q1 2021	After 2029
Distribution Overhead Feeder	$289.7	$8.9	38 to 42	30	Q2 2020	After 2029
Transmission Access Enhancements	$14.8	$0.0	10	74	Q1 2021	After 2029

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2020-2029 SPP Programs plus depreciation and return on

SPP, as outlined in Rule 25-6.030 F.A.C. The estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures using the depreciation rates from Tampa Electric's most current depreciation study. In addition, the depreciation expense has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital Projects. Lastly, in accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the company's 2012 Stipulation and Settlement Agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report. Only capital expenditures for SPP Projects after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total revenue requirements (capital and O&M) by Program:

Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions)

Capital	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Lateral Undergrounding	$0.19	$4.66	$13.83	$23.93	$33.76	$43.83	$54.01	$64.01	$73.84	$83.91	$395.97
Transmission Asset Upgrades	$0.14	$1.25	$2.69	$4.16	$5.45	$6.82	$8.45	$9.91	$11.40	$12.66	$62.93
Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.28	$0.95	$1.42	$1.93	$2.47	$2.82	$9.87
Distribution Overhead Feeder Hardening	$0.14	$1.33	$3.42	$6.33	$9.30	$12.19	$15.06	$17.83	$20.64	$23.53	$109.77
Transmission Access Enhancements	$0.00	$0.06	$0.19	$0.33	$0.48	$0.61	$0.69	$0.85	$1.07	$1.22	$5.50
Distribution Pole Replacements	$0.25	$1.41	$2.60	$3.96	$5.32	$6.69	$7.79	$8.61	$9.42	$10.22	$56.27

O&M	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Vegetation Management – planned	$16.49	$19.76	$21.18	$24.00	$24.22	$25.55	$26.77	$27.99	$29.42	$30.94	$246.31
Distribution Vegetation Management – unplanned	$1.30	$1.30	$1.20	$1.10	$1.10	$1.10	$1.20	$1.20	$1.30	$1.30	$12.10
Transmission Vegetation Management – planned	$2.63	$3.53	$3.59	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$32.95
Transmission Vegetation Management – unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.11	$0.30	$0.30	$0.33	$0.24	$0.38	$0.36	$0.33	$0.39	$0.24	$2.98
Distribution Overhead Feeder Hardening	$0.21	$0.38	$0.40	$0.79	$0.82	$1.02	$1.06	$1.17	$1.42	$1.64	$8.92
Distribution Infrastructure Inspections	$0.71	$1.00	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$10.46
Transmission Infrastructure Inspections	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.56	$5.09
SPP Planning & Common	$0.99	$0.39	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$3.10
Other Legacy Storm Hardening Plan Items	$0.28	$0.28	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$3.01
Distribution Pole Replacements	$0.52	$0.62	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$6.93

8 Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts of the Storm Protection Plan for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through the Storm Protection Plan Cost Recovery Clause ("SPPCRC") rates initiating in January 2021.

Each year's costs derive from the SPP Programs described in this Plan and are the capital and O&M costs combined into a revenue requirement. For each year, the SPP Programs were itemized and identified as to whether they are substation, transmission or distribution costs. Each of those functionalized costs were then allocated to the appropriate rate class using the allocation factors for that function.

The allocation factors used were from the Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI which was used for the current company's base rate design. Using these factors assures that the incremental SPP costs are being recovered from customers in the same manner as the comparable costs included in base rates are being recovered through current base rates.

Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the clause rates were determined in the same manner as current clause rates are designed.

For Residential, the charge is a kWh charge.   For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the most recent 2020 energy billing

determinants (for residential) and by the most recent 2020 demand billing determinants (for commercial and industrial). Those clause charges were then applied to the billing determinants associated with typical bills for those groups to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

A similar procedure will be used to derive actual clause charges in the clause cost recovery docket to come this summer, but in that case applied to all rate classes and using 2021 projected billing determinants.

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

Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
Customer Class			
Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

The rate impacts presented above reflect the total cost of the SPP, even though some of the costs in the Plan are currently being recovered through base rates and the incremental cost of the Plan to customers will be less than shown above. For example, using the average of the certain actual storm hardening costs reflected in the company's operation and maintenance

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expenses for 2017, 2018 and 2019 as a proxy, Tampa Electric estimates that the revenue requirement associated with amount of SPP O&M expenses currently being recovered through base rates is approximately $12.9 million.

9 Storm Protection Plan Alternatives and Considerations

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

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

As described in the overview, the company engaged Accenture to evaluate several initiatives to enhance existing vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits.

Tampa Electric and 1898 & Co. used the resilience-based planning approach to establish an overall capital budget level and to identify and prioritize resilience investment in the company's T&D system. The budget optimization analysis was performed in $250 million increments up to $2.5 billion. The analysis showed

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significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion. The company's overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's SPP has an appropriate level of investment over the 2020-2029 ten-year period capturing the Storm Protection Projects that provide the most value to customers.

In addition to the Programs included in the 2020-2029 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in the Plan. Examples of things considered, but not included in this initial ten-year SPP are as follows:

- Undergrounding Distribution Feeders – The majority of customers are on laterals and analysis demonstrated higher cost-benefit to harden feeders and underground laterals.
- Upgrading wood distribution poles to non-wood materials – The company will continue to evaluate this option as manufacturing capabilities improve. At this time, the upgraded wood materials provide the best cost-benefit ratio for customers.
- Purchasing additional temporary access solutions such as increasing the number of mats – The solutions proposed in this Plan are more cost-effective and sustainable

As in the past with the company's prior Storm Hardening Plan Initiatives, Tampa Electric will also examine and analyze the processes and procedures used to implement the company's proposed 2020-2029 SPP Programs for any ongoing continuous improvement opportunities. This examination will assist in mitigating the resulting rate impact and ensure the benefits from the proposed SPP are realized.

Tampa Electric's

2020-2029

Storm Protection Plan

Appendices

Appendix A

Project Detail

Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding - Year 2020 Details

Project ID	Circuit No.	Specific Project Detail		Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2020
		OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-60588225	13174	0.29	15	374	34	1	409	1	Q2 2020	Q3 2020	Q4 2020	$125,235
Lateral Hardening-Fuse-10786382	14040	0.23	13	98	6	2	106	10	Q2 2020	Q3 2020	Q4 2020	$150,431
Lateral Hardening-Fuse-90755954	13454	0.30	23	292	21	1	314	0	Q2 2020	Q3 2020	Q4 2020	$238,629
Lateral Hardening-Fuse-60451701	13174	0.24	14	301	11	2	314	0	Q2 2020	Q3 2020	Q4 2020	$230,114
Lateral Hardening-Fuse-10933151	13897	0.79	33	64	20	1	85	1	Q2 2020	Q3 2020	Q4 2020	$221,051
Lateral Hardening-Fuse-92421291	13972	0.44	23	379	6	1	386	0	Q2 2020	Q3 2020	Q4 2020	$248,973
Lateral Hardening-Fuse-92881445	13710	0.45	32	158	17	0	175	0	Q2 2020	Q3 2020	Q4 2020	$401,397
Lateral Hardening-Fuse-92599119	13390	0.72	46	266	27	3	296	0	Q2 2020	Q3 2020	Q4 2020	$750,732
Lateral Hardening-Fuse-92407065	13815	0.38	15	12	3	1	16	0	Q2 2020	Q3 2020	Q4 2020	$68,399
Lateral Hardening-Fuse-93019714	13840	0.13	9	39	2	0	41	0	Q2 2020	Q3 2020	Q4 2020	$51,112
Lateral Hardening-Fuse-92634300	14032	0.31	21	306	10	2	318	1	Q2 2020	Q3 2020	Q4 2020	$390,745
Lateral Hardening-Fuse-60287236	13509	0.15	14	144	14	0	158	0	Q2 2020	Q3 2020	Q4 2020	$175,078
Lateral Hardening-Fuse-60182741	13312	0.15	15	52	11	7	70	0	Q2 2020	Q3 2020	Q4 2020	$101,387
Lateral Hardening-Fuse-90241880	13972	0.90	49	130	7	6	143	0	Q2 2020	Q3 2020	Q4 2020	$687,129
Lateral Hardening-Fuse-10643541	13390	1.17	67	221	22	2	245	0	Q2 2020	Q3 2020	Q4 2020	$1,095,650
Lateral Hardening-Fuse-10786374	14040	0.27	16	205	13	0	218	11	Q2 2020	Q3 2020	Q4 2020	$334,434
Lateral Hardening-Fuse-92829453	13961	0.34	25	447	3	2	452	0	Q2 2020	Q3 2020	Q4 2020	$292,496
Lateral Hardening-Fuse-91406672	13836	0.35	25	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$248,786
Lateral Hardening-Fuse-90288627	13815	0.88	32	51	9	0	60	0	Q2 2020	Q3 2020	Q4 2020	$423,948
Lateral Hardening-Fuse-91432109	13071	0.14	15	20	5	0	25	0	Q2 2020	Q3 2020	Q4 2020	$163,279
Lateral Hardening-Fuse-90738378	13071	0.16	20	296	35	0	331	0	Q2 2020	Q3 2020	Q4 2020	$145,327
Lateral Hardening-Fuse-90911087	13724	0.54	32	31	4	0	35	6	Q2 2020	Q3 2020	Q4 2020	$423,395
Lateral Hardening-Fuse-93026469	13815	0.49	15	27	2	0	29	0	Q2 2020	Q3 2020	Q4 2020	$375,085
Lateral Hardening-Fuse-10629014	13146	0.54	30	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$608,468

Appendix B

Project Detail

Transmission Asset Upgrades

Tampa Electric's Transmission Asset Upgrades - Year 2020 Details						
Project ID	Circuit No.	Pole Count	Project Start Month	Construction		Project Cost in 2020
				Start Month	End Month	
Transmission Upgrades-69 kV-66654	66654	10	May-20	Jul-20	Jul-20	$317,000
Transmission Upgrades-69 kV-66840	66840	34	May-20	Jul-20	Aug-20	$1,077,800
Transmission Upgrades-69 kV-66007	66007	43	Jun-20	Aug-20	Aug-20	$1,363,100
Transmission Upgrades-69 kV-66019	66019	21	Jul-20	Sep-20	Oct-20	$665,700
Transmission Upgrades-69 kV-66425	66425	3	Jul-20	Oct-20	Oct-20	$95,100
Transmission Upgrades-138/230 kV-230403	230403	5	Jul-20	Oct-20	Oct-20	$105,700
Transmission Upgrades-69 kV-66413	66413	5	Jul-20	Oct-20	Oct-20	$158,500
Transmission Upgrades-69 kV-66046	66046	30	Jul-20	Oct-20	Nov-20	$939,900
Transmission Upgrades-69 kV-66059	66059	2	Aug-20	Nov-20	Nov-20	$63,400
Transmission Upgrades-138/230 kV-230008	230008	59	Aug-20	Nov-20	Jan-21	$700,150
Transmission Upgrades-138/230 kV-230010	230010	2	Sep-20	Jan-21	Jan-21	$900
Transmission Upgrades-138/230 kV-230038	230038	1	Oct-20	Jan-21	Jan-21	$450
Transmission Upgrades-138/230 kV-230003	230003	35	Oct-20	Jan-21	Feb-21	$15,750
Transmission Upgrades-138/230 kV-230005	230005	24	Oct-20	Feb-21	Feb-21	$10,800
Transmission Upgrades-138/230 kV-230004	230004	40	Nov-20	Feb-21	Mar-21	$18,000
Transmission Upgrades-138/230 kV-230625	230625	12	Nov-20	Mar-21	Mar-21	$5,400
Transmission Upgrades-138/230 kV-230021	230021	17	Nov-20	Mar-21	Apr-21	$7,650
Transmission Upgrades-138/230 kV-230052	230052	9	Dec-20	Apr-21	Apr-21	$2,700
Transmission Upgrades-69 kV-66024	66024	25	Dec-20	Apr-21	Apr-21	$27,750
Transmission Upgrades-138/230 kV-230608	230608	18	Dec-20	May-21	May-21	$7,200
Transmission Upgrades-138/230 kV-230603	230603	13	Dec-20	May-21	May-21	$1,800

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

Appendix C

Project Detail

Substation Extreme Weather Hardening

Reserved for Future Use

Appendix D

Project Detail

Distribution Overhead Feeder Hardening

| Project ID | Circuit No. | Specific Project Detail | Customers | | | | Priority Customers | Project Start Month | Construction | | Project Cost in 2020 |
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
Distribution Feeder Hardening-60067752	13308	Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles	1,220	260	36	1,516	26	May-20	Aug-20	Dec-20	$1,153,700
Distribution Feeder Hardening-60095496-Recloser-92203202	13807	Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles	1,159	103	16	1,278	12	May-20	Aug-20	Dec-20	$1,679,500
Distribution Feeder Hardening-60315127-Recloser-92189137	13805	Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles	356	61	4	421	0	May-20	Aug-20	Dec-20	$1,565,900
Distribution Feeder Hardening-60066445	13745	Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles	3,106	242	50	3,398	62	May-20	Aug-20	Dec-20	$833,150
Distribution Feeder Hardening-60064337	13533	Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles	2,161	235	36	2,432	34	May-20	Aug-20	Dec-20	$1,044,300

Appendix E

Project Detail

Transmission Access Enhancement

Reserved for Future Use

Appendix F

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

Storm Protection Plan Resilience Benefits Report

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 121429

Revision 0
4/10/2020

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

1.0   EXECUTIVE SUMMARY

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

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers

2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system

3. Establish an overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's Storm Protection Plan. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

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

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

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

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

1.1   Resilience Based Planning Approach

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

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

Figure 1-1: Storm Resilience Model Overview

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

Table 1-1:   Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is

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hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

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

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

1.2   Results & Conclusions

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

Figure 1-2: Budget Optimization Results

The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total with substations and transmission site access making up 2.2 percent and 1.0 percent, respectively. The plan

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includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

Figure 1-3: Storm Protection Plan Investment Profile

Customer benefits are calculated in terms of the:

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

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

Figure 1-4: Storm Protection Plan Restoration Cost Benefit

The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the restoration costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration cost benefit is approximately 36 to 53 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 36 to 53 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 1-5: Storm Protection Plan Customer Benefit

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

- ■ The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.

- ■ TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.

- ■ The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.

- ■ The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

- ■ TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.

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

2.0 INTRODUCTION

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

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

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

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

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades

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

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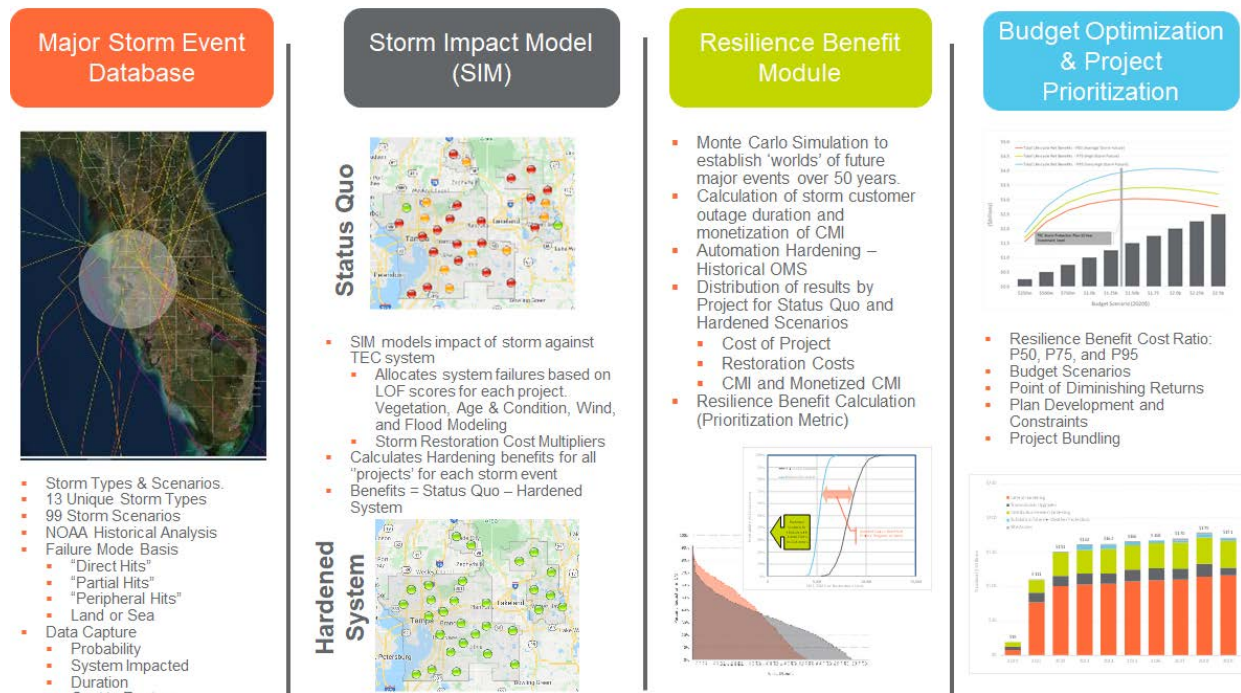- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

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

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

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

2.1   Resilience as the Benefits Assessment

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

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

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

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

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

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

- Prepare (Before)

  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)

  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)

  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

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

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

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

Figure 2-1: Phases of Resilience

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

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

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

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

2.2   Evaluated System for Resilience Investment

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

Table 2-1:   TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**216**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

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

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

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '2' were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening is the preferred approach for feeders.

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

TEC identified 96 separate transmission access, road, and bridge projects based on field inspection of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, over 20,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2:   Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

2.3   Resilience Planning Approach Overview

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

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

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

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2.3.1   Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events, the Storm Resilience Model starts with the 'universe' of major storm events that could impact TEC's service territory, the Major Events Storms Database.

Figure 2-2: Resilience Planning Approach Overview

The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events database includes the following:

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

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

2.3.2   Storm Impact Model

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

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

identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

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

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

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

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

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

2.3.3   Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4   Project Scheduling and Budget Optimization

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10 year period and portions of the system evaluated.

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

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

2.4   S-Curves and Resilience Benefit

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

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

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

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

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

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Figure 2-4: S-Curves and Future Storms

For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

Figure 2-5: S-Curves and Resilience Focus

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3.0   MAJOR STORMS EVENT DATABASE

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

- ■ Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- ■ Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if they have been over land for a period of time.
- ■ Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, only a few storm bands may hit the TEC service territory.

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

3.1   Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen

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shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

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

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

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

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

- ■ 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage

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

■ 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 3-1:   Historical Storm Summary

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

Table 3-1 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from has significant impact on the overall damage to TEC's system. Based on these results and the various

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quantities by event type, the following 13 unique storm types serves as the foundation for the Major Storms Event Database:

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

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

3.1.2   Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 167 years. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

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

Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100.

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

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

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

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[3] See Footnote 2

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The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Storms until 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2019, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3   Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 167 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory.   The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

Figure 3-5: "Partial Hits" (51 to 100 Miles)[4]

Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

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

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[4] See Footnote 2

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

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

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[5] See Footnote 2

3.1.4   Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 167 years. A storm is classified as a partial hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[6]

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

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

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[6] See Footnote 2

Figure 3-9: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Avg.[7]
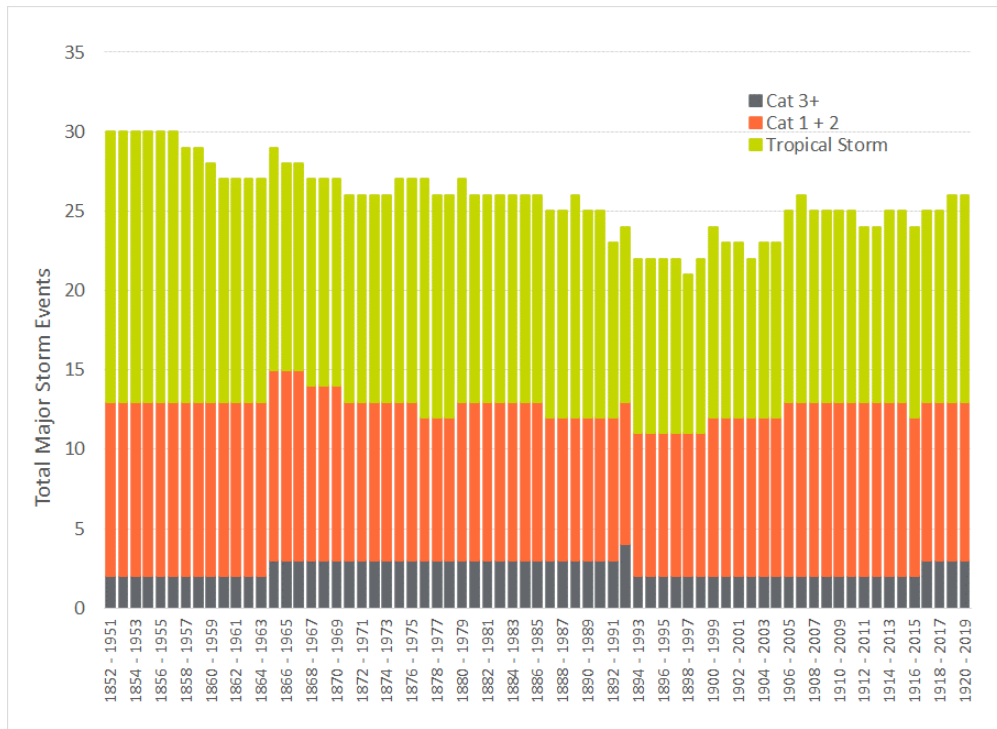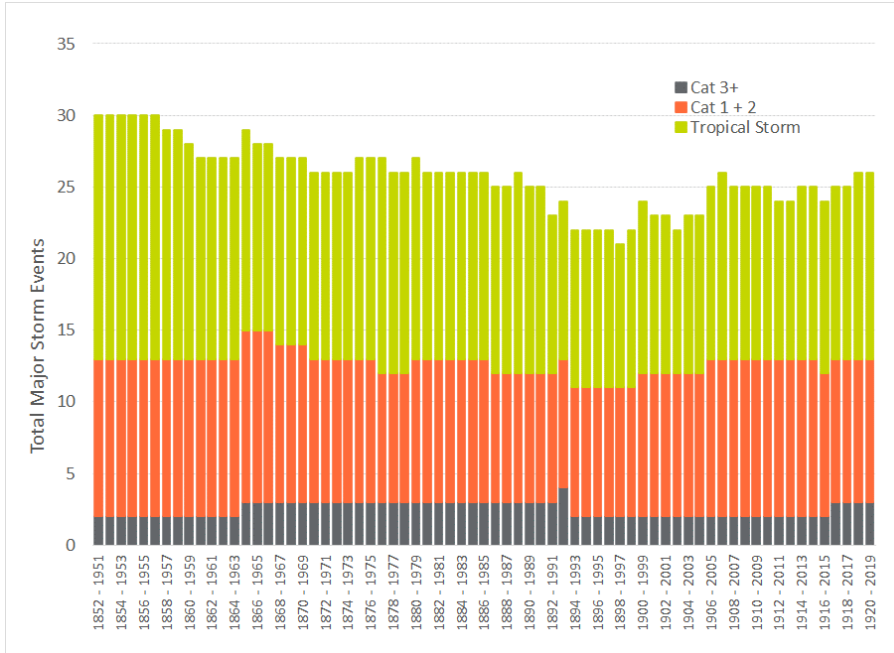
Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]

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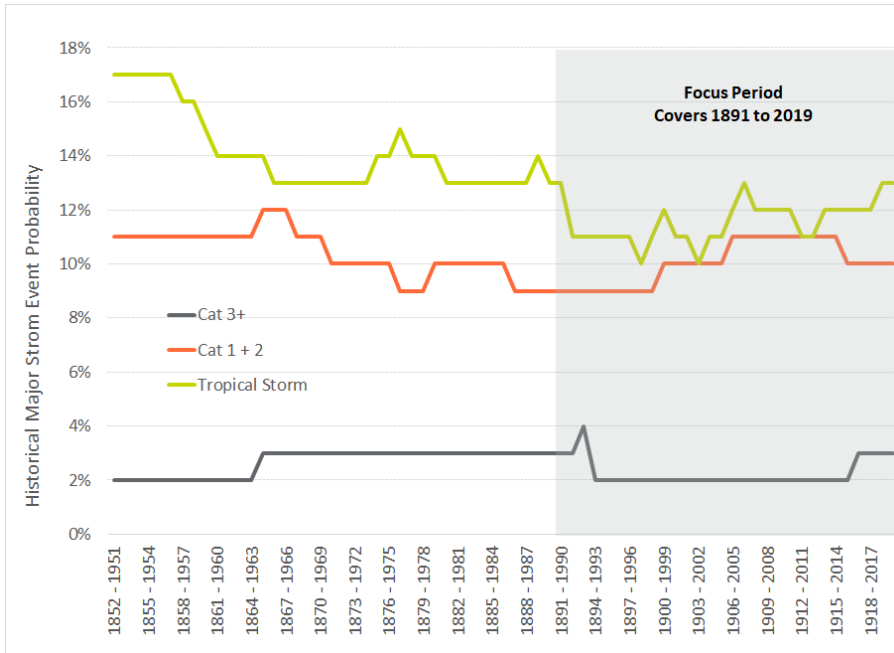
[7] See Footnote 2

3.2   Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 167 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

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

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

3.3   Major Storms Impact

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

Table 3-2:   Recent Major Event Damages Cost

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

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

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

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

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

Pos: 33.52 , -92.59   Search Center: 27.93 , -82.28

Table 3-3:   Storm Report Summary

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

3.4   Major Storms Database

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

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[8] See Footnote 2

Table 3-4:   Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

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4.0   STORM IMPACT MODEL

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

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

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

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

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Figure 4-1: Storm Impact Model Overview

4.1   Core Data Sets and Algorithms

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

4.1.1   Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up

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based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan.

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

Table 4-1:   TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**216**

Table 4-2:   Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	916
Total	19,666

4.1.2   Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The

OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3   Customer Type Data

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

Table 4-3:   Customer Counts by Type

Customer Type	Customer Count
Residential	695,000
Small Commercial and Industrial	71,100
Large Commercial and Industrial	16,300
Total	782,400

4.1.4   Vegetation Density Algorithm

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

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

Figure 4-2: Vegetation Density on TEC Primary Conductor

Figure 4-3: Vegetation Density on TEC Transmission Conductor

4.1.5   Wood Pole Inspection Data

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

4.1.6   Wind Zone

A third driver of storm-based failure is the asset's location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the

adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records

and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-4 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

Figure 4-4: Pole Wind Zone Distribution

4.1.7   Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8   ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman,

Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

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

4.1.9   Substation Flood Modeling

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

4.2   Weighted Storm Likelihood of Failure Module

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

4.2.1   Substation Storm Likelihood of Failure

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

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. This model provides the estimated feet of flooding above site elevation assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

4.2.2   Circuits Storm Likelihood of Failure

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

Figure 4-5 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are: wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density,

normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

Figure 4-5: Storm LOF Framework for Circuit Assets

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

Figure 4-6 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute on average 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-6: Age & Condition LOF Distribution

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

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

4.2.3   Site Access Storm Likelihood of Failure

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

4.3   Project & Asset Reactive Storm Restoration

The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles,

overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

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

4.4   Duration and Customer Impact

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

Figure 4-7: Example Storm Duration Profile

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

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would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 400, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

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

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5   'Status Quo' and Hardening Scenarios

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

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

5.0   RESILIENCE NET BENEFIT CALCULATION MODULE

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

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

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

5.1   Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

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

5.2   Project Cost

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

5.2.1   Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.1.7) were leveraged to estimate:

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

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

5.2.2   Transmission Asset Upgrades Project Costs

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

5.2.3   Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

5.2.4   Distribution Overhead Feeder Hardening Project Costs

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

5.2.5   Transmission Access Enhancements

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

5.3   Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 167 years.

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

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

Table 5-1: Monte Carlo Simulation Storm Event Selection

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

Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms. This calculation is repeated for all 1,000 iterations for the over 20,000 projects in the Storm Resilience Model.

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

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

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

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

5.4 Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 400 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS (see Section 4.1.2). TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the

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OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

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

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

Figure 5-2: Automation Hardening Percent CMI Decrease
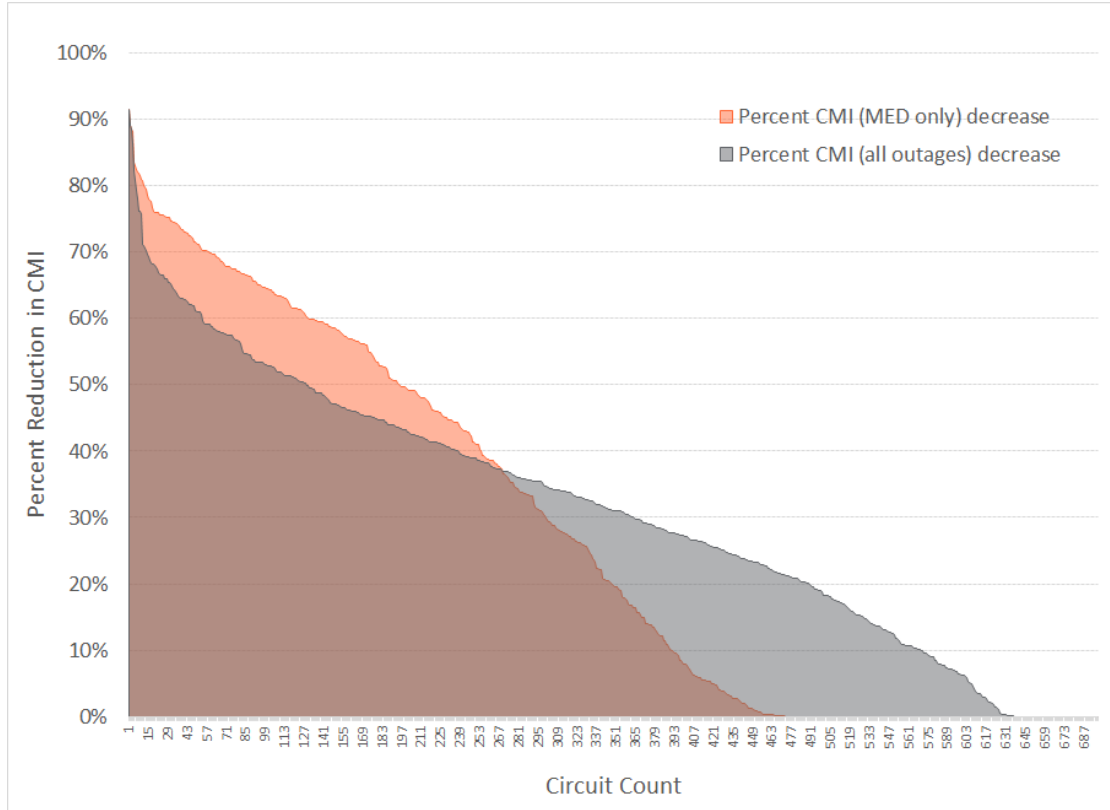
The resilience benefit calculation also monetized the CMI decrease using the ICE Calculator (Section 4.1.8). Figure 5-3 shows the percent decrease in monetized CMI for each circuit. The CMI was monetized and discounted over the 50-year time horizon to calculate the NPV. The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

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Figure 5-3: Automation Hardening Monetization of CMI Decrease

6.0   BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 20,000 projects. Resilience benefit values include:

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

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

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

The following sections discuss the prioritization metric, budget optimization, and approach to developing the Storm Protection Plan.

6.1   Prioritization Metric - Benefit Cost Ratio

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

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

investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2   Budget Optimization

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

Figure 6-1: Budget Optimization Results

The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection

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

6.3   Storm Protection Plan Project Prioritization

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

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time).

7.0   RESULTS & CONCLUSIONS

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

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

7.1   Storm Protection Plan

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

7.1.1   Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

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

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

7.1.2   Restoration Cost Reduction

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

Figure 7-1: Storm Protection Plan Restoration Cost Benefit

The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration costs decrease benefit is approximately 36 to 53 percent of the project costs.

7.1.3   Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit
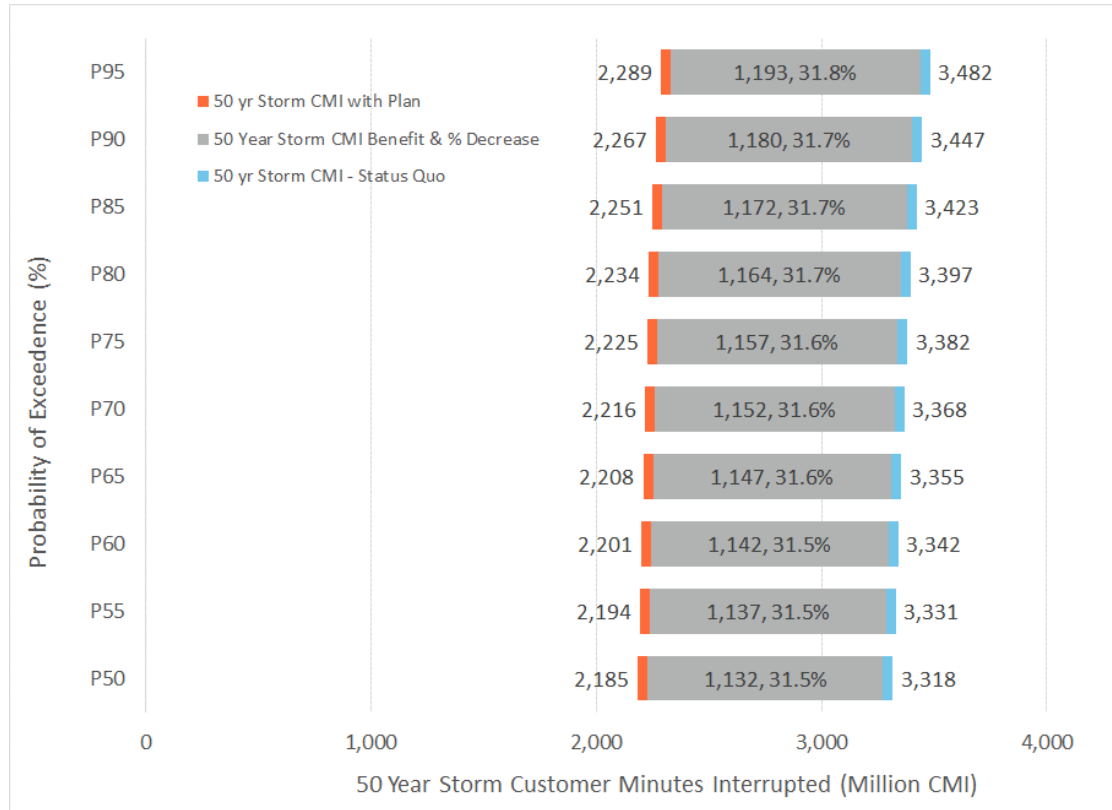
7.2   Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 131 different circuits.

Table 7-2:　Distribution Lateral Undergrounding Investment Profile

Year 1	Lateral Count	Miles	Nominal Cost ($000)
2020	24	10	$8,000
2021	281	101	$79,500
2022	316	119	$108,100
2023	308	105	$101,400
2024	286	124	$107,000
2025	283	106	$110,800
2026	286	118	$114,000
2027	318	146	$111,400
2028	298	126	$115,500
2029	282	152	$121,100
Total	2,682	1,107	$976,800

Table 7-3:　Transmission Asset Upgrades Investment Profile

Year 1	Circuits Worked On	Nominal Cost ($000)
2020	21	$5,600
2021	35	$15,200
2022	28	$15,000
2023	15	$16,500
2024	15	$11,900
2025	6	$19,000
2026	7	$17,700
2027	10	$16,300
2028	13	$19,600
2029	20	$12,100
Total	NA	$148,900

Table 7-4:　Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	0	$0
2022	0	$0
2023	0	$0
2024	1	$7,300
2025	2	$5,500
2026	2	$4,700
2027	4	$6,700
2028	1	$5,200
2029	1	$2,900
Total	11	$32,400

Table 7-5:   Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2020	5	$6,200
2021	18	$15,400
2022	13	$29,600
2023	41	$33,400
2024	43	$32,500
2025	40	$33,200
2026	45	$33,800
2027	40	$32,800
2028	59	$36,400
2029	53	$36,300
Total	357	$289,600

Table 7-6:   Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	8	$1,400
2022	6	$1,500
2023	5	$1,600
2024	4	$1,700
2025	4	$1,300
2026	1	$400
2027	3	$3,300
2028	3	$2,000
2029	3	$1,700
Total	37	$14,800

7.3   Program Benefits

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

Table 7-7:   Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~33%	~44%
Transmission Asset Upgrades	~90%	~13%
Substation Extreme Weather Hardening	70% to 80%	50% - 65%
Distribution Feeder Hardening	38% to 42%	30%
Transmission Access Enhancements	10%	~74%

Figure 7-3: Program Benefits vs. Capital Investment

Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 87 percent of the total capital investment, nearly all the CMI benefit, and approximately 71 percent of the restoration benefit.

■ The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 44 and 33 percent, respectively. Additionally, the program accounts for approximately 67 percent of the total plan's invested capital, approximately 54 percent of the plan's restoration benefit, and approximately 12 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.

■ The Distribution Feeder Hardening program contributes approximately 87 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.

■ While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).

■ Substation Hardening accounts for over 10.5 percent of the restoration benefit of the plan while only accounting for approximately 2.2 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4   Conclusions

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

■ The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.

■ TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.

■ The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.

■ The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

■ TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.

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

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Appendix G

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

VEGETATION MANAGEMENT STORM PROTECTION PROGRAM ANALYTIC SUPPORT REPORT

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1   Executive Summary

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

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities including:

A.   The projected frequency (trim cycle);
B.   The projected miles of affected transmission and distribution overhead facilities;
C.   The estimated annual labor and equipment costs for both utility and contractor personnel; and
D.   A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

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

1.   Four-year distribution vegetation management cycle
2.   Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
    a.   400 miles in 2020
    b.   500 miles in 2021
    c.   700 miles in 2022 and beyond
3.   Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
    a.   Ensure fast-growing species are kept in check until the next scheduled trimming.
    b.   Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.
    The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

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

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

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

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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.

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[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:

Figure 4-1: Program Comparison

	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

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.

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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.

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

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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.

Annual Costs & SAIDI: Recommended Program 3ab-457 (400/500/700 Supplemental Miles with Graduated Mid-Cycle)

	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

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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.

Study-Based Curve

$$y = -0.0171x^2 + 0.2286x + 0.9997$$

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:
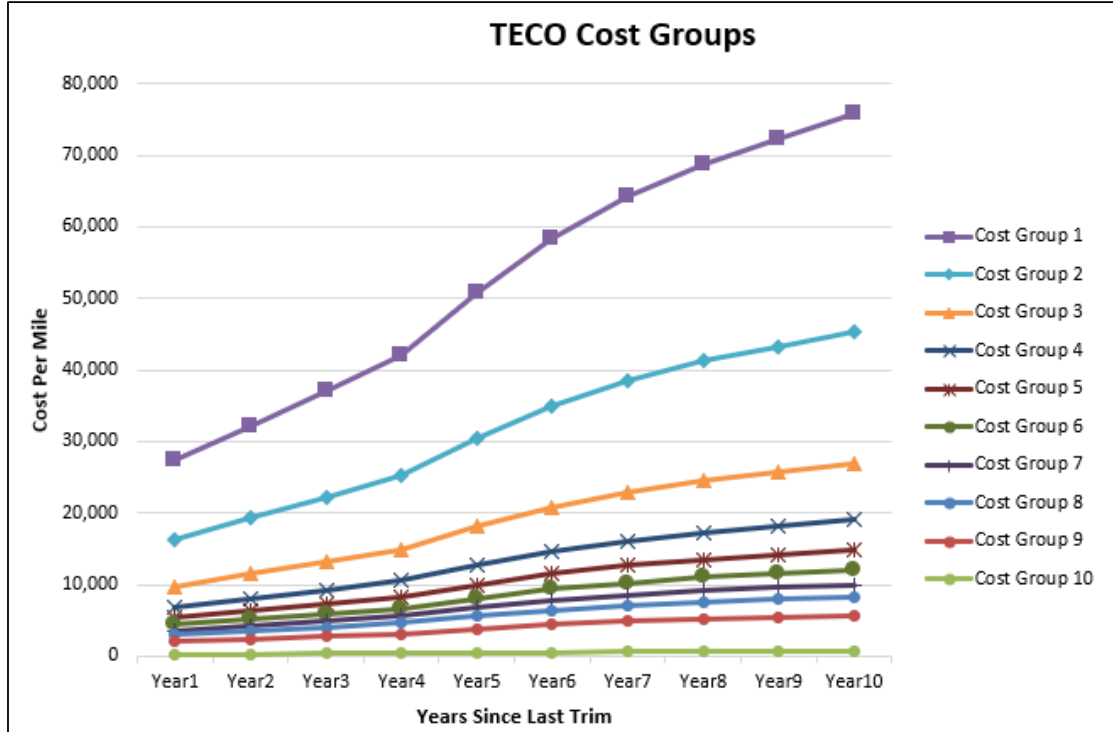
Figure 6-5: Cost Groups

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%	6.48%	8.74%	11.13%
75	1.27%	3.18%	5.45%	7.99%	10.74%	13.69%
80	1.54%	3.88%	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%	14.95%	21.92%	29.48%	37.56%
110	3.99%	10.03%	17.19%	25.20%	33.90%	43.19%
115	4.56%	11.48%	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%	28.08%	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

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TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

TAMPA ELECTRIC'S
2020-2029
STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

GERARD R. CHASSE

1   BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

2   PREPARED DIRECT TESTIMONY

3   OF

4   GERARD R. CHASSE

5

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INTRODUCTION

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

A. My name is Gerard R. Chasse. My business address is 702
N. Franklin Street, Tampa, Florida 33602. I am employed
by Tampa Electric Company ("Tampa Electric" or "the
Company") as Vice President, Electric Delivery.

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

A. My duties and responsibilities include the oversight of
all functions within Tampa Electric's Electric Delivery
Department including the planning, engineering,
operation, maintenance and restoration of the
transmission, distribution and substation systems;
operation of the distribution and energy control
centers; administration of tariffs and compliance;
execution of the Company's Transmission and Distribution
("T&D") strategic solutions including advanced metering
infrastructure, outdoor and streetlight LED conversion
project, and advanced distribution management system;
line clearance activities; warehouse and stores; and
fleet and equipment. As it relates to this filing, I am

2

1   responsible for the development of Tampa Electric's

2   Storm Protection Plan and the safe, timely, and

3   efficient implementation of that Plan.

4

5 **Q.** Please describe your educational background and

6   professional experience?

7

8 **A.** I received a Bachelor of Science degree in electrical

9   engineering from the University of Maine in 1990 and

10   became a licensed professional engineer in 1996. I have

11   held numerous positions of increasing responsibility in

12   Bangor Hydro Electric and its successor, Emera Maine,

13   including Substation Engineer, Planning Engineer,

14   Substation Operations Supervisor, Manager of

15   Engineering, Manager of Assets, Project Manager for an

16   international transmission line, Vice-President of

17   Operations, Executive Vice-President, and President of

18   Emera Maine from 2010 through 2015. In 2015 and 2016, I

19   was Vice-Chair of the Emera Maine Board. My position

20   was also focused on renewable strategy, grid

21   modernization strategy, and customer strategy for Emera

22   companies from 2015 to 2016 before my current role.

23

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

25

1	**A.**	The purpose of my direct testimony is to present, for
2		Commission review and approval, Tampa Electric's 2020-
3		2029 Storm Protection Plan. I will introduce the
4		company's Plan and provide a description of how
5		implementation of the company's proposed 2020-2029 Storm
6		Protection Plan will reduce restoration costs and outage
7		times associated with extreme weather and enhance
8		reliability by strengthening the company's
9		infrastructure. I will also offer a description of the
10		company's service area and describe the process used to
11		develop the Plan, as well as a description of how the
12		Plan's implementing Programs were selected and
13		prioritized. Finally, I will describe the alternatives
14		to implementation of the Plan that the company
15		considered.
16		
17	**Q.**	Are you sponsoring any exhibits in this proceeding?
18		
19	**A.**	Yes, I am. Exhibit No. GRC-1, entitled, "Tampa
20		Electric's 2020-2029 Storm Protection Plan", was prepared
21		under my direction and supervision. This Exhibit details
22		the company's plans to implement the Storm Protection
23		Plan Rule.
24		
25	**Q.**	Will any other witnesses testify in support of Tampa

4

1   Electric's Proposed Storm Protection Plan?

2

3 **A.**   Yes. Regan B. Haines will testify about six of the eight

4   Programs contained within the Storm Protection Plan.

5   John H. Webster will testify regarding the company's

6   planned Vegetation Management Program and Transmission

7   Access Program. Jason D. De Stigter will testify

8   regarding the methodology to select and prioritize Storm

9   Protection Programs and Projects. Finally, A. Sloan

10   Lewis will testify regarding the estimated annual

11   jurisdictional revenue requirement for the Plan and the

12   estimated rate impacts for each of the first three years

13   of the Plan.

14

15

16 **TAMPA ELECTRIC'S SERVICE AREA**

17 **Q.**   Please describe Tampa Electric's service area and how

18   many customers does the company serve?

19

20 **A.**   Tampa Electric's Service Area covers approximately 2,000

21   square miles in West Central Florida, including all of

22   Hillsborough County and parts of Polk, Pasco and Pinellas

23   Counties. Tampa Electric provides service to 794,953

24   retail electric customers as of January 1, 2020.

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

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

2 below.

3

18 **Q.** How many structures does the company's transmission,

19 distribution electrical system have?

20

21 **A.** The company has 1,350 miles of overhead facilities,

22 including 25,416 transmission poles. The company's

23 transmission system also includes approximately nine

24 miles of underground facilities. The company's

25 distribution system has 6,300 miles of overhead

1   facilities, including approximately 404,000 poles. The

2   company currently has approximately 5,100 circuit miles

3   of underground facilities. The company currently has 216

4   substations.

5

6 **Q.**   In the development of the company's Storm Protection

7   Plan, did Tampa Electric place a higher priority on any

8   areas of the company's service area for hardening or

9   enhancement projects contained in the company's Storm

10   Protection Plan, and if so, please explain the reasoning

11   for this prioritization?

12

13 **A.**   No. Each of the Programs and each of the Projects are

14   prioritized based on modeled cost/benefit ratios. For

15   example, Tampa Electric used the 1898 & Co. modelling

16   tool to assist in the prioritization of individual

17   Projects and to set the overall Program funding levels

18   for the Distribution Lateral Undergrounding Program. In

19   the initial years of the Program, Projects were selected

20   taking into account modeling results in conjunction with

21   operational and design efficiency which include some

22   level of geographic diversity.

23

24 **Q.**   In the development of the company's Storm Protection

25   Plan, were there any areas of the company's service area

7

1   that Tampa Electric determined would be impractical,

2   unfeasible or imprudent for hardening or enhancement

3   projects within the company's Storm Protection Plan, and

4   if so, please explain the reasoning for this reasoning?

5

6   **A.**   No. There are no areas of the company's service area

7   where it would impractical, unfeasible or imprudent to

8   harden.   All components of the transmission and

9   distribution system can be hardened to achieve resiliency

10 benefits.

11

12

13 **PROCESS TO DEVELOP THE 2020-2029 STORM PROTECTION PLAN**

14 **Q.**   Please explain Tampa Electric's systematic approach to

15 achieve the objectives of reducing restoration costs and

16 outage times and enhancing reliability, and how that

17 approach was utilized to develop the company's proposed

18 Storm Protection Plan?

19

20 **A.**   In response to the new requirement to develop a

21 comprehensive SPP, Tampa Electric evaluated its existing

22 storm hardening activities and searched for potential

23 additions and improvements.   The company began by

24 consulting its internal subject-matter experts to

25 identify major causes of storm-related outages and major

1		barriers to restoration following storms. The company
2		then engaged three outside consultants to help it
3		evaluate potential solutions and to assist with
4		estimation of costs and benefits for those solutions.
5		The result is a Plan that includes several newly
6		developed incremental Storm Protection Programs, Projects
7		and activities that resulted from the thorough and
8		comprehensive analysis. These new Programs, as well as
9		the company's legacy Storm Hardening Plan activities, are
10		described more fully in Tampa Electric's Storm Protection
11		Plan. This approach is designed to fully achieve the
12		goals, objectives and requirements of the Florida
13		Legislature and the Commission's Rule.

14

15 **Q.** Did Tampa Electric incur any incremental costs in the
16 development of the company's Storm Protection Plan?

17

18 **A.** Yes, Tampa Electric hired a program manager in the Energy
19 Delivery Department to facilitate the company's Storm
20 Protection Plan activities. The company also obtained the
21 assistance of three consultants.

22

23 **Q.** What role did the three consultants play in the
24 development of the company's Storm Protection Plan?

25

1   **A.**   The three consultants assisted the company in the

2   development of the Storm Protection Plan in the following

3   three areas:

4   1. Performing project prioritization and benefits

5   calculations for several of the company's proposed

6   Storm Protection Programs, including: (1)

7   Distribution Lateral Undergrounding; (2)

8   Transmission Asset Upgrades; (3) Substation

9   Extreme Weather Hardening; (4) Distribution

10   Overhead Feeder Hardening; and (5) Transmission

11   Access Enhancements. This prioritization and

12   cost-benefit analysis is described more fully in

13   the Direct Testimony of Jason D. De Stigter.

14   2. Analyzing the company's current vegetation

15   management activities and developing a methodology

16   for selecting and prioritizing incremental

17   vegetation management activities. This analysis

18   is described more fully in John H. Webster's

19   Direct Testimony.

20   3. Performing an automation analysis for the 22

21   prioritized distribution circuits for the Overhead

22   Feeder Hardening Program for 2020-2022.

23

24   **Q.**   Would you explain why the company chose to obtain the

25   consulting services for assistance with the development

1   of the Storm Protection Plan?

2

3   **A.**   The company chose to obtain consulting services for

4   assistance with the development of the Storm Protection

5   Plan for a number of reasons including: (1) it did not

6   have the incremental resources available to continue its

7   existing operations and meet the filing requirements

8   required by the Rule; and (2) it did not have the

9   sophisticated modeling tools necessary to perform a

10   thorough and detailed benefits and prioritization

11   analysis for the Vegetation Management Program or the

12   other five Programs listed above.

13

14

15   **TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN**

16   **Q.**   Would you describe Tampa Electric's 2020-2029 Storm

17   Protection Plan?

18

19   **A.**   Tampa Electric's Storm Protection Plan is designed with

20   the primary objective of enhancing the resiliency and

21   reliability of its transmission and distribution systems

22   during extreme weather events. Over the next ten years,

23   Tampa Electric will build upon the success of its

24   existing Storm Hardening Plan to materially improve

25   resiliency through targeted investments in the following

11

1   Programs: (1) Distribution Lateral Undergrounding;

2   (2)Vegetation Management; (3) Transmission Asset

3   Upgrades; (4)Substation Extreme Weather Hardening; (5)

4   Distribution Overhead Feeder Hardening; (6) Transmission

5   Access Enhancement; (7) Infrastructure Inspections; and

6   (8) Legacy Storm Hardening Initiatives. These Programs

7   will minimize the impact of severe weather by hardening

8   Tampa Electric's infrastructure.

9

10   Q.   Will Tampa Electric's Storm Protection Plan further the

11   objectives of Section 366.96 of the Florida Statutes?

12

13   A.   Yes. We developed a Storm Protection Plan based on a

14   rigorous analysis of possible methods to achieve the

15   goals of Section 366.96 of the Florida Statutes. The

16   goal of our analysis was to identify those activities

17   that deliver the greatest storm resiliency and

18   reliability benefits for the lowest cost. We believe

19   that the company's Plan will deliver significant

20   resiliency benefits, reliability benefits and reduced

21   outage times to our customers in a cost-effective manner.

22

23   Q.   How is Tampa Electric Company's Plan designed to deliver

24   those benefits?

25

1   A.   Tampa Electric's Storm Protection Plan is comprised of

2   four new and four currently ongoing Storm Protection

3   Programs. Four of these Storm Protection Programs are

4   comprised of individual Projects. In addition, the

5   company plans to incorporate existing activities from its

6   2019-2021 Storm Hardening Plan into the new 2020-2029

7   Storm Protection Plan. This will result in overall

8   regulatory and business efficiency in managing one

9   program rather than two.

10

11 Q.   Would you describe the Programs in Tampa Electric's Storm

12   Protection Plan?

13

14 A.   Tampa Electric separated the three main requirements of

15   the Storm Protection Statute — overhead hardening of

16   electrical transmission and distribution facilities, the

17   undergrounding of certain electrical distribution lines,

18   and vegetation management — into eight distinct Programs.

19   The Programs are as follows:

20   • **Distribution Lateral Undergrounding**

21   • **Vegetation Management**

22   • **Transmission Asset Upgrades**

23   • **Substation Extreme Weather Hardening**

24   • **Distribution Overhead Feeder Hardening**

25   • **Transmission Access Enhancement**

13

1   • **Infrastructure Inspections**

2   • **Legacy Storm Hardening Initiatives**

3

4   **Q.**   Would you provide a brief description of each of the

5   eight supporting Storm Protection Programs?

6

7   **A.**   Yes, a brief description of each of the supporting Storm

8   Protection Programs is below:

9

10   **Distribution Lateral Undergrounding:** Tampa Electric has

11   approximately 4,900 miles of overhead lateral

12   distribution lines. Tampa Electric does not currently

13   have an organization or program for undergrounding

14   laterals. Accordingly, the company will spend 2020

15   building an organization, developing and refining

16   processes and acquiring formal arrangements with external

17   resources to build and sustain this Program for the

18   duration of the SPP. The company is targeting 10 miles of

19   overhead to underground conversion in 2020 and targeting

20   100 – 110 miles of overhead to underground conversion

21   from the start of the program in 2020 through the end of

22   2021. Beginning in 2022, the company plans to underground

23   100 miles or more annually.

24

25   The company and its consultant, 1898 & Co., determined

the priority of these laterals through use of a robust modeling tool. The primary factor in prioritizing undergrounding Projects is reliability performance during extreme weather events. To illustrate, approximately 55 percent of all outages are caused by 30 percent of the company's lateral distribution lines. The prioritization method also gives due regard to the distribution of Projects across Tampa Electric's service area. All targeted laterals served by the same feeder will be undergrounded at once for efficiency in construction and in future storm response.

Vegetation Management: The company's Vegetation Management Program is comprised of four components: (1) existing trim cycles; (2) supplemental distribution trimming; (3) inspection-based mid-cycle trimming; and (4) reclamation of the 69kV transmission system.

The company currently implements a four-year effective distribution vegetation management cycle. Over a four-year period, 100 percent of the approximately 6,300 miles of distance of overhead lines are targeted to be cleared with due regard to circuit performance. Additionally, over the past three years, approximately $1.7M per year of reactionary trim has been performed. Reactionary

15

vegetation management is typically driven by customer requests or degraded circuit reliability performance, often in the latter half of a circuit's trim cycle due to specific species demonstrating faster growth cycles.

Additionally, for transmission circuits above 200kV, the company complies with FERC standards and employs strict two- and three-year cycles for transmission circuits operating at voltages below 200kV.

As part of its Storm Protection Plan, the company proposes three additional vegetation management initiatives with the purpose of enhancing its current cycle-based program specifically to increase resiliency. Those initiatives include supplemental distribution circuit vegetation management, inspection-based mid-cycle distribution vegetation management, and 69kV vegetation management reclamation work. Detailed modeling by the company's consultant, Accenture, demonstrates that an additional 700 miles of supplemental distribution trimming would achieve the greatest ratio of benefits to costs under extreme weather conditions. The mid-cycle vegetation management initiative is inspection-based and designed to eliminate trees and vegetation that pose a hazard to the distribution lines but can't effectively be

eliminated within the four-year cycle. Finally, the 69kV reclamation project is designed to increase access to difficult-to-reach areas of the company's high voltage transmission system. Accessibility to transmission in rights of way is an important factor in the speed of restoration and significantly enhances overall system resiliency.

Transmission Asset Upgrades: Approximately 20 percent of Tampa Electric's 25,400 transmission poles are wood pole structures. This Program consists of the proactive replacement of all remaining wood pole structures on the company's transmission system. The company proposes to accelerate the replacement of those structures to non-wood material, typically steel or concrete, to enhance the resiliency of the transmission system during extreme weather events.

Tampa Electric utilized 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects based on historical performance relative to criticality of the transmission line, reduction of customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. Technical and

17

1   operational constraints like access and long-lead time

2   permits were also accounted for in the development of

3   priority.

5   This Program offers a high level of benefits, yet these

6   benefits are highly dependent on the frequency of extreme

7   weather events.   The CMI reduction benefit for the

8   Transmission Asset Upgrades Program is approximately 29

9   percent while the resulting restoration cost reduction

10   benefit is approximately 90 percent after an extreme

11   weather condition.

13   **Substation Extreme Weather Hardening:**   This Program is

14   designed to increase the resiliency of flood-prone

15   critical substation equipment.   It may include the

16   installation of extreme weather protection barriers;

17   installation of flood or storm surge prevention barriers;

18   additions, modifications or relocation of substation

19   equipment; modification to the designs of the company's

20   substations; or other approaches identified to protect

21   against extreme weather damage in or around the company's

22   substations.   Tampa Electric has approximately 59

23   substations that are at risk in the event of hurricane-

24   related storm surge.   The company plans to commission a

25   study to assess the vulnerability of the top 20 of these

18

59 substations, which will result in a recommendation for the prioritization of future substation Projects and a recommendation for the tactics used to mitigate their vulnerabilities.

Distribution Overhead Feeder Hardening: The performance of three phase feeders is critical during extreme weather events. Tampa Electric's Distribution Overhead Feeder Hardening Program will include enhancements designed to increase resiliency, reliability, and flexibility of its three phase feeders including Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

Distribution Feeder Strengthening will incorporate design standards changes focused on the physical strength of the distribution infrastructure. The company will transition to using minimum Class 2 poles for all feeders and 3-phase laterals providing for longer life and increased overall strength.

Distribution Feeder Sectionalizing and Automation will enable the transfer of load to adjacent unfaulted feeders through the addition of new equipment such as breakers, reclosers, sectionalizers, sensors, relays, and

communication equipment in addition to increased feeder capacity in some locations. Feeders will be divided into sections feeding smaller numbers of customers so that when faults occur on a feeder section, that section can automatically isolate from the remainder of the healthy system. These design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Transmission Access Enhancement: Ready access to the company's approximately 1,350 miles of transmission facilities is critical to the efficient and timely restoration of its transmission system under all types of conditions, including blue sky and extreme weather events. This Program is designed to ensure effective access to those facilities with the addition or enhancement of roads and rights of way. Access roads also enable more efficient maintenance of the rights of way, including vegetation management in and along those corridors. Adequate access roads eliminate the need for costly and time-consuming installments of matting to provide temporary access to critical infrastructure. This Program also includes the design and construction of 17 access bridges. Access bridges are critical for

moving heavy equipment in and along transmission corridors, enabling efficient restoration, maintenance and repair of transmission structures.

Infrastructure Inspections: Infrastructure inspections are a foundational element of an asset management program. A clear understanding of the condition of distribution, substation, and transmission assets is a critical piece of asset performance under any conditions. Tampa Electric's Infrastructure Inspection Program is a comprehensive inspection program that combines the legacy Storm Hardening Plan initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company's inspection programs drive decisions on whether to replace, repair or restore its wood pole transmission, distribution, and substation infrastructure as well as the company's understanding of whether unauthorized attachments may have overloaded that infrastructure. The company believes that these are core initiatives with demonstrated value. As a result, the company has not prepared a new cost-benefit analysis for these activities. These are existing programs and the

1 company proposes to continue them at approximately
2 historical spending levels.

3

4 **Legacy Storm Hardening Initiatives:** The final category
5 of storm protection activities consists of those legacy
6 Storm Hardening Plan Initiatives that are ongoing and
7 well-established, and for which the company does not
8 propose any specific Storm Protection Projects at this
9 time. Tampa Electric will continue these activities
10 because the company believes they are necessary utility
11 activities, conform to good utility practice, and
12 continue to offer the storm resiliency benefits
13 identified by previous Commission orders which required
14 the company to perform these activities. These
15 activities are still mandated by the Commission and the
16 associated initiatives are all integrated into the
17 company's ongoing operations. Historically, Tampa
18 Electric has not performed a formal cost benefit analysis
19 for these activities because they were mandated by the
20 Commission. Most notable of these programs is Tampa
21 Electric's distribution pole replacement initiative. It
22 starts with the company's wood pole inspections and
23 includes designing and constructing distribution
24 facilities that meet or exceed the company's current
25 design criteria for the distribution system. The company

1   will continue to appropriately address all poles

2   identified through its Infrastructure Inspection Program

3   and in accordance with the National Electric Safety Code

4   for wood pole strength requirements.

6   Given that this is a reactive activity (poles are

7   replaced or restored only when they fail an inspection),

8   Tampa Electric concluded that it was not practical or

9   feasible to identify specific distribution pole

10   replacement Storm Protection Projects.

12   Q.   Please explain how the implementation of the company's

13   proposed Storm Protection Plan will strengthen the

14   company's infrastructure to withstand extreme weather

15   conditions through overhead hardening of electrical

16   transmission and distribution facilities as required by

17   Rule 25-6.030(3)(a)?

19   A.   Implementation of the company's Transmission Asset

20   Upgrades and Distribution Overhead Feeder Hardening

21   Programs will strengthen the company's infrastructure to

22   withstand extreme weather conditions through overhead

23   hardening of electrical transmission and distribution

24   facilities. These Programs include transmission pole

25   upgrades from wood to primarily steel or concrete, and

1   the overhead hardening of distribution facilities through

2   both feeder strengthening and sectionalization and

3   automation. Increasing the strength of overhead

4   facilities increases the ability of the company's poles,

5   conductors and fixtures to resist wind loading during

6   extreme weather events as well as loading from vegetation

7   contacts. Eliminating infrastructure failures

8   significantly reduces outages and time to restore

9   outages. Automatic switching during storm events is

10   designed to minimize outage impact to approximately 400

11   or fewer customers depending on the characteristics of

12   the circuit. Outage locations are sensed, isolated, and

13   adjacent unfaulted sections of feeders can be

14   reenergized.

15

16 **Q.** Please explain how the implementation of the company's

17   proposed Storm Protection Plan will strengthen the

18   company's infrastructure to withstand extreme weather

19   conditions through undergrounding certain portions of

20   electrical distribution lines as required by Rule 25-

21   6.030(3)(a)?

22

23 **A.** Implementation of the company's Distribution Lateral

24   Undergrounding Program will strengthen the company's

25   infrastructure through undergrounding portions of its

1   lateral distribution lines. Underground laterals are

2   shielded from many of the potential harmful effects of

3   extreme weather events resulting in a number of

4   significant benefits to customers. Indeed, metrics from

5   past extreme weather events clearly show that underground

6   systems prove to be much stronger and more resilient.

7   The Program will reduce the number and severity of

8   customer outages during extreme weather events, reduce

9   the amount of system damage during extreme weather,

10 reduce the material and manpower resources needed to

11 respond to extreme weather events, reduce the number of

12 customer complaints from the reduction in outages during

13 extreme weather events, and reduce restoration costs

14 following extreme weather events.

15

16 **Q.** Please explain how the implementation of the company's

17 proposed Storm Protection Plan will strengthen the

18 company's infrastructure to withstand extreme weather

19 conditions through vegetation management as required by

20 Rule 25-6.030(3)(a)?

21

22 **A.** The implementation of the company's proposed Vegetation

23 Management Program will strengthen the company's

24 infrastructure to withstand extreme weather conditions

25 through vegetation management initiatives. Trees are the

1 leading cause of outages both during extreme weather

2 events and normal operations. Three new vegetation

3 management initiatives in addition to the company's

4 existing cycles will reduce the potential for vegetation

5 to come into contact with the company's distribution and

6 transmission lines during extreme weather events.

7

8 **Q.** Please explain how the implementation of the company's

9 proposed Storm Protection Plan will reduce restoration

10 costs and outage times associated with extreme weather

11 conditions as required by Rule 25-6.030(3)(b)?

12

13 **A.** The implementation of the company's proposed Storm

14 Protection Plan will reduce restoration costs and outage

15 times associated with extreme weather conditions through

16 a comprehensive approach using eight specific Programs.

17 The combination of five of the first six Programs were

18 modeled, assessed and optimized using a sophisticated

19 storm resilience model employed by the company's

20 consultant 1899 & Co. The incremental vegetation

21 management initiatives were developed through detailed

22 analysis using Accenture's TTM model. The proposed

23 Programs also underwent additional analysis performed by

24 Tampa Electric. These analyses demonstrate there are

25 significant benefits associated with these Programs

1	including reduced restoration costs, reduced outages, and
2	reduced restoration times. Further Program benefits will
3	accrue in day-to-day operations.
4	
5	**Q.** Please explain how the implementation of the company's
6	proposed Storm Protection Plan will improve overall
7	service reliability and customer service as required by
8	Rule 25-6.030(3)(b)?
9	
10	**A.** The implementation of the company's proposed Storm
11	Protection Plan will improve overall service reliability
12	and customer service. Each of the eight Storm Protection
13	Plan Programs will not only meet the storm resiliency
14	goals of the Rule and the statute, but will also have
15	significant reliability benefits during blue sky
16	operations. The Plan will result in reduced outages,
17	both momentary and sustained, and reduced restoration
18	times resulting in reduced operating and capital costs.
19	
20	
21	**ESTIMATED COSTS OF STORM PROTECTION PLAN**
22	**Q.** Did the company prepare an estimate of the annual
23	jurisdictional revenue requirements for each year of the
24	proposed Plan?
25	

1   **A.**   Yes. The estimated annual jurisdictional review

2   requirements for each year of the proposed Storm

3   Protection Plan are included in Section 7 of the

4   company's Storm Protection Plan. A full explanation of

5   the detail of these jurisdictional revenue requirements

6   and how they were calculated for each year of the

7   proposed storm protection plan is included as Exhibit No.

8   ASL-1, Document No. 1 within A. Sloan Lewis's direct

9   testimony in this proceeding.

10

11

12   **ESTIMATED RATE IMPACTS OF STORM PROTECTION PLAN**

13   **Q.**   Did the company prepare an estimate of rate impacts for

14   each of the first three years of the proposed storm

15   protection plan for a typical residential, commercial and

16   industrial Tampa Electric customer?

17

18   **A.**   Yes. The estimated rate impacts for each of the first

19   three years of the proposed Storm Protection Plan for a

20   typical residential, commercial and industrial Tampa

21   Electric customer are included in the table below. A full

22   detail explanation of these rate impacts and how they

23   were calculated for each of the first three years of the

24   proposed Storm Protection Plan is included in A. Sloan

25   Lewis's direct testimony in this proceeding.

Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

IMPLEMENTATION ALTERNATIVES

Q. Did the company consider any implementation alternatives that would mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan?

A. Yes. The company considered and quickly rejected an alternative that involved no incremental storm protection activities. This alternative was quickly dismissed because it does not achieve the objectives of the statute, which are to further reduce restoration costs and outage times associated with extreme weather and to

1   enhance reliability. The company engaged Accenture to

2   evaluate several initiatives to enhance the company's

3   vegetation management plans and performance. As part of

4   this analysis, several increments of activity and

5   spending were evaluated. The company selected the option

6   that yielded the most customer benefits. Tampa Electric

7   also worked with 1898 & Co. to perform a budget analysis,

8   which demonstrated significantly increasing levels of net

9   benefit from the $250 million to $1.5 billion budget

10   scenarios. The company's planned investment level is at

11   the optimal point before diminishing returns. Tampa

12   Electric also considered and rejected some capital

13   programs and projects including undergrounding

14   distribution feeders, proactively upgrading wood

15   distribution poles, and purchasing temporary transmission

16   access solutions such as matting.

17

18

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

20   **Q.**   Does the process utilized by Tampa Electric to establish

21   its proposed Storm Protection Plan for the 2020-2029

22   period address the requirements of Rule 25-6.030, F.A.C.?

23

24   **A.**   Yes. Under Rule 25-6.030(3), F.A.C., a utility's Storm

25   Protection Plan must contain several specific categories

1   of information. The table below shows where each

2   category of information is located within the company's

3   Proposed Storm Protection Plan.

Tampa Electric's 2020-2029 Storm Protection Plan Adherence to Rule 25-6.030 F.A.C.	
Required Contents of Plan	Section of the Storm PP
25-6.030(3)(a)-(b)	Section 3 - SPP Overview
25-6.030(3)(c)	Section 1 - Tampa Electric's Service Area
25-6.030(3)(d)1-4	Section 6 – Storm Protection Programs
25-6.030(3)(d)5	Section 3 – SPP Overview
25-6.030(3)(e)	Section 6 – Storm Protection Programs
25-6.030(3)(f)	Section 6.2 – Vegetation Management
25-6.030(3)(g)	Section 7 - Projected Costs and Benefits
25-6.030(3)(h)	Section 8 – Estimated Rate Impacts
25-6.030(3)(i)	Section 9 – Alternatives and Considerations
25-6.030(3)(j)	N/A (optional)

21   **Q.** Does Tampa Electric's Storm Protection Plan further the

22   objectives of reducing restoration costs and outage times

23   associated with extreme weather events and enhancing

24   reliability set out in Section 366.96(3) of the Florida

25   Statutes?

1   **A.** Yes. As my testimony demonstrates, the company's Storm

2   Protection Plan will achieve these objectives by

3   hardening the company's infrastructure and making it more

4   resilient and reliable during extreme weather events.

5

6

7   **CONCLUSIONS:**

8   **Q.** Please summarize your direct testimony.

9

10 **A.** My testimony and the direct testimony of Regan B. Haines,

11   A. Sloan Lewis, John H. Webster, and Jason D. DeStigter

12   and the accompanying exhibits present and support Tampa

13   Electric's proposed 2020-2029 Storm Protection Plan.

14   This Plan was developed in a manner consistent with the

15   requirements of Section 366.96, Florida Statutes and the

16   implementing Rule 25-6.030, F.A.C., adopted by the

17   Commission.

18

19 **Q.** Should Tampa Electric's proposed 2020-2029 Storm

20   Protection Plan be approved?

21

22 **A.** Yes. Tampa Electric's proposed 2020-2029 Storm

23   Protection Plan should be approved. The Plan contains

24   all of the required contents set out in Rule 25-6.030,

25   F.A.C. The Plan will also build on the benefits the

1		company achieved through the prior Storm Hardening Plans
2		and initiatives that were established by this Commission
3		in 2007. Finally, the Plan will accelerate the company's
4		existing hardening efforts to achieve the objectives of
5		Section 366.96(3) of the Florida Statutes by
6		strengthening the company's infrastructure to withstand
7		extreme weather conditions, reducing restoration costs
8		and outage times, and by improving overall reliability
9		and customer satisfaction.
10		
11	**Q.**	Does this conclude your testimony?
12		
13	**A.**	Yes.

EXHIBIT

OF

GERARD R CHASSE

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Tampa Electric's

2020–2029

Storm Protection Plan

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TECO.
TAMPA ELECTRIC
AN EMERA COMPANY

Tampa Electric's
2020-2029 Storm Protection Plan Summary

Tampa Electric's 2020-2029 Storm Protection Plan describes the company's comprehensive approach to protect and strengthen its electric utility infrastructure to withstand extreme weather conditions as well as to reduce restoration costs and outage times in a prudent, practical and cost-effective manner. Protecting and strengthening Tampa Electric's transmission and distribution electric utility infrastructure against extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

Tampa Electric's 2020-2029 Storm Protection Plan will be its first ten-year protection plan filed in response to Rule 25-6.030, Storm Protection Plan. That Rule, which became effective on February 18, 2020, requires utilities to file storm protection plans. Tampa Electric has developed this Plan to comply with the Rule. This Plan contains a description of the company's Storm Protection Programs, the specific supporting Projects to these Programs and required detail as prescribed by Rule 25-6.030. This Plan also incorporates the continuation of legacy Storm Hardening Plan Initiatives that have been in place since 2006 and wood pole inspections.

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1 Tampa Electric's Service Area:

Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties as shown in the figure below. The company's service area is divided into seven "service areas" for operational and administrative purposes. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.

Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including 25,416 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,250 circuit miles of overhead facilities and 414,000 poles. The company currently has approximately 5,550 circuit miles of underground distribution

1

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facilities. The company currently has 216 substations. Tampa Electric also has approximately 322,000 authorized joint user attachments on the company's transmission and distribution poles.

Tampa Electric developed the proposed 2020-2029 Storm Protection Plan and its supporting Programs and initiatives by examining the entire company's service area for the most cost-effective enhancement opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness or practicality concerns.

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2 References:

The following resources are referenced in this Plan:

a) 2017 National Electrical Safety Code

b) National Hurricane Center Database

c) Florida State Building Code

d) Hillsborough County Wind Maps

e) Tampa Electric's prior Storm Implementation Plans

f) Tampa Electric's Distribution Engineering Technical Manual

g) Tampa Electric's Standard Electrical Service Requirements

h) Tampa Electric's General Rules and Specifications-Overhead

i) Tampa Electric's General Rules and Specifications-Underground

j) Tampa Electric's Approved Materials Catalog

k) Hillsborough County Flood Hazard Maps

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3 Storm Protection Plan Overview

Tampa Electric's Storm Protection Plan ("Plan" or "SPP") sets out a systematic and comprehensive approach to storm protection focused on those Programs and Projects that provide the highest level of reliability and resiliency benefits for the lowest relative cost. The company believes that these activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" in a cost-efficient manner.

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

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

In response to the new requirement to develop a comprehensive

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SPP, Tampa Electric evaluated its existing Storm Hardening Plan activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions.

First, Tampa Electric engaged Accenture, LLP ("Accenture") to evaluate its existing vegetation management ("VM") activities and determine what types of incremental vegetation trimming would reduce storm-related outage times and restoration costs. Tampa Electric's Line Clearance Department and Accenture developed and finalized the SPP spending plan described in the VM section. Spending levels were evaluated for each of the initiatives, using multiple activities, and ultimately resulted in the proposed list of VM initiatives and spending levels. A complete copy of Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report is included as Appendix "G".

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

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

Tampa Electric and 1898 & Co. used a resilience-based planning approach to identify hardening Projects and prioritize investment in the transmission and distribution (T&D) system using 1898 & Co's Storm Resilience Model. The Storm Resilience

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Model consistently models the benefits of all potential hardening Projects for an accurate comparison across the system. The resilience-based planning approach calculates the benefits of storm hardening Projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, Project, and Program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as Customer Minutes of Interruption("CMI")

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

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

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

The Budget Optimization and Project Scheduling model prioritized the Projects based on the highest resilience benefit cost ratio. The model prioritized each Project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the Project cost. This was done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric's technical and operational (transmission outages) in scheduling the Projects.

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

Early iterations of the modeling tool allowed the company to understand the Storm Protection Programs and the benefits that could be expected. In addition, Tampa Electric personnel

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factored the legacy Program Storm Hardening Plan Initiatives into these evaluations. Also, real-world considerations were included that examined practical realities of multi-year implementation, such as growing and sustaining an external workforce, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the modeling tool to develop the final set of Programs, Program funding and ultimately individual Project selection. A complete copy of Tampa Electric's Storm Protection Plan Resilience Benefits Report is included as Appendix "F".

Third, Tampa Electric engaged Power Engineers, Incorporated, to perform an automation analysis for the (22) prioritized distribution circuits for the 2020-2022 Overhead Feeder Hardening Program. The analysis determined the number and placement of reclosers, conductor upgrades, substation transformer capacity increases, relay upgrades and in some instances circuit extensions, to meet the company's criteria to reduce customer exposure, impact and count for unplanned outages. These proposed system enhancements were also used as input to the broader 1898 & Co. analysis described below.

Finally, the company used the analyses provided by these consultants as a basis for establishing the spending levels in the proposed 2020-2029 SPP. This information was used in conjunction with technical and operational constraints to select Storm Protection Programs, Program funding levels and Project selection and prioritization. The company's 2020-2029 SPP is thus comprised of both the company's legacy Storm Hardening Plan activities, as well as those incremental activities that emerged from this rigorous analysis process to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission.

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4 Experience with Major Storm Events

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

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

Table 1: Named Storms Affecting Tampa Electric Service Area since 1960			
Year	**Storm Name**	**Size [1]**	**Wind Speed [2]**
1960	Donna	Cat 3	115
1995	Erin	TS	57
2004	Charley	Cat 2	86
2004	Francis	Cat 1	63
2004	Jeanne	Cat 1	63
2005	Dennis	TS	43

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2005	Wilma	TS	44
2006	Alberto	TS	45
2007	Barry	TS	31
2012	Debby	TS	53
2012	Isaac	TS	36
2013	Andrea	TS	47
2015	Erika	TS	<39
2016	Colin	TS	<39
2016	Hermine	Cat 1	37
2016	Matthew	TS	20
2017	Emily	TS	<39
2017	Irma	Cat 1	90
2018	Alberto	TS	29
2019	Nestor	TS	26

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

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

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5 Construction Standards, Policies, Practices and Procedures

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

5.1 National Electrical Safety Code Compliance

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

5.2 Wind Loading Standards

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

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loading criteria must be applied when constructing facilities less than 60 feet in height when crossing railroads, bridges and highways.

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

5.2.1 Extreme Wind Loading Criteria

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

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

5.3 Distribution

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

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

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

5.3.1 Design Philosophy

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

5.3.2 Overhead System

5.3.2.1 Voltage

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

5.3.2.2 Clearances

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

5.3.2.3 Pole Loading

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

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

5.3.2.4 Materials

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

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

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5.3.2.5 Construction Types

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

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

5.3.2.6 Pole Loading Compliance

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

5.3.3 Underground Facilities

5.3.3.1 Standard Design

Tampa Electric's standard underground distribution system consists of normally looped circuits operating at 13.2kV three-

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

5.3.3.2 Network Service

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

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

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

5.3.4 Construction Standards in Coastal Areas

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

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

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

5.3.5 Location of Facilities

Tampa Electric's policy as stated in the DETM is to ensure that the route for new lines is located within the Public ROW or an

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

5.3.6 Critical Infrastructure

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

5.4   Transmission

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

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5.4.1 Design Criteria

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

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

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

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

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5.4.2 Transmission Structures

5.4.2.1 Voltage levels

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

5.4.2.2 Material types

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

5.4.2.3 Configuration Types

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

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

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- Number of circuits

- Conductor size

- Structure strength

- Span length

- Soil conditions

- ROW width

- Potential permitting requirements

- Utilization of adjacent land

- Environmental impacts

- Electric and magnetic field criteria

- Aesthetics

- Economics and cost-effectiveness

- Community input

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

5.4.3 Foundations

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

When a structure location requires it, Tampa Electric uses an industry accepted program for foundation design. Soil borings

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are collected, or standard penetration tests are conducted to compile the appropriate soil data for foundation analysis.

5.5   Substation

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

Tampa Electric designs, constructs and maintains transmission and distribution substations and switchyards ranging from 13.2kV to 230kV.   This includes performing siting studies, physical design, grading and drainage, foundation design, layout and design of control buildings, structure design and analysis, protection and control systems, and preparation of complete specifications for material, equipment and construction.   The company currently has 216 substations.

5.5.1 Design Philosophy

5.5.1.1 Wind Strength Requirements

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

The design standards summarized above meet the NESC loading criteria for extreme wind, Grade B construction.   As previously

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stated, Tampa Electric's service area is within the 100 mph to 120 mph extreme wind contours referenced in the NESC.

5.5.1.2 Equipment Elevations

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

5.5.1.3 Protection

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

5.5.1.4 Flood Zones

The company carefully evaluates flood zones when building on existing sites or when selecting future sites. The company will continue to review existing sites in the Flood Zone 1 designated area. The major focus will be on the elevation and water resistance of control cabinets and related equipment. Prudent modifications will be made. Consideration will be given to

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whether there will be load to be served in the area of the substation immediately after a storm and if any load can be served from adjacent substations that are outside the flooded area.

5.5.1.5 Other

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

5.5.2 Construction Standards

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

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

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Electric has determined that this fencing standard is most effective in blocking debris and exceeds county codes.

5.6 Deployment Strategy

Tampa Electric's 2020-2029 Storm Protection Plan's deployment strategy will reduce storm restoration costs and customer outage duration following major storm events and enhance system reliability through the continuation of several core components of the company's Storm Hardening Plans. The deployment strategy includes the continuation of legacy Storm Hardening Plan Initiatives and the implementation of new and expanded Storm Protection Plan Programs.

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6 Storm Protection Plan Programs

Tampa Electric's proposed 2020-2029 SPP includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis previously described. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described in this section. These Programs will achieve the goals, objectives and requirements of the Florida Legislature and the Commission.

6.1 Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding Program aims to strategically underground existing overhead lateral primary, lateral secondary and service lines. The expected benefits from this Program are:

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

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

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

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

- Total Circuit Miles: 11,800
- Total Overhead Miles: 6,251 (53 percent)
- Total Underground Miles: 5,549 (47 percent)
- Total Overhead Lateral Miles: 4,471
- Total Overhead Feeder Miles: 1,780
- Total Underground Lateral Miles: 4,949
- Total Underground Feeder Miles: 600
- Customers served off Laterals: 88 percent
- Customers served off Feeders: 12 percent

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

	Tampa Electric's Distribution System Overhead versus Underground Outage Comparison (in Percent)			
	Distribution System	Day-to-Day Outages	Major Event Day Outages	Irma Repair/Replace
Overhead	53	81	91	99.60
Underground	47	19	9	0.40

These metrics show that the underground system proves to be much stronger and more resilient during extreme weather events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years. This SPP Program is also expected to provide similar reliability improvements and restoration benefits (time and costs) during normal day-to-day operations and summer thunderstorm events.

As previously discussed, Tampa Electric used the 1898 & Co.

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modeling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. Initial model runs provided the optimal 10-year SPP spending levels and demonstrated that this Program's undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. Tampa Electric relied on the model output to confirm appropriate funding levels in alignment with the need to attract and sustain external workforces capable of executing a large-scale Distribution Lateral Undergrounding Program for the duration of the 2020-2029 SPP. The company also relied on the model output to identify the 2020-2021 Projects, selecting Projects that would allow it to most rapidly grow the Program, execute at small scale initially and develop operationally sound, sustainable and efficient processes. The individual Projects, the prioritization of these Projects and the annual Program funding levels are supported by the model. For operational efficiencies, laterals on the same feeder circuit were grouped and scheduled together in the same time frame. Laterals were then selected based on their ease of execution (e.g. fewer joint use attachers, fewer rear lot spans, and no major road or railroad crossings) balanced against their customer benefits. Strategically and operationally, these Projects are intended to allow the company to most rapidly complete projects to learn, adapt and enhance its processes to ensure the Program is sustainable, efficient and cost-effective. The 2020 activity will largely consist of designing, permitting, obtaining easements and attempting to coordinate with joint users on the identified Projects in detail included in Appendix "A". While this currently reflects a construction quarter end date of "Q4 2020" for these Projects, the Projects can be completed only if all permitting and required easements are obtained. The company anticipates the permits and easements will be obtained, however if they cannot be, the company will begin the process by accelerating future planned Projects into

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2020.

For the SPP years 2022 to 2029, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The table below shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	24	$8.0
2021	281	$79.5
2022	316	$108.1

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

6.2 Vegetation Management
Tampa Electric's Vegetation Management Program ("VMP") combines a continuation of its existing filed and approved distribution and transmission VMP activities with three additional strategic VM initiatives.

6.2.1 Existing Vegetation Management Activities
Tampa Electric currently trims the company's distribution system on a four-year cycle. This approach was approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012. The four-year cycle is flexible enough to allow the company to change circuit prioritization

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utilizing the company's reliability-based methodology. Since 2007, Tampa Electric has partnered with a third-party consultant and used their proprietary vegetation management software application. The software analyzes multi-year circuit performance data, trim cycles, and corrective and restoration costs to generate a priority list for circuit trimming for the four-year distribution trimming cycle. The software optimizes circuit selection in terms of both reliability and cost-effectiveness.

The company also adheres to a comprehensive vegetation management strategy for its transmission system. The company operates three categories of transmission lines 230kV, 138kV, and 69kV. For the circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4. This standard imposes performance-based, risk-based, and competency-based requirements for vegetation management on these circuits. The company imposes a two-year vegetation management cycle for 138kV circuits, and a three-year cycle for 69kV circuits. The company's vegetation management strategy for its transmission system includes the maintenance of the transmission ROWs.

6.2.2 New VMP Initiatives

In addition to continuing its existing VMP plans, Tampa Electric partnered with Accenture to analyze various VMP strategies to further enhance the transmission and distribution facilities while reducing outage times and restoration costs due to extreme weather conditions. Accenture updated its existing vegetation management software to include the most recent outage, cost, and trim data, and to add functionality to estimate the value derived from activities that address only part of a circuit at a time. Tampa Electric and Accenture then analyzed and compared full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather

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events, as well as overall service reliability. Based on this analysis, Tampa Electric is proposing two additional distribution VM initiatives and one additional transmission VM initiative. The purpose of these additional VM initiatives is to enhance the company's current cycles, specifically for the purpose of system storm hardening. These additional VM initiatives are:

   Initiative 1: Supplemental Distribution Circuit VM

   Initiative 2: Mid-Cycle Distribution VM

   Initiative 3: 69 kV VM Reclamation

6.2.2.1 Initiative 1: Supplemental Distribution Circuit VM

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

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

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and customers is detailed below:

Supplemental Vegetation Management Project Schedule by Service Area						
	2020		2021		2022	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	77.9	21,357	159.1	29,226	113.5	20,418
Dade City	99.9	5,208	6.2	484	127.6	5,578
Eastern	99.8	18,598	153.3	12,341	72.9	8,794
Plant City	76.7	9,702	25.2	2,443	202.2	8,347
South Hillsborough	15.3	2,264	20.5	2,427	20.2	3,236
Western	15.7	3,926	82.8	13,024	112.4	20,376
Winter Haven	16.8	1,277	63.1	5,063	43.2	5,784
Total	402.3	62,332	510.2	65,008	692	72,533

The total Supplemental Circuit VM initiative costs are detailed below for the 2020-2029 SPP:

Supplemental Vegetation Management Project Costs (in thousands)	
2020	$3,200
2021	$5,200
2022	$6,100
2023	$7,100
2024	$4,800
2025	$5,300
2026	$6,500
2027	$5,900
2028	$5,900
2029	$5,900

6.2.2.2 Initiative 2: Mid-Cycle Distribution VM

Tampa Electric's experience with existing VM activities is that some trees cannot be effectively maintained within the four-year distribution VM cycle because of their rapid growth rate. For instance, the company estimates that up to twenty-five percent of trees grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. Additionally, some trees develop into a threat to distribution facilities due to an

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evident defect or hazard trees. The current four-year cycle has limited tree removal potential. Fall-in trees were determined to be a major damage factor in recent storms.

The Mid-Cycle VM initiative is inspection-based and designed to identify and selectively mitigate these trees. Tampa Electric and Accenture's analysis showed that this initiative will lead to reductions in both extreme weather outages and restoration costs as well as day-to-day outage costs. For the first three years of the Storm Protection Plan, the company will inspect feeders that have not been trimmed in the last two years and then prescribe additional VM work based on the inspection findings. After the first three years, the company plans to expand the initiative to include laterals. The Mid-Cycle VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed below:

Mid-Cycle Vegetation Management Project Schedule by Service Area						
	2020		2021		2022	
Service Area	Miles	Customers	Miles	Customers	Miles	Customers
Central	0	0	48.6	17,262	36	9,488
Dade City	0	0	2.8	1,293	5.1	904
Eastern	0	0	17.3	4,730	34.5	12,007
Plant City	0	0	18	8,234	12	7,191
South Hillsborough	0	0	51.7	16,233	23	13,900
Western	0	0	58.8	27,318	53.3	19,073
Winter Haven	0	0	45.9	20,663	32.1	14,565
Total	0	0	243.1	95,733	196	77,128

The total Mid-Cycle VM Project costs are detailed below. The 2020 costs are associated with the initial inspections.

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Mid-Cycle Vegetation Management Project Costs (in thousands)	
2020	$100
2021	$1,200
2022	$3,500
2023	$4,000
2024	$5,600
2025	$6,000
2026	$5,700
2027	$6,200
2028	$7,300
2029	$6,300

6.2.2.3 Initiative 3: 69kV VM Reclamation

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

An additional benefit to the Project is improved access. One of the VM lessons learned from recent storm recovery efforts is

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that unobstructed access to transmission facilities is critical to minimizing restoration times. Clearing these vegetation-obstructed areas will reduce outage potential, allow for faster restoration times, and lower restoration costs due to the following:

- Improving vegetation to conductor clearances will reduce blow-in outages;

- Removing hazard trees will reduce fall-in outages;

- Removing vegetation overgrowth will allow the ground to dry faster, promoting deeper tree roots and improving accessibility, reducing the need for access matting;

- Outage locations can be identified much easier, up to 200 percent faster;

- Damage assessment can be completed more accurately;

- Safer work sites reduce the number of personnel and equipment needed to restore; and

- Normal line and vegetation inspection and maintenance costs will be reduced by the improved clearances and unobstructed access.

The time to restore transmission outages is dependent on several factors, such as voltage, switching, design, and other facility impacts, but the key factor to restoration is accessibility. Outages that occur in areas obstructed by vegetation, on average, take up to 75 percent longer to restore. Tampa Electric has identified areas along the 69kV system where these vegetative conflicts and obstructions exist and mapped them to determine Project scope, cost, and schedule. The entire 69kV Vegetation Reclamation Initiative is a short-term initiative planned for four years beginning in 2020 and concluding in 2023. The Project scope and cost detail for the 69kV Vegetation Reclamation Initiative is listed below.

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

6.2.3 Estimated Costs – VMP

Tampa Electric and Accenture estimate that, in total, approximately 270 VM contract trimmers and six contract forestry inspectors will be needed for all distribution VM activities once the new initiatives are scaled up to their future steady state. The 69kV Reclamation Initiative will require approximately 40 VM total contract trimmers to complete.

6.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of this initial ten-year SPP. Tampa Electric has over 25,400 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 20 percent are supported with wood poles. Historically, the company's transmission hardening Program focused on replacing existing wood transmission poles with non-wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2019, the company hardened 8,971 wood transmission structures with non-wood material as a part of the existing Storm Hardening Plan. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood

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transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

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

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access issues to be addressed.

The table below shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	21	$5.6
2021	35	$15.2
2022	28	$15.0

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

6.4 Substation Extreme Weather Hardening

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

Tampa Electric engaged 1898 & Co. to perform preliminary analysis and prioritization of the company's 216 substations. The SLOSH model, described in the 1898 & Co. report included as

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Appendix "F", identified 59 of these 216 substations with some level of flooding risk and the height of a wall needed to mitigate that risk. The 59 substations were evaluated and prioritized in the model using only the single solution of building a flood wall around the perimeter of each substation. Using this methodology, the model identified 11 substations that were prioritized to be hardened within the 2020-2029 SPP.

Tampa Electric will begin this Program in early 2021 by engaging an additional third-party consultant that specializes in substation engineering and asset management to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled. This study will include the 11 identified substations, as well as others that Tampa Electric subject matter experts determine have potential vulnerability to extreme weather. The study, to be completed by the end of 2021, will examine the potential for flooding for each substation, flood mitigation options, and provide an engineering recommendation for station flood protection or mitigation, if applicable. The study is estimated to cost $250,000 and will also include:

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

The Company expects the 2021 study and analysis to identify the proper hardening solution for each of the substations, with cost estimates that are more reflective of the unique characteristics of each substation. Once the study is complete, Tampa Electric will determine a final prioritized list of Substation Extreme Weather Protection Projects. The required Project-level information will be provided at the appropriate filing

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opportunity in the Storm Protection Plan Cost Recovery Clause Docket.

The table below shows the Substation Extreme Weather Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

	Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	0	$0.0
2021	1 (Note 1)	$0.3
2022	0	$0.0

Note 1: The Project identified in 2021 is the further study of potential substation solutions as described above.

6.5 Distribution Overhead Feeder Hardening

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

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6.5.1 **Distribution Feeder Strengthening**

These enhancements will incorporate changes to the Company's distribution design standards to focus on the physical strength of Tampa Electric's distribution infrastructure. The company plans to harden selected feeders to meet NESC construction Grade B criteria with the Rule 250C (Extreme Wind) loading and strength criteria applied. This will involve the evaluation of the feeder, including a thorough review of the poles, conductor and equipment to determine the upgrades necessary to ensure the feeder meets new hardened design and construction standards.

6.5.2 **Distribution Feeder Sectionalizing and Automation**

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

- Allowing for the automatic transfer of load to neighboring feeders in the event of unplanned outages that can occur during both normal and extreme weather events;

- Allowing for the network to be re-configured automatically to minimize the number of customers experiencing prolonged outages during both normal and extreme weather events; and

- Reducing restoration time by isolating only those parts of the electrical system that contain faults that require assessment, investigation, follow-up and repair.

Upgraded conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgraded additional transformer capacity at strategic substations will ensure maximum load restoration capacity.

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Combined, these design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Tampa Electric has approximately 800 distribution circuits, which were prioritized based on their reliability performance and priority customer count to identify the target circuits for the 2020-2022 timeframe. Reliability performance was considered for both extreme weather and blue-sky days with a higher weighting factor assigned to circuit reliability under extreme weather conditions.

With a list of (22) circuits targeted for an OH distribution investment, Tampa Electric identified improvements on each circuit that would result in increased sectionalizing of the system with the following measures:

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

For 2020 implementation, the company identified circuits for improvement that require minimal engineering, minimal lead-time on material and do not require permits. Circuit improvements that require complex engineering, longer lead-times for materials and could result in local and state permits and approval have been scheduled for 2021 and 2022 in-service dates. The remainder of the SPP years (2023-2029) were prioritized by the model.

The table below shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

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Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	5	$6.5
2021	18	$15.4
2022	13	$29.6

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

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

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

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management Program for all high voltage circuits, 200kV and above. These routes are necessary to ensure compliance.

The company has identified a total of 70 potential Access Road Projects, subdivided by circuit. In many cases, more than one circuit benefits from the installation or repair of the road. While engineering will determine the exact scope and cost of the road, company subject matter experts developed a preliminary cost estimate for each Project that was used in the 1898 & Co. model for cost-benefit prioritization. The costs were based on the number of road miles and construction type. The total Access Roads initiative costs are detailed below for the 20 Access Road Projects proposed in the 2020-2029 SPP:

Access Road Projects Costs (in thousands)	
2020	$0
2021	$604
2022	$391
2023	$0
2024	$810
2025	$978
2026	$0
2027	$3,325
2028	$1,982
2029	$1,065

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

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

The company currently maintains a total of 24 bridges, with three of these bridges being recently installed in a transmission upgrade Project. In addition to the 21 current bridges identified for replacement, the company identified an additional five bridges for a net total of 26 potential bridge Projects. The total Access Bridges initiative costs are detailed below for the 17 Access Bridge Projects proposed in the 2020-2029 SPP:

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Access Bridge Project Costs (in thousands)	
2020	$0
2021	$780
2022	$1,118
2023	$1,606
2024	$853
2025	$360
2026	$354
2027	$0
2028	$0
2029	$601

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

Tampa Electric used 1898 & Co.'s resilience-based modeling described in Appendix "F" to evaluate the cost-benefit expectation for each of the 96 Access Enhancement Projects. Since permitting is the primary driver of the schedule, it was assumed that Access Projects could not begin until 2021. The model then developed a prioritization of these Projects based on the cost-benefit expectations. This SPP Plan reflects the completion of 37 Access Enhancement Projects over the ten-year SPP.

The table below shows the Transmission Access Enhancements Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

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Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	0	$0.0
2021	8	$1.4
2022	6	$1.5

6.7 Infrastructure Inspections

Tampa Electric's Infrastructure Inspection Program is a comprehensive inspection Program that combines the existing Commission approved Storm Hardening Plan Initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

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

Tampa Electric has not historically attempted to quantify the benefits of these inspection activities because they were required by Commission Order. In those Orders, the Commission found that these activities offered significant storm resiliency benefits. For instance, the Commission found that wood pole inspections and corrective maintenance "can reduce the impact of hurricanes and tropical storms upon utilities' transmission and distribution systems." Order No. PSC-06-0144-PAA-EI. The Commission also found that wood pole inspections reduce

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restoration times because, in the named storms in Florida in 2004 and 2005, "the number of failed poles resulting from a storm [were] correlated with the number of days required to restore service to customers." Order No. PSC-06-0144-PAA-EI. The Commission later found that a transmission structure inspection program would offer similar benefits. Order No. PSC-06-0351-PAA-EI. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because "[u]tility poles that are overloaded or approaching overloading are subject to failure in extreme weather." Order No. PSC-06-0351-PAA-EI. Tampa Electric believes that infrastructure inspection activities still offer these benefits.

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

6.7.1 Wood Pole Inspections

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

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission and distribution

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poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair, reinforcement or replacement to meet strength requirements of the NESC.

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

Tampa Electric estimates that this initiative will cost approximately $1,000,000 annually over the ten-year horizon of this SPP.

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

6.7.2 Transmission Inspections

Tampa Electric will continue to conduct the multi-pronged inspection approach the company has historically applied to the system which has led to the transmission system having a history of strong reliability performance. This approach includes the eight-year above ground structure inspection cycle, eight-year ground line wood inspection cycle, annual ground patrol, annual aerial infrared patrol, annual substation inspection cycle and the pre-climb inspection requirement. Tampa Electric will continue these inspections and will also continue the company's ongoing efforts to monitor and evaluate the appropriateness of its transmission structure inspection program to ensure that any

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cost-effective storm hardening or reliability opportunities found are taken advantage of.

Tampa Electric estimates the annual cost of this initiative is approximately $360,000 over the ten-year Plan horizon. Tampa Electric believes this cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

6.7.2.1 Groundline Inspections

Tampa Electric conducts groundline inspections in compliance with the Commission's order requiring groundline inspection of wooden transmission structures. A groundline inspection includes excavation, sounding and boring wood poles. Excavation requires removing earth at the base of the pole around the entire circumference to a minimum depth of 18 inches below groundline. All poles passing the excavation inspection will then be sounded with a hammer. If sounding provides evidence of possible interior voids or rot, at least one boring shall be made where the void is indicated. If rot or voids are detected, enough boring shall be made so that the extent can be determined. Poles set in concrete, or otherwise inaccessible below groundline, shall be bored at least twice at groundline at a 45-degree downward direction. All bored holes shall be plugged with treated dowels. Groundline inspections are performed on an eight-year cycle. Each year approximately 12.5 percent of all wooden transmission structures are scheduled for inspection. For 2020 through 2022, the company plans to perform approximately 1,750 groundline inspections over the three-year period.

6.7.2.2 Ground Patrol

The ground patrol is a visual inspection for deficiencies including poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware and

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encroachment. The ground patrol will include identification of vegetation encroachment as well as all circuit deficiencies. All transmission circuits are patrolled by ground at least once each year.

6.7.2.3 Aerial Infrared Patrol

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

6.7.2.4 Above Ground Inspections

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

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UAS has allowed the company to complete the Above Ground Inspections in conjunction with the Ground Patrol utilizing the UAS for an aerial view of the structures identified for the comprehensive inspection.

For 2020 through 2022, annual above ground inspections are planned on approximately 10,500 structures. This is in line with the company's petition that changed the above ground inspection cycle from a six-year cycle to an eight-year cycle which was approved in Docket 20140122-EI, Order No. PSC-14-0684-PAA-EI and confirmed by Consummating Order No. PSC-15-0017-CO-EI.

6.7.2.5 Substation Inspections

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

Tampa Electric estimates that the annual cost of these inspections is approximately $150,000 over the ten-year horizon of the SPP.

6.7.2.6 Pre-Climb Inspections

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

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

6.7.3 Joint Use Pole Attachments Audit

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

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

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

There is no incremental cost of this initiative as each audit is ultimately paid for by the joint attacher.

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6.7.4 Infrastructure Inspections Summary

The Infrastructure Inspection Program has no estimated completion date because the inspection activities are continuous and ongoing. The infrastructure inspection activities are either part of an ongoing cycle – such as wood pole and transmission structure inspections – or only occur when triggered by a specific event – such as pre-climb and joint use inspections. Given the nature of this Program, Tampa Electric concluded that it was not practical or feasible to identify specific Storm Protection Projects under this Program. Instead, the table below shows the number of infrastructure inspections the company is projecting over the 2020-2022 storm Protection Plan period.

Projected Number of Infrastructure Inspections			
	2020	2021	2022
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	22,500	22,500	35,625
Groundline Inspections	13,275	13,275	21,018
Transmission			
Wood Pole/Groundline Inspections	702	367	707
Above Ground Inspections	2,949	3,895	3,396
Aerial Infrared Patrols	Annually	Annually	Annually
Ground Patrols	Annually	Annually	Annually
Substation Inspections	Annually	Annually	Annually

Note 1: Tampa Electric completed its most recent Joint Use Pole Attachment Audit in the first quarter of 2020.

The table below provides the annual O&M expenses for each of the inspection programs for the 2020-2022 period.

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Projected Costs of Infrastructure Inspections (in thousands)			
	2020	2021	2022
Distribution			
Wood Pole/Groundline Inspections	$708	$1,000	$1,020
Transmission			
Wood Pole/Groundline Inspections	$60	$61	$62
Above Ground Inspections	$10	$10	$10
Aerial Infrared Patrols	$110	$112	$114
Ground Patrols	$145	$148	$151
Substation Inspections	$140	$143	$146

6.8 Legacy Storm Hardening Plan Initiatives

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

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project. In this internal analysis, the company would project the costs and estimate the benefits that should be realized. Tampa Electric recognizes that assigning a monetary value to customer benefits is challenging due to the lack of specific information about the financial impacts of outages, and because assigning value to public safety and health may skew the project's benefit analysis.

6.8.1 Geographic Information System

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. All new computing technology requests and new initiatives are evaluated with a goal to eliminate redundant, exclusive and difficult to update databases as well as to place emphasis on full integration with Tampa Electric's business processes. These evaluations further cement GIS as the foundational database for Tampa Electric's facilities.

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

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is $0 because the company's GIS system is an integral system used by the company to maintain its transmission and distribution asset information. Tampa Electric

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will continue to update and make improvements/enhancements to its GIS as needed.

6.8.2 Post-Storm Data Collection

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

- Pole/Structure – type of damage, size and type of pole, and likely cause of damage;
- Conductor – type of damage, conductor type and size, and likely cause of damage;
- Equipment – type of damage, overhead or underground, size, and likely cause of damage; and
- Hardware – type of damage, size and likely cause of damage.

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

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

The incremental cost of this initiative is estimated to be approximately $113,000 per storm and will depend on the severity of the storm and extent of system damage.

6.8.3 Outage Data - Overhead and Underground Systems

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

- Centralized capture of outage related data;
- Analysis and clean-up of outage-related data;
- Maintenance and adjustment to distribution outage database data;
- Automatic Generation and distribution of canned reliability reports; and
- Generating ad hoc operational and managerial reports.

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

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

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underground systems are correctly assessed.

The company does not propose any specific DOD Projects because there will only be DOD activity when there are storm related outages, and the company cannot predict when storm-related outages will occur during the ten-year planning horizon.

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

6.8.4 Increase Coordination with Local Governments

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

The company does not propose any specific local government coordination Projects because these activities occur intermittently and often on an unplanned basis before, during, and after severe weather events.

There are no incremental costs associated with this activity.

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6.8.5 Collaborative Research

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

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

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

6.8.6 Disaster Preparedness and Recovery Plan

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

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

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

Tampa Electric will also continue to plan, participate in, and conduct internal and external preparedness exercises, collaborating with government emergency management agencies, at the local, state and federal levels. Internal company exercises focus on testing lessons learned from prior exercises/activations, new procedures, and educating new team members on roles and responsibilities in the areas of incident command, operations, logistics, planning and finance. The scope and type of internal exercises vary from year to year based on exercise objectives defined by a cross-functional exercise design team, following the Homeland Security Exercise and Evaluation Program ("HSEEP"). External preparedness exercises are coordinated by local, state and federal governmental emergency management agencies. Tampa Electric personnel participate in these exercises to test the company's internal emergency response plans, including coordination with Emergency Support Functions ("ESF") to maintain key business relationships at local Emergency Operation Centers ("EOC"). Like Tampa Electric, the exercise type (tabletop, functional or full-scale) and scope varies from year to year, and

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depending upon the emergency management agencies' exercise objectives, Tampa Electric participants may not be included.

Annually, Tampa Electric participates in the State of Florida's hurricane exercise with the FPSC, which often coincides with exercises conducted by Hillsborough, Pasco, Pinellas and Polk counties. In addition, municipalities within Tampa Electric's service area (Oldsmar, Plant City, Tampa and Temple Terrace) may also host exercises and/or pre-storm season briefings. For example, in 2019, Tampa Electric participated in exercises and/or pre-storm briefings hosted by the State of Florida (in conjunction with FPSC), Hillsborough and Pinellas counties, as well as the cities of Oldsmar, Tampa and Temple Terrace. However, in 2020, Tampa Electric has been advised that the State of Florida will not conduct an annual hurricane exercise. As a result, some counties and municipalities are following the State's lead.

Tampa Electric has been incorporating Lessons Learned from Hurricane Irma and the company's experience supporting the restoration for Hurricane Michael into the company's Emergency Response plans. While the updates cover a broad category or processes, a focus has been on insuring the plan can scale up to handle major storms (Cat 3, 4, 5), in Logistics (life support) and the ability to restore internal communications in the event public networks are negatively impacted (Internet, cellular and satellite).

Tampa Electric will implement a Damage Assessment tool as an integrated part of its Advanced Distribution Management System ("ADMS") scheduled for implementation in 2021.

The total cost to support all Emergency Management activities and initiatives is estimated to be $300,000 annually.

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6.8.7 Distribution Pole Replacements

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

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

Tampa Electric estimates the annual capital and O&M costs of this initiative is approximately $13,300,000 over the ten-year Plan horizon.

6.8.8 Legacy Storm Hardening Plan Initiatives Costs

The table below shows the projected costs for the first three years of the 2020-2029 SPP for the Legacy Storm Hardening Plan Initiatives:

Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)		
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2020	$0.3	$9.9
2021	$0.3	$11.8
2022	$0.3	$15.5

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7 Storm Protection Plan Projected Costs and Benefits

Tampa Electric developed the projected 2020-2029 SPP costs by examining the time, the scope of work, and reasonably expected costs for each of the SPP Programs. To develop the company's estimations of costs, Tampa Electric relied upon the following key underlying assumptions:

1. Initially, the company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This initially was determined to be between 100 to 200 million dollars on an annual basis, based upon work constraints.

2. Recognizing the sustained amount of work it would take for external resource companies to physically build or obtain a work force that could support several ongoing Storm Protection Programs.

3. Recognizing that there will be some competition for resources between utilities which could push costs upward.

4. Identification of the range of work necessary for each Storm Protection Program and the feasibility of success with external resources.

5. The costs would be made up of new incremental capital and O&M costs for each of the proposed Storm Protection Programs and their associated Projects.

6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2020-2029 spend at approximately $1.5 billion over the ten-year Plan.

7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be between 100 to 200 million on an annual basis.

8. Actual historical costs would be used where the company has significant history and recent experience in developing the cost for each type of Project. Costs were also analyzed for impacts for potential competition and

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future contractor capacity impacts.

9. Costs were validated for reasonableness and range by a variety of means, either in discussions amongst internal team members with this experience, discussions with Accenture LLP and 1898 & Co., or discussions with neighboring utilities.

10. Costs were used to complete SPP programs within the designated proposed timeline as described in the Transmission Asset Upgrade Program and the 69kV Reclamation initiative within the Vegetation Management Program.

11. Recognizing costs were projected based upon single solution modeling for the Substation Extreme Weather Hardening Program. The company needs to evaluate other potential solutions and opportunities before committing to an appropriate cost-effective solution for Tampa Electric's substations.

12. The company will continue the components of the Commission's legacy Storm Hardening Plan and will seek recovery of the costs associated with these activities through the SPPCRC, with the exception of the Geographical Information System, Post-Storm Data Collection, Increased Coordination with Local Governments, Disaster Preparedness and Recovery Plan, Distribution Pole Replacements, and unplanned (reactive) vegetation management.

13. The company would show with transparency the total costs for the proposed 2020-2029 SPP, the total revenue requirements for the proposed 2020-2029 SPP, and the total revenue requirements which would be recoverable through the Storm Protection Plan Cost Recovery Clause.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total costs (capital and O&M) by Programs:

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Tampa Electric's 2020-2029 Storm Protection Plan Total Costs by Program (in Millions)

Capital	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Lateral Undergrounding	$8.00	$79.45	$108.08	$101.44	$107.00	$110.78	$113.96	$111.42	$115.52	$121.17	$976.81
Transmission Asset Upgrades	$5.50	$15.21	$14.98	$16.51	$11.99	$19.04	$17.92	$16.28	$19.56	$12.11	$149.12
Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$7.34	$5.54	$4.67	$6.71	$5.24	$2.88	$32.37
Distribution Overhead Feeder Hardening	$6.50	$15.38	$29.58	$33.39	$32.49	$33.19	$33.82	$32.76	$36.36	$36.25	$289.73
Transmission Access Enhancements	$0.00	$1.38	$1.52	$1.56	$1.66	$1.40	$0.54	$3.17	$1.93	$1.57	$14.73
Distribution Pole Replacements	$9.42	$11.18	$14.72	$15.16	$15.62	$16.09	$10.64	$10.86	$11.07	$11.29	$126.05

O&M	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Vegetation Management - planned	$16.49	$19.76	$21.18	$24.00	$24.22	$25.55	$26.77	$27.99	$29.42	$30.94	$246.31
Distribution Vegetation Management - unplanned	$1.30	$1.30	$1.20	$1.10	$1.10	$1.10	$1.20	$1.20	$1.30	$1.30	$12.10
Transmission Vegetation Management - planned	$2.63	$3.53	$3.59	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$32.95
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.11	$0.30	$0.30	$0.33	$0.24	$0.38	$0.36	$0.33	$0.39	$0.24	$2.98
Distribution Overhead Feeder Hardening	$0.21	$0.38	$0.40	$0.79	$0.82	$1.02	$1.06	$1.17	$1.42	$1.64	$8.92
Distribution Infrastructure Inspections	$0.71	$1.00	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$10.46
Transmission Infrastructure Inspections	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.56	$5.09
SPP Planning & Common	$0.99	$0.39	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$3.10
Other Legacy Storm Hardening Plan Items	$0.28	$0.28	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$3.01
Distribution Pole Replacements	$0.52	$0.62	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$6.93

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Tampa Electric developed the 2020-2029 SPP projected costs and benefits for each of the proposed SPP Programs through the thorough and comprehensive analysis the company performed with Accenture LLP and 1898 & Co. Accenture, as described above, modeled the current VM Program against the proposed SPP initiatives during extreme weather. For the other SPP Programs, Tampa Electric worked with 1898 & Co. to evaluate the benefits of the 10-year Programs against a status quo scenario. Both the reduction in restoration costs and the reduction in customer minutes of interruption show the percentage improvement expected during major event days from the SPP Programs when compared to the status quo.

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	$976.8	$0.0	33	44	Q2 2020	After 2029
Vegetation Management	$0.0	$279.3	21	22 to 29	Q2 2020	After 2029
Transmission Asset Upgrades	$148.9	$3.0	90	13	Q2 2020	2029
Substation Extreme Weather	$32.4	$0.0	70 to 80	50 to 65	Q1 2021	After 2029
Distribution Overhead Feeder	$289.7	$8.9	38 to 42	30	Q2 2020	After 2029
Transmission Access Enhancements	$14.8	$0.0	10	74	Q1 2021	After 2029

Table title: Tampa Electric - Proposed 2020-2029 Storm Protection Plan Projected Costs versus Benefits

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2020-2029 SPP Programs plus depreciation and return on

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SPP, as outlined in Rule 25-6.030 F.A.C. The estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures using the depreciation rates from Tampa Electric's most current depreciation study. In addition, the depreciation expense has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital Projects. Lastly, in accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the company's 2012 Stipulation and Settlement Agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report. Only capital expenditures for SPP Projects after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total revenue requirements (capital and O&M) by Program:

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Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions)

Capital	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Lateral Undergrounding	$0.19	$4.66	$13.83	$23.93	$33.76	$43.83	$54.01	$64.01	$73.84	$83.91	$395.97
Transmission Asset Upgrades	$0.14	$1.25	$2.69	$4.16	$5.45	$6.82	$8.45	$9.91	$11.40	$12.66	$62.93
Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.28	$0.95	$1.42	$1.93	$2.47	$2.82	$9.87
Distribution Overhead Feeder Hardening	$0.14	$1.33	$3.42	$6.33	$9.30	$12.19	$15.06	$17.83	$20.64	$23.53	$109.77
Transmission Access Enhancements	$0.00	$0.06	$0.19	$0.33	$0.48	$0.61	$0.69	$0.85	$1.07	$1.22	$5.50
Distribution Pole Replacements	$0.25	$1.41	$2.60	$3.96	$5.32	$6.69	$7.79	$8.61	$9.42	$10.22	$56.27
O&M	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
Distribution Vegetation Management - planned	$16.49	$19.76	$21.18	$24.00	$24.22	$25.55	$26.77	$27.99	$29.42	$30.94	$246.31
Distribution Vegetation Management - unplanned	$1.30	$1.30	$1.20	$1.10	$1.10	$1.10	$1.20	$1.20	$1.30	$1.30	$12.10
Transmission Vegetation Management - planned	$2.63	$3.53	$3.59	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$32.95
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.11	$0.30	$0.30	$0.33	$0.24	$0.38	$0.36	$0.33	$0.39	$0.24	$2.98
Distribution Overhead Feeder Hardening	$0.21	$0.38	$0.40	$0.79	$0.82	$1.02	$1.06	$1.17	$1.42	$1.64	$8.92
Distribution Infrastructure Inspections	$0.71	$1.00	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$10.46
Transmission Infrastructure Inspections	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.56	$5.09
SPP Planning & Common	$0.99	$0.39	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$3.10
Other Legacy Storm Hardening Plan Items	$0.28	$0.28	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.32	$0.33	$3.01
Distribution Pole Replacements	$0.52	$0.62	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$6.93

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8 Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts of the Storm Protection Plan for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through the Storm Protection Plan Cost Recovery Clause ("SPPCRC") rates initiating in January 2021.

Each year's costs derive from the SPP Programs described in this Plan and are the capital and O&M costs combined into a revenue requirement. For each year, the SPP Programs were itemized and identified as to whether they are substation, transmission or distribution costs. Each of those functionalized costs were then allocated to the appropriate rate class using the allocation factors for that function.

The allocation factors used were from the Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI which was used for the current company's base rate design. Using these factors assures that the incremental SPP costs are being recovered from customers in the same manner as the comparable costs included in base rates are being recovered through current base rates.

Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the clause rates were determined in the same manner as current clause rates are designed.

For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the most recent 2020 energy billing

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determinants (for residential) and by the most recent 2020 demand billing determinants (for commercial and industrial). Those clause charges were then applied to the billing determinants associated with typical bills for those groups to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

A similar procedure will be used to derive actual clause charges in the clause cost recovery docket to come this summer, but in that case applied to all rate classes and using 2021 projected billing determinants.

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

Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
Customer Class			
Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

The rate impacts presented above reflect the total cost of the SPP, even though some of the costs in the Plan are currently being recovered through base rates and the incremental cost of the Plan to customers will be less than shown above. For example, using the average of the certain actual storm hardening costs reflected in the company's operation and maintenance

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expenses for 2017, 2018 and 2019 as a proxy, Tampa Electric estimates that the revenue requirement associated with amount of SPP O&M expenses currently being recovered through base rates is approximately $12.9 million.

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9 Storm Protection Plan Alternatives and Considerations

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

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

As described in the overview, the company engaged Accenture to evaluate several initiatives to enhance existing vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits.

Tampa Electric and 1898 & Co. used the resilience-based planning approach to establish an overall capital budget level and to identify and prioritize resilience investment in the company's T&D system. The budget optimization analysis was performed in $250 million increments up to $2.5 billion. The analysis showed

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significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion. The company's overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's SPP has an appropriate level of investment over the 2020-2029 ten-year period capturing the Storm Protection Projects that provide the most value to customers.

In addition to the Programs included in the 2020-2029 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in the Plan. Examples of things considered, but not included in this initial ten-year SPP are as follows:

- Undergrounding Distribution Feeders – The majority of customers are on laterals and analysis demonstrated higher cost-benefit to harden feeders and underground laterals.
- Upgrading wood distribution poles to non-wood materials – The company will continue to evaluate this option as manufacturing capabilities improve. At this time, the upgraded wood materials provide the best cost-benefit ratio for customers.
- Purchasing additional temporary access solutions such as increasing the number of mats – The solutions proposed in this Plan are more cost-effective and sustainable

As in the past with the company's prior Storm Hardening Plan Initiatives, Tampa Electric will also examine and analyze the processes and procedures used to implement the company's proposed 2020-2029 SPP Programs for any ongoing continuous improvement opportunities. This examination will assist in mitigating the resulting rate impact and ensure the benefits from the proposed SPP are realized.

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Appendix A

Project Detail

Distribution Lateral Undergrounding

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Tampa Electric's Distribution Lateral Undergrounding - Year 2020 Details

Project ID	Circuit No.	Specific Project Detail OH to UG Length Converted (miles)	Poles	Customers				Priority Customers	Project Start Qtr	Construction		Project Cost in 2020
				Residential	Small C&I	Large C&I	Total			Start Qtr	End Qtr	
Lateral Hardening-Fuse-60558225	13174	0.29	15	374	34	1	409	1	Q2 2020	Q3 2020	Q4 2020	$125,235
Lateral Hardening-Fuse-10786382	14040	0.23	13	98	6	2	106	10	Q2 2020	Q3 2020	Q4 2020	$150,431
Lateral Hardening-Fuse-90755954	13454	0.30	23	292	21	1	314	0	Q2 2020	Q3 2020	Q4 2020	$238,629
Lateral Hardening-Fuse-60451701	13174	0.24	14	301	11	2	314	0	Q2 2020	Q3 2020	Q4 2020	$230,114
Lateral Hardening-Fuse-10933151	13897	0.79	33	64	20	1	85	1	Q2 2020	Q3 2020	Q4 2020	$221,051
Lateral Hardening-Fuse-92421291	13972	0.44	23	379	6	1	386	0	Q2 2020	Q3 2020	Q4 2020	$248,973
Lateral Hardening-Fuse-92881445	13710	0.45	32	158	17	0	175	0	Q2 2020	Q3 2020	Q4 2020	$401,397
Lateral Hardening-Fuse-92599119	13390	0.72	46	266	27	3	296	0	Q2 2020	Q3 2020	Q4 2020	$750,732
Lateral Hardening-Fuse-92407065	13815	0.38	15	12	3	1	16	0	Q2 2020	Q3 2020	Q4 2020	$68,399
Lateral Hardening-Fuse-93019714	13840	0.13	9	39	2	0	41	0	Q2 2020	Q3 2020	Q4 2020	$51,112
Lateral Hardening-Fuse-92634300	14032	0.31	21	306	10	2	318	1	Q2 2020	Q3 2020	Q4 2020	$390,745
Lateral Hardening-Fuse-60287236	13509	0.15	14	144	14	0	158	0	Q2 2020	Q3 2020	Q4 2020	$175,078
Lateral Hardening-Fuse-60182741	13312	0.15	15	52	11	7	70	0	Q2 2020	Q3 2020	Q4 2020	$101,387
Lateral Hardening-Fuse-90241880	13972	0.90	49	130	7	6	143	0	Q2 2020	Q3 2020	Q4 2020	$687,129
Lateral Hardening-Fuse-10643541	13390	1.17	67	221	22	2	245	0	Q2 2020	Q3 2020	Q4 2020	$1,095,650
Lateral Hardening-Fuse-10786374	14040	0.27	16	205	13	0	218	11	Q2 2020	Q3 2020	Q4 2020	$334,434
Lateral Hardening-Fuse-92829453	13961	0.34	25	447	3	2	452	0	Q2 2020	Q3 2020	Q4 2020	$292,496
Lateral Hardening-Fuse-91406672	13836	0.35	25	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$248,786
Lateral Hardening-Fuse-90288627	13815	0.88	32	51	9	0	60	0	Q2 2020	Q3 2020	Q4 2020	$423,948
Lateral Hardening-Fuse-91432109	13071	0.14	15	20	5	0	25	0	Q2 2020	Q3 2020	Q4 2020	$163,279
Lateral Hardening-Fuse-90738378	13071	0.16	20	296	35	0	331	0	Q2 2020	Q3 2020	Q4 2020	$145,327
Lateral Hardening-Fuse-90911087	13724	0.54	32	31	4	0	35	6	Q2 2020	Q3 2020	Q4 2020	$423,395
Lateral Hardening-Fuse-93026469	13815	0.49	15	27	2	0	29	0	Q2 2020	Q3 2020	Q4 2020	$375,085
Lateral Hardening-Fuse-10629014	13146	0.54	30	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$608,468

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Appendix B

Project Detail

Transmission Asset Upgrades

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Tampa Electric's Transmission Asset Upgrades - Year 2020 Details						
Project ID	Circuit No.	Pole Count	Project Start Month	Construction		Project Cost in 2020
				Start Month	End Month	
Transmission Upgrades-69 kV-66654	66654	10	May-20	Jul-20	Jul-20	$317,000
Transmission Upgrades-69 kV-66840	66840	34	May-20	Jul-20	Aug-20	$1,077,800
Transmission Upgrades-69 kV-66007	66007	43	Jun-20	Aug-20	Aug-20	$1,363,100
Transmission Upgrades-69 kV-66019	66019	21	Jul-20	Sep-20	Oct-20	$665,700
Transmission Upgrades-69 kV-66425	66425	3	Jul-20	Oct-20	Oct-20	$95,100
Transmission Upgrades-138/230 kV-230403	230403	5	Jul-20	Oct-20	Oct-20	$105,700
Transmission Upgrades-69 kV-66413	66413	5	Jul-20	Oct-20	Oct-20	$158,500
Transmission Upgrades-69 kV-66046	66046	30	Jul-20	Oct-20	Nov-20	$939,900
Transmission Upgrades-69 kV-66059	66059	2	Aug-20	Nov-20	Nov-20	$63,400
Transmission Upgrades-138/230 kV-230008	230008	59	Aug-20	Nov-20	Jan-21	$700,150
Transmission Upgrades-138/230 kV-230010	230010	2	Sep-20	Jan-21	Jan-21	$900
Transmission Upgrades-138/230 kV-230038	230038	1	Oct-20	Jan-21	Jan-21	$450
Transmission Upgrades-138/230 kV-230003	230003	35	Oct-20	Jan-21	Feb-21	$15,750
Transmission Upgrades-138/230 kV-230005	230005	24	Oct-20	Feb-21	Feb-21	$10,800
Transmission Upgrades-138/230 kV-230004	230004	40	Nov-20	Feb-21	Mar-21	$18,000
Transmission Upgrades-138/230 kV-230625	230625	12	Nov-20	Mar-21	Mar-21	$5,400
Transmission Upgrades-138/230 kV-230021	230021	17	Nov-20	Mar-21	Apr-21	$7,650
Transmission Upgrades-138/230 kV-230052	230052	9	Dec-20	Apr-21	Apr-21	$2,700
Transmission Upgrades-69 kV-66024	66024	25	Dec-20	Apr-21	Apr-21	$27,750
Transmission Upgrades-138/230 kV-230608	230608	18	Dec-20	May-21	May-21	$7,200
Transmission Upgrades-138/230 kV-230603	230603	13	Dec-20	May-21	May-21	$1,800

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.

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Appendix C

Project Detail

Substation Extreme Weather Hardening

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Appendix D

Project Detail

Distribution Overhead Feeder Hardening

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Tampa Electric's Distribution Overhead Feeder Hardening – Year 2020 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2020
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
Distribution Feeder Hardening-Breaker-60067752	13308	Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles	1,220	260	36	1,516	26	May-20	Aug-20	Dec-20	$1,153,700
Distribution Feeder Hardening-Breaker-60095496-Recloser-92203202	13807	Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles	1,159	103	16	1,278	12	May-20	Aug-20	Dec-20	$1,679,500
Distribution Feeder Hardening-Breaker-60315127-Recloser-92189137	13805	Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles	356	61	4	421	0	May-20	Aug-20	Dec-20	$1,565,900
Distribution Feeder Hardening-Breaker-60066445	13745	Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles	3,106	242	50	3,398	62	May-20	Aug-20	Dec-20	$833,150
Distribution Feeder Hardening-Breaker-60064337	13533	Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles	2,161	235	36	2,432	34	May-20	Aug-20	Dec-20	$1,044,300

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Project Detail

Transmission Access Enhancement

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Appendix F

1898 & Co, Tampa Electric's Storm Protection

Plan Resilience Benefits Report

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Storm Protection Plan Resilience Benefits Report

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 121429

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

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Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

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1.0 EXECUTIVE SUMMARY

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

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's Storm Protection Plan. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

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

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

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

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

1.1 Resilience Based Planning Approach

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

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

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Figure 1-1: Storm Resilience Model Overview

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

Table 1-1:   Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is

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hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

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

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

1.2   Results & Conclusions

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

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Figure 1-2: Budget Optimization Results

The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total with substations and transmission site access making up 2.2 percent and 1.0 percent, respectively. The plan

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includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

Figure 1-3: Storm Protection Plan Investment Profile

Customer benefits are calculated in terms of the:

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

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

Figure 1-4: Storm Protection Plan Restoration Cost Benefit

The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the restoration costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration cost benefit is approximately 36 to 53 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 36 to 53 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

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Figure 1-5: Storm Protection Plan Customer Benefit

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

■ The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.

■ TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.

■ The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.

■ The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

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- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.

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

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2.0   INTRODUCTION

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

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

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

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

■ Distribution Lateral Undergrounding
■ Transmission Asset Upgrades

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

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

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

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

2.1 Resilience as the Benefits Assessment

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

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

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

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

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

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

- ■ Prepare (Before)

  The grid is running normally but the system is preparing for potential disruptions.

- ■ Mitigate (Before)

  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.

- ■ Respond (During)

  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).

- ■ Recover (After)

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

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

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

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

Figure 2-1: Phases of Resilience

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

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

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

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

2.2   Evaluated System for Resilience Investment

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

Table 2-1:   TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**216**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

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

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

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '2' were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening is the preferred approach for feeders.

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

TEC identified 96 separate transmission access, road, and bridge projects based on field inspection of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, over 20,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2:   Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

2.3   Resilience Planning Approach Overview

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

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

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

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2.3.1   Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency

and magnitude of future major storm events, the Storm Resilience Model starts with the 'universe' of

major storm events that could impact TEC's service territory, the Major Events Storms Database.

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Figure 2-2: Resilience Planning Approach Overview

Major Storm Event Database

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

Storm Impact Model (SIM)

Status Quo

Hardened System

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

Resilience Benefit Module

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

Budget Optimization & Project Prioritization

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

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The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events database includes the following:

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

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

2.3.2   Storm Impact Model

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

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

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identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

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

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

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

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

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

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2.3.3   Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4   Project Scheduling and Budget Optimization

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10 year period and portions of the system evaluated.

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

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

2.4   S-Curves and Resilience Benefit

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

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

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

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

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

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Figure 2-4: S-Curves and Future Storms

For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

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Figure 2-5: S-Curves and Resilience Focus

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3.0   MAJOR STORMS EVENT DATABASE

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

- ■ Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- ■ Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if they have been over land for a period of time.
- ■ Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, only a few storm bands may hit the TEC service territory.

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

3.1   Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen

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shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

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

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

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

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

- ■ 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage

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

■ 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 3-1:   Historical Storm Summary

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

Table 3-1 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from has significant impact on the overall damage to TEC's system. Based on these results and the various

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quantities by event type, the following 13 unique storm types serves as the foundation for the Major Storms Event Database:

1. Category 3 and Above 'Direct Hit' from the Gulf

2. Category 1 & 2 'Direct Hit' over Florida

3. Category 1 & 2 'Direct Hit' from the Gulf

4. Tropical Storm 'Direct Hit'

5. Tropical Depression 'Direct Hit'

6. Localized Event 'Direct Hit'

7. Category 3 and Above 'Partial Hit'

8. Category 1 & 2 'Partial Hit'

9. Tropical Storm 'Partial Hit'

10. Tropical Depression 'Partial Hit'

11. Category 3 and Above 'Peripheral Hit'

12. Category 1 & 2 'Peripheral Hit'

13. Tropical Storm 'Peripheral Hit'

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

3.1.2   Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 167 years. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

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

Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100.

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

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

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

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[3] See Footnote 2

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The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Storms until 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2019, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3   Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 167 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory.   The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

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Figure 3-5: "Partial Hits" (51 to 100 Miles)[4]

Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

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

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[4] See Footnote 2

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

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

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[5] See Footnote 2

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3.1.4   Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 167 years. A storm is classified as a partial hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[6]

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

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

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[6] See Footnote 2

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

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

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[7] See Footnote 2

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3.2   Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 167 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

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

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

3.3   Major Storms Impact

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

Table 3-2:   Recent Major Event Damages Cost

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

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

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

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

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

Pos: 33.52 , -92.59 Search Center: 27.93 , -82.28

Table 3-3:   Storm Report Summary

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

3.4   Major Storms Database

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

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[8] See Footnote 2

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Table 3-4:   Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

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4.0   STORM IMPACT MODEL

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

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

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

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

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Figure 4-1: Storm Impact Model Overview

4.1 Core Data Sets and Algorithms

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

4.1.1 Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up

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based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan.

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

Table 4-1:　　TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**216**

Table 4-2:　　Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	916
Total	19,666

4.1.2　　Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The

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OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3 Customer Type Data

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

Table 4-3:   Customer Counts by Type

Customer Type	Customer Count
Residential	695,000
Small Commercial and Industrial	71,100
Large Commercial and Industrial	16,300
Total	782,400

4.1.4 Vegetation Density Algorithm

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

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

Figure 4-2: Vegetation Density on TEC Primary Conductor

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Figure 4-3: Vegetation Density on TEC Transmission Conductor

4.1.5　Wood Pole Inspection Data

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

4.1.6　Wind Zone

A third driver of storm-based failure is the asset's location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the

adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records

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and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-4 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

Figure 4-4: Pole Wind Zone Distribution

4.1.7   Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8   ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman,

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Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

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

4.1.9   Substation Flood Modeling

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

4.2   Weighted Storm Likelihood of Failure Module

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

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4.2.1   Substation Storm Likelihood of Failure

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

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. This model provides the estimated feet of flooding above site elevation assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

4.2.2   Circuits Storm Likelihood of Failure

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

Figure 4-5 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are: wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density,

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normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

Figure 4-5: Storm LOF Framework for Circuit Assets

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

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Figure 4-6 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute on average 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-6: Age & Condition LOF Distribution

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

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

4.2.3 Site Access Storm Likelihood of Failure

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

4.3 Project & Asset Reactive Storm Restoration

The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles,

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overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

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

4.4   Duration and Customer Impact

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

Figure 4-7: Example Storm Duration Profile

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

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would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 400, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

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

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5   'Status Quo' and Hardening Scenarios

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

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

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5.0   RESILIENCE NET BENEFIT CALCULATION MODULE

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

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

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

5.1   Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

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

5.2   Project Cost

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

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5.2.1   Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.1.7) were
leveraged to estimate:

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

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

5.2.2   Transmission Asset Upgrades Project Costs

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

5.2.3   Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of
each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary
by the required height of the wall. The substation wall height is based off the needed height to mitigate
the flooding from the SLOSH model results.

5.2.4   Distribution Overhead Feeder Hardening Project Costs

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

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5.2.5 Transmission Access Enhancements

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

5.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 167 years.

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

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

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Table 5-1:   Monte Carlo Simulation Storm Event Selection

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

Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms. This calculation is repeated for all 1,000 iterations for the over 20,000 projects in the Storm Resilience Model.

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

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

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

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

5.4   Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 400 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS (see Section 4.1.2). TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the

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OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

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

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

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Figure 5-2: Automation Hardening Percent CMI Decrease

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

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Figure 5-3: Automation Hardening Monetization of CMI Decrease

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6.0   BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 20,000 projects. Resilience benefit values include:

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

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

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

The following sections discuss the prioritization metric, budget optimization, and approach to developing the Storm Protection Plan.

6.1   Prioritization Metric - Benefit Cost Ratio

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

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

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investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2 Budget Optimization

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

Figure 6-1: Budget Optimization Results

The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection

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

6.3 Storm Protection Plan Project Prioritization

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

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time).

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7.0   RESULTS & CONCLUSIONS

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

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

7.1   Storm Protection Plan

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

7.1.1   Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

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

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

7.1.2   Restoration Cost Reduction

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

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Figure 7-1: Storm Protection Plan Restoration Cost Benefit

The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration costs decrease benefit is approximately 36 to 53 percent of the project costs.

7.1.3   Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

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Figure 7-2: Storm Protection Plan Customer Benefit

7.2 Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 131 different circuits.

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Table 7-2:   Distribution Lateral Undergrounding Investment Profile

Year 1	Lateral Count	Miles	Nominal Cost ($000)
2020	24	10	$8,000
2021	281	101	$79,500
2022	316	119	$108,100
2023	308	105	$101,400
2024	286	124	$107,000
2025	283	106	$110,800
2026	286	118	$114,000
2027	318	146	$111,400
2028	298	126	$115,500
2029	282	152	$121,100
Total	2,682	1,107	$976,800

Table 7-3:   Transmission Asset Upgrades Investment Profile

Year 1	Circuits Worked On	Nominal Cost ($000)
2020	21	$5,600
2021	35	$15,200
2022	28	$15,000
2023	15	$16,500
2024	15	$11,900
2025	6	$19,000
2026	7	$17,700
2027	10	$16,300
2028	13	$19,600
2029	20	$12,100
Total	NA	$148,900

Table 7-4:   Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	0	$0
2022	0	$0
2023	0	$0
2024	1	$7,300
2025	2	$5,500
2026	2	$4,700
2027	4	$6,700
2028	1	$5,200
2029	1	$2,900
Total	11	$32,400

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Table 7-5:   Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2020	5	$6,200
2021	18	$15,400
2022	13	$29,600
2023	41	$33,400
2024	43	$32,500
2025	40	$33,200
2026	45	$33,800
2027	40	$32,800
2028	59	$36,400
2029	53	$36,300
Total	357	$289,600

Table 7-6:   Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	8	$1,400
2022	6	$1,500
2023	5	$1,600
2024	4	$1,700
2025	4	$1,300
2026	1	$400
2027	3	$3,300
2028	3	$2,000
2029	3	$1,700
Total	37	$14,800

7.3   Program Benefits

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

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Table 7-7:   Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~33%	~44%
Transmission Asset Upgrades	~90%	~13%
Substation Extreme Weather Hardening	70% to 80%	50% - 65%
Distribution Feeder Hardening	38% to 42%	30%
Transmission Access Enhancements	10%	~74%

Figure 7-3: Program Benefits vs. Capital Investment

Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 87 percent of the total capital investment, nearly all the CMI benefit, and approximately 71 percent of the restoration benefit.

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- The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 44 and 33 percent, respectively. Additionally, the program accounts for approximately 67 percent of the total plan's invested capital, approximately 54 percent of the plan's restoration benefit, and approximately 12 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.

- The Distribution Feeder Hardening program contributes approximately 87 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.

- While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).

- Substation Hardening accounts for over 10.5 percent of the restoration benefit of the plan while only accounting for approximately 2.2 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4   Conclusions

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

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.

- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.

- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.

- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

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- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.

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

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Appendix G

Accenture, Tampa Electric's Vegetation

Management Storm Protection Program Analytic

Support Report

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1   Executive Summary

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

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities including:

A. The projected frequency (trim cycle);
B. The projected miles of affected transmission and distribution overhead facilities;
C. The estimated annual labor and equipment costs for both utility and contractor personnel; and
D. A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

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

1. Four-year distribution vegetation management cycle
2. Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
    a. 400 miles in 2020
    b. 500 miles in 2021
    c. 700 miles in 2022 and beyond
3. Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
    a. Ensure fast-growing species are kept in check until the next scheduled trimming.
    b. Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.
    The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

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

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

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

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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.

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[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

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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.

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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:

<p align="center">Table 3-1: Initiative Approach</p>

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:

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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.

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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.

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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.

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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:

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	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.

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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.

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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

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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.

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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.

Annual Costs & SAIDI: Recommended Program 3ab-457
(400/500/700 Supplemental Miles with Graduated Mid-Cycle)

	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

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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.

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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).

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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.

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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.

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- 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.

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

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

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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)

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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

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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.

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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

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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

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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

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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.

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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%	6.48%	8.74%	11.13%
75	1.27%	3.18%	5.43%	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%	11.48%	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.

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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.

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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

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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

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TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

TAMPA ELECTRIC's
2020-2029
STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

REGAN B. HAINES

1   **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2   **PREPARED DIRECT TESTIMONY**

3   **OF**

4   **REGAN B. HAINES**

5

6   **TABLE OF CONTENTS:**

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25

1   **INTRODUCTION:**

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

3

4   **A.**   My name is Regan B. Haines. My business address is 702

5   N. Franklin Street, Tampa, Florida 33602. I am employed

6   by Tampa Electric Company ("Tampa Electric" or "the

7   company") as Director, Asset Management, Project

8   Management and System Planning.

9

10 **Q.**   Please describe your duties and responsibilities in that

11 position.

12

13 **A.**   My duties and responsibilities include the governance and

14 oversight of all Energy Delivery transmission and

15 distribution assets. I am also responsible for developing

16 and executing strategy and priorities for Energy

17 Delivery's overall network for system planning,

18 reliability planning and system maintenance. In

19 addition, I am responsible for Energy Delivery's capital

20 planning and budgeting, large project management, system

21 root cause analysis, and benchmarking.

22

23 **Q.**   Please describe your educational background and

24 professional experience.

25

1   A.   I graduated from Clemson University in June 1989 with a

2   Bachelor of Science degree in Electrical Engineering and

3   again in December 1990 with a Master of Science degree in

4   Electrical Engineering specializing in Power Systems

5   Engineering. I have been employed at Tampa Electric since

6   1998. My career has included various positions in the

7   areas of Transmission and Distribution Engineering and

8   Operations.

9

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

11   proceeding?

12

13   A.   The purpose of my direct testimony is to explain six of the

14   eight Storm Protection Programs in the company's proposed

15   2020-2029 Storm Protection Plan ("SPP" or "Plan"). I will

16   also describe the Storm Protection Projects associated with

17   these Programs as applicable. My testimony will describe

18   how the company's Plan complies with Rule 25-6.030(3) by

19   providing all the information required for each of these

20   six Programs and their implementing Projects.

21

22   Q.   Are you sponsoring any exhibits in this proceeding?

23

24   A.   Yes. I have prepared an exhibit entitled, "Exhibit of Regan

25   B. Haines."   It consists of four documents and has been

1   identified as Exhibit No. RBH-1, which contains the

2   following documents:

3

4   • Document No. 1 provides Tampa Electric's – Proposed

5   2020-2029 Storm Protection Plan Projected Costs

6   versus Benefits by Program.

7   • Document No. 2 provides the Project Detail for the

8   Distribution Lateral Undergrounding Program.

9   • Document No. 3 provides the Project Detail for the

10   Transmission Asset Upgrades Program.

11   • Document No. 4 provides the Project Detail for the

12   Distribution Overhead Feeder Hardening Program.

13

14   **TAMPA ELECTRIC'S SERVICE AREA**

15   **Q.** Are there any parts of Tampa Electric's service area that

16   were prioritized for enhancement, or any areas where

17   enhancement would not be feasible, reasonable or practical,

18   under the six Programs described in your testimony?

19

20   **A.** No. The company did not exclude any area of the company's

21   existing transmission and distribution facilities for

22   enhancement under these Programs due to feasibility,

23   reasonableness, or practicality.

24

25

4

TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN

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

A. Tampa Electric's proposed 2020-2029 Storm Protection Plan is comprised of eight distinct Programs. The Programs are:

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. You mentioned that you would be describing six of the eight Storm Protection Programs. Which Programs are you not describing?

A. I will not be describing the Vegetation Management or Transmission Access Enhancement Programs. The direct testimony of John H. Webster will cover those two Storm Protection Programs.

Q. How is your testimony organized?

1 **A.** For each Program I am describing, my testimony will explain

2   how the company developed the information required by Rule

3   25-6.030(d)1-4, including: (1) a description of how the

4   Program is designed to enhance existing transmission and

5   distribution facilities, including an estimate of the

6   resulting restoration in outage times and restoration

7   costs; (2) actual or estimated start and completion dates

8   of the program; (3) a cost estimate including capital and

9   operating expenses; and (4) an analysis of costs and

10   benefits.

11

12 **Q.** Will you testify regarding the information required by Rule

13   25-6.030(3)(d)5 – the criteria the company used to select

14   and prioritize its proposed Storm Protection Programs?

15

16 **A.** No. The direct testimony of Gerard R. Chasse will describe

17   the process Tampa Electric used to select and prioritize

18   Programs.

19

20 **Q.** Will your testimony also address certain Storm Protection

21   Projects?

22

23 **A.** Yes. In addition to explaining the required Program

24   details, for each Program with Projects, my testimony will

25   also explain how the company developed the required

1   Project-level details for the first year of the Plan,

2   including: (1) actual or estimated construction start and

3   completion dates; (2) a description of the affected

4   facilities, including the number and type of customers

5   served; and (3) a cost estimate including capital and

6   operating expenses. My testimony will also describe how

7   the company forecasted Project-level detail for the second

8   and third years of the Plan.

9

10 **Q.** In the direct testimony of Gerard R. Chasse, he mentions

11   that Tampa Electric used a consultant to assist with the

12   development of the Plan. Why did Tampa Electric use this

13   consultant?

14

15 **A.** Tampa Electric hired a consulting firm to help develop the

16   company's Plan. The company was looking for and found a

17   consulting firm with expertise in the areas of T&D system

18   hardening and cost-benefit analysis. The company also

19   wanted an independent third-party review of our proposed

20   SPP Programs and our methodology and prioritization

21   approach. In addition, the company needed assistance with

22   performing a thorough cost-benefit analysis. Tampa Electric

23   selected 1898 & Co., part of Burns & McDonnell, which

24   offered a very robust asset management modeling approach

25   that would allow us to effectively analyze the storm impact

1		risks associated with each component of the T&D system.
2		Their model also gave us the capability to perform scenario
3		analysis and ultimately prepare a robust cost-benefit
4		analysis for several of our proposed Programs, including
5		the Distribution Lateral Undergrounding, Transmission Asset
6		Upgrades, Substation Extreme Weather Hardening and
7		Distribution Overhead Feeder Hardening Programs. This
8		analysis was critical as we prioritized Projects within
9		each of these Programs and analyzed the costs and benefits
10		of the Programs. In addition, 1898 gave us the ability to
11		model the combined improvements from multiple Programs
12		simultaneously, model multiple scenarios and optimize
13		portfolio spend, and finally, gain confirmation that
14		modeled benefits were appropriate, achievable and in range
15		with the industry. The company believes that 1898 possessed
16		the model needed to effectively perform the type of required
17		analysis. Jason D. De Stigter from 1898 will provide direct
18		testimony to more fully detail the approach taken for each
19		of the Programs they supported.
20		
21	Q.	Please explain how Tampa Electric and 1898 & Co. prepared
22		the estimate of the reduction in outage times and
23		restoration costs due to extreme weather conditions that
24		will result from the Distribution Lateral Undergrounding,
25		Transmission Asset Upgrades, Substation Extreme Weather

1 Hardening and Distribution Overhead Feeder Hardening

2 Programs?

3

4 **A.** The methodology used to develop the estimate of the

5 reduction in outage times and restoration costs is

6 addressed in detail in Jason D. De Stigter's direct

7 testimony, but in general, 1898 developed a storm model

8 that simulated 99 different storms scenarios and each

9 scenario was modeled to identify which parts of the electric

10 system are most likely to fail given each type of storm.

11 The likelihood of failure is driven by the age and condition

12 of the asset, the wind zone the asset is located within and

13 the vegetation density around each conductor asset. 1898's

14 Storm Impact Model also created an estimate of the

15 restoration costs and Customer Minutes of Interruption

16 ("CMI") associated with each potential Project for each

17 storm scenario. Finally, the model calculated the benefit

18 in terms of decreased restoration cost and reduced CMI if

19 that Storm Protection Project were implemented per the

20 company's hardening standards. This approach was repeated

21 for every potential Storm Protection Project within each of

22 these Programs. Finally, the estimated benefits of avoided

23 restoration costs and outages were summed over the life of

24 all hardened assets proposed for each Program during the 10

25 year plan and compared to the projected performance of the

1   current assets or status quo. This comparison gave the

2   company an estimated relative percentage reduction in

3   restoration costs and outage times for each SPP Program.

4   These estimates are included in my Exhibit No. RBH-1,

5   Document No. 1 and are represented in terms of the relative

6   benefit or improvement that the 10-year Program will

7   provide. The benefits of a reduction in restoration costs

8   and outage times are shown as a percentage improvement

9   expected during extreme weather events or major event days

10   when compared to the status quo.

11

12 Q. Please explain the methodology Tampa Electric used to

13   prioritize the Projects the company is including in the

14   Distribution Lateral Undergrounding, Transmission Asset

15   Upgrades, Substation Extreme Weather Hardening and

16   Distribution Overhead Feeder Hardening Programs?

17

18 A. The methodology used to develop the prioritization of

19   Projects in these Programs is addressed in detail in Jason

20   D. De Stigter's direct testimony. In general, we developed

21   a Project cost estimate for each potential Project in our

22   system that was based on several factors depending on the

23   Program.   For   example,   for   distribution   lateral

24   undergrounding, factors such as the length of the line,

25   location of the facilities (front or rear lot), number of

10

1		transformers and customer services, etc. were considered.
2		Secondly, we estimated the benefits each potential Project
3		could provide by determining the savings of avoided
4		restoration costs and the reduction in outage times or
5		reduced customer minutes of interruption. The outage time
6		reductions or savings were then converted to financial
7		benefits utilizing the Department of Energy's Interruption
8		Cost Estimator (ICE) calculator. The ICE Calculator is an
9		electric reliability planning tool designed for electric
10		reliability planners to estimate interruption costs and/or
11		the benefits associated with reliability improvements.
12		Both benefits were combined and a cost benefit NPV was
13		calculated for each potential Project. The NPVs were then
14		used to rank or prioritize each Project within a given SPP
15		Program.
16		
17	**Q.**	Does the final ranking of projects in the SPP strictly
18		follow 1898's prioritization?
19		
20	**A.**	No. The ranking serves as a guide, but the company will
21		also apply operational experience and judgment when
22		selecting Projects. This will help us to first, gain
23		valuable experience early on in a Program by picking
24		Projects that will ensure our procedures and approach are
25		fully vetted with some of the less complex areas, and

1   second, ensure that we are addressing all areas and

2   communities equitably within our service territory.

3

4   Q. Did Tampa Electric prepare an analysis of the estimated

5   costs and benefits of the Distribution Lateral

6   Undergrounding, Transmission Asset Upgrades and

7   Distribution Overhead Feeder Hardening Programs?

8

9   A. Yes. As I mentioned earlier, the company created cost

10   estimates for each potential Project within each Program

11   and then determined the benefit of each Project by using

12   1898's model to compare its performance before and after

13   hardening. The benefits of a reduction in restoration costs

14   and outage times for all of the Projects planned for each

15   Program are shown as a percentage improvement expected

16   during extreme weather events or major event days when

17   compared to the status quo. A table comparing the estimated

18   costs and benefits for each Program is included as Exhibit

19   No. RBH-1, Document No. 1.

20

21 Q. You stated previously that the company compared the

22   estimated costs and benefits of the Distribution Lateral

23   Undergrounding, Transmission Asset Upgrades, Substation

24   Extreme Weather Hardening and Distribution Overhead Feeder

25   Hardening Programs. How did the company use the Project-

1   level costs and benefits described above to perform this

2   comparison?

3

4 **A.** A detailed description of how the company used Project-

5   level costs and benefits is addressed in Jason D. De

6   Stigter's direct testimony. In general, a cost benefit NPV

7   was developed for each potential Project which was then

8   used to first determine its relative cost effectiveness and

9   then to rank or prioritize Projects within each of the

10   Programs. As mentioned earlier, this established a ranked

11   Project listing that the company will use together with its

12   business and operational judgement to determine when

13   Projects will be implemented. Then the estimated costs and

14   benefits for all Projects selected for each Program during

15   the 2020-2029 plan period were aggregated to determine the

16   total costs and benefits of each Program illustrated in my

17   Exhibit No. RBH-1, Document No. 1.

18

19

20 **Distribution Lateral Undergrounding**

21 **Q.** Please provide a description of the Distribution Lateral

22   Undergrounding Program.

23

24 **A.** The primary objective of Tampa Electric's Distribution

25   Lateral Undergrounding Program is to increase the

13

1		resiliency and reliability of the distribution system
2		serving our customers during and following a major storm
3		event by converting existing overhead distribution
4		facilities to underground. Tampa Electric has approximately
5		6,250 miles of overhead distribution lines of which
6		approximately 4,500 miles or 72% of the overhead
7		distribution system are considered lateral lines or fused
8		lines that branch off the main feeder lines. These lateral
9		lines can be one, two or three phase lines and typically
10		serve communities and neighborhoods.
11		
12	**Q.**	Did Tampa Electric work with 1898 to develop this Program?
13		
14	**A.**	Yes. The company worked with 1898 & Co. to prioritize all
15		lateral lines utilizing a methodology that factors in the
16		probability or likelihood of failure and the impact or
17		consequence if a failure occurs during a major weather
18		event. The company's distribution system contains 787
19		circuits or feeders and over 18,000 lateral lines. While
20		the company has experience converting small areas of
21		overhead distribution facilities to underground, this is
22		the first time it will do so in this scale.
23		
24	**Q.**	What role does community outreach play in an undergrounding
25		Program?

1	**A.** Community and customer outreach will be critical to the
2	success of this Program. The company has accordingly placed
3	an emphasis on this. A comprehensive outreach process will
4	be developed to work cooperatively with property owners and
5	neighborhoods impacted by this Program.
6	
7	**Q.** How does the company plan to implement this Program?
8	
9	**A.** This SPP Program will include a ramp up of overhead to
10	underground conversion Projects in 2020 and 2021 to help
11	establish the best overall process to maintain moving
12	forward as this Program will continue past the ten-year
13	horizon of this plan. Using the lateral line ranking as a
14	guide, the company has created Projects that it will
15	undertake each year. The company's plan is to develop an
16	organization and structure that supports undergrounding
17	100-150 miles annually over the period 2022-2029. For plan
18	year 2020 and 2021, the company plans to underground a total
19	of 90-100 miles. This will include converting the existing
20	overhead lateral primary, lateral secondary and service
21	lines to underground.
22	
23	**Q.** Please explain how Tampa Electric's Distribution Lateral
24	Undergrounding Program will enhance the utility's existing
25	transmission and distribution facilities?

A.   This Program will provide 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 occurring on the company's overhead

distribution system originate from an event on an overhead

distribution lateral line. In addition, a significant

amount of a utility's restoration efforts deals with

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

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 that also create the

most significant impact during a major storm event.

Comparatively, very few, if any outages have originated on

underground facilities during the recently experienced

named storms and only 6% during blue sky, day-to-day

conditions. By undergrounding these overhead lateral

lines, the risk of failure during a major storm event should

16

1		be significantly mitigated.
2		
3	**Q.**	Did Tampa Electric prepare a list of Distribution Lateral
4		Undergrounding Projects that the company is planning on
5		initiating in 2020, including their associated starting and
6		projected completion dates?
7		
8	**A.**	Yes, the list of Distribution Lateral Undergrounding
9		Projects for 2020 and their associated starting and
10		projected completion dates is included in Appendix A of the
11		Plan and in my Exhibit No. RBH-1, Document No. 2. The
12		company has also developed a very preliminary list of
13		Projects for 2021. Given that this is a new Program for
14		the company, the list of Projects selected for 2020 and
15		2021 were those identified from the prioritized list that
16		will increase the company's chances of early success while
17		providing the most benefit to customers.
18		
19	**Q.**	Did Tampa Electric prepare a description of the facilities
20		that will be affected by each Project including the number
21		and type of customer(s) served?
22		
23	**A.**	Yes, a description of facilities affected by Project is
24		included in my Exhibit No. RBH-1, Document No. 2. For this
25		SPP Program, this will include a unique Project identifier,

1		the number of and type of customers served by the
2		facilities, and the number of miles of overhead line
3		converted to underground for each Project.
4		
5	**Q.**	Did Tampa Electric prepare a cost estimate for this Program,
6		including capital and operating expenses?
7		
8	**A.**	Yes. The company has developed cost estimates for each
9		Project within this Program for 2020 and 2021 and then
10		totaled those estimates to derive the annual cost estimates
11		for the Program. The company utilized several
12		characteristics of the existing overhead facilities
13		targeted for conversion to develop the cost estimates for
14		each Project including, the number of phases involved, the
15		length of the line, and location of the facilities (front
16		or rear lot), etc. Based on the results of 1898's budget
17		optimization model, the company then estimated the number
18		of Projects it expects to complete in years 2022-2029 with
19		average Project cost estimates to develop the annual
20		Program costs in those years. The estimated costs for
21		this Program include $8M in 2020, $80M in 2021 and then
22		approximately $100M-$120M in each year 2022-2029. There
23		were no incremental O&M costs associated with this Program.
24		The table below sets out the estimated number of Projects
25		and annual costs for 2020-2022.

Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	24	$8.0
2021	281	$79.5
2022	316	$108.1

Transmission Asset Upgrades

Q. Please provide a description of the Transmission Asset Upgrades Program?

A. The main objective of this SPP Program is to address the vulnerability that our remaining wood transmission poles pose on the grid 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 over the next ten years. The company has identified 131 of its existing 217 transmission circuits that have at least one existing wooden pole and will conduct replacement of those remaining transmission wood poles on an entire circuit basis.

1	**Q.** Please explain how Tampa Electric's Transmission Asset
2	Upgrade Program will enhance the utility's existing
3	transmission and distribution facilities?
4	
5	**A.** Tampa Electric has over 1,000 miles of overhead
6	transmission lines at voltage levels of 230kV, 138kV and
7	69kV. While the company experiences far fewer transmission
8	outages and pole failures during major storm events than on
9	the distribution system, an outage on the transmission
10	system can have far greater impact and significance. The
11	vast majority of these pole failures are associated with
12	wood poles. Of the ten transmission poles replaced due to
13	Hurricane Irma in 2017, nine were wooden poles with no
14	previously identified deficiencies that would warrant the
15	pole to be replaced under the existing Storm Hardening Plan
16	Initiative. The company has already made significant
17	progress in reducing storm-related transmission outages
18	through implementation of Extreme Wind Loading design and
19	construction standards. In the early 1990s, Tampa Electric
20	changed its standards and began building all new
21	transmission circuits with non-wood structures. Today,
22	approximately 80 percent of Tampa Electric's transmission
23	system is constructed of steel or concrete
24	poles/structures. The remaining 20 percent, however, are
25	still comprised of wood poles installed over 30 years ago.

1		Replacing the remaining wood transmission wood poles with
2		non-wood material gives Tampa Electric the opportunity to
3		bring aging structures up to current, and more robust, wind
4		loading standards then required at the time of
5		installation. This will greatly reduce the likelihood of a
6		failure during a major storm event.
7		
8	**Q.**	Did Tampa Electric prepare a list of Transmission Asset
9		Upgrades Projects that the company is planning on
10		initiating in 2020, including their associated starting and
11		projected completion dates?
12		
13	**A.**	Yes, the list of Transmission Asset Upgrades Projects for
14		2020 and their associated starting and projected completion
15		dates is included in Appendix C of the Plan and in my
16		Exhibit No. RBH-1, Document No. 3. The company is planning
17		21 projects in 2020 and has identified a very preliminary
18		list of 35 projects for 2021. The remaining transmission
19		circuits with wood poles were prioritized and scheduled for
20		upgrade in the years 2022-2029.
21		
22	**Q.**	Did Tampa Electric prepare a description of the facilities
23		that will be affected by each Project including the number
24		and type of customer(s) served?
25		

A. Yes, in my Exhibit No. RBH-1, Document No. 3, the description of the affected facilities for this Program include 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 has developed cost estimates for each Project within this Program for 2020 and 2021 and then totaled those estimates to derive the annual cost estimates for the Program. The company utilized 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 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $5.6M in 2020, $15.2M in 2021 and then approximately $15M in each year 2022-2029. There were no incremental O&M costs associated with this Program. The

1   table below sets out the estimated number of Projects and

2   estimated annual costs for this Program for 2020-2022.

3

4

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	21	$5.6
2021	35	$15.2
2022	28	$15.0

11

12

13   **Substation Extreme Weather Hardening**

14   **Q.**   Please provide a description of the Substation Extreme

15   Weather Hardening Program?

16

17   **A.**   The primary objective of this Program is to harden and

18   protect the company's substation assets that are vulnerable

19   to flood or storm surge.   This Program will minimize

20   outages, reduce restoration times and enhance emergency

21   response during extreme weather events. The company has

22   identified 59 of its 216 substations that have some level

23   of risk to flood or surge.   1898 modeled these 59

24   substations and prioritized based on the expected benefits

25   of mitigation after hardening each with a flood wall

solution. Utilizing this approach, 1898's model selected 11 substation hardening projects for the SPP Plan. Surprisingly, 1898's model indicated that the substation hardening projects account for a sizable restoration benefit while requiring a small percentage of the Plan's capital investment. Given this dramatic benefit to cost ratio, the company decided that further evaluation and assessment of this Program is needed. The company plans to perform a study utilizing a third party consultant that specializes in substation hardening and asset management in 2021 to evaluate various substation hardening solutions and assess the potential vulnerability of the identified substations to extreme weather, including flooding or storm surge. The results of the study will include a recommendation for each substation to be hardened, including the most cost effective hardening solution identified for each and a cost-benefit analysis. The study is estimated to cost around $250,000 and will produce a list of prioritized substation hardening projects.

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 will increase the resiliency and reliability of the substations through measures such as permanent or temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding. For those substations that are located closest to the coastline and of greatest risk, substation hardening efforts will 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 certainly 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. Yes. Installing either permanent/temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding, will reduce restoration costs and times, as substation control houses and equipment would not exposed to major saltwater intrusion due to storm surge and/or flooding. If hardening efforts are not implemented, it would take Substation personnel or contractors an extremely long amount of time

1		to flush equipment with clean water and air dry the
2		equipment. Each piece of equipment would then need to be
3		tested before it is placed back into service. All of these
4		efforts will lead to significantly higher restoration costs
5		and longer outage times. 1898's model was utilized to
6		estimate the benefits in reduced restoration costs and
7		outage times as previously explained.
8		
9	Q.	Did Tampa Electric prepare a list of Substation Extreme
10		Weather Protection Projects that the company is planning on
11		initiating in 2020, including their associated starting and
12		projected completion dates?
13		
14	A.	The company does not propose any substation projects for
15		2020.
16		
17	Q.	Did Tampa Electric prepare a description of the facilities
18		that will be affected by each Project including the number
19		and type of customer(s) served?
20		
21	A.	The company has not proposed any projects in 2020 but has
22		identified 11 substations that have the greatest risk of
23		impact due to flood or surge by an extreme weather event
24		based on the preliminary analysis. The planned study will
25		further refine this list and produce a project list and

1		implementation plan.
2		
3	Q.	Would you explain in detail the methodology Tampa Electric
4		used in prioritizing the projects the company is including
5		in this Program?
6		
7	A.	The detailed engineering study the company plans to conduct
8		will produce a list of recommendations including a
9		prioritized list of substations to harden and the
10		methodology utilized.
11		
12	Q.	Did Tampa Electric prepare a cost estimate for this Program,
13		including capital and operating expenses?
14		
15	A.	The company estimates that the study will cost around
16		$250,000. The planned study will produce a project list
17		with project cost estimates and the implementation plan.
18		
19	Q.	Did Tampa Electric prepare an estimate of benefits
20		(reduction in outage time, reduction in extreme weather
21		restoration cost) for the projects the company is planning
22		on initiating for this Substation Extreme Weather Hardening
23		Program?
24		
25	A.	The company has not proposed any projects in 2020, however,

1		the planned engineering study will provide a list of
2		projects and an estimate of costs and benefits for each
3		proposed substation hardening project.
4		
5	**Q.**	Did Tampa Electric prepare a comparison of the estimated
6		costs and benefits of the Program?
7		
8	**A.**	The scope of the planned engineering study will include a
9		recommended list of proposed hardening projects and a
10		comparison of the estimated costs and benefits of the
11		Program.
12		
13		

Distribution Overhead Feeder Hardening

15	**Q.**	Please provide a description of the Distribution Overhead
16		Feeder Hardening Program?
17		
18	**A.**	Tampa Electric's distribution system includes feeders, also
19		referred to as mainline or backbone, and laterals, which
20		are tap lines off the main feeder line. The feeder is the
21		main line that originates from the substation and is the
22		most critical to ensuring power is reliably delivered to
23		our customers one it leaves the substation. While the
24		company has hardened some of its feeders that serve critical
25		customers, this SPP Program will expand that effort to

1		include some of our highest priority feeders, starting with
2		those that have the worst historical day-to-day performance
3		and performance during major storm events, those with the
4		highest likelihood of failure, and those that would present
5		the greatest impact if an outage were to occur.
6		
7	**Q.**	How will this Program harden the company's feeders?
8		
9	**A.**	The Distribution Overhead Feeder Hardening Program includes
10		strategies to further enhance the resiliency and
11		reliability of the distribution network by further
12		hardening the grid to minimize interruptions and reduce
13		customer outage counts during extreme weather events and
14		abnormal system conditions. These include
15		stronger/hardened poles and facilities, installation of
16		switching equipment to allow for automatic isolation of
17		damaged facilities, upgrading of small wire conductor to
18		ensure automatic service restoration is not limited by
19		capacity constraints and the use of new equipment to
20		minimize the interruption of service during atypical system
21		configurations.
22		
23	**Q.**	What switching equipment does the company plan to install
24		as a part of this Program?
25		

1	**A.**	The company will install reclosers and trip savers to
2		minimize the number of customers interrupted during events
3		as well as reduce the outage time for customers. This
4		equipment will allow for the automatic isolation of faults
5		on the system and then ultimately allow the network to re-
6		configure itself real-time without operator intervention.
7		
8	**Q.**	How does the company plan to harden poles on feeder lines?
9		
10	**A.**	Hardening these feeders will include upgrading the poles
11		older than 35 years of age, smaller than class 2 and
12		ensuring the feeders meet NESC extreme wind loading
13		standards along the feeder to increase the overall
14		resiliency of the feeder. As an example, concrete poles
15		that have a higher wind loading capacity may be utilized at
16		key locations on the feeder such as switch, recloser, 3-
17		phase transformer bank and capacitor bank locations.
18		Additional steps that will be taken to harden the feeders
19		and reduce restoration times will be installing
20		sectionalizing switching devices, fault current
21		sensors/indicators, and creating circuit ties to allow for
22		automation.
23		
24	**Q.**	Please explain how Tampa Electric's Distribution Overhead
25		Feeder Hardening Program will enhance the utility's

1		existing transmission and distribution facilities?
2		
3	**A.**	The Distribution Overhead Feeder Hardening Program will
4		enhance the resiliency of the distribution system by
5		increasing the strength of the poles at most risk of failing
6		during a major weather event as well as the poles at key
7		locations along the feeder that would cause the greatest
8		impact if a failure occurred. Tampa Electric has
9		approximately 800 distribution feeders that serve near
10		1,000 customers on average each so mitigating the potential
11		of an outage on these feeders is critical to minimizing
12		customer outages. In addition, the company plans to add
13		fault detection, isolation and restoration devices on
14		feeders, which will significantly reduce the number of
15		customers experiencing an outage during an event and allow
16		those that do to be restored significantly quicker.
17		
18	**Q.**	Did Tampa Electric prepare a list of Distribution Overhead
19		Feeder Hardening Projects that the company is planning on
20		initiating in 2020, including their associated starting and
21		projected completion dates?
22		
23	**A.**	Yes, the list of Distribution Overhead Feeder Hardening
24		Projects for 2020 and their associated starting and
25		projected completion dates is included in Appendix D of the

1   Plan and in my Exhibit No. RBH-1, Document No. 4. The

2   company has a very preliminary list of Projects for 2021

3   and has identified how many distribution feeders the

4   company plans to harden in the years 2022-2029.

5

6 Q. Did Tampa Electric prepare a description of the facilities

7   that will be affected by each Project including the number

8   and type of customer(s) served?

9

10 A. Yes, included in Appendix D of the Plan and in my Exhibit

11   No. RBH-1, Document No. 4, the description of facilities

12   affected include a unique Project identifier, the number

13   and type of major equipment upgraded or installed, and the

14   number and type of customers served by the facilities.

15

16 Q. Did Tampa Electric prepare a cost estimate for this Program,

17   including capital and operating expenses?

18

19 A. Yes. The company has developed cost estimates for each

20   Project within this Program for 2020 and 2021 and totaled

21   those estimates to derive the annual cost estimates for the

22   Program. The company first defined the attributes of a

23   hardened feeder and then applied the new criteria to each

24   potential overhead feeder to develop its cost estimate to

25   harden. The estimated costs for each Project reflect

1	bringing that feeder up to the new hardened standard which
2	includes poles meeting NESC Extreme Wind loading criteria,
3	no poles lower than a class 2, no conductor size smaller
4	than 336 ACSR, single phase reclosers or trip savers on
5	laterals, feeder segmented and automated with no more than
6	200-400 customers per section and no segment longer than 2-
7	3 miles, no more than two to three MWs of load served on
8	each segment, and circuit ties to other feeders with
9	available switching capacity. The company then estimated
10	the number of Projects it expects to complete in years 2022-
11	2029 with average Project cost estimates to develop the
12	annual Program costs in those years. The estimated costs
13	for this Program include $6.5M in 2020, $15.4M in 2021,
14	29.6M in 2022, and then approximately $33M in each year
15	2023-2029. There were no incremental O&M costs associated
16	with this Program. The table below includes the estimated
17	number of Projects and estimated costs per year for 2020-
18	2022.

Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)		
	Projects	Costs
2020	5	$6.5
2021	18	$15.4
2022	13	$29.6

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 in a resilient state should the company
     experience 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.

1 20060078-EI which requires each investor-owned electric

2 utility to implement an inspection program of its wooden

3 transmission, distribution and lighting poles on an eight-

4 year cycle based on the requirements of the NESC. This

5 Program provides a systematic identification of poles that

6 require repair or replacement to meet strength requirements

7 of NESC. Tampa Electric performs inspections of all wood

8 poles on an eight-year cycle. Tampa Electric has

9 approximately 290,000 wooden distribution and lighting

10 poles and 25,700 transmission poles and structures that are

11 part of an inspection program. Approximately 12.5 percent

12 of the known pole population will be targeted for

13 inspections annually although the actual number of poles

14 may vary from year to year due to recently constructed

15 circuits, de-energized circuits, reconfigured circuits,

16 etc.

17

18 **Q.** How will the Infrastructure Inspection Program identify

19 potential system issues?

20

21 **A.** The Tampa Electric Transmission System Inspection Program

22 identifies potential system issues along the entire

23 transmission circuit by analyzing the structural conditions

24 at the ground line and above ground as well as the conductor

25 spans. Formal inspection activities included in the Program

1		are ground line inspection, ground patrol, aerial infrared
2		patrol, above ground inspection and transmission substation
3		inspections. Typically, the ground patrol, aerial infrared
4		patrol and substation inspections are performed every year
5		while the above ground inspections and the ground line
6		inspection are performed on an eight-year cycle.
7		
8		The company also performs joint use audits and inspections
9		to mitigate the impact unknown foreign attachments could
10		create by placing additional loading on a facility. All
11		Tampa Electric joint use agreements have provisions that
12		allow for periodic inspections and/or audits of all joint
13		use attachments to the company's facilities to be paid for
14		by the attaching entities.
15		
16	Q.	Please explain how Tampa Electric's Infrastructure
17		Inspections Program will enhance the utility's existing
18		transmission and distribution facilities?
19		
20	A.	Timely inspections and identification of required
21		maintenance items can greatly reduce the impact of major
22		storm events to the transmission and distribution system.
23		Given that poles are critical to the integrity of the
24		transmission and distribution grid, pole inspections are a
25		key component of this SPP Program. Pole failures during a

1		major storm event can cause a significant impact since there
2		is high probability that the equipment attached to the pole
3		will also experience damage. Cascading failures of other
4		poles will also likely occur. Specifically, wood poles
5		pose the greatest risk of failure and must be maintained
6		and eventually replaced given they are prone to
7		deterioration. The 8-year wood pole inspection requirement
8		put in place by the Florida Public Service Commission is
9		aimed at identifying any problems with a pole so they can
10		be mitigated before they cause a problem during a major
11		storm event. In addition, the other FPSC required
12		inspections included in this SPP Program are also aimed at
13		identifying compromised equipment that may create a
14		vulnerability so that they can be addressed prior to causing
15		a problem during a major storm event.
16		
17	Q.	Please explain how Tampa Electric prepared the estimate of
18		the reduction in outage times and restoration costs due to
19		extreme weather conditions that will result from the
20		Infrastructure Inspections Program?
21		
22	A.	While Tampa Electric did not prepare estimates of the
23		reduction in outage times and restoration costs for this
24		Program, as I previously discussed, inspections play a
25		critical role in identifying issues with infrastructure and

1		facilities so appropriate repairs can be made before a
2		failure and resulting outage occurs. By doing so, the
3		number of outages and outage times, not only during a major
4		storm event, but also during day-to-day operations will be
5		significantly reduced. In addition, planned repairs of
6		equipment and facilities identified through an inspection
7		are significantly less costly than restoring after a
8		failure or following a major storm event.
9		
10	**Q.**	Did Tampa Electric prepare a list of Infrastructure
11		Inspections Projects that the company is planning on
12		initiating in 2020, including their associated starting and
13		projected completion dates?
14		
15	**A.**	Tampa Electric conducts thousands of inspections each year
16		so rather than identify various projects, the company has
17		identified the number of inspections by type planned for
18		2020 – 2022 along with the estimated spend. The table
19		included below sets out this information. Typically, these
20		inspections are conducted throughout the year and have no
21		specific start and completion date except for the bulk
22		electric transmission and critical 69kV transmission
23		substation and line inspections which are inspected first
24		and prior to the peak of hurricane season each year.
25		

Projected Number of Infrastructure Inspections			
	2020	2021	2022
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	22,500	22,500	35,625
Groundline Inspections	13,275	13,275	21,018
Transmission			
Wood Pole/Groundline Inspections	702	367	707
Above Ground Inspections	2,949	3,895	3,396
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 customer(s) served?

A. As previously mentioned, Tampa Electric conducts thousands
    of inspections each year and has not identified specific
    projects or affected facilities.   The company has
    identified the number of inspections by type planned for
    2020 – 2022.   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.

39

1		
2	**Q.**	Would you explain in detail the methodology Tampa Electric
3		used in prioritizing inspections?
4		
5	**A.**	Tampa Electric typically prioritizes its inspections by age
6		or date of last inspection. Other criteria used to
7		prioritize when inspections are performed include; bulk
8		electric transmission and critical 69kV transmission
9		substations and lines are inspected first and prior to the
10		peak of hurricane season each year, circuits are patrolled
11		based on their criticality or priority ranking, and
12		finally, aerial infrared scans are scheduled in the summer
13		time when load is highest which improves the accuracy of
14		the results.
15		
16	**Q.**	Did Tampa Electric prepare a cost estimate for this Program,
17		including capital and operating expenses?
18		
19	**A.**	Yes. This can be located in the table below. The estimated
20		costs for this Program include $1.2M in 2020, $1.5M in 2021
21		and then approximately $1.5M in each year 2022-2029. All
22		costs associated with this Program are O&M.
23		
24		
25		

Projected Costs of Infrastructure Inspections (in thousands)			
	2020	2021	2022
Distribution			
Wood Pole/Groundline Inspections	$708	$1,000	$1,020
Transmission			
Wood Pole/Groundline Inspections	$60	$61	$62
Above Ground Inspections	$10	$10	$10
Aerial Infrared Patrols	$110	$112	$114
Ground Patrols	$145	$148	$151
Substation Inspections	$140	$143	$146

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 in place Storm Hardening Plan activities, referred to here as

41

1   Legacy Storm Hardening Plan Initiatives.   Tampa Electric

2   believes these Initiatives will continue to offer the storm

3   resiliency   benefits   previously   identified   by   the

4   Commission.   These Initiatives include a Geographical

5   Information System, Post-Storm Data Collection, Outage Data

6   - Overhead and Underground Systems, Increase Coordination

7   with Local Governments, Collaborative Research, Disaster

8   Preparedness and Recovery Plan and Distribution Pole

9   Replacements.

10

11   Tampa Electric's Geographic Information System ("GIS") will

12   continue to serve as the foundational database for all

13   transmission,   substation   and   distribution   facilities.

14   Regarding Post-Storm Data Collection, Tampa Electric has a

15   formal process in place to randomly sample and collect

16   system damage information following a major weather event.

17   Tampa Electric has a Distribution Outage Database that it

18   uses to track and store overhead and underground system

19   outage data.   Tampa Electric has an Emergency Preparedness

20   team and representatives that will continue to focus on

21   maintaining existing vital governmental contacts and

22   participating on committees to collaborate in disaster

23   recovery planning, protection, response, recovery and

24   mitigation efforts.   Tampa Electric will also continue to

25   participate in the collaborative research effort with

1   Florida's other investor-owned electric utilities, several

2   municipals and cooperatives to further the development of

3   storm resilient electric utility infrastructure and

4   technologies to reduce storm restoration costs and customer

5   outage times. Tampa Electric will continue to maintain and

6   improve its Disaster Preparedness and Emergency Response

7   Plans and be active in many ongoing activities to support the

8   improved restoration of the system before, during and after

9   storm activation. Tampa Electric's distribution pole

10   replacement initiative starts with the company's

11   distribution wood pole and groundline inspections and

12   includes restoring, replacing and/or upgrading those

13   distribution facilities identified to meet or exceed the

14   company's current storm hardening design and construction

15   standards.

16

17   **Q.** Please explain how Tampa Electric's Legacy Storm Hardening

18   Plan Initiatives will enhance the utility's existing

19   transmission and distribution facilities?

20

21   **A.** As I've mentioned, all of these initiatives are well-

22   established and have been in place since the Commission

23   determined that they should be implemented and would

24   provide benefits by enhancing the transmission and

25   distribution system, reducing restoration costs and/or

1   customer outage times.

2

3 **Q.**   Did Tampa Electric prepare a cost estimate for this Program,

4   including capital and operating expenses?

5

6 **A.**   Yes. In the table below, the company summarizes the

7   expected capital and operating expenses for these

8   initiatives during the 2020-2022 period. Tampa Electric

9   plans to invest $9.42M in 2020, $11.18M in 2021 and $14.72M

10   in 2022 of capital for distribution pole replacements.

11   There is an associated operating expense of $520k in 2020,

12     $620k in 2021 and $810k in 2022 for this activity. In

13   addition, the company plans to incur $300k per year 2020-

14   2022 in operating expenses for Disaster Preparedness and

15   Emergency Response activities.

16

17

Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)		
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2020	$0.3	$9.9
2021	$0.3	$11.8
2022	$0.3	$15.5

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

Q.   Does Tampa Electric's 2020-2029 Storm Protection Plan 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 Plan includes all the required Program-level detail for the six Storm Protection Programs described in my testimony. The Plan also includes the necessary Project-level detail for the Programs that contain Storm Protection Projects.

CONCLUSIONS

Q.   Please summarize your direct testimony.

A.   My testimony demonstrates that the six Programs I've discussed in Tampa Electric's proposed 2020-2029 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, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder

1		Hardening, Infrastructure Inspections, and Legacy Storm
2		Hardening Programs be approved?
3		
4	**A.**	Yes. These Programs should be approved. These Programs
5		meet the requirements of Rule 25-6.030 and they are designed
6		to strengthen the company's infrastructure to withstand
7		extreme weather conditions, reduce restoration costs,
8		reduce outage times, improve overall reliability and
9		increase customer satisfaction in a cost-effective manner.
10		
11	**Q.**	Does this conclude your testimony?
12		
13	**A.**	Yes.

EXHIBIT

OF

REGAN B. HAINES

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Tampa Electric - Proposed 2020-2029 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	$976.8	$0.0	33	44	Q2 2020	After 2029
Vegetation Management	$0.0	$279.3	21	22 to 29	Q2 2020	After 2029
Transmission Asset Upgrades	$148.9	$3.0	90	13	Q2 2020	2029
Substation Extreme Weather	$32.4	$0.0	70 to 80	50 to 65	Q1 2021	After 2029
Distribution Overhead Feeder	$289.7	$8.9	38 to 42	30	Q2 2020	After 2029
Transmission Access Enhancements	$14.8	$0.0	10	74	Q1 2021	After 2029

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Tampa Electric's Distribution Lateral Undergrounding – Year 2020 Details

Project ID	Circuit No.	OH to UG Length Converted (miles)	Poles	Residential	Small C&I	Large C&I	Total	Priority Customers	Project Start Qtr	Construction Start Qtr	End Qtr	Project Cost in 2020
Lateral Hardening-Fuse-60588225	13174	0.29	15	374	34	1	409	1	Q2 2020	Q3 2020	Q4 2020	$125,235
Lateral Hardening-Fuse-10786382	14040	0.23	13	98	6	2	106	10	Q2 2020	Q3 2020	Q4 2020	$150,431
Lateral Hardening-Fuse-90755954	13454	0.30	23	292	21	1	314	0	Q2 2020	Q3 2020	Q4 2020	$238,629
Lateral Hardening-Fuse-60451701	13174	0.24	14	301	11	2	314	0	Q2 2020	Q3 2020	Q4 2020	$230,114
Lateral Hardening-Fuse-10933151	13897	0.79	33	64	20	1	85	1	Q2 2020	Q3 2020	Q4 2020	$221,051
Lateral Hardening-Fuse-92421291	13972	0.44	23	379	6	1	386	0	Q2 2020	Q3 2020	Q4 2020	$248,973
Lateral Hardening-Fuse-92881445	13710	0.45	32	158	17	0	175	0	Q2 2020	Q3 2020	Q4 2020	$401,397
Lateral Hardening-Fuse-92599119	13390	0.72	46	266	27	3	296	0	Q2 2020	Q3 2020	Q4 2020	$750,732
Lateral Hardening-Fuse-92407065	13815	0.38	15	12	3	1	16	0	Q2 2020	Q3 2020	Q4 2020	$68,399
Lateral Hardening-Fuse-93019714	13840	0.13	9	39	2	0	41	0	Q2 2020	Q3 2020	Q4 2020	$51,112
Lateral Hardening-Fuse-92634300	14032	0.31	21	306	10	2	318	1	Q2 2020	Q3 2020	Q4 2020	$390,745
Lateral Hardening-Fuse-60287236	13509	0.15	14	144	14	0	158	0	Q2 2020	Q3 2020	Q4 2020	$175,078
Lateral Hardening-Fuse-60182741	13312	0.15	15	52	11	7	70	0	Q2 2020	Q3 2020	Q4 2020	$101,387
Lateral Hardening-Fuse-90241880	13972	0.90	49	130	7	6	143	0	Q2 2020	Q3 2020	Q4 2020	$687,129
Lateral Hardening-Fuse-10643541	13390	1.17	67	221	22	2	245	0	Q2 2020	Q3 2020	Q4 2020	$1,095,650
Lateral Hardening-Fuse-10786374	14040	0.27	16	205	13	0	218	11	Q2 2020	Q3 2020	Q4 2020	$334,434
Lateral Hardening-Fuse-92829453	13961	0.34	25	447	3	2	452	0	Q2 2020	Q3 2020	Q4 2020	$292,496
Lateral Hardening-Fuse-91406672	13836	0.35	25	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$248,786
Lateral Hardening-Fuse-90288627	13815	0.88	32	51	9	0	60	0	Q2 2020	Q3 2020	Q4 2020	$423,948
Lateral Hardening-Fuse-91432109	13071	0.14	15	20	5	0	25	0	Q2 2020	Q3 2020	Q4 2020	$163,279
Lateral Hardening-Fuse-90738378	13071	0.16	20	296	35	0	331	6	Q2 2020	Q3 2020	Q4 2020	$145,327
Lateral Hardening-Fuse-90911087	13724	0.54	32	31	4	0	35	0	Q2 2020	Q3 2020	Q4 2020	$423,395
Lateral Hardening-Fuse-93026469	13815	0.49	15	27	2	0	29	0	Q2 2020	Q3 2020	Q4 2020	$375,085
Lateral Hardening-Fuse-10629014	13146	0.54	30	91	6	0	97	0	Q2 2020	Q3 2020	Q4 2020	$608,468

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Tampa Electric's Transmission Asset Upgrades - Year 2020 Details						
Project ID	Circuit No.	Pole Count	Project Start Month	Construction		Project Cost in 2020
				Start Month	End Month	
Transmission Upgrades-69 kV-66654	66654	10	May-20	Jul-20	Jul-20	$317,000
Transmission Upgrades-69 kV-66840	66840	34	May-20	Jul-20	Aug-20	$1,077,800
Transmission Upgrades-69 kV-66007	66007	43	Jun-20	Aug-20	Aug-20	$1,363,100
Transmission Upgrades-69 kV-66019	66019	21	Jul-20	Sep-20	Oct-20	$665,700
Transmission Upgrades-69 kV-66425	66425	3	Jul-20	Oct-20	Oct-20	$95,100
Transmission Upgrades-138/230 kV-230403	230403	5	Jul-20	Oct-20	Oct-20	$105,700
Transmission Upgrades-69 kV-66413	66413	5	Jul-20	Oct-20	Oct-20	$158,500
Transmission Upgrades-69 kV-66046	66046	30	Jul-20	Oct-20	Nov-20	$939,900
Transmission Upgrades-69 kV-66059	66059	2	Aug-20	Nov-20	Nov-20	$63,400
Transmission Upgrades-138/230 kV-230008	230008	59	Aug-20	Nov-20	Jan-21	$700,150
Transmission Upgrades-138/230 kV-230010	230010	2	Sep-20	Jan-21	Jan-21	$900
Transmission Upgrades-138/230 kV-230038	230038	1	Oct-20	Jan-21	Jan-21	$450
Transmission Upgrades-138/230 kV-230003	230003	35	Oct-20	Jan-21	Feb-21	$15,750
Transmission Upgrades-138/230 kV-230005	230005	24	Oct-20	Feb-21	Feb-21	$10,800
Transmission Upgrades-138/230 kV-230004	230004	40	Nov-20	Feb-21	Mar-21	$18,000
Transmission Upgrades-138/230 kV-230625	230625	12	Nov-20	Mar-21	Mar-21	$5,400
Transmission Upgrades-138/230 kV-230021	230021	17	Nov-20	Mar-21	Apr-21	$7,650
Transmission Upgrades-138/230 kV-230052	230052	9	Dec-20	Apr-21	Apr-21	$2,700
Transmission Upgrades-69 kV-66024	66024	25	Dec-20	Apr-21	Apr-21	$27,750
Transmission Upgrades-138/230 kV-230608	230608	18	Dec-20	May-21	May-21	$7,200
Transmission Upgrades-138/230 kV-230603	230603	13	Dec-20	May-21	May-21	$1,800

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.

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Tampa Electric's Distribution Overhead Feeder Hardening – Year 2020 Details

Project ID	Circuit No.	Specific Project Detail	Customers				Priority Customers	Project Start Month	Construction		Project Cost in 2020
			Residential	Small C&I	Large C&I	Total			Start Month	End Month	
Distribution Feeder Hardening-Breaker-60067752	13308	Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles	1,220	260	36	1,516	26	May-20	Aug-20	Dec-20	$1,153,700
Distribution Feeder Hardening-Breaker-60095496-Recloser-92203202	13807	Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles	1,159	103	16	1,278	12	May-20	Aug-20	Dec-20	$1,679,500
Distribution Feeder Hardening-Breaker-60315127-Recloser-92189137	13805	Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles	356	61	4	421	0	May-20	Aug-20	Dec-20	$1,565,900
Distribution Feeder Hardening-Breaker-60066445	13745	Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles	3,106	242	50	3,398	62	May-20	Aug-20	Dec-20	$833,150
Distribution Feeder Hardening-Breaker-60064337	13533	Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles	2,161	235	36	2,432	34	May-20	Aug-20	Dec-20	$1,044,300

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

JOHN H. WEBSTER

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN H. WEBSTER

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INTRODUCTION:

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

A. My name is John H. Webster. My business address is 2200 East Sligh Av, Tampa, Florida 33610. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") as the Line Clearance Arborist Lead, Line Clearance and Construction Services, Energy Delivery Department.

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

A. My duties and responsibilities include ensuring safe, efficient, and cost-effective methods are in place for all line clearance activities associated with the construction and maintenance of Tampa Electric's transmission and distribution systems. This includes responsibility for line clearance contracted personnel, assigned budgets, equipment, and implementation of proper line clearance methodology. As it relates to this filing, I am responsible for the safe, timely, and efficient implementation of the company's Vegetation Management Program and Transmission Access Program.

1	**Q.**	Please describe your educational background and
2		professional experience?
3		
4	**A.**	I received a Bachelor of Science degree in forestry from
5		the University of Kentucky in 2003 and became an
6		International Society of Arboriculture certified
7		arborist in 2003 and an International Society of
8		Arboriculture certified utility specialist in 2004. I
9		have been with Tampa Electric for fourteen years, and
10		held positions as a Line Clearance Supervisor, Line
11		Clearance Arborist, and Line Clearance Arborist Lead.
12		
13	**Q.**	What is the purpose of your testimony in this proceeding?
14		
15	**A.**	The purpose of my direct testimony is to present the
16		Vegetation Management and Transmission Access Storm
17		Protection Programs in Tampa Electric's 2020-2029 Storm
18		Protection Plan. My testimony will explain how the
19		company's Vegetation Management Program complies with
20		Rule 25-6.030(3)(f), and how the Transmission Access
21		Program complies with Rule 25-6.030(3)(d)-(e). I will
22		provide a description of the proposed Vegetation
23		Management ("VM") Program and the Transmission Access
24		Program. I will explain in detail the systematic
25		approach the company used to develop the Vegetation

1	Management Program and the Transmission Access Program to
2	ensure the objectives of reducing restoration costs and
3	outage times associated with extreme weather events and
4	enhancing reliability are achieved.
5	
6	**Q.** Are you sponsoring any exhibits in this proceeding?
7	
8	**A.** No.
9	
10	
11	**TAMPA ELECTRIC'S SERVICE AREA**
12	**Q.** How many circuit miles of overhead distribution and
13	transmission lines does Tampa Electric have?
14	
15	**A.** The company has approximately 6,250 circuit miles of
16	overhead distribution facilities and 1,350 circuit miles
17	of overhead transmission facilities over the five
18	counties Tampa Electric serves.
19	
20	**Q.** Are there any parts of Tampa Electric's service area that
21	were prioritized for enhancement, or any areas where
22	enhancement would not be feasible, reasonable or
23	practical, under the Vegetation Management and
24	Transmission Access Programs?
25	

1   **A.**   No.   The company did not exclude any area of the

2   company's existing transmission and distribution

3   facilities for enhancement under these programs due to

4   feasibility, reasonableness, or practicality.

5

6

7   **TAMPA ELECTRIC'S CURRENT VEGETATION MANAGEMENT PROGRAM**

8   **Q.**   What are the components of the proposed Vegetation

9   Management Program in the company's SPP?

10

11   **A.**   The company's VM Program consists of four parts including

12   existing legacy storm hardening VM activities and three

13   new VM initiatives. The company's existing VM activities

14   and the three new VM initiatives are described below.

15

16   **Q.**   Please explain Tampa Electric's current distribution and

17   transmission vegetation management cycles.

18

19   **A.**   Tampa Electric's current Vegetation Management Program

20   ("VMP") calls for trimming the company's distribution

21   system on a four-year cycle. The company's bulk

22   transmission lines of 138kV and 230kV are maintained on a

23   two-year cycle and 69kV lines are maintained on a three-

24   year cycle.

25

1	**Q.** When did Tampa Electric begin a four-year trim cycle for
2	its distribution system?
3	
4	**A.** The company received approval from the Commission in
5	Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI,
6	issued June 12, 2012 to convert from a three-year trim
7	cycle to a four-year trim cycle. This approved trim
8	cycle change gave Tampa Electric flexibility to change
9	circuit prioritization using the company's reliability-
10	based methodology.
11	
12	**Q.** Approximately how many miles of distribution lines does
13	Tampa Electric trim per year as part of this four-year
14	cycle?
15	
16	**A.** Tampa Electric's current four-year trim cycle calls for
17	trimming approximately 1,560 distribution miles annually.
18	
19	**Q.** Describe Tampa Electric's transmission VM cycle.
20	
21	**A.** As I mentioned previously, the company's bulk
22	transmission lines of 138kV and 230kV are maintained on a
23	two-year cycle and 69kV lines are maintained on a three-
24	year cycle. Transmission circuits are managed on a
25	'strict' or 'hard' cycle. Although strict, the schedule

1		allows adequate flexibility to accommodate new or
2		redesigned circuits. All circuits above 200kV are
3		managed in accordance with Federal Energy Regulatory
4		Commission ("FERC") standard FAC-003-4.
5		
6	Q.	Approximately how many miles of transmission lines does
7		Tampa Electric trim per year as a part of these cycles?
8		
9	A.	Tampa Electric's current transmission cycle calls for
10		trimming approximately 530 total transmission miles
11		annually, 255 non-bulk miles and 275 bulk miles.
12		
13	Q.	Would you explain the company's reliability-based
14		methodology?
15		
16	A.	Tampa Electric's System Reliability and Line Clearance
17		Departments use a third-party vegetation management
18		software application to develop a multi-year VMP which
19		optimizes activities from both a reliability-based and
20		cost-effectiveness standpoint. This approach allows the
21		company to model circuit behavior and schedule trimming
22		at the optimal time.
23		
24	Q.	Please describe the company's current VM specifications.
25		

7

1	**A.** Tampa Electric uses a contract workforce of approximately
2	220 tree trim personnel throughout the company's
3	distribution and transmission system. Vegetation to
4	conductor clearance for distribution primary facilities
5	is ten feet, and vegetation to conductor clearances for
6	transmission varies from fifteen feet to thirty feet,
7	depending on voltage. All Tampa Electric contractors are
8	required to follow American National Standards Institute
9	("ANSI") A300 pruning guidelines.
10	
11	**Q.** What are ANSI pruning guidelines?
12	
13	**A.** The American National Standards Institute or ANSI uses
14	industry research to generate a set of guidelines for a
15	variety of industry practices. The ANSI A-300 guidelines
16	help arborists determine the manner in which vegetation
17	should be trimmed to achieve desired objectives all while
18	preserving tree health and structure. The Z-133
19	guidelines help arborists and non-arborists follow safe
20	work practices.
21	
22	
23	**Incremental Vegetation Management Initiatives**
24	**Q.** In his direct testimony, Gerard R. Chasse mentions that
25	Tampa Electric used a consultant to analyze potential

1		incremental vegetation management activities. Please
2		explain why Tampa Electric used this consultant.
3		
4	**A.**	The company used Accenture for its industry knowledge and
5		data analysis expertise. Additionally, Accenture has
6		worked with Tampa Electric on a number of VM analyses in
7		the past, owns the software application, and has a
8		working knowledge of the company's VM processes.
9		
10	**Q.**	How did Accenture analyze Tampa Electric's existing VM
11		activities?
12		
13	**A.**	Accenture analyzed Tampa Electric's historical
14		reliability and VM data and incorporated (FEMA HAZUS)
15		wind speed and storm probability data to model the costs
16		and benefits of various VM activities. Accenture
17		collected thirteen years of reliability and VM data. The
18		reliability data included outages related to vegetation
19		as well as a percentage of other outages that may have a
20		vegetation component such as weather cause codes and
21		unknown cause codes. The VM data included circuit-
22		specific trim dates and costs. The VM software
23		application was the primary tool for analysis.
24		
25	**Q.**	How does Accenture's VM software application work?

9

1	**A.** The VM software application uses multi-year outage data
2	and pairs it with multi-year VM activity and cost to
3	generate reliability and cost 'curves.' These curves
4	model circuit behavior and recommend the optimal time for
5	VM. The application also has a corrective trimming and
6	storm function that allows it to estimate costs
7	associated with corrective or mid-cycle trimming and
8	storm restoration.
9	
10	**Q.** Did Accenture update the tree trimming model for this
11	study?
12	
13	**A.** Yes. Tampa Electric worked with Accenture to update the
14	software application with the company's most recent
15	outage and cost data. Accenture further updated the
16	application by creating an enhanced storm module to
17	accompany the existing storm module already in the
18	application. The enhanced storm module allowed the
19	application to perform analyses on partial circuits and
20	entire circuits.
21	
22	**Q.** Did Accenture analyze multiple scenarios involving
23	potential incremental VM activities?
24	
25	**A.** Yes, Accenture looked at multiple mileage scenarios to

1   determine the costs of incremental VM activities and the

2   benefits associated with extreme weather events and

3   overall service reliability.   Accenture modeled seven

4   scenarios ranging from zero incremental VM miles to nine-

5   hundred incremental VM miles.   The addition of the

6   enhanced storm module allowed Accenture to analyze the

7   costs and benefits of two mid-cycle VM scenarios.

8

9   Q.   What were Accenture's conclusions?

10

11   A.   Accenture   concluded   a   supplemental   VM   initiative

12   consisting   of   seven   hundred   incremental   miles   would

13   provide a twenty-one percent improvement in the company's

14   storm restoration times and costs. Based on Accenture's

15   work, the proposed mid-cycle VM initiative, consisting of

16   four-hundred forty incremental miles inspected, would net

17   an additional five percent improvement in the company's

18   storm restoration times and costs.

19

20   Q.   Did Accenture determine which combination of incremental

21   activities provided the greatest level of benefit for the

22   cost?

23

24   A.   Yes.   Accenture   determined   which   combination   of

25   incremental   activities   provided   the   greatest   benefit

1		through the analysis and worked closely with company
2		subject-matter experts to produce an operational plan
3		that incorporates efficient, cost-effective contractor
4		uptake. The result was a phased-in approach of four-
5		hundred, five-hundred, seven-hundred miles scheduled for
6		the first three years of the Storm Protection Plan.
7		
8	**Q.**	Did Accenture analyze potential incremental transmission
9		VM activities?
10		
11	**A.**	No, Accenture did not analyze the incremental
12		transmission activities primarily because the VM software
13		application is designed for distribution circuits.
14		Additionally, much of the company's transmission VM plan
15		is regulated by FERC standard FAC-003-4.
16		
17	**Q.**	Did Tampa Electric determine that it should perform any
18		incremental transmission vegetation management?
19		
20	**A.**	Yes, the company assessed its transmission circuits and
21		found through operational experience and storm "lessons
22		learned" that approximately ten percent of the 69kV
23		transmission miles were particularly difficult and
24		expensive to maintain, largely inaccessible, and prone to
25		hazard trees. The company's proposed 69kV reclamation

1		project would essentially remove the vegetative
2		obstructions and minimize outages related to hazard tree
3		fall-ins.
4		
5	**Q.**	Can you please describe each of the incremental VM
6		activities, both for transmission and distribution, that
7		Tampa Electric proposes as elements of its 2020-2029
8		Storm Protection Plan?
9		
10	**A.**	In addition to its existing VM activities, Tampa Electric
11		is proposing three initiatives (two distribution and one
12		transmission) designed to further harden the company's
13		electrical infrastructure against extreme weather events
14		and improve overall system reliability. They are the
15		Supplemental Distribution Circuit VM Initiative, the Mid-
16		Cycle Distribution VM Initiative and 69 kV Transmission
17		VM Reclamation Initiative.
18		
19		The Supplemental Distribution Circuit VM Initiative will
20		increase the volume of full circuit VM performed on an
21		annual basis. The Mid-cycle Distribution VM Initiative
22		is an inspection-driven, site-specific approach designed
23		to target vegetation that cannot be effectively
24		maintained by cycle trimming. This initiative will also
25		target hazard trees. The 69 kV Transmission VM

13

1		Reclamation Initiative is designed to remove obstructing
2		vegetation and hazard trees from specific sites along the
3		company's 69 kV transmission system.
4		
5	**Q.**	Please explain how Tampa Electric's Incremental
6		Vegetation Management Initiatives will enhance the
7		utility's existing transmission and distribution
8		facilities?
9		
10	**A.**	The Supplemental Distribution Circuit VM Initiative, once
11		fully implemented, is expected to provide a sixteen
12		percent and twenty-one percent improvement in the
13		company's day-to-day and storm restoration times and
14		costs, respectively. The Mid-Cycle Distribution VM
15		Initiative is expected to net an additional two percent
16		and five percent improvement in the company's day-to-day
17		and storm restoration times and costs, respectively. The
18		hazard tree removal portion of the initiative will add
19		further benefit to storm outage prevention. The 69 kV
20		Transmission VM Reclamation Initiative will benefit storm
21		outage prevention by improving vegetation to conductor
22		clearance and reducing hazard tree potential. During
23		extreme weather events, these initiatives will have added
24		benefit for faster outage detection, more accurate damage
25		assessment, and lower restoration times and costs.

1	**Q.** How many incremental miles of distribution and
2	transmission overhead facilities does Tampa Electric plan
3	to trim over the first three years of the Plan?
4	
5	**A.** For the first three years, the company plans to trim
6	approximately 1,600 additional miles of distribution
7	lines and an additional 56 miles of 69 kV transmission
8	lines. The number of miles of mid-cycle trimming and
9	removal will be determined by the inspection findings;
10	however, the company plans to inspect 439 miles in the
11	first three years of the SPP.
12	
13	**Q.** What is the total number of miles, including both
14	baseline and incremental trimming, that Tampa Electric
15	plans to trim over the first three years of the Plan?
16	
17	**A.** The company plans to trim approximately 4,680 miles of
18	distribution facilities under the baseline cycle and
19	1,600 miles under the Supplemental Trimming Initiative
20	for a total of approximately 6,280 miles of distribution
21	trimming. The company also plans to inspect an
22	additional 439 miles of distribution facilities under the
23	Mid-Cycle Initiative. The company plans to trim
24	approximately 1,590 miles of transmission facilities
25	under the baseline cycle, plus an additional 83 miles

1   under the 69kV Reclamation Initiative, for a total of

2   approximately 1,673 miles of transmission facility

3   trimming.

4

5   **Q.** What are the estimated annual labor and equipment costs

6   for the VM Program during the first three years of the

7   SPP?

8

9   **A.** The estimated annual labor and equipment costs for the

10   first three years of the SPP total $67.2M, commencing

11   second quarter of 2020. The four-year distribution cycle

12   labor and equipment costs for the first three years are

13   $36.8M, and the incremental distribution VM labor and

14   equipment costs are $20.6M. The first three years of

15   transmission cycle(s) labor and equipment costs are

16   $8.3M, and the incremental transmission VM labor and

17   equipment costs are $1.5M. The total cost for the

18   Program is set out in Section 7 of the company's 2020-

19   2029 SPP.

20

21   **Q.** Did Tampa Electric prepare an analysis of the estimated

22   costs and benefits of the Program?

23

24   **A.** Yes, pursuant to Rule 25-6.030(3)(i), the company

25   explored incremental VM strategies for the express

1	purposes of protecting its electrical infrastructure
2	against extreme weather events and reducing restoration
3	times and costs. The company further acquired the
4	assistance of Accenture, an outside consultant with
5	expertise in data analysis and utility VM, to help with
6	the analysis. Based on the data available and the
7	analysis performed, Tampa Electric believes that the
8	twenty-six percent improvement in storm restoration time
9	and cost are worth the $10.7M annual average increase in
10	distribution VM operations and maintenance expenses. The
11	benefits associated with reduced restoration time and
12	cost and lessened vegetation contact potential also
13	clearly show that the $2.2M 69kV reclamation project
14	additional annual expense is a tremendous value for Tampa
15	Electric customers.
16	
17	
18	**TRANSMISSION ACCESS PROGRAM**
19	**Q.** Please describe the Transmission Access Program?
20	
21	**A.** Tampa Electric's Transmission Access Program is designed
22	to ensure the company always has access to its
23	transmission facilities so it can promptly restore its
24	transmission system when outages occur. Increased power
25	demands and changes in topography and hydrology related to

1		customer development, along with several years of active
2		storm seasons, have negatively impacted the company's
3		access to its transmission infrastructure. The company's
4		proposed Transmission Access Program involves repairing
5		and restoring transmission access by constructing access
6		roads and access bridges to critical routes throughout the
7		company's transmission corridors. The program is expected
8		to start projects in 2021 and complete the program by
9		2030.
10		
11	Q.	Please explain how Tampa Electric's Transmission Access
12		Program will enhance the utility's existing transmission
13		facilities.
14		
15	A.	This program will enhance the existing transmission
16		facilities by improving the company's access to its
17		critical transmission circuits, especially during 'wet'
18		and storm seasons, which will promote system resiliency
19		and timelier storm restoration.
20		
21	Q.	In the direct testimony of Gerard R. Chasse, he mentions
22		that Tampa Electric used a consultant to assist with the
23		development of the Transmission Access Program. Please
24		explain why Tampa Electric used a consultant to develop
25		the Transmission Access Program.

1	**A.**	Tampa Electric hired 1898 & Co, a consultant with
2		expertise in the areas of T&D system hardening and cost-
3		benefit analysis. 1898 was selected for its industry
4		knowledge and data analysis expertise. 1898 & Co. was
5		engaged to analyze the cost-benefits of the access
6		projects for prioritization within the Program as well as
7		the overall Plan. Jason D. De Stigter from 1898 will
8		provide direct testimony to more fully detail the
9		approach taken for each of the Programs they supported,
10		including Transmission Access.
11		
12	**Q.**	Please explain how Tampa Electric and 1898 & Co. prepared
13		the estimate of the reduction in outage times and
14		restoration costs due to extreme weather conditions that
15		will result from the Transmission Access Program?
16		
17	**A.**	The methodology used to develop the estimate of the
18		reduction in outage times and restoration costs is
19		addressed in detail in Jason D. De Stigter's direct
20		testimony, but in general, 1898 developed a model that
21		calculates the benefit in terms of decreased restoration
22		cost and reduced Customer Minutes of Interruption ("CMI")
23		for each proposed Transmission Access Project.
24		
25	**Q.**	Did Tampa Electric prepare an analysis of the estimated

1   costs and benefits of the Transmission Access Program?

3 **A.** Yes. A table comparing the estimated costs and benefits

4   of this Program is included below.

Tampa Electric - Proposed 2020-2029 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	$14.8	$0.0	10	74	Q1 2021	After 2029

18 **Q.** Please explain the methodology Tampa Electric used in

19   prioritizing the Projects the company is including in the

20   Transmission Access Program.

22 **A.** The methodology used to develop the prioritization of

23   Projects in these Programs is addressed in detail in

24   Jason D. De Stigter's direct testimony. In general, the

25   company and 1898 developed a potential cost estimate and

1   estimated benefits for each potential Project in the

2   Program. These estimated benefits included both reduced

3   customer minutes of interruption and reduced restoration

4   costs. These benefits were then combined and a cost

5   benefit NPV was calculated for each potential Project.

6   The NPVs were then used to rank or prioritize each

7   Project within a given SPP Program. The rankings will

8   serve as a guide, but the company will also apply

9   operational experience and judgment when selecting

10   Projects.

11

12 Q. Did Tampa Electric prepare a list of transmission access

13   projects that the company is planning to begin in 2020,

14   including their associated starting and projected

15   completion dates?

16

17 A. No, the company did not prepare a list of Transmission

18   Access Projects for 2020. Tampa Electric plans to use

19   2020 to select engineering and construction vendors and

20   coordinate the necessary environmental permitting.

21

22 Q. Did Tampa Electric prepare an estimated number of

23   Transmission Access projects it plans on initiating in

24   2021 and 2022?

25

1	**A.**	Yes, using the analysis provided by 1898, the company
2		prioritized a list of fourteen Projects it plans to begin
3		in 2021 and 2022.
4		
5	**Q.**	Did Tampa Electric prepare an estimate of the costs for
6		the projects planned for 2021 and 2022?
7		
8	**A.**	Yes, the company plans to spend $2.9M for Projects
9		planned in 2021 and 2022. The table below sets out the
10		total number of Projects and the estimated costs for the
11		first three years of the Plan.

<table>
<tr><td colspan="3">Tampa Electric's
Transmission Access
Enhancements Program
Projects by Year and Projected Costs
(in millions)</td></tr>
<tr><td></td><td>Projects</td><td>Costs</td></tr>
<tr><td>2020</td><td>0</td><td>$0.0</td></tr>
<tr><td>2021</td><td>8</td><td>$1.4</td></tr>
<tr><td>2022</td><td>6</td><td>$1.5</td></tr>
</table>

21	**Q.**	Did Tampa Electric prepare a cost estimate for this
22		Program, including capital and operating expenses?
23		
24	**A.**	Yes, the company used recent road and bridge actuals to
25		prepare estimates for the permitting, surveying,

22

engineering, and construction costs. The total capital cost estimate for the Transmission Access Enhancement Program is $14.8M. The are no operating costs associated with the Projects. The table below sets out the estimated costs for the Program by year over the ten-year plan horizon.

	Total Transmission Access Enhancements Program Costs (in thousands)		
	Access Road Projects Costs	Access Bridge Project Costs	Total Transmission Access Project Costs
2020	$0	$0	$0
2021	$604	$780	$1,383
2022	$391	$1,118	$1,509
2023	$0	$1,606	$1,606
2024	$810	$853	$1,663
2025	$978	$360	$1,338
2026	$0	$354	$354
2027	$3,325	$0	$3,325
2028	$1,982	$0	$1,982
2029	$1,065	$601	$1,667

CONCLUSIONS:

Q. Please summarize your direct testimony.

1	**A.**	My testimony and my accompanying exhibits present and
2		support the Incremental Vegetation Management Program
3		within Tampa Electric's proposed 2020-2029 Storm
4		Protection Plan. This Plan was developed consistent with
5		the requirements of Section 366.96, Florida Statutes and
6		the implementing Rule 25-6.030, F.A.C., adopted by the
7		Commission.
8		
9	**Q.**	Should Tampa Electric's proposed Vegetation Management
10		and Transmission Access Programs be approved?
11		
12	**A.**	Yes. Tampa Electric's proposed 2020-2029 Vegetation
13		Management and Transmission Access Programs should be
14		approved. These Programs are designed to reduce
15		restoration costs, reduce outage times, improve overall
16		reliability and increase customer satisfaction in a cost-
17		efficient manner.
18		
19	**Q.**	Does this conclude your testimony?
20		
21	**A.**	Yes.
22		
23		
24		
25		

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

TAMPA ELECTRIC'S
2020-2029
STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

A. SLOAN LEWIS

1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **PREPARED DIRECT TESTIMONY**

3 **OF**

4 **A. SLOAN LEWIS**

5

6 **INTRODUCTION:**

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

8

9 **A.** My name is A. Sloan Lewis. My business address is 702 N.

10 Franklin Street, Tampa, Florida 33602. I am employed by

11 Tampa Electric Company ("Tampa Electric" or "the

12 Company") in the Finance Department as Director,

13 Regulatory Accounting.

14

15 **Q.** Please describe your duties and responsibilities in that

16 position.

17

18 **A.** My duties and responsibilities include the accounting

19 oversight of all cost recovery clauses and riders for

20 Tampa Electric and Peoples Gas, the settlement of all

21 fuel and power transactions for Tampa Electric and Peoples

22 Gas System and the accounts payable department for Tampa

23 Electric, Peoples Gas System and New Mexico Gas Company.

24

25 **Q.** Please describe your educational background and

1   professional experience.

2

3 **A.** I received a Bachelor of Science degree in accounting

4   from Florida State University in 1994 and a Master of

5   Education from the University of North Florida in 1996.

6   I joined Tampa Electric in 2000 as a Fuels Accountant and

7   over the past 19 years have expanded my cost recovery

8   clause responsibilities. Then in 2015, I was promoted to

9   Manager, Regulatory Accounting with responsibilities for

10   all the recovery clauses and riders for Tampa Electric

11   and Peoples Gas System. I was promoted to my current

12   role as Director, Regulatory Accounting in 2017.

13

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

15

16 **A.** The purpose of my testimony in this proceeding is to

17   demonstrate that the company's 2020-2029 Storm Protection

18   Plan complies with Rule 25-6.030(g)-(h), Florida

19   Administrative Code, *i.e.*, the Storm Protection Plan

20   ("SPP") rule. Section 3(g) requires a utility to provide an

21   estimate of the annual jurisdictional revenue requirements

22   for each year of its SPP. Section 3(h) requires a utility

23   to provide an estimate of rate impacts for each of the first

24   three years of the SPP for the utility's typical

25   residential, commercial, and industrial customers. My

1		testimony also explains the methodology used to calculate
2		these estimates.
3		
4	Q.	Have you prepared an exhibit to accompany your direct
5		testimony?
6		
7	A.	Yes. Exhibit No. ASL-1, entitled "Tampa Electric's 2020-
8		2029 SPP Total Revenue Requirements by Program" was
9		prepared under my direction and supervision. This Exhibit
10		shows the Annual Revenue Requirement for the company's
11		2020-2029 SPP Programs.
12		
13		
14		**CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE**
15		**REQUIREMENTS FOR TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION**
16		**PLAN**
17	Q.	What is the estimated annual jurisdictional revenue
18		requirements for each year of the company's proposed SPP?
19		
20	A.	The estimated annual jurisdictional revenue requirements
21		for each year of the SPP are included in the table below.
22		The revenue requirements of each SPP are set out in my
23		Exhibit No. ASL-1.
24		
25		

Total SPP Revenue Requirement (2020-2029)

YEAR	Revenue Requirements
2020	$24,428,727
2021	$36,739,224
2022	$52,213,995
2023	$71,458,756
2024	$86,932,411
2025	$105,253,007
2026	$122,774,696
2027	$139,916,133
2028	$157,595,194
2029	$174,852,375

Q. How were the estimated annual jurisdictional revenue requirements for the proposed plan developed?

A. The estimated annual jurisdictional revenue requirements were developed with cost estimates for each of the SPP Programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the Storm Protection Plan Cost Recovery Clause ("SPPCRC") Rule.

1	**Q.** Do these revenue requirements include any costs that are
2	currently recovered in base rates?
3	
4	**A.** Yes. As described further below, the revenue requirement
5	amounts shown above reflect all of the investments and
6	expenses associated with the activities in the Plan without
7	regard to whether some of those costs may currently be
8	subject to recovery through the company's existing base
9	rates and charges. For illustrative purposes, the company
10	calculated the 2017 to 2019 three-year actual amounts of
11	certain operations and maintenance expenses associated with
12	its current Storm Hardening Plan to be approximately $12.9
13	million. Since these Storm Hardening Plan activities are
14	proposed to be part of the company's SPP and are not "new"
15	or "incremental" storm protection activities, this $12.9
16	million amount can be viewed as a reasonable proxy for the
17	amount of Storm Protection Plan costs currently being
18	recovered by the company through its base rates and charges.
19	Of course, whether and the extent to which the investments
20	and costs associated with the company's SPP will be
21	recovered through the SPPCRC or continue to be recovered
22	through base rates will be addressed in Docket No. 20200092-
23	EI, the SPPCRC Docket.
24	
25	**Q.** Do the estimated annual jurisdictional revenue requirements

1   include the annual depreciation expense on SPP capital

2   expenditures?

3

4 **A.**   Yes. Rule 25-6.031 states that the annual depreciation

5   expense is a cost that may be recovered through the SPPCRC.

6   As a result, the estimated annual jurisdictional revenue

7   requirements include the annual depreciation expense

8   calculated on the SPP capital expenditures, *i.e.*, those

9   initiated after April 10, 2020, using the depreciation

10   rates from Tampa Electric's most current Depreciation

11   Study, approved in PSC-12-0175-PAA-EI.

12

13 **Q.**   Was the depreciation savings on the retirement of assets

14   removed from service during the SPP capital projects

15   considered in the development of the revenue requirement?

16

17 **A.**   Yes. In the development of the revenue requirements,

18   depreciation expense from the SPP capital asset additions

19   has been reduced by the depreciation expense savings

20   resulting from the estimated retirement of assets removed

21   from service during the SPP capital projects.

22

23 **Q.**   Do the estimated annual jurisdictional revenue requirements

24   include a return on the undepreciated balance of the SPP

25   assets?

1	**A.**	Yes. Rule 25-6.031 6(c) states that the utility may recover
2		a return on the undepreciated balance of the asset costs
3		through the SPPCRC. As a result, this return was included
4		in the estimated annual jurisdictional revenue requirement.
5		In accordance with the FPSC Order No. PSC-12-0425-PAA-EU,
6		from the 2012 Stipulation and Settlement agreement, Tampa
7		Electric calculated a return on the undepreciated balance
8		of the asset costs at a weighted average cost of capital
9		using the return on equity from the May 2019 Actual
10		Surveillance Report.
11		
12	**Q.**	In the development of the estimated annual jurisdictional
13		revenue requirements did the company consider SPP capital
14		expenditures prior to the plan filing date in the
15		depreciation and return on asset calculations?
16		
17	**A.**	No. Only capital expenditures for SPP Projects to be
18		initiated after April 10, 2020 were included in the
19		depreciation and return on asset calculations included in
20		the estimated annual jurisdictional revenue requirements.
21		
22	**Q.**	In the calculation of the estimated annual jurisdictional
23		revenue requirements did the company include Allowance for
24		Funds Used During Construction ("AFUDC")?
25		

1   **A.**   No. Per Rule 25-6.0141, F.A.C, in order for projects to be

2   eligible for AFUDC, they must involve "gross additions to

3   plant in excess of 0.5 percent of the sum of the total

4   balance in Account 101, Electric Plant in Service, and

5   Account 106, Completed Construction not Classified, at the

6   time the project commences and are expected to be completed

7   in excess of one year after commencement of construction."

8   None of the projects proposed in Tampa Electric's 2020-2029

9   SPP meet the criteria for AFUDC eligibility.

10

11   **Q.**   Does Tampa Electric intend to seek recovery of the estimated

12   SPP costs through the SPPCRC, in accordance with FAC rule

13   26-6.031?

14

15   **A.**   Yes, Tampa Electric will be filing for cost recovery of the

16   estimated SPP costs through the SPPCRC.   However, as

17   mentioned above, the extent to which the investments and

18   costs associated with the company's SPP will be recovered

19   through the SPPCRC or continue to be recovered through base

20   rates will be addressed in Docket No. 20200092-EI.

21

22

23   **CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2020-2023 OF**

24   **THE STORM PROTECTION PLAN**

25   **Q.**   Please provide an estimate of rate impacts for each of the

1   first three years of the proposed SPP for typical Tampa

2   Electric residential, commercial, and industrial customers.

3

4 **A.**   Tampa Electric prepared estimated rate impacts of the SPP

5   for 2020, 2021, 2022 and 2023. While there are not going

6   to be any billed rate impacts during 2020, the 2020 costs

7   have been calculated separately from the 2021 costs so the

8   impact of each year on the 2021 rate impacts is clear. This

9   is because the 2020 costs will be recovered at the same

10   time as the 2021 costs through clause rates initiating in

11   January 2021. The estimated rate impacts for each of the

12   first three years of the proposed SPP for a typical

13   residential, commercial, and industrial Tampa Electric

14   customer are listed in the table below.

15

Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

1	**Q.**	How were the estimated rate impacts for each of the first
2		three years of the proposed SPP for a typical residential
3		and commercial/industrial customer determined?
4		
5	**A.**	For each year, the Programs were itemized and identified as
6		either substation, transmission, or distribution costs.
7		Each of those functionalized costs was then allocated to
8		rate class using the allocation factors for that function.
9		The allocation factors were from the Tampa Electric 2013
10		Cost of Service Study prepared in Docket No. 20130040-EI,
11		which was used for the company's current (non-SoBRA) base
12		rate design. Once the total SPP revenue requirement
13		recovery allocation to the rate classes was derived, the
14		rates were determined in the same manner. For Residential,
15		the charge is a kWh charge. For both Commercial and
16		Industrial, the charge is a kW charge. The charges are
17		derived by dividing the rate class allocated SPP revenue
18		requirements by the 2020 energy billing determinants (for
19		residential) and by the 2020 demand billing determinants
20		(for commercial and industrial). Those charges were then
21		applied to the billing determinants associated with typical
22		bills for each group to calculate the impact on those bills.
23		This was done using a combination of 2020 and 2021 costs
24		for the 2021 bills, and for each year 2022 and 2023 for
25		those bills.

1	**Q.**	When will the company file its petition for the
2		establishment of the 2021 SPPCRC rates for Tampa Electric's
3		SPP'S costs?
4		
5	**A.**	The company plans to file the SPPCRC petition for 2021 rates
6		on the schedule specified in applicable orders establishing
7		procedure in Docket No. 20200092-EI.
8		
9	**Q.**	Will the rates established through the 2021 SPPCRC differ
10		from those presented in the rate impact calculations in the
11		SPP?
12		
13	**A.**	Yes. The rate impacts presented above reflect the "all-
14		in" costs of the company's SPP without regard to whether
15		the costs are or will be recovered through the SPPCRC or
16		through the company's base rates and charges. The extent
17		to which the investments and costs associated with the
18		company's SPP will be recovered through the SPPCRC or
19		continue to be recovered through base rates will be
20		addressed in Docket No. 20200092-EI.
21		
22		In addition, when it makes its SPPCRC filing, the company
23		will use more recent billing determinants based on the most
24		current load forecast.
25		

1	The company will also take steps to prevent double recovery
2	of any costs through both base rates and the clause.
3	
4	**CONCLUSIONS**
5	**Q.** Please summarize your direct testimony.
6	
7	**A.** My testimony and exhibit demonstrate that Tampa Electric's
8	estimated annual jurisdictional revenue requirements for
9	each of the 10 years of the SPP and rate impacts for each
10	of the first 3 years of the SPP for the utility's typical
11	residential, commercial, and industrial customers comply
12	with Rule 25-6.030(3)(g)-(h). These calculations were
13	performed in accordance with the requirements of Section
14	366.96, Florida Statutes and the implementing Rule 25-
15	6.030, F.A.C., adopted by the Commission.
16	
17	**Q.** Does this conclude your testimony?
18	
19	**A.** Yes.
20	
21	
22	
23	
24	
25	

EXHIBIT

OF

A. SLOAN LEWIS

13

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200067-EI
EXHIBIT NO. ASL-1
WITNESS: LEWIS
PAGE 1 OF 1
FILED: 04/10/2020

Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions)

Capital	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Lateral Undergrounding	$0.19	$4.66	$13.83	$23.93	$33.76	$43.83	$54.01	$64.01	$73.84	$83.91	$395.97
Transmission Asset Upgrades	$0.14	$1.25	$2.69	$4.16	$5.45	$6.82	$8.45	$9.91	$11.40	$12.66	$62.93
Substation Extreme Weather Protection	$0.00	$0.00	$0.00	$0.00	$0.28	$0.95	$1.42	$1.93	$2.47	$2.82	$9.87
Distribution Overhead Feeder Hardening	$0.14	$1.33	$3.42	$6.33	$9.30	$12.19	$15.06	$17.83	$20.64	$23.53	$109.77
Transmission Access Enhancements	$0.00	$0.06	$0.19	$0.33	$0.48	$0.61	$0.69	$0.85	$1.07	$1.22	$5.50
Distribution Pole Replacements	$0.25	$1.41	$2.60	$3.96	$5.32	$6.69	$7.79	$8.61	$9.42	$10.22	$56.27

O&M	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Distribution Vegetation Management - planned	$16.49	$19.76	$21.18	$24.00	$24.22	$25.55	$26.77	$27.99	$29.42	$30.94	$246.31
Distribution Vegetation Management - unplanned	$1.30	$1.30	$1.20	$1.10	$1.10	$1.10	$1.20	$1.20	$1.30	$1.30	$12.10
Transmission Vegetation Management - planned	$2.63	$3.53	$3.59	$3.66	$3.04	$3.13	$3.23	$3.30	$3.38	$3.46	$32.95
Transmission Vegetation Management - unplanned	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Asset Upgrades	$0.11	$0.30	$0.30	$0.33	$0.24	$0.38	$0.36	$0.33	$0.39	$0.24	$2.98
Distribution Overhead Feeder Hardening	$0.21	$0.38	$0.40	$0.79	$0.82	$1.02	$1.06	$1.17	$1.42	$1.64	$8.92
Distribution Infrastructure Inspections	$0.71	$1.00	$1.02	$1.04	$1.06	$1.08	$1.10	$1.13	$1.15	$1.17	$10.46
Transmission Infrastructure Inspections	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.56	$5.09
SPP Planning & Common	$0.99	$0.39	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$3.10
Other Legacy Storm Hardening Plan Items	$0.28	$0.28	$0.29	$0.29	$0.30	$0.30	$0.31	$0.32	$0.33	$0.33	$3.01
Distribution Pole Replacements	$0.52	$0.62	$0.81	$0.83	$0.86	$0.88	$0.59	$0.60	$0.61	$0.62	$6.93

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

TAMPA ELECTRIC's
STORM PROTECTION PLAN

VERIFIED DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF

TAMPA ELECTRIC COMPANY

VERIFIED DIRECT TESTIMONY OF JASON D. DE STIGTER

ON BEHALF OF

TAMPA ELECTRIC COMPANY

1.   INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. By whom are you employed and in what capacity?

A2. I am employed by 1898 & Co., and lead the Capital Asset Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 200 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made

1	up of more than 7,000 engineers, architects, construction
2	professionals, scientists, consultants and entrepreneurs
3	with more than 40 offices across the country and
4	throughout the world.
5	
6	**Q3.** **Briefly describe your educational background and**
7	**certifications.**
8	
9	**A3.** I received a Bachelor of Science Degree in Engineering
10	and a Bachelor's in Business Administration from Dordt
11	University. I am also a registered Professional Engineer
12	in the state of Kansas.
13	
14	**Q4.** **Please briefly describe your professional experience and**
15	**duties at 1898 & Co.**
16	
17	**A4.** I am a professional engineer with 13 years of experience
18	providing consulting services to electric utilities. I
19	have extensive experience in asset management, capital
20	planning and optimization, risk and resilience
21	assessments and analysis, asset failure analysis, and
22	business case development for utility clients. I have
23	been involved in numerous studies modeling risk for
24	utility industry clients. These studies have included
25	risk and economic analysis engagements for several multi-

1		billion-dollar capital projects and large utility
2		systems. In my role as a project manager I have worked on
3		and overseen risk and resilience analysis consulting
4		studies on a variety of electric power transmission and
5		distribution assets, including developing complex and
6		innovative risk and resilience analysis models. My
7		primary responsibilities are business development and
8		project delivery within the Utility Consulting Practice
9		with a focus on developing risk and resilience based
10		business cases for large capital projects/programs.
11		
12		Prior to joining 1898 & Co. and Burns & McDonnell, I
13		served as a Principal Consultant at Black & Veatch inside
14		their Asset Management Practice performing similar
15		studies to the effort performed for Tampa Electric
16		Company ("TEC").
17		
18	**Q5.**	**Have you previously testified before the Florida Public**
19		**Service Commission or other state commissions?**
20		
21	**A5.**	I have not testified before the Florida Public Service
22		Commission. I provided written, rebuttal, and oral
23		testimony on behalf of Indianapolis Power & Light before
24		the Indiana Utility Regulatory Commission and have
25		supported many other regulatory filings. I have also

1   testified in front of the Alaska Senate Resources
2   Committee.

3

4 **Q6. What is the purpose of your direct testimony in this**
5 **proceeding?**

6

7 **A6.** The purpose of my testimony is to summarize the results
8   and methodology used by 1898 & Co. to develop a Storm
9   Resilience Model with the following objectives:
10   1. Calculate the customer benefit of hardening
11   projects through reduced utility restoration costs
12   and impacts to customers
13   2. Prioritize hardening projects with the highest
14   resilience benefit per dollar invested into the
15   system
16   3. Establish overall investment level that maximizes
17   customers benefit while not exceeding TEC
18   technical execution constraints

19

20   Through my testimony I will describe the major elements
21   of the Storm Resilience Model, which include a Major
22   Storms Event Database, Storm Impact Model, Resilience
23   Benefit Module, and Budget Optimization & Project
24   Prioritization. Specifically, I will define resilience,
25   review historical major storm event to impact TEC service

1   territory, describe the datasets used in the Storm Impact

2   Model and how they were used to model system impacts due

3   to storms events, and explain how to understand the

4   resilience benefit results. Throughout my testimony I

5   will describe both how the assessment was performed and

6   why it was performed as such. Finally, I will describe

7   the calculations and results of the Storm Resilience

8   Model.

9

10   **Q7. Are you sponsoring any attachments in support of your**

11   **testimony?**

12

13   **A7.** Yes, I am sponsoring the 1898 & Co, Tampa Electric's

14   Storm Protection Plan Resilience Benefits Report that is

15   being included as Appendix F in Tampa Electric's 2020-

16   2029 Storm Protection Plan.

17

18   **Q8. Were your testimony and the attachment identified above**

19   **prepared or assembled by you or under your direction or**

20   **supervision?**

21

22   **A8.** Yes.

23

24   **Q9. Are you also submitting workpapers?**

25

1 **A9.** No.

2

3 **Q10. What was the extent of your involvement in the**

4 **preparation of the Storm Protection Plan?**

5

6 **A10.** I served as the 1898 & Co. project manager on the TEC

7 Storm Protection Plan Assessments and Benefits

8 Assessment. The evaluation utilized a Storm Resilience

9 Model to calculate benefits. I worked directly with the

10 TEC Team involved in the resilience-based planning

11 approach. I was responsible for the overall project and

12 was directly involved in the development of the Storm

13 Resilience Model, the assessment and results, as well as

14 being the main author of the report.

15

16 **2. RESILIENCE-BASED PLANNING OVERVIEW**

17 **Q11. Which of the Storm Protection Plan programs are evaluated**

18 **within the Storm Resilience Model?**

19

20 **A11.** The Storm Resilience Model includes project benefits

21 results, budget optimization, and project prioritization

22 for the following Storm Protection Plan programs:

23 ■ Distribution Lateral Undergrounding

24 ■ Transmission Asset Upgrades

25 ■ Substation Extreme Weather Hardening

1   ■ Distribution Overhead Feeder Hardening

2   ■ Transmission Access Enhancements

3

4   **Q12. How is resilience defined?**

5

6   **A12.** There are many definitions for resilience, I gravitate to

7   the one used by the National Infrastructure Advisory

8   Council (NIAC). Their definition of resilience is: "The

9   ability to reduce the magnitude and/or duration of

10   disruptive events. The effectiveness of a resilient

11   infrastructure or enterprise depends upon its ability to

12   anticipate, absorb, adapt to, and/or rapidly recover from

13   a potentially disruptive event."

14

15   This definition can be broken down into four phases of

16   resilience described below with applicable definitions

17   for the grid:

18   ■ **Prepare (Before)**

19   The grid is running normally but the system is

20   preparing for potential disruptions.

21   ■ **Mitigate (Before)**

22   The grid resists and absorbs the event until, if

23   unsuccessful, the event causes a disruption.

24   During this time the precursors are normally

25   detectable.

- **Respond (During)**

  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).

- **Recover (After)**

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

This is depicted graphically in Figure 1 below as a conceptual view of understanding resilience and how to mitigate the impact of events. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on the system in terms of the magnitude of impact (vertical) and the duration (horizontal).

Figure 1: Phases of Resilience
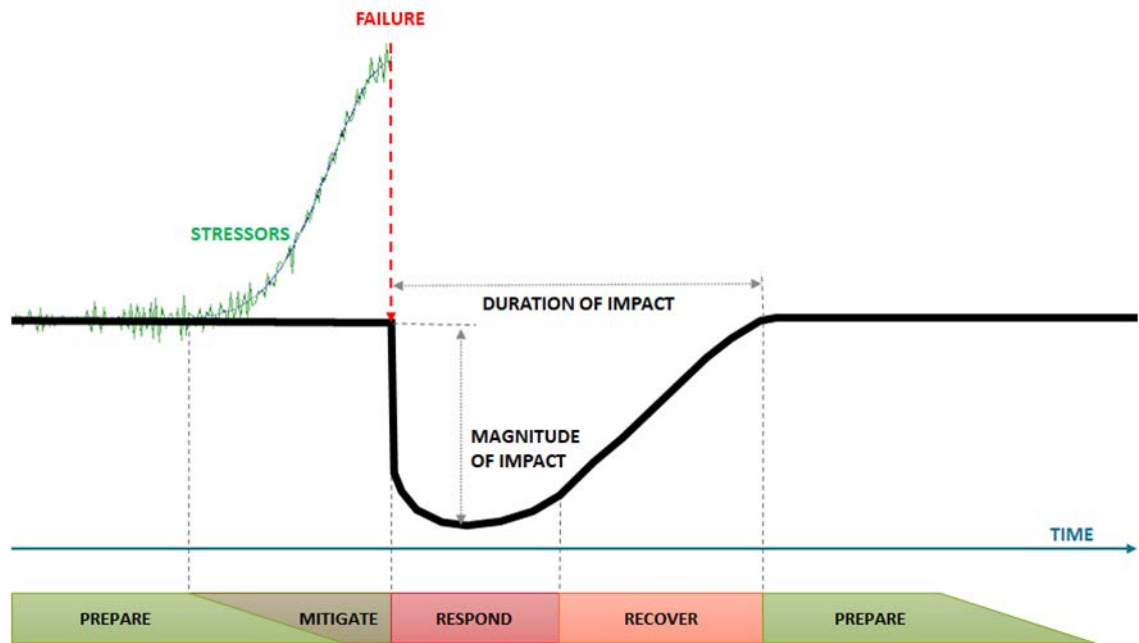
Q13. How does the Storm Resilience Model incorporate this definition?

A13. The Storm Resilience Model utilizes a resilience-based planning approach to calculate hardening project benefits and prioritize projects. The model includes a 'universe' of major storm events as stressors on the TEC system. The database includes the probability of these events occurring as well as the magnitude of impact, in terms of the percentage of the sub-systems (e.g. substations, transmission lines, feeders, laterals), and duration to restore the system. The database also includes the

1   restoration cost to return the system back to normal

2   operation after each of the storm events.

3

4   The Storm Resilience Model also identifies, on a

5   probability weighted basis, which specific portions of

6   the TEC system would be impacted and their contribution

7   to the overall restoration costs. The model also

8   evaluates the storms impact for each portion of the

9   system based on current status of the system and if that

10   part of the system is hardened. For example, the Storm

11   Resilience Model calculates magnitude and duration of a

12   storm event on a distribution circuit given its current

13   state and after it has been hardened.

14

15   **Q14. Please outline the type and count of hardening projects**

16   **evaluated in the Storm Resilience Model.**

17

18   **A14.** Table 1 on the page below contains the list of potential

19   hardening projects by program evaluated in the Storm

20   Resilience Model.

21

22

23

24

25

Table 1: Potential Hardening Project Count

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

Q15. How were these potential hardening projects identified?

A15. The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of TEC's system during major storm events. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. Additionally, hardening approaches for parts of the system were based on the balance of the resilience benefit they provide with the overall costs. I discuss this more below. Table 2 on the page below shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

11

Table 2: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**255**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

All of the assets that benefit from hardening are strategically grouped into potential hardening projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. The main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures. Therefore, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e. bigger and stronger

12

poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '2' were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone is still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than that of laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provides a balanced resilience strategy for feeders. It

13

1	should be noted that this balanced strategy with
2	automation hardening is not available for laterals. As
3	such, undergrounding is preferred approach for lateral
4	hardening while overhead physical hardening combined with
5	automation hardening is the preferred approach for
6	feeders.
7	
8	At the transmission circuit level, wood poles were
9	identified for hardening by replacing with non-wood
10	materials like steel, spun concrete, and composites. The
11	non-wood materials have a consistent internal strength
12	while wood poles can vary widely and are more likely to
13	fail. Transmission wood poles were grouped at the circuit
14	level into projects.
15	
16	TEC identified 96 separate transmission access, road, and
17	bridge projects based on field inspections of the system.
18	
19	TEC performed detailed storm surge modeling using the
20	Sea, Land, and Overland Surges from Hurricanes (SLOSH)
21	model. The SLOSH model identified 59 substations with a
22	flood risk, depending on the hurricane category.
23	
24	**Q16. Why is this approach to hardening project identification**
25	**important?**

A16. This approach to hardening project identification is important for several reasons.

    1. The approach is comprehensive. As Table 2 shows, the approach evaluates nearly all the TEC's transmission and distribution (T&D) system. By considering and evaluating the entire system on a consistent basis, the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.

    2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and industrial, and priority customers. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of

1   all weak links in the circuit and for capturing

2   the full benefit for customers.

3 3. The granularity at the asset and project levels

4   allows TEC to invest in portions of the system

5   that provide the most value to customers from a

6   restoration cost reduction, customers impacted

7   (CI), and customer minutes interrupted (CMI)

8   perspective. For example, a circuit may have 10

9   laterals, the Storm Resilience Model may determine

10   that only 3 out of the 10 should be hardened.

11   Without this granularity, hardening over

12   investment is a concern. The adopted approach

13   provides confidence that the overall plan is

14   investing in parts of the system that provide the

15   most value for customers.

16 4. The types of hardening projects include the

17   mitigation measures over all the four phases of

18   resilience providing a diverse investment plan.

19   Since storm events cannot be fully eliminated, the

20   diversification allows TEC to provide a higher

21   level of system resilience.

22 5. The approach balances the use of robust data sets

23   with TEC experience with storm events to develop

24   storm hardening projects. Data-only approaches may

25   provide decisions that don't match reality, while

1	people-driven only solutions can be filled with
2	bias. The approach balances the two to better
3	identify types of hardening projects.
4	
5	**Q17. Please describe the analysis 1898 & Co. conducted for**
6	**TEC.**
7	
8	**A17.** 1898 & Co. utilized a resilience-based planning approach
9	to identify hardening projects and prioritize investment
10	in the TEC T&D system utilizing a Storm Resilience Model.
11	The Storm Resilience Model consistently models the
12	benefits of all potential hardening projects for an
13	'apples to apples' comparison across the system. The
14	resilience-based planning approach calculates the benefit
15	of storm hardening projects from a customer perspective.
16	This approach consistently calculates the resilience
17	benefit at the asset, project, and program level. The
18	results of the Storm Resilience Model are:
19	1. Decrease in the Storm Restoration Costs
20	2. Decrease in the customers impacted and the
21	duration of the overall outage, calculated as CMI
22	
23	The Storm Resilience Model employs a data-driven
24	decision-making methodology utilizing robust and
25	sophisticated algorithms to calculate the resilience

benefit. Figure 2 provides an overview of the Storm Resilience Model used to calculate the project benefits and prioritize projects.

Figure 2: Storm Resilience Model Overview
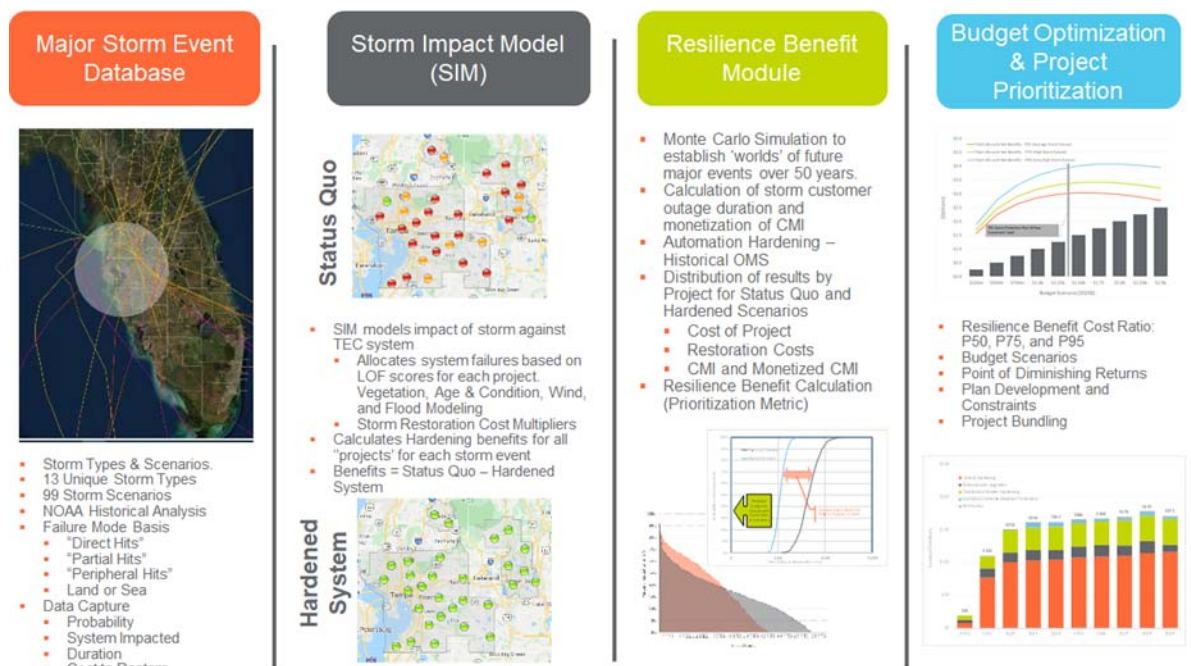
The storms database includes the future 'universe' of potential storm events to impact the TEC service territory. The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios.

Each storm scenario is then modeled within the Storm

Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone the asset is in. Substation LOF is based on the SLOSH model results. The Storm Impact Model also estimates the restoration costs and CMI for each of the projects. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (i.e. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types storm events to impact the TEC service territory over the next 50 years. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a

1 resilience weighted benefit for each project in dollars.

2 Feeder Automation Hardening projects are evaluated based

3 on historical outages and the expected decrease in

4 historical outages if automation had been in place.

6 The Budget Optimization and Project Scheduling model

7 prioritizes the projects based on the highest resilience

8 benefit cost ratio. The model prioritizes each project

9 based on the sum of the restoration cost benefit and

10 monetized CMI benefit divided by the project cost. This

11 is done for the range of potential benefit values to

12 create the resilience benefit cost ratio. The model also

13 incorporates TEC's technical and operational realities

14 (e.g. transmission outages) in scheduling the projects.

16 This resilience-based prioritization facilitates the

17 identification of the critical hardening projects that

18 provide the most benefit. Prioritizing and optimizing

19 investments in the system helps provide confidence that

20 the overall investment level is appropriate and that

21 customers get the most value

23 **Q18. Why is it necessary to model storm hardening projects**

24 **benefits using this resilience-based planning approach**

25 **and Storm Resilience Model?**

A18. The Storm Resilience Model was architected and designed for the purpose of calculating storm hardening project benefit in terms of reduced restoration costs and customer minutes interrupted to build a Storm Protection Plan with the right level of investment that provides the most benefit for customer. It was necessary to model storm hardening projects using the resilience-based planning approach shown in Figure 2 for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms to impact the TEC service territory. Different storms have dramatically different impact to TEC's system, for instance, in review of TEC's historical storm reports, it was observed that tropical storm events even 100 to 150 miles away from TEC's service territory from the Gulf side have greater impact in terms of restoration costs than larger storms 100 to 150 miles away on the Florida or Atlantic side. This is mainly caused by the energy that exists in the storm bands when they reach TEC's service territory. For this reason, the resilience-based planning approach includes the 'universe' of

1	potential major events that could impact TEC over
2	the next 50 years, this is the Major Storms Event
3	Database. In relation to the conceptual model
4	showing the phases of resilience (Figure 1), I
5	will discuss how the probabilities and system
6	impacts of storm events were developed later in my
7	testimony.
8	2. Major events cause assets to fail. Assets
9	collectively serve customers. It only takes one
10	asset failure to cause customer outages. The cost
11	to restore the failed assets is dependent on the
12	extent of the damage and resources used to fix the
13	system. The duration to restore affected customers
14	is dependent on the extent of the asset damage and
15	the extent of the damage on the rest of the
16	system. It may only take 4 hours to fix the failed
17	equipment, but customers could be without service
18	for 4 days if crews are busy fixing other parts of
19	the system for 3 days and 20 hours. All of this is
20	dependent on the type of storm to impact the
21	system. Modeling this series of events, the phases
22	of resilience from Figure 1, for the entire system
23	at the asset and project level for both a Status
24	Quo and Hardened scenarios is needed to accurately
25	model hardening project benefits. Therefore, the

resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 99 storm events for both scenarios. I discuss core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan in further detail below in my testimony.

3. The output of the Storms Impact Model is the resilience benefit of each project for each of the 99 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm, and the mix of storm events to occur over the life of the hardening projects. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life-cycle of the assets. A future 'world' of major storm events could include a higher frequency of category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of category 1 type storms with high impact and a high frequency of tropical storms with lower impacts.

The number of storm combination scenarios is significant given there are 13 unique types of storm events. To model this range of combinations, the Storm Restoration Model employs stochastic modeling, or Monte Carlo Simulation, to randomly select from the 99 storm events to create a future 'world' of the 13 unique storm events to hit the TEC service territory. The Monte Carlo Simulation creates a 1,000-future storm 'worlds'. From this, the life-cycle resilience benefit of each hardening project can be calculated. This is done in the Resilience Benefit Module, I discuss this in more detail below in my Testimony.

4. To answer the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include a Budget Optimization and Scheduling Model within the Storm Resilience Model. The Budget Optimization algorithm develops the project plan and associated benefits over a range of budget levels to identify a point of diminishing returns where additional investment provides very little return. The Project Scheduling component uses the preferred budget level and develops an executable plan by prioritizing projects that provide the

1	most benefit while balancing TEC's technical
2	constraints. I outline this in more detail below.
3	
4	**3. MAJOR STORMS EVENT DATABASE**
5	**Q19. Please provide an overview of the Major Storms Event**
6	**Database and how it was developed.**
7	
8	**A19.** The Major Storms Event Database includes the 'universe'
9	of storm events that could impact TEC's service territory
10	over the next 50 years. The database describes the phases
11	of resilience (Figure 1) for the TEC high-level system
12	perspective for a range of storm stressors. It was
13	developed collaboratively between TEC and 1898 & Co. It
14	utilizes information from the National Oceanic and
15	Atmospheric Administration (NOAA) database of major storm
16	events, TEC historical storm reports, available
17	information on the impact of major storms to other
18	utilities, and TEC experience in storm recovery. From
19	that information, 13 unique storm types were observed to
20	impact the TEC service territory. For each of the storm
21	types, various storm scenarios were developed to capture
22	the range of probabilities and impacts of each storm
23	type. In total, 99 storms scenarios were developed to
24	capture the 'universe' of storm events to impact the TEC
25	service territory. Table 3 provides a summary of the

1 Major Storms Event Database. The table includes the

2 ranges of probabilities, restoration costs, impact to the

3 system, and duration of the event.

4

5 **Table 3: Major Storms Event Database Overview**

6

7

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit - Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit - Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

25 **Q20. What does the NOAA data show on the number and types of**

major storm events to impact the TEC service territory?

A20. The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. The NOAA major events database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

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

27

■ **'Partial Hits'** – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.

■ **'Peripheral Hits'** – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 4 on the page below includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 4: Historical Storm Summary from NOAA

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

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

Table 4 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the

1	results show approximately 46 percent of the events come
2	from the Gulf of Mexico while the other 54 percent come
3	over Florida.
4	
5	**Q21. What analysis of this historical storm information was**
6	**done to determine the storm probability ranges?**
7	
8	**A21.** 1898 & Co. converted the storm information from Table 4
9	above to show the total storm count for 100-year rolling
10	average starting with the period of 1852 to 1951 ending
11	with the period 1920 to 2019. This provides 69, 100 year
12	periods. This was done for each of the 13 unique storm
13	events. The counts of each 100 year period for each storm
14	type were then converted to probabilities. Starting on
15	the page below, Figure 3, Figure 4, and Figure 5 show the
16	100 year rolling storm probability for "direct hits" (50
17	miles), "partial hits" (51 to 100 miles), and "peripheral
18	hits" (101 – 150 miles), respectively.

Figure 3: "Direct Hits" (50 Miles) 100 Year Rolling Probability
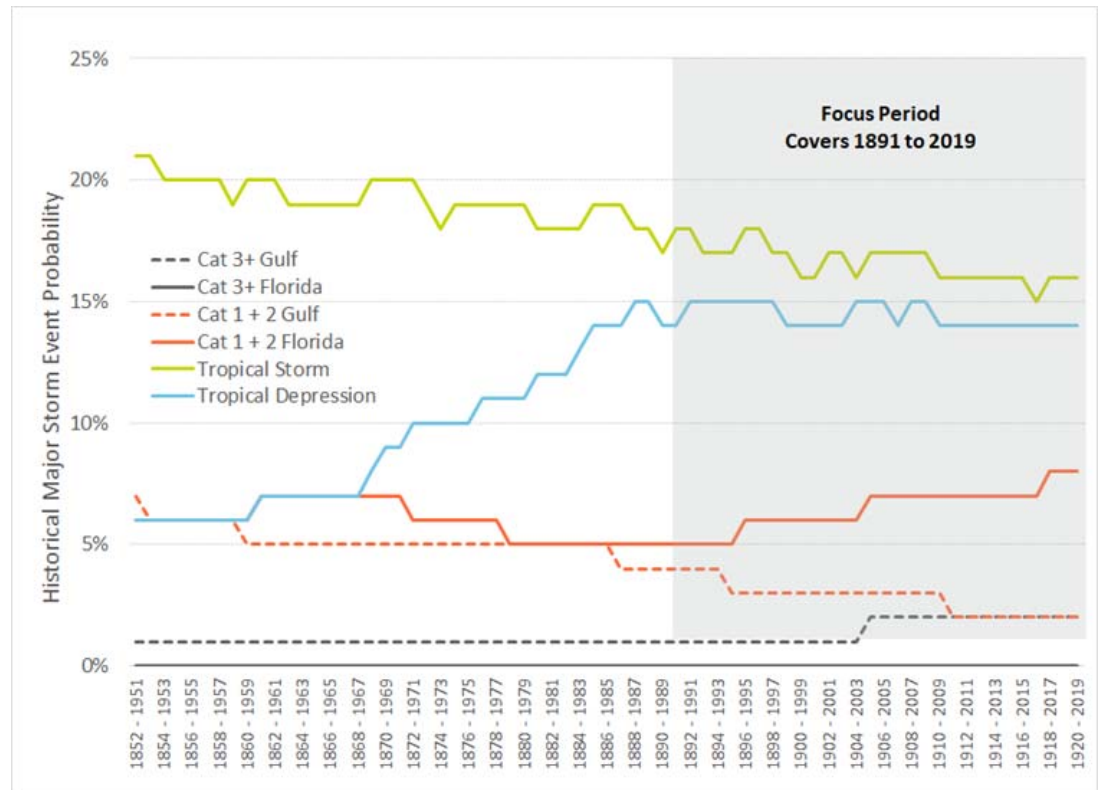
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 4: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability

Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.
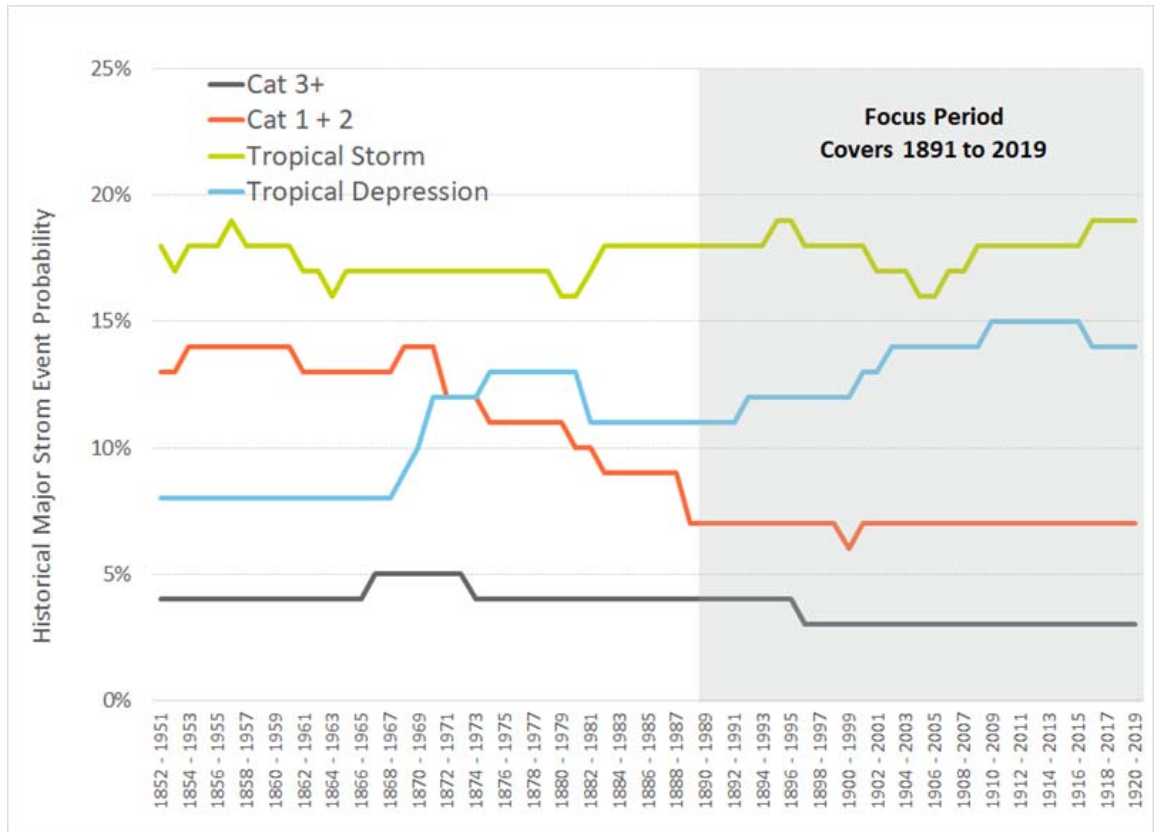
Figure 5: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability

Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.
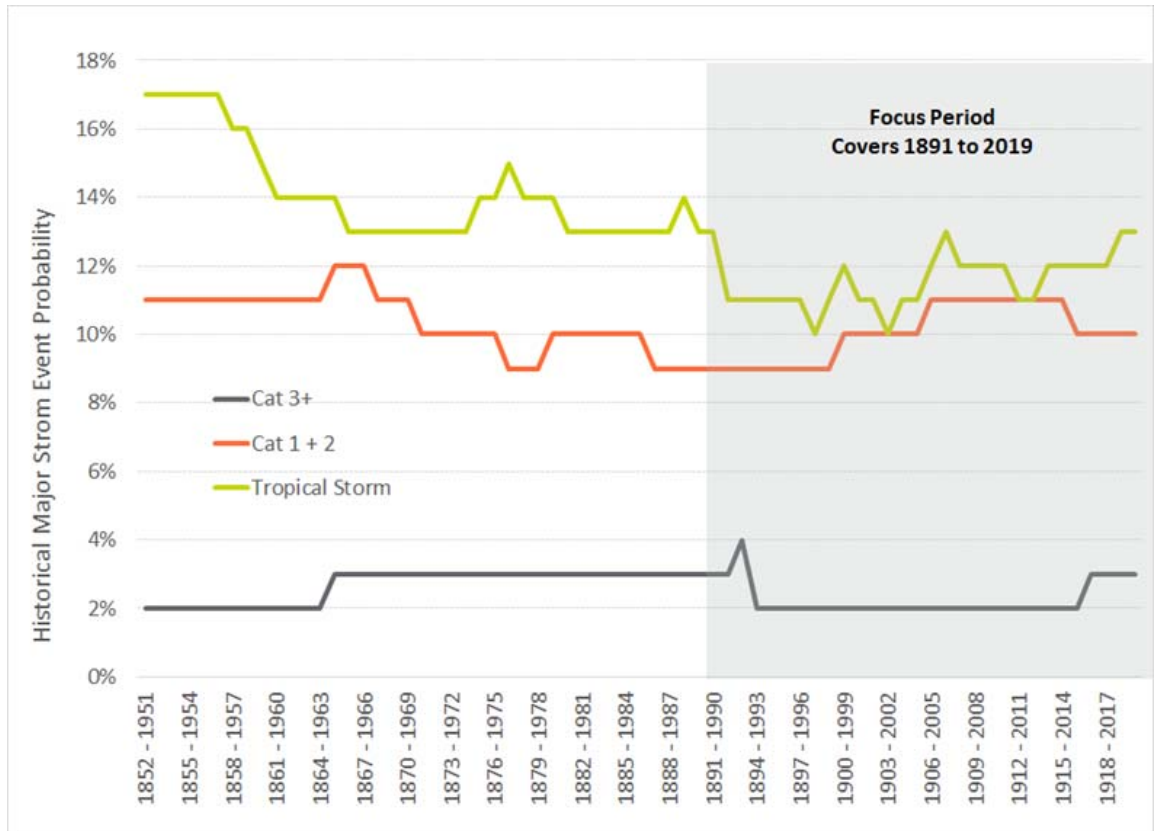
Each of the figures show a relative stability in the 100 year probability levels for the last 30 periods corresponding to storm events from 1891 through 2019. This time horizon served as the basis for developing the probability ranges for the 13 unique storm events.

Q22. How were the storm impact ranges developed?

A22. The range of system impacts for each storm scenario were developed based on historical storm reports from TEC and augmented by the TEC's team experience with historical storm events. The database includes events that have not recently impacted TEC's service territory. The approach followed an iterative process of filling out more known impact information from recent events and developing impacts for those events without impact data based on their relative storm strength to the more known events.

4. STORM IMPACT MODEL

Q23. Please provide an overview of the Storm Impact Model.

A23. The Storm Impact Model describes the phases of resilience, Figure 1, for each potential hardening project on the TEC T&D system for each storm stressor scenario from the Major Storms Event Database. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to

1	customers in terms of CMI. Finally, the Storm Impact
2	Model models each storm event for both the Status Quo and
3	Hardened scenario. The Hardened scenario assumes the
4	assets that make up each project have been hardened. The
5	Storm Impact Model then calculates the benefit of each
6	hardening project from a reduced restoration cost, CMI,
7	and monetized CMI perspective.
8	
9	**Q24. You have mentioned that the Storm Resilience Model**
10	**employs a data-driven decision-making methodology. Please**
11	**describe what core data sets that are in the model and**
12	**how they are used in the resilience benefit calculation.**
13	
14	**A24.** The Storm Impact Model utilizes a robust and
15	sophisticated set of data and algorithms at a very
16	granular system level to model the benefits of each
17	hardening project for each storm scenario. TEC's data
18	systems include a connectivity model that allows for the
19	linkage of three foundational data sets used in the Storm
20	Impact Model – the Geographical Information System (GIS),
21	the Outage Management System (OMS), and Customer.
22	
23	**GIS** - The GIS provides the list of assets in TEC's system
24	and how they are connected to each other. Since the
25	resilience-based approach is fundamentally an asset

management bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan. The strategic assignment of assets to projects and the value of the approach is discussed above.

OMS - The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects.

Customer - The third foundational data set is customer count and customer type information that featured connectivity to the GIS and OMS systems. This allowed the Storm Impact Model to directly link the number and type

of customers impacted to each project and the project's assets. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate each storms CMI (customers affected * outage duration) for each lateral or feeder project.

Vegetation Density - The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor (approximately 240,000 spans) utilizing tree canopy data and geospatial analytics.

Wood Pole Condition - A compromised, or semi-compromised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole.

Wind Zones - Wind zones have been created across the

United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically higher closer to the coast and lower the further inland. The Storm Impact Model utilizes the provided wind zone data from the public records and the asset geospatial location from GIS to designate the appropriate wind zone.

Accessibility - The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. The Storm Impact Model performs a geospatial analysis of each structure to identify if there is road access or if the asset is in a deep right-of-way (ROW).

Flood Modeling - The model also includes detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations

1   applied to the specific location shoreline, Tampa in this

2   case, incorporating the unique bay and river

3   configurations, water depths, bridges, roads, levees and

4   other physical features to establish surge height. These

5   results are simulated several thousand times to develop

6   the Maximum of the Maximum Envelope of Water, the worst-

7   case scenario for each storm category. The SLOSH model

8   results were overlaid with the location of TEC's 216

9   substations to estimate the height of above the ground

10   elevation for storm surge. The SLOSH model identified 59

11   substations with flooding risk depending on the hurricane

12   category.

13

14   **Q25.** **What were the results of the vegetation density**

15   **algorithm?**

16

17   **A25.** Figure 6 and Figure 7 on the page below show the range of

18   vegetation density for OH Primary and Transmission

19   Conductor, respectively. The figures rank the conductors

20   from highest to lowest level of vegetation density. As

21   shown in the figures, approximately 30 to 35 percent of

22   the OH Primary and Transmission Conductor have near zero

23   tree canopy coverage, while approximately 65 to 70

24   percent have some level of coverage all the way up to 100

25   percent coverage.

Figure 6: Vegetation Density on TEC Primary Conductor
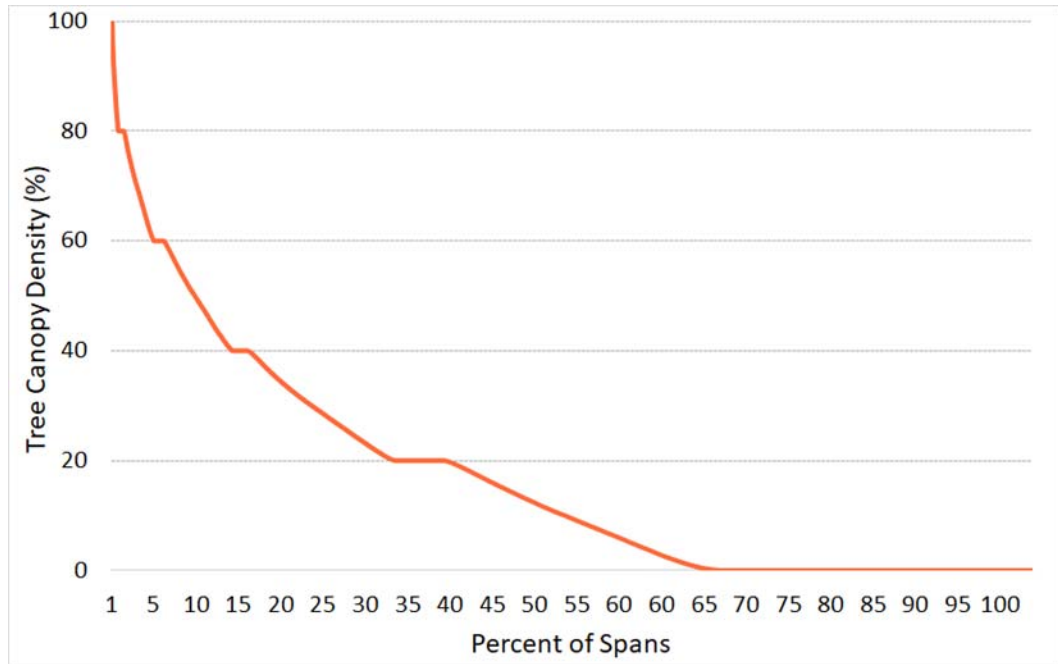
Figure 7: Vegetation Density on TEC Transmission Conductor
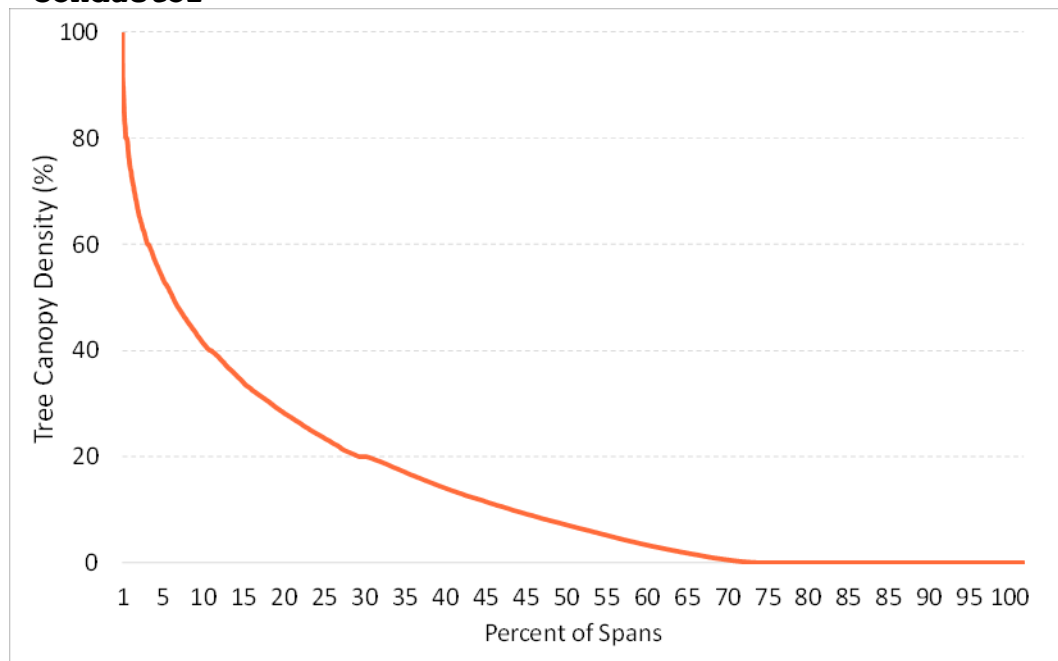
Q26. How are asset and system failures during major storm events identified in the Storm Impact Model hardening projects?

A26. The Storm Impact Model identifies system failures based on the primary failure mode of the asset base. The model identifies the parts of the system that are likely to fail given the specific storm event from the Major Storms Event Database.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing conductor or structures to fail. If structures (i.e. wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilizes expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF

1 score for all circuit assets. The project level scores

2 are equal to the sum of the asset scores normalized for

3 length. The project level scores are then used to rank

4 each project against each other to identify the likely

5 lateral, backbone, or transmission circuit to fail for

6 each storm type. The model estimates the weighted storm

7 LOF based on the asset level scoring.

8

9 The model determines which substations are likely to

10 flood during various storm types based on the flood

11 modeling analysis. That analysis provides the flood

12 level, meaning feet of water above the site elevation,

13 for various storm types. Only the storm scenarios with

14 hurricanes coming from the Gulf of Mexico provide the

15 necessary condition for storm surge that would cause

16 substation flooding.

17

18 The site access dataset includes a hierarchy of the

19 impacted circuits. Using this hierarchy, each site access

20 LOF is equal to the total LOF of the circuits it provides

21 access to.

22

23 **Q27. How are restoration costs allocated to the asset base for**

24 **each major storm events?**

25

A27. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration cost multipliers above planned replacement costs. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF and the overall restoration costs outlined in the Major Event Storms Database.

Q28. How are customer outage durations calculated in the model for each major storm event?

A28. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset and project in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known

1	customer count to calculate the CMI. The CMI benefit are
2	also monetized.
3	
4	**Q29. Why were CMI benefit monetized?**
5	
6	**A29.** The CMI benefits were monetized for project
7	prioritization purposes. The Storm Impact Model
8	calculates each hardening project's CMI and restoration
9	cost reduction for each storm scenario. In order to
10	prioritize projects, a single prioritization metric is
11	needed. Since CMI is in minutes and restoration costs is
12	in dollars, the resilience-based planning approach
13	monetized CMI. The monetized CMI benefit is combined with
14	the restoration cost benefit for each project to
15	calculate a total resilience benefit in dollars.
16	
17	**Q30. How was the CMI benefit monetized?**
18	
19	**A30.** CMI was monetized using DOE's ICE Calculator. The ICE
20	Calculator is an electric outage planning tool developed
21	by Freeman, Sullivan & Co. and Lawrence Berkeley National
22	Laboratory. This tool is designed for electric
23	reliability planners at utilities, government
24	organizations or other entities that are interested in
25	estimating interruption costs and/or the benefits

associated with reliability or resilience improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE). The ICE calculator incudes the cost of an outage for different types of customers. The calculator was extrapolated for the longer outage durations associated with storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

Q31. How are the storm specific resilience benefits calculated for each project by major storm event?

A31. The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers

45

1   impacted) for each project.

2

3   The output from the Storm Impact Model is a project by

4   project probability-weighted estimate of annual storm

5   restoration costs, annual CMI, and annual monetized CMI

6   for both the 'Status Quo' and Hardened Scenarios for all

7   99 major storm scenarios. The following section describes

8   the methodology utilized to model all 99 major storms and

9   calculate the resilience benefit of each project.

10

11   **5.   RESILIENCE BENEFIT MODULE**

12   **Q32. Please provide an overview of the Resilience Benefit**

13   **Calculation Module**

14

15   **A32.** The Resilience Benefit Calculation Module of the Storm

16   Resilience Model uses the annual benefit results of the

17   Storm Impact Model and the estimated project costs to

18   calculate the net benefits for each project. Since the

19   benefits for each project are dependent on the type and

20   frequency of major storm activity, the Resilience Benefit

21   Module utilizes stochastic modeling, or Monte Carlo

22   Simulation, to randomly select a thousand future worlds

23   of major storm events to calculate the range of both

24   'Status Quo' and Hardened restoration costs and CMI. The

25   benefit calculation is performed over a 50-year time

horizon, matching the expected life of hardening projects.

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

Q33. What economic assumptions are used in the life-cycle Resilience Benefit Module?

A33. The resilience net benefit calculation includes the following economic assumptions.

- 50 year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years.
- 2 percent escalation rate
- 6 percent discount rate

Q34. How were hardening project costs determined?

A34. Project costs were estimated for over 20,000 projects in

the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that were then multiplied by unit cost estimates to calculate the project costs.

Distribution Lateral Undergrounding – The GIS and accessibility algorithm calculated the following scope items for each of the lateral undergrounding projects:

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

TEC provided unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit cost estimates are based on supplier information and previous undergrounding projects.

Transmission Asset Upgrades – The Transmission Asset

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

Substation Extreme Weather Hardening - The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

Distribution Overhead Feeder Hardening - The distribution overhead feeder hardening project costs are based on the number of wood poles that don't meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the cost to add automation to each circuit. Automation hardening cost estimates include the cost to add reclosers, pole replacements, re-conductor portions of the line, and substation upgrades that may be needed to handle load

1   transfer.

2

3   **Transmission Access Enhancements** - TEC provided all the

4   project costs for the Transmission Access Enhancements.

5   The cost estimates were based on the length of the bridge

6   or road. Those lengths were developed using geospatial

7   solutions using TEC's GIS for each problem area.

8

9   **Q35.** **How are the resilience results of the Monte Carlo**

10   **Simulation displayed and how should they be interpreted?**

11

12   **A35.** The results of the 1,000 iterations are graphed in a

13   cumulative density function, also known as an 'S-Curve'.

14   In layman's terms, the thousand results are sorted from

15   lowest to highest (cumulative ascending) and then

16   charted. Figure 8 on the page below shows an illustrative

17   example of the 1,000 iteration simulation results for the

18   'Status Quo' and Hardened Scenarios.

19

20

21

22

23

24

25

Figure 8: Status Quo and Hardened Results Distribution Example
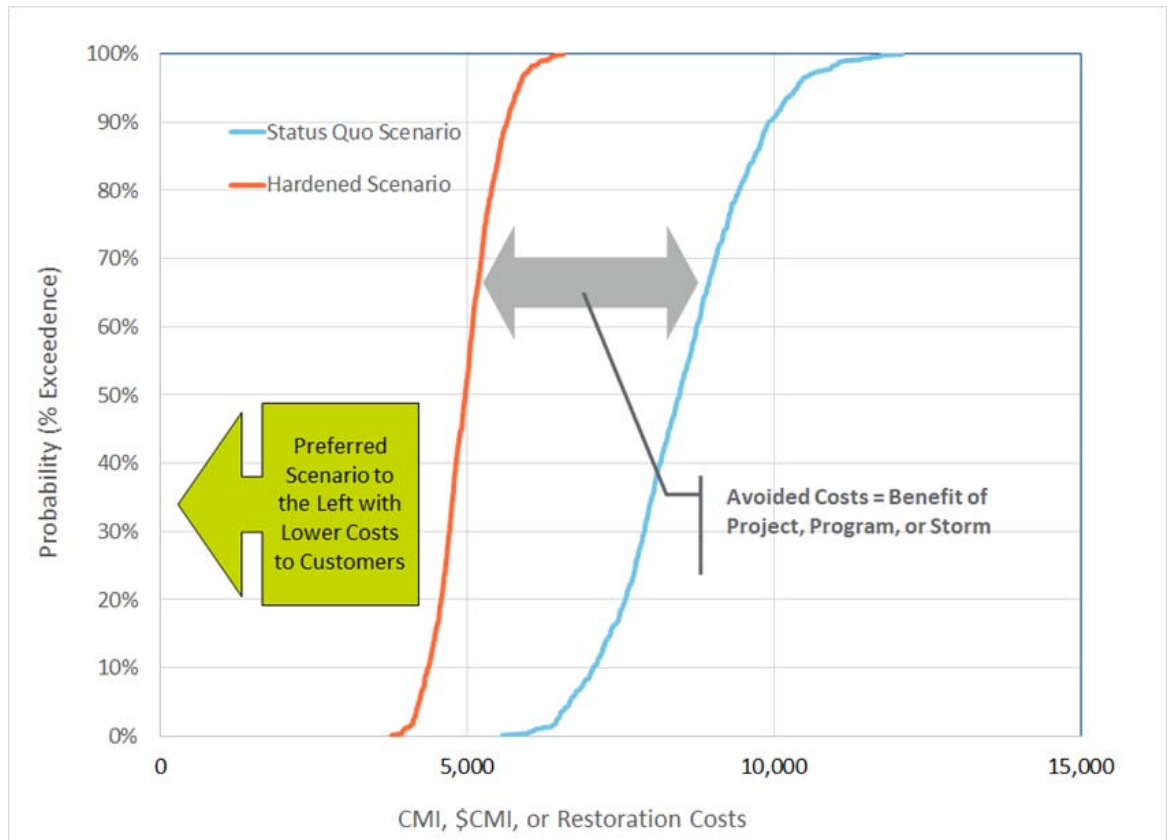
Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line

1   shows the variability in results. The steeper the slope

2   (i.e. vertical) the less range in the result. The more

3   horizontal the slope the wider the range and variability

4   in the results.

5

6   **Q36. How do S-Curves map to potential Future Storm Worlds?**

7

8   **A36.** Figure 9 below provides additional guidance on

9   understanding the S-Curves and the kind of future storm

10 worlds they represent.

11 **Figure 9: S-Curves and Future Storms**
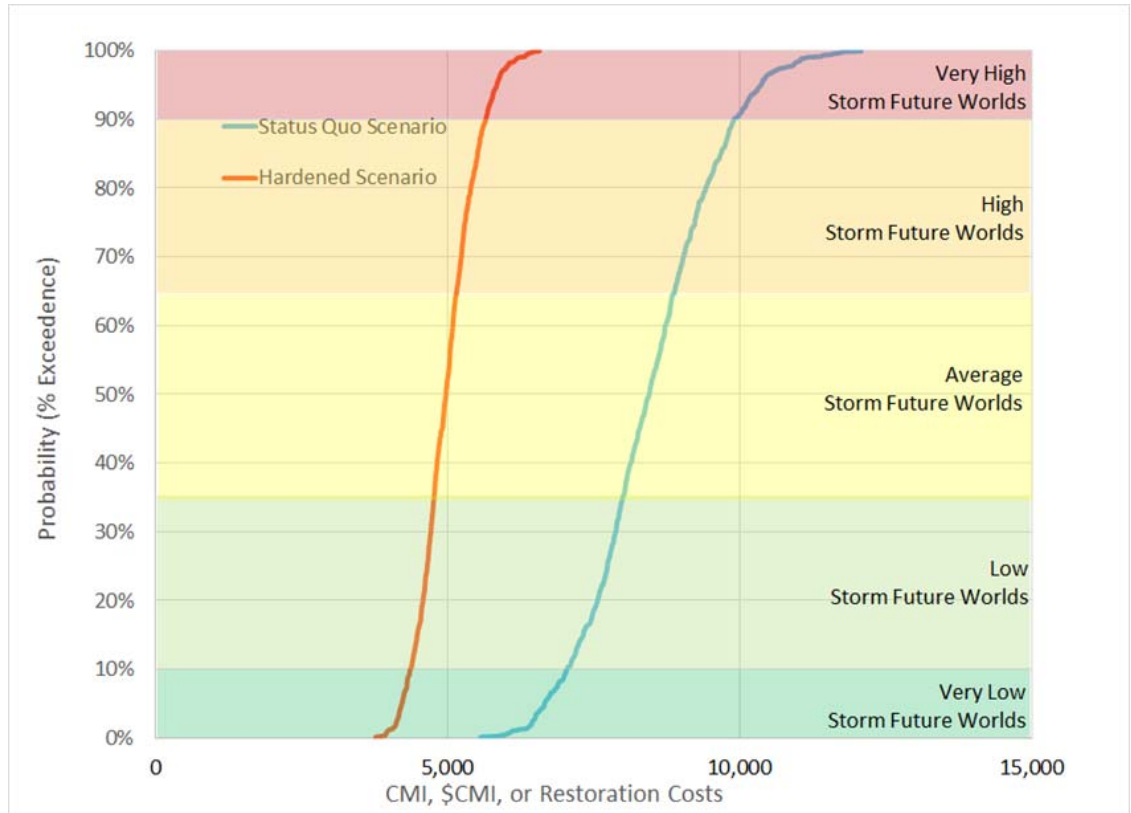
Q37. How are the S-Curves used to display the resilience benefit results?

A37. For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the resilience results will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 10 on the page below illustrates this concept of looking at the top part of the S-curves and showing the P-values.

Figure 10: S-Curves and Resilience Focus
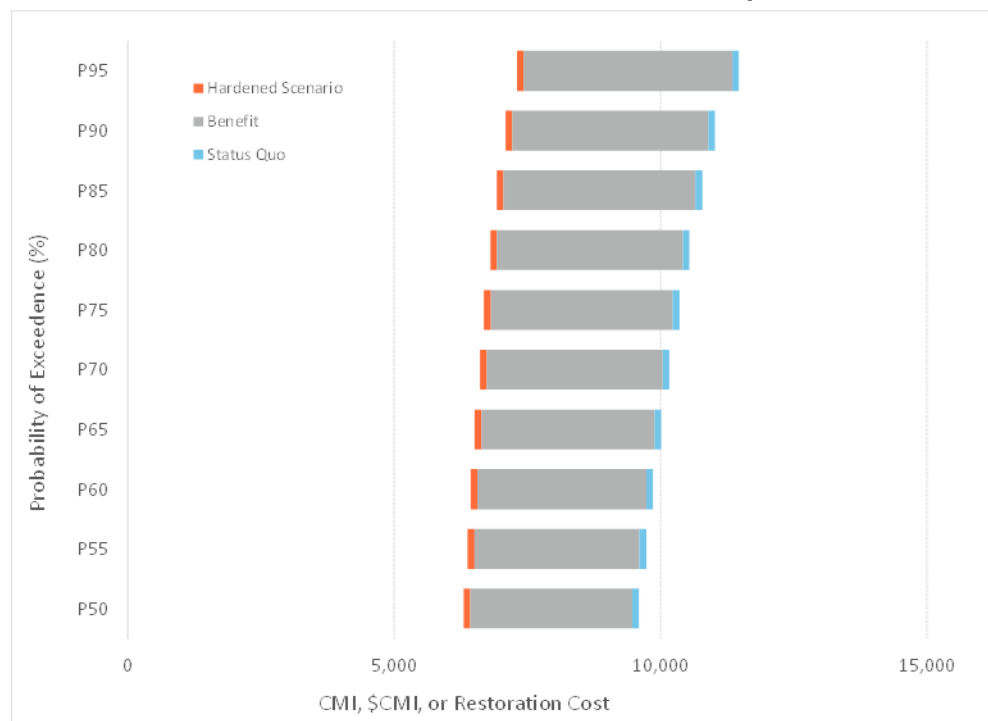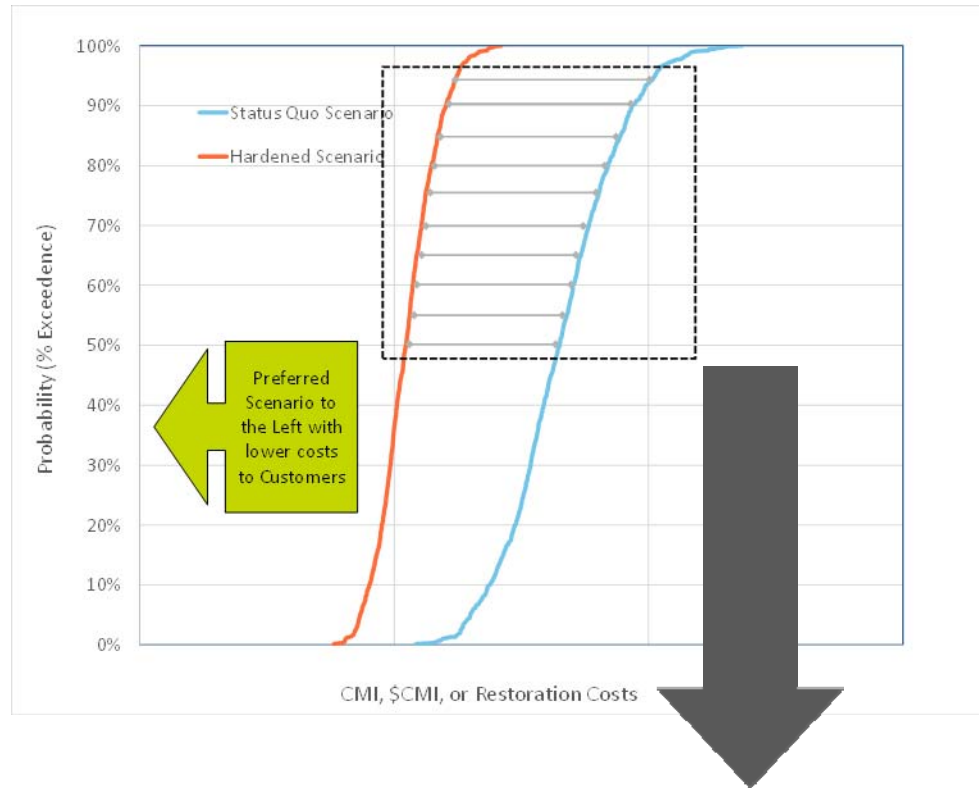
Q38. **Please describe the analysis to calculate resilience benefit for automation hardening projects.**

A38. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 1.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days. TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects. Additionally, the CMI was monetized and discounted over

| 1 | the 50-year time horizon to calculate the net present |
2	value (NPV). The NPV calculation assumed a replacement of
3	the reclosers in year 25; the rest of the feeder
4	automation investment has an expected life of 50 years or
5	more. The monetization and discounted cash flow
6	methodology was performed for project prioritization
7	purposes.
8	
9	**Q39. Please provide an example of this calculation.**
10	
11	**A39.** A historical outage may include a down pole from a storm
12	event, causing the substation breaker to lock out
13	resulting in a four-hour outage for 1,500 customers, or
14	360,000 CMI (4*1500*60). The Storm Resilience Model re-
15	calculates the outages as 400 customers without power for
16	four hours, or 96,000 CMI. That example provides a
17	reduction in CMI of over 70 percent.
18	
19	**Q40. What are the results of this analysis for the automation**
20	**hardening projects?**
21	
22	**A40.** Figure 11 and Figure 12 starting on the page below show
23	the percent decrease in CMI and monetized CMI for all
24	circuits ranked from highest to lowest from left to
25	right. The figures also include the benefits to all

outages.

Figure 11: Automation Hardening Percent CMI Decrease
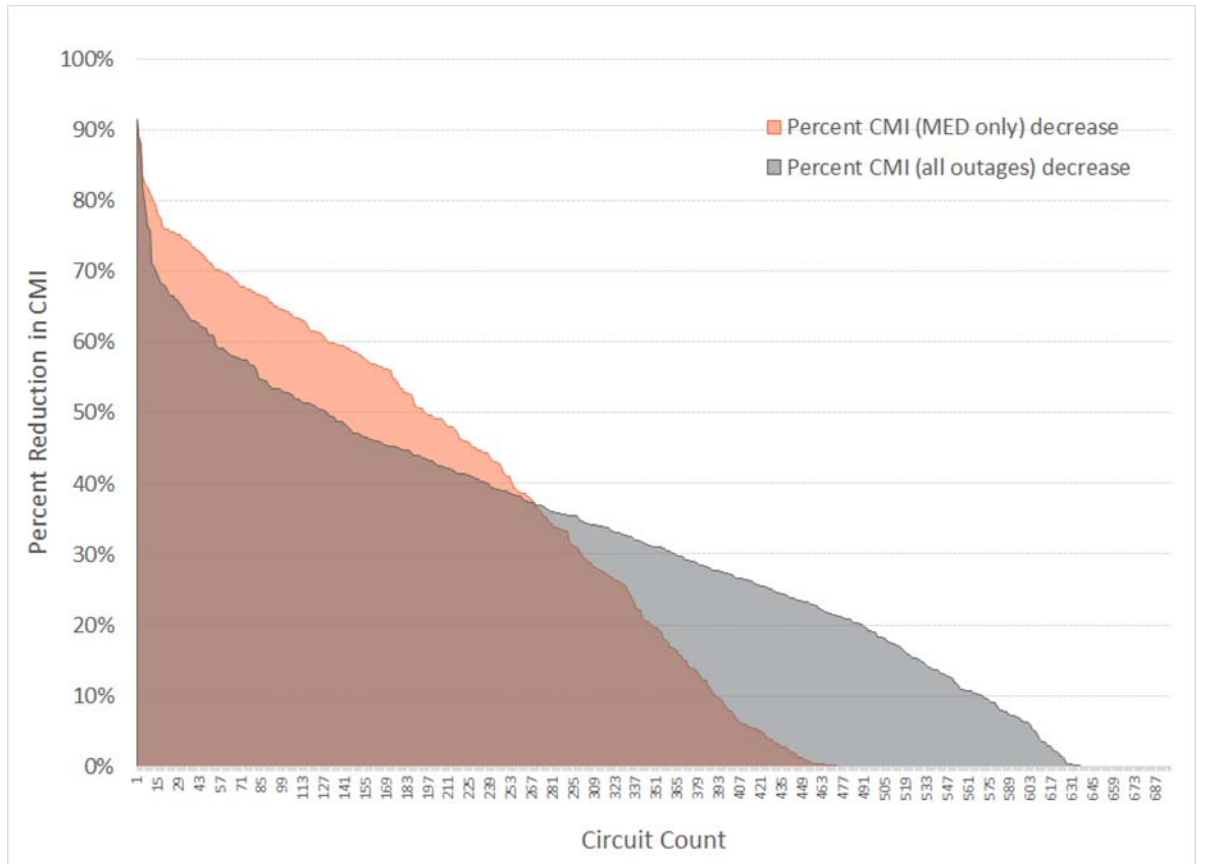
Figure 12: Automation Hardening Monetization of CMI Decrease
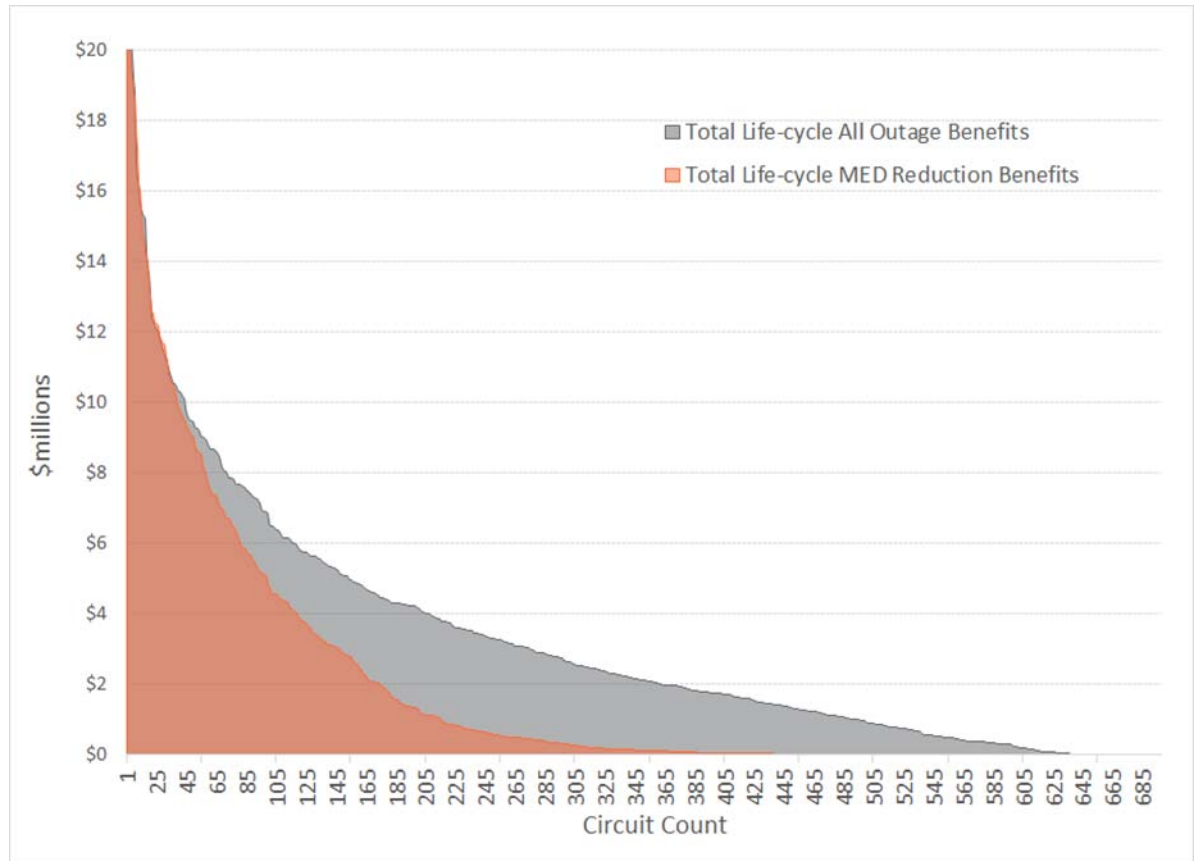
Q41. What are the specific outputs from the Resilience Benefit module?

A41. The Resilience Benefit Module includes the following values for each project:

- CMI 50-year Benefit

- Restoration Cost 50-year NPV Benefit

- Life-cycle 50 year NPV gross Benefit (monetized

CMI benefit + restoration cost benefit)

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

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

■ P50 – Average Storm Future

■ P75 – High Storm Future

■ P95 – Extreme Storm Future

6. BUDGET OPTIMIZATION AND PROJECT SCHEDULEING

Q42. How were hardening projects prioritized?

A42. All the projects are evaluated and prioritized using the same criteria allowing all 20,459 projects to be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each of the P-values (P50, P75, and P95) as well as a weighted value.

1	Performing prioritization for the four benefit cost
2	ratios is important since each project has a different
3	slope in their benefits from P50 to P95. For instance,
4	many of the lateral undergrounding projects have the same
5	benefit at P50 as they do at P95. Alternatively, many of
6	the transmission asset hardening projects are minorly
7	beneficial at P50 but have significant benefits at P75
8	and even more at P95. TEC and 1898 & Co. settled on a
9	weighting on the three values for the base prioritization
10	metric, however, investment allocations are adjusted for
11	some of the programs where benefits are small at P50 but
12	significant at P75 and P95.

Q43. How and why was the budget optimization performed?

A43. The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. For each budget level, the optimization model selects the projects with the highest benefit cost ratio to hardening in the

next 10 years. The model then strategically groups projects by type of program and circuit. For instance, all the selected laterals on a circuit are scheduled for undergrounding in the same year. This allows TEC to gain capital deployment efficiencies by deploying resources to the same geographical area at one time.

Q44. What were the results of the budget optimization analysis?

A44. Figure 13 on the page below shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

1   **Figure 13: Budget Optimization Results**

2
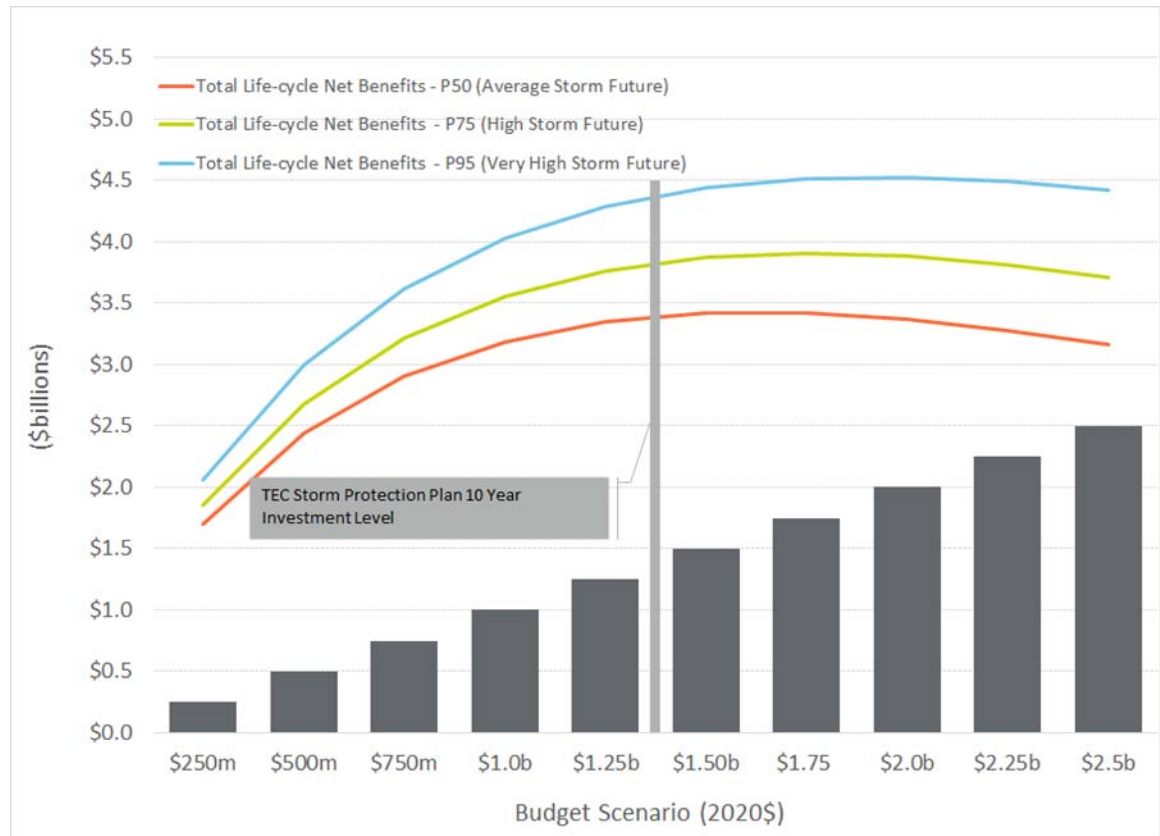
16

17   The figure shows significantly increasing levels of net

18   benefit from the $250 million to $1.5 billion with the

19   benefit level flattening from $1.5 billion to $2.0

20   billion and decreasing from $2.0 billion to $2.5 billion.

21

22   **Q45. What conclusions can be made from the results of the**

23   **budget optimization analysis?**

24

25   **A45.** The budget optimization results show that TEC's overall

1   investment level is right before the point of diminishing

2   returns showing that TEC's plan has an appropriate level

3   of investment capturing the hardening projects that

4   provide the most value to customers.

5

6 **Q46. How was the overall investment level set and projects**

7   **selected?**

8

9 **A46.** TEC and 1898 & Co. used the Storm Resilience Model as a

10   tool for developing the overall budget level and the

11   budget levels for each category. It is important to note

12   that the Storm Resilience Model is only a tool to enable

13   more informed decision making. While the Storm

14   Resilience Model employs a data-driven decision-making

15   approach with robust set of algorithms at a granular

16   asset and project level, it is limited by the

17   availability and quality of assumptions. In developing

18   the TEC Storm Protection plan project identification and

19   schedule, the TEC and 1898 & Co team factored in the

20   following:

21   ■ Resilience benefit cost ratio including the

22   weighted, P50, P75, and P95 values.

23   ■ Internal and external resources available to

24   execute investment by program and by year.

25   ■ Lead time for engineering, procurement, and

1	construction
2	■ Transmission outage and other agency coordination.
3	■ Asset bundling into projects for work
4	efficiencies.
5	■ Project coordination (i.e. project A before
6	project B, project Y and project Z at the same
7	time)

7. RESILIENCE BENEFIT RESULTS

Q47. What is the investment profile of the Storm Protection Plan?

A47. Table 5 on the page below shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

**Table 5: Storm Protection Plan Investment Profile by Program (Nominal $000)**

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

Q48. What are the restoration cost benefits of the plan?

A48. Figure 14 on the page below shows the range in restoration cost reduction at various probability of exceedance levels. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent

1 and intense, and the P90 and P95 levels represent a

2 future world where storm frequency and impact are all

3 high.

4

5 **Figure 14: Storm Protection Plan Restoration Cost Benefit**
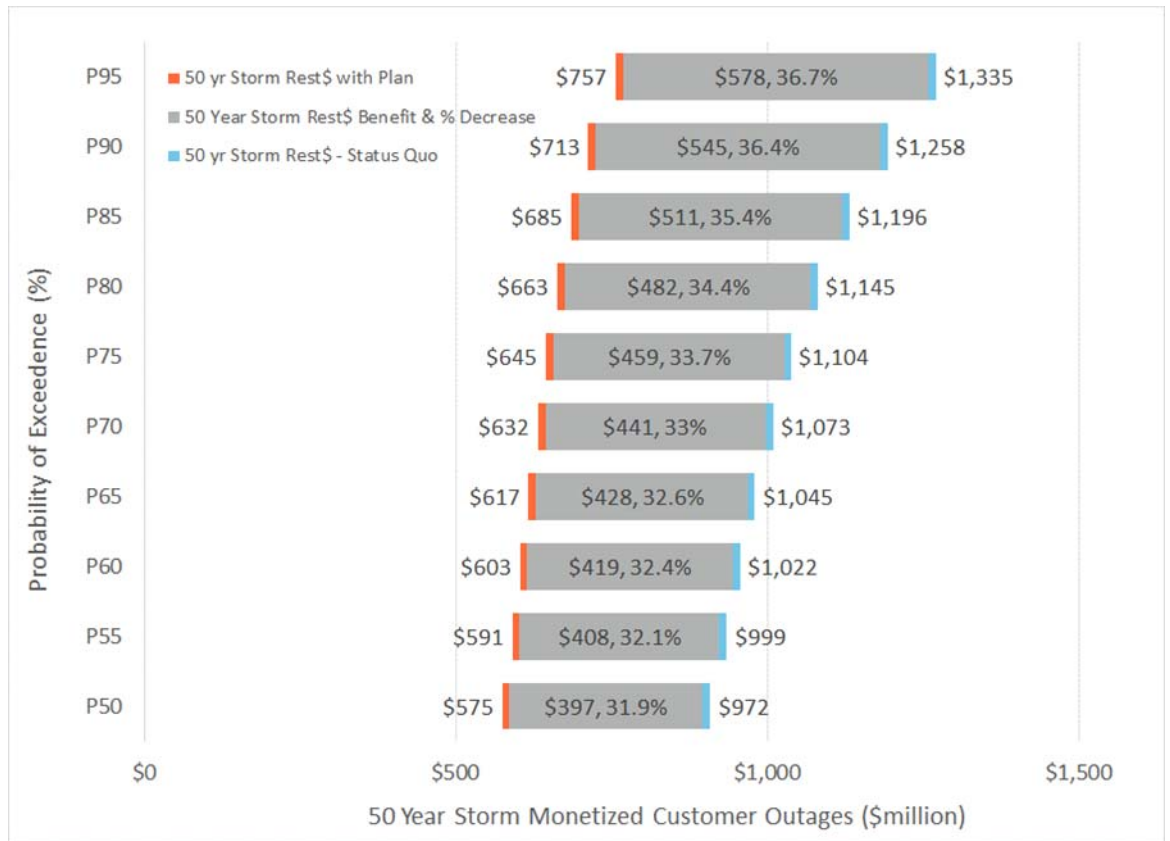
6

21 The figure shows that the 50-year NPV of future storm

22 restoration costs in a Status Quo scenario from a

23 resilience perspective is $970 million to $1,340 million.

24 With the Storm Protection Plan, the costs decrease by

25 approximately 32 to 37 percent. The decrease in

1   restoration costs is approximately $400 to $580 million.

2   From an NPV perspective, the restoration costs decrease

3   benefit is approximately 36 to 53 percent of the project

4   costs.

5

6   **Q49. What are the customer outage benefits of the plan?**

7

8   **A49.** Figure 15 on the page below shows the range in CMI

9   reduction at various probability of exceedance levels.

10   The figure shows relative consistency in benefit level

11   across the P-values with approximately 32 percent

12   decrease in the storm CMI over the next 50 years.
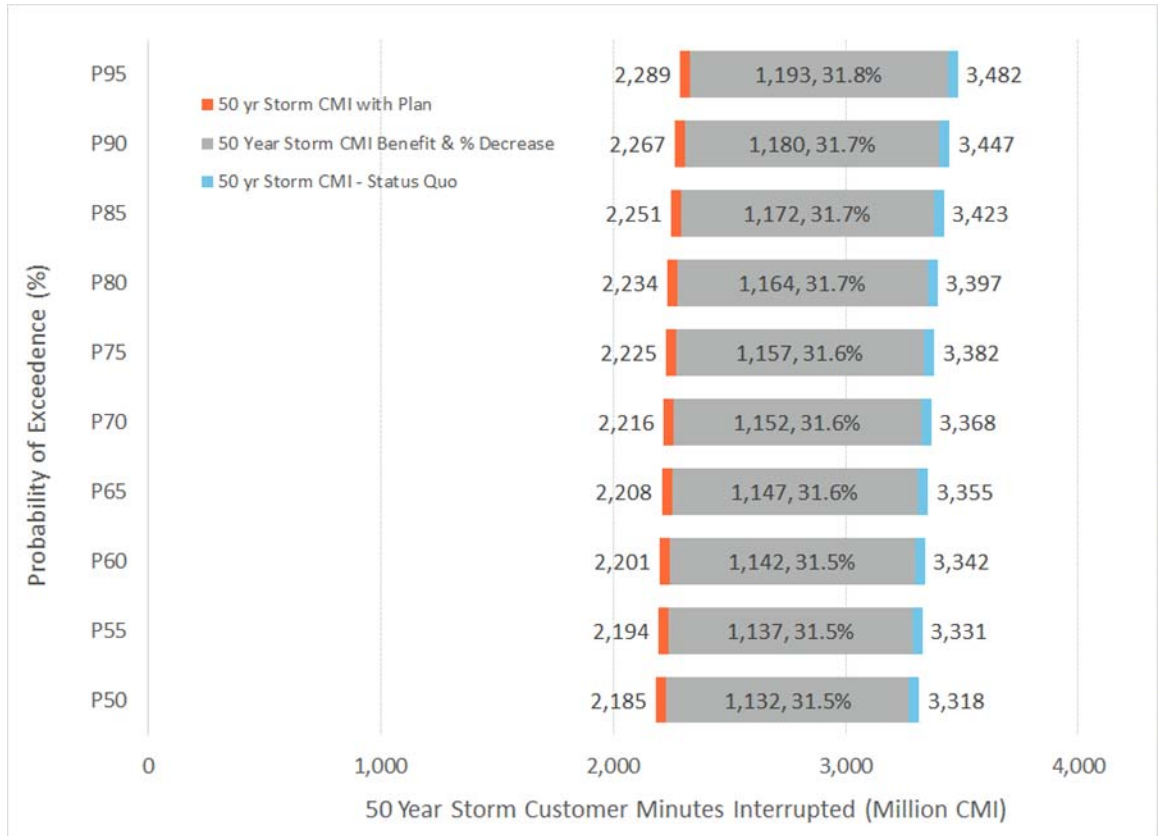
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Figure 15: Storm Protection Plan Customer Benefit

Q50. **What are the key take-aways from how resilience-based planning assessment was performed?**

A50. The follow are the key take-aways from how the resilience-based planning assessment was performed in the Storm Resilience Model:

■ **Customer and Asset Centric:** The model is foundationally customer and asset centric in how

it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset weak links that serve customers shows that the Storm Resilience Model is directly aligned with the intent of the statute to identify hardening projects that provide the most benefit to customers. Additionally, with this customer and asset centric approach, the specific benefits required from the statute can be calculated, restoration cost saving and impact to customers in terms of CMI, more accurately.

■ **Comprehensive:** The comprehensive nature of the assessment is best practice, by considering and evaluating nearly the entire T&D system the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.

■ **Consistency:** The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits calculation between asset types. For example, the model can compare a substation hardening project to an lateral undergrounding project. This is a

significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this capability, the assessment would not have been able to identify a point a diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis for the entire plan.

- **Rooted in Cause of Failure:** The Storm Resilience Model is rooted in the causes of asset and system failure from two perspectives. Firstly, the Major Storms Event Database outlines the range of storm stressors and the high level impact to the system. Secondly, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail, mainly vegetation density, asset condition, wind zone, and flood modeling. With this basis, hardening investment identification and prioritization provides a robust assessment to focus investment on the portions of the system that are more likely to fail in the major storm.

- **Drives Prudency:** The assessment and modeling approach drive prudency for the Storm Protection Plan on two main levels. Firstly, the granularity of potential hardening projects, over 20,000,

1	allows TEC to invest in the portions of the system
2	that provide the model value to customers. Without
3	granularity, there is risk that parts of the
4	system "ride the coat-tails" of needed investment
5	causing efficient allocation of limited capital
6	resources. Secondly, the budget optimization
7	allows for the identification of the point of
8	diminishing returns so that over investment in
9	storm hardening is less likely.

- **Balanced:** Hardening projects include mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows TEC to provide a higher level of system resilience for customers.

Q50. What conclusions can be made from the results of the resilience analysis?

A50. The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The

budget optimization analysis (see Figure 13) shows the investment level is right before the point of diminishing returns. This provides confidence that TEC's plan does not over invest in storm hardening.

■ TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.

■ The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.

■ The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys. This reinforces that TEC's plan is prudent and making hardening investments that provide customer

1   benefits.

2   ■ TEC's mix of hardening investment strikes a

3   balance between investment in the substations and

4   transmission system targeted mainly at increasing

5   resilience for the high impact / low probability

6   events and investment in the distribution system,

7   which is impacted by all ranges of event types.

8   ■ The hardening investment will provide additional

9   'blue sky' benefits to customers not factored into

10   this report. From a storm hardening perspective

11   alone, the hardening investment types and overall

12   level are prudent providing maximum value to

13   customers. These 'blue sky' benefits just further

14   enhance the business case for TEC customers

15   On the whole, TEC's storm hardening plan benefits

16   assessment aligns with the requirements of the statue,

17   shows prudency in the overall investment level and where

18   hardening investment is focuses, provides maximum benefit

19   to customers, and shows significant benefits to customers

20   with a reasonable cost to buy down storm outages.

21

22   **8.   CONCLUSION**

23   **Q51. Does this conclude your prepared verified direct**

24   **testimony?**

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1   **A51.** Yes.

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