DUKE ENERGY
FLORIDA

Matthew R. Bernier
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Duke Energy Florida, LLC.

June 24, 2020

VIA ELECTRONIC FILING

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

Re: *Review of 2020-2029 Storm Protection Plan Pursuant to Rule 25-6.030, F.A.C. Duke Energy Florida, LLC; Docket No. 20200069-EI*

Dear Mr. Teitzman:

Please find attached for filing updated Exhibit Nos. ___(JWO-2) and __(JWO-4) to the direct testimony of Jay W. Oliver, filed April 10, 2020, and revised on April 14, 2020.

After the SPP filing was submitted, Guidehouse and DEF conducted follow-on working sessions to review model-generated circuit-level prioritization results as a part of the project pipeline development process. This process uncovered an isolated error in the extract-transform-load (ETL) routine which converted conductor data from the geographic information system (GIS) and asset management system data into cleaned and binned asset classes designated by wire size as well as branch vs. backbone that were then used in the model. The Guidehouse team had originally assigned existing 795-size conductors on the backbone as eligible to be upgraded as part of the Feeder Hardening program. A related text string parsing issue was also identified and fixed for branch conductors, impacting the Lateral Hardening program. This caused certain circuits to be prioritized in the model when in fact they already contained upgraded conductors and, thus, should have been prioritized lower than they were. It also caused an overestimation of the reduction in CMI and annual estimated restoration costs. These issues have now been addressed, and the resulting corrected results updated in the attached exhibits.

The overall impact of this change is a decrease in forecasted CMI reduction for the Feeder Hardening program, along with minimal decreases in forecasted CMI reductions for the Lateral Hardening, Self-Optimizing Grid, and Substation Hardening programs. Additionally, this update of the model also resulted in a minimal decrease in cost reductions for the Feeder Hardening and Lateral Hardening programs. Finally, the prioritization of work to be performed for the Feeder Hardening program has been adjusted as a result of the model update, which ensures the correct project selection for 2021.

As discussed in the Prioritization Methodology sections of Exhibit JWO-2, after receiving results from the Guidehouse model, DEF utilizes subject matter experts from the relevant business units to "use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability". This specific part of the process performed as intended and addressed the found issue as described above. As DEF works annually to develop discreet work for the upcoming year, it is expected that local subject matter expertise will continue to refine model recommendations.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

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MRB/mw
Enclosures

CERTIFICATE OF SERVICE
Docket No. 20200069-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to the following by electronic mail this 24th day of June, 2020, to all parties of record as indicated below.

/s/ Matthew R. Bernier
Attorney

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DUKE ENERGY

Storm Protection Plan

Florida

Program Descriptions

Contents

PROGRAM DESCRIPTIONS

The following sections of this document describe each of the Duke Energy Florida programs that are in the Storm Protection Plan (SPP). This exhibit includes the program vision, description, costs as well as estimated benefits from completion of the program.

Note: Shifts of scope may occur between years to optimize benefits delivery to customers and execution efficiencies.

At the Commission's direction and under its supervision, DEF has engaged in significant storm hardening activities since the 2006 adoption of the Storm Hardening Rule (Rule 25-6.0342, F.A.C., now proposed for repeal due to the adoption of § 366.96, Fla. Stat., and subsequent adoption of Rule 25-6.030, F.A.C.). After the 2016/2017 storm seasons, the Commission initiated its "Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018"[1] to evaluate the efficacy of the approximately 12 years of hardening efforts. As a result of the analysis performed in that docket, the Commission determined that "Florida's aggressive storm hardening programs are working."[2] This conclusion was borne out by several observations: the length of outages the 2016/2017 storm outages was reduced markedly from the 2004-2005 storm season, hardened overhead distribution facilities performed better than non-hardened facilities, and underground facilities performed much better than overhead facilities.[3]

DEF agrees with the Commission's determination. In recognition of the efficacy of the storm hardening plans implemented since 2006, DEF's Storm Protection Plan ("SPP") carries on the storm hardening work included in the Company's recently approved 2019-2021 Storm Hardening Plan ("SHP); as such, the programs that are being carried over from the SHP into the SPP are the very programs the Commission has previously acknowledged "are grounded in substantive strengthening and protection of the utility's electric facilities. Programs include tree trimming, pole inspections, hardening of feeders and laterals, and undergrounding."[4] DEF's plan will continue these programs and build upon them, adding incremental investment over the life of the Plan. DEF will also continue researching and investigating additional technologies and programs.

That said, DEF also agrees with the Commission's recognition that "[n]o amount of preparation can eliminate outages in extreme weather events" so while DEF's Plan is designed with an eye toward strengthening the system and reducing outages and outage duration, it must be understood that there is no panacea and individual storms will produce unique challenges.

[1] Docket No. 20170215-EU.
[2] *Id.* at p. 1.
[3] *See id.* at pp. 2-3.
[4] *See id.* at p. 9.

Distribution Programs

Florida

Program Summaries

Feeder Hardening Program Description

Vision

Feeder Hardening is a long-term program that will systematically upgrade the feeder backbone to meet the NESC 250C extreme wind load standard. The existing backbone is approximately 6,300 miles on 1,325 feeders.

Description

The Feeder Hardening program will enable the feeder backbone to better withstand extreme weather events. This includes strengthening structures, updating BIL (basic insulation level) to current standards, updating conductor to current standards, relocating difficult to access facilities, replacing oil filled equipment as appropriate, and will incorporate the company's pole inspection and replacement activities.

Structure Strengthening

Structure strengthening includes upgrading existing poles and other facilities as necessary to align with meeting the NESC 250C extreme wind load standard. For example, a stronger pole class reduces the extent of damage incurred on feeder lines during extreme wind events. Other related hardware upgrades will occur simultaneously, such as insulators, crossarms, support brackets, and guys.

BIL

While upgrading feeders to the extreme wind load standard, the company will also upgrade the BIL to further harden the system. Upgrading the BIL involves framing for more space between phases, more wood material between insulator mounting points, application of the larger standard insulator sizes, and moving arresters to the lowest level of the primary space.

Conductor Upgrades

As part of Feeder Hardening, DEF will replace any deteriorated or undersized conductor on the feeder backbone. This conductor is more susceptible to storm damage. It will be replaced with our current standard conductor.

Relocating Difficult to Access Facilities

Where practical, feeder sections that traverse hard to access areas, such as wetlands, will be relocated to truck-accessible routes. These line sections often suffer damage in extreme wind load events and, due to their location, are among the most expensive and longest to restore outages.

Replacing Oil-Filled Equipment

While working to upgrade each feeder, hydraulic (oil-filled) reclosers will be upgraded to electronic reclosers (vacuum interrupters) with communications and remote SCADA control capability, as available. Electronic reclosers enable remote visibility and control. Real-time operational information is remotely available, such as current per phase, voltage per phase, var flow per phase, health condition of the device, on-board battery health, fault information, and interrupter status by phase. This real-time data will help target restoration efforts helping to reduce outage durations. Additionally, these oil-filled devices can cause negative environmental impacts. Electronic reclosers are vacuum interruption devices and have no internal oil.

Figure 1: SCADA enabled Electronic Recloser

Pole Inspection and Replacement

PER FPSC Order, pole inspection is performed on an 8-year cycle. These inspections determine the extent of pole decay and any associated loss of strength. The information gathered from these inspections is used to determine pole replacements and to effectuate the extension of pole life through treatment and reinforcement.

Cost

It is expected that the 10-year cost will be approximately $1.5B Capital and $73M O&M. This would cover approximately 1,500 miles of feeder hardening and costs of the pole inspection and replacement activities.

	DEF		
Feeder Hardening	**2020**	**2021**	**2022**
Totals	$ -	$ 62,400,005	$ 111,365,448
Feeder Hardening	$ -	$ 62,400,005	$ 93,600,008
Capital	$ -	$ 60,000,000	$ 90,000,000
O&M	$ -	$ 2,400,005	$ 3,600,008
Total Units	0	63	95
Pole Inspection/Replacement*	$ -	$ -	$ 17,765,440
Capital	$ -	$ -	$ 15,629,040
O&M	$ -	$ -	$ 2,136,400
Total Units	0	0	1,680

**Pole Inspection and Replacement details for years 2020 and 2021 are included in Exhibit JWO-1. Beginning in 2022 these activities will be incorporated into the Feeder Hardening Program.*

Cost Benefit Comparison

The Feeder Hardening Program will begin in 2021 and is estimated to take 30 years to complete. Based on today's cost, the program will cost an estimated $6B in Capital and $239M in Project O&M. At completion, approximately 6,300 feeder miles will be hardened.

When the Feeder Hardening Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Distribution system by approximately $13M to $16M annually based on today's costs. This represents a reduction of approximately 6% to 8% when compared to the average of 2016 to 2019 Distribution Major Event Day (MED) costs.

When the Feeder Hardening Program is complete, DEF estimates it will reduce Distribution MED Customer Minutes Interrupted (CMI) by approximately 91 million to 113 million minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Prioritization Methodology

Work will be prioritized using the following process.

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and Sea, Lake, and Overland Surges from Hurricanes (SLOSH) models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.
2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g., each pole, or segment of conductor on a feeder), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each feeder and the hardened configuration resulting from the

particular program. The difference between the existing condition and the hardened configuration is the program impact.

3. Distribution subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Lateral Hardening

Vision

Lateral Hardening is a long-term program that will systematically upgrade and harden branch line sections fed by the feeder backbone. There will be two main approaches, undergrounding and overhead hardening. The existing lateral system is approximately 11,800 miles on 1,325 feeders.

Description

The Lateral Hardening program will enable branch lines to better withstand extreme weather events. This will include undergrounding of the laterals most prone to damage during extreme weather events and overhead hardening of those laterals less prone to damage.

Lateral Undergrounding

Lateral segments that are most prone to damage resulting in outages during extreme weather events will be placed underground. Doing so will greatly reduce both damage costs and outage duration for DEF customers. Lateral Undergrounding focuses on branch lines that historically experience the most outage events, contain assets of greater vintage, are susceptible to damage from vegetation, and/or often have facilities that are inaccessible to trucks. These branch lines will be replaced with a modern, updated, and standard underground design of today.

Figure 1: An example of residential customers that would be candidates for Undergrounding due to section of line and service in heavily vegetated areas.

Figure 2: Section of lines that runs through backlot and heavily vegetated areas will be underground.

Lateral Hardening Overhead

The overhead hardening strategy will include structure strengthening, deteriorated conductor replacement, removing open secondary wires, replacing fuses with automated line devices, pole replacement (when needed), line relocation, and/or hazard tree removal.

Figure 3: The teal tap line branches off the main road through an open lot to side streets where it splits again. It serves a few customers with minimal, to no vegetation. The street view is a view of the red line where there are no vegetation concerns.

Structure Strengthening

Structure Strengthening includes upgrading existing poles and other facilities as necessary to align with the NESC 250C extreme wind loading standard. For example, a stronger pole class reduces the extent of damage incurred on lateral lines during extreme wind events. Other related hardware upgrades will occur simultaneously, such as installation of insulators, crossarms, support brackets, and guys.

Conductor Upgrades

As part of Lateral Hardening Overhead, DEF will replace any deteriorated or undersized conductor on the lateral. This conductor is more susceptible to storm damage. It will be replaced with our current standard conductor.

Upgrade Open Wire Secondary

Removing the open secondary wire will mitigate outages during extreme weather conditions. This activity will eliminate an older design standard that is susceptible to wires contacting vegetation and debris. Modern triplex cable will be installed to replace the open wire secondary.

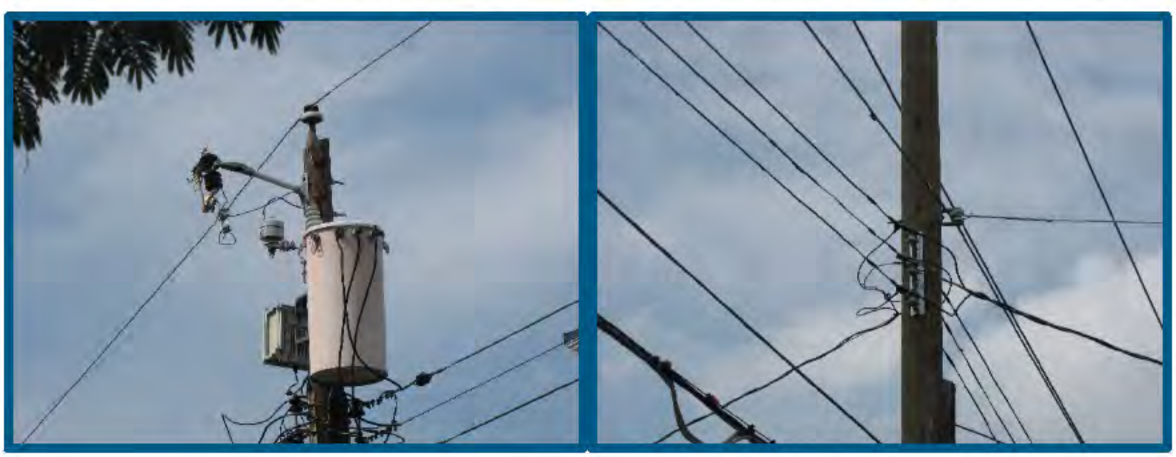


Figure 4: Three examples of open wire secondary that will be addressed

Fusing

DEF will replace current one-time use fuses with automated line devices (ALDs), which are small vacuum reclosers, to improve lateral performance in extreme weather events. ALDs use current fuse holders and do not generally require pole reframing. The reclosing capability inherent in the ALD will reduce outage events for downstream customers. ALDs will also serve as the temporary fault clearing device, thus reducing momentary interruptions for customers upstream on the feeder.

Figure 5: Installed ALD.

Line Relocation

Where practical, lateral line sections that traverse hard to access areas, such as wetlands, will be relocated to truck accessible routes. These line sections often suffer damage in extreme wind load events, and due to their location are among the most expensive to repair and take the longest to restore to service from an outage.

Hazard Tree

During the upgrade process DEF will identify hazard trees in the area surrounding the lateral requiring remediation. A hazard tree is a tree that is dead, structurally unsound, dying, diseased, leaning, or otherwise in a condition that is likely to result in striking electrical lines or other assets. Once identified, hazard trees are assigned to a contractor for remediation. When hazard trees are located in areas where DEF does not have the legal right to mitigate the danger, DEF or its contractor will work with the property owner to gain access and remediate.

Pole Inspection and Replacement

Per FPSC Order, pole inspection is performed on an 8-year cycle. These inspections determine the extent of pole decay and any associated loss of strength. The information gathered from these inspections is used to determine pole replacements and to effectuate the extension of pole life through treatment and reinforcement.

Cost

It is expected that the 10-year cost will be approximately $2.2B Capital and $66M O&M. This would cover approximately 1,500 miles of Lateral Hardening Underground, approximately 1,400 miles of Lateral Hardening Overhead, and costs of the pole inspection and replacement activities.

	DEF		
Lateral Hardening	**2020**	**2021**	**2022**
Totals	$ -	$ -	$ 187,320,107
Lateral Hardening	$ -	$ -	$ 141,637,547
Capital	$ -	$ -	$ 140,000,000
O&M	$ -	$ -	$ 1,637,547
Total Units	0	0	207
Pole Inspection/Replacement*	$ -	$ -	$ 45,682,560
Capital	$ -	$ -	$ 40,188,960
O&M	$ -	$ -	$ 5,493,600
Total Units	0	0	4,320

**Pole Inspection and Replacement details for years 2020 and 2021 are included in Exhibit JWO-1. Beginning in 2022 these activities will be incorporated into the Lateral Hardening Program.*

Cost Benefit Comparison

The Lateral Hardening Program will begin in 2022 and is estimated to take 30 years to complete. Based on today's cost, the program will cost an estimated $7.9B in Capital and $92M in Project O&M. At completion, approximately 11,800 lateral miles will be hardened.

When the Lateral Hardening Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Distribution system by approximately $91M to $114M annually based on today's costs. This represents a reduction of approximately 44% to 55% when compared to the average of 2016 to 2019 Distribution MED costs.

When the Lateral Hardening Program is complete, DEF estimates it will reduce Distribution MED CMI by approximately by 378 million to 472 million minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Prioritization Methodology

The following steps are used to prioritize the work:

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.
2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g. each pole, or segment of conductor on a feeder), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each feeder, and the hardened configuration resulting from the particular program. The difference between the existing condition and the hardened configuration is the program impact.
3. Distribution subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

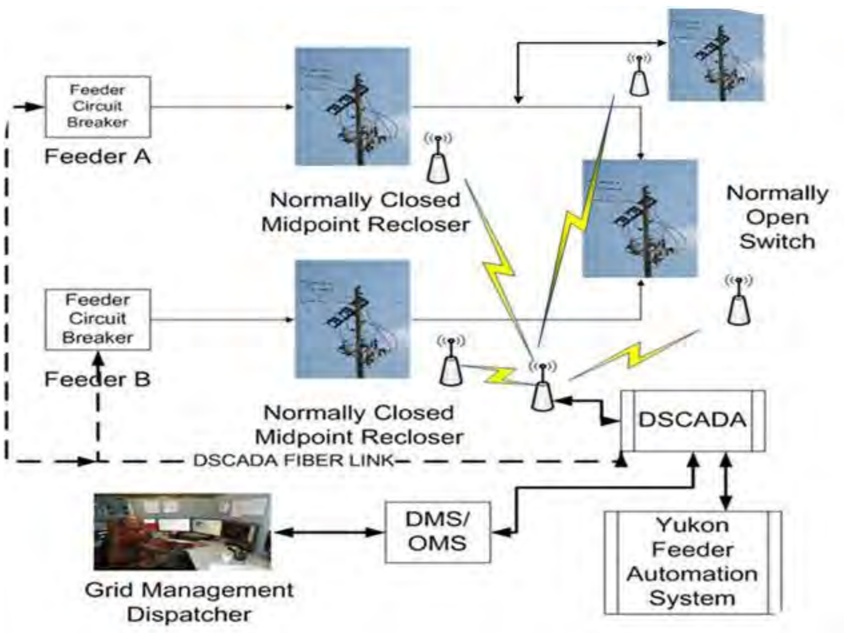
Self-Optimizing Grid – SOG

Vision

The SOG program started as part of DEF's Grid Investment Plan which was partially funded through the 2017 Revised and Restated Settlement Agreement. DEF plans to continue this program through the SPP and at completion in 2027, approximately 80% of the distribution feeders on the DEF system will have the ability to automatically reroute power around damaged line sections. 100% of the distribution feeders will have automated switching capability.

Description

The current grid has limited ability to reroute and rapidly restore power. The SOG program is established to address both of these issues.



The SOG program consists of three (3) major components: capacity, connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing network. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent on affected feeders.

The **SOG Capacity projects** focus on expanding substation and distribution line capacity to allow for two-way power flow. **SOG Connectivity projects** create tie points between circuits. **SOG Automation projects** provide intelligence and control for the SOG operations; Automation projects enable the grid to dynamically reconfigure around trouble and restore customers not impacted by an outage.

Cost

The SOG program is planned to be complete in 2027. Below are the projected units and costs for 2020-2022:

	DEF		
Self-Optimizing Grid (SOG)	2020	2021	2022
Totals	$ 56,483,391	$ 81,269,879	$ 76,500,000
Automation	$ 35,611,138	$ 56,911,355	$ 45,900,000
Capital	$ 34,860,275	$ 55,795,446	$ 45,000,000
O&M	$ 750,863	$ 1,115,909	$ 900,000
Total ASD's	580	851	686
Connectivity & Capacity	$ 20,872,253	$ 24,358,525	$ 30,600,000
Capital	$ 20,541,619	$ 23,880,906	$ 30,000,000
O&M	$ 330,634	$ 477,618	$ 600,000

Cost Benefit Comparison

Costs from 2020 through 2027 are approximately $550M capital and $11M O&M.

At completion, with more customers automatically restored through automated switching, cost reductions can be achieved through better targeting of restoration efforts and personnel. SOG enables the grid to rapidly reroute power around damaged line sections. Accordingly, the benefit from the completion of this program is a reduction in customers affected by long duration outages as a result of extreme weather events and enhancement of overall reliability via anticipated decrease in CMI.

When the SOG Program is complete, DEF estimates it will reduce Distribution MED CMI by approximately by 197 million to 247 million minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Prioritization Methodology

The following steps are used to prioritize the work:

1. Probability of Damage: While SOG does not directly reduce damage but rather is intended to reduce the duration of outages, SOG impacts are conservatively assessed after other hardening projects. Since other hardening projects reduce equipment failures and outages, the simulated SOG impacts are evaluated against this new hardened baseline. To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.

2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g., each pole, or segment of conductor on a feeder), observed outage durations, the mix of customers, and critical facilities. For SOG, this step is performed based on the hardened configuration of the feeder after completion of the Feeder Hardening program (see above for a description of the Feeder Hardening program).
3. Consequence of Automation: Because the program benefits are tied to reduction in outage length and customers affected during outages, these values were calculated as a part of the simulation described in steps 1 and 2, with the addition of SOG automation. The outage time reduction varied feeder by feeder, based on number of customers served, historic observed outage durations by asset class on each feeder, the reduction impact of feeder hardening on the feeder, and current level of automation.
4. Distribution subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Underground Flood Mitigation

Vision

The Underground Flood Mitigation program is a targeted program to harden existing underground distribution facilities in locations that are prone to storm surge during extreme weather events. This program will address the areas identified as being at high risk for significant flooding by installing submersible equipment within 20 years.

Description

Underground Flood Mitigation will harden existing underground line and equipment to withstand a storm surge through the use of DEF's current storm surge standards. This involves the installation of specialized stainless-steel equipment and submersible connections. The primary purpose of this hardening activity is to minimize the damage caused by a storm surge to the equipment and thus reduce customer outages and/or expedite restoration after the storm surge has receded.

For selected locations, DEF would raise any pad mount transformer currently in an area that is prone to storm surge onto an elevated pad and change all the connections to waterproof (submersible) connections. Conventional switchgear would be replaced with submersible switchgears that are able to withstand the storm surge.

Cost

It is expected that the 10-year cost will be approximately $11M.

	DEF		
UG Flood Mitigation*	**2020**	**2021**	**2022**
Totals	**$ -**	**$ -**	**$ 500,000**
Capital	$ -	$ -	$ 500,000
O&M	$ -	$ -	$ -

Cost Benefit Comparison

The Underground Flood Mitigation Program is scheduled to start in 2022 and estimated to take 20 years to complete. Based on today's cost, the program will cost an estimated $26M in Capital.

When the Underground Flood Mitigation Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Distribution system by approximately $1M to $1.4M annually based on today's costs. This represents a reduction of approximately 1% when compared to the average of 2016 to 2019 Distribution MED costs.

When the Underground Flood Mitigation Program is complete, DEF estimates it will reduce Distribution MED CMI by approximately 500,000 to 650,000 minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Prioritization Methodology

Work will be prioritized using the following process.

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.
2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g., each pole, or segment of conductor on a feeder), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each feeder, and the hardened configuration resulting from completion of the program. The difference between the existing condition and the hardened configuration is the program impact.
3. Distribution subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Distribution Vegetation Management

Vision

DEF will continue to utilize a fully Integrated Vegetation Management (IVM) to minimize the impact of vegetation on the distribution assets.

Description

DEF Distribution will continue a fully IVM program focused on trimming feeders and laterals on an average 3 and 5-year cycles respectively. This corresponds to trimming approximately 1,930 miles of feeder backbone and 2,455 miles of laterals annually. The IVM program consists of the following: routine maintenance “trimming”, hazard tree removal, herbicide applications, vine removal, customer requested work, and right-of-way brush “mowing” where applicable. The IVM program incorporates a combination of both cycle-based maintenance and reliability-driven prioritization of work to reduce event possibilities during extreme weather events and enhance overall reliability.

Additionally, a hazard tree patrol is conducted every year on all three-phase circuits. Hazard trees are defined as trees that are dead, dying, structurally unsound, diseased, leaning or otherwise defective. The trees that are located within the right of way are removed prior to hurricane season each year, hazard trees that are located outside the right of way require landowner permission prior to removal. The contact with the landowner is initiated, permission for removal and the removal is also targeted for completion prior to hurricane season. If a feeder circuit is relocated or circuit height changes, an additional hazard tree assessment will be conducted in the line segments that will be impacted.

DEF will optimize the IVM program costs against reliability and storm performance objectives to harden the system for extreme weather events. There are four key objectives for optimization:

- Customer and employee safety;
- Tree-caused outage minimization, with the objective to reduce the number of tree-caused outages, particularly in the “preventable” category;
- Effective cost management; and
- Customer satisfaction.

Cost

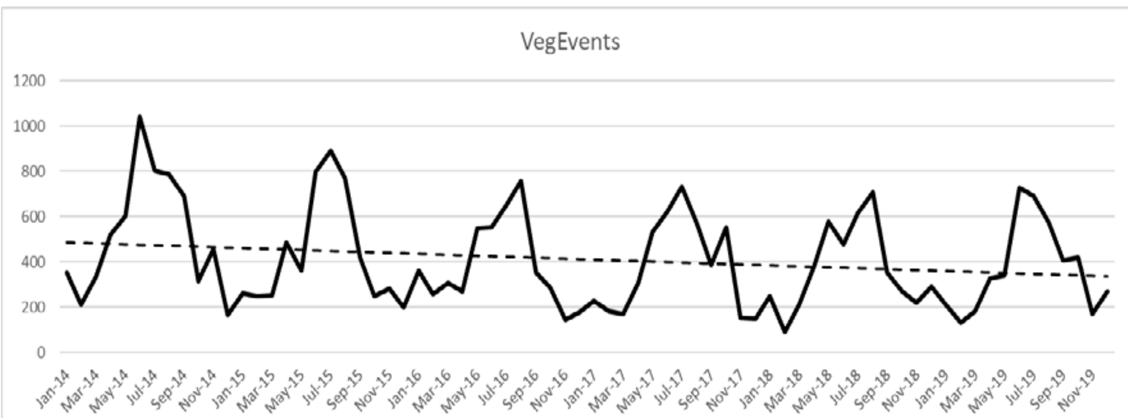
It is expected that the 10-year cost will be approximately $20M Capital and $477M O&M. This would cover the inspection and vegetation remediation activities. The circuit maintenance work performed is predominantly billed under a unit-based contract structure and not differentiated between labor and equipment. The estimated contractor ratio is 95%. The estimated utility personal ratio is 5%.

2020 -2022 Labor / Equipment Breakout		
	Labor	Equipment
Utility Personnel Totals	$ 6,557,823	$ 202,819
Capital	$ 1,132,128	$ 35,014
O&M	$ 5,425,695	$ 167,805
Contract Personnel Totals	$ 97,703,126	$ 32,187,368
Capital	$ 3,092,319	$ 1,030,773
O&M	$ 94,610,807	$ 31,156,595

	DEF		
VM - Distribution*	2020	2021	2022
Totals	$ 46,398,605	$ 44,477,139	$ 45,775,391
Capital	$ 1,499,298	$ 1,867,457	$ 1,923,480
O&M	$ 44,899,307	$ 42,609,682	$ 43,851,911
Approximate Miles	5,209	4,383	4,383

**Costs for 2021 and 2022 are based on an average of 1/3 of feeder mileage and 1/5 of lateral mileage being patrolled and remediated.*

Cost Benefit Comparison



DEF's Distribution IVM program is focused on ensuring the safe and reliable operation of the distribution system by minimizing vegetation-related interruptions and ensuring adequate conductor-to-vegetation clearances, while maintaining compliance with regulatory, environmental and safety requirements/standards. The chart above shows a reduction in vegetation related outage events over the past 5 years and demonstrates the effectiveness of the IVM program. Activities focus on the removal and/or control of incompatible vegetation within and along the right of way to minimize the risk of vegetation-related outages.

Prioritization Methodology

As part of the IVM program, DEF uses a comprehensive circuit prioritization model to minimize tree-caused outages by focusing on the feeders and or laterals that rate high in the model. Prioritization ranking factors are based on past feeder or lateral performance and probable future performance. Examples of the criteria used in prioritization include tree-caused outages in prior years, outages per vegetated mile, and total tree customer minutes of interruption. Utilizing this prioritized process, DEF follows the ANSI 300 standard for pruning and the guide "Pruning Trees Near Electric Utility Lines" by Dr. Alex L. Shigo.

Transmission Programs

Florida

Program Summaries

Structure Hardening

Vision

The Structure Hardening program focuses on DEF's transmission structures throughout the state. As part of the program, all wood poles on the Florida transmission system will be replaced with non-wood structures within 15 years. In addition, Structure Hardening will upgrade lattice tower structure types that have failed during extreme weather and/or fail inspection.

Description

The Transmission Structure Hardening program addresses existing vulnerabilities on the system. This will enable the transmission system to better withstand extreme weather events. This program includes wood to non-wood upgrades, tower upgrades, adding cathodic protection, automating gang operated air break switches, Overhead Groundwire upgrades, and structure inspections.

Figure 1: Wood Pole to Non-Wood Upgrade candidate

Wood to Non-Wood Upgrade

This activity will upgrade wood poles to non-wood material such as steel or concrete. Wood pole failure has been the predominate structure damage to the transmission system during extreme weather. This strengthens structures by eliminating damage from woodpeckers and wood rot. The new structures will be more resistant to damage from extreme weather events. Other related hardware upgrades will occur simultaneously, such as insulators, crossarms, switches, and guys. This will upgrade an identified 20,520 wood poles.

Tower Upgrade

Tower Upgrade will prioritize towers based on inspection data and enhanced weather modeling. The upgrade activities will replace tower types that have previously failed during extreme weather events. Over 700 towers have been identified as having this design type.

In addition, the tower upgrade activities will upgrade lattice towers identified by visual ground inspections, aerial drone inspections and data gathered during cathodic protection installations (discussed below). This will improve the ability of the transmission grid to sustain operations during extreme weather events by reducing outages and improving restoration times. Other related hardware upgrades will occur simultaneously such as insulators, cathodic protection, and guys.

Figure 2: Double Circuit Tower

Cathodic Protection

The purpose of the Cathodic Protection (CP) activities will be to mitigate active groundline corrosion on the lattice tower system. This will be done by installing passive CP systems comprised of anodes on each leg of lattice towers. The anodes serve as sacrificial assets that corrode in place of structural steel, preventing loss of structure strength to corrosion. Each CP project will address all towers on a line from beginning point to end point.

The following tangible benefits will be gained related to hardening the lattice system:

- <u>Site Classification</u> - Subsurface investigation and cathodic protection installation on all lattice structures, prioritizing lines based on system criticality, age, and potential storm impact. Galvanization and member thickness measurements will be taken on all legs and diagonals, and structural steel will be classified by corrosion severity. Concrete piers will be classified on concrete health, cracking, and rebar corrosion. This system evaluation will identify any potential weak spots resulting from ground line corrosion on DEF's lattice system.

- <u>Corrosion Mitigation</u> – Each lattice-structure tower leg will have cathodic protection installed on it in order to arrest the corrosion process.

- <u>Corrosion Database</u> – Soil conditions recorded at each tower site will include resistivity, soil pH, redox, and half-cell potentials. These values will be saved into a database which will be used to help classify areas of DEF's system prone to corrosion. This information will be used to aid in condition-based maintenance of system infrastructure.

Gang Operated Air Break (GOAB)

The GOAB line switch automation project is a 20-year initiative that will upgrade 305 switch locations with modern switches enabled with SCADA communication and remote-control capabilities. Automation will add resiliency to the transmission system. Later years will include adding new switch locations to add further resiliency to the transmission system. Transmission line switches are currently manually operated and cannot be remotely monitored or controlled. Switching, a grid operation often used to section off portions of the transmission system in order to perform equipment maintenance or isolate trouble spots to minimize impacts to customers, has historically required a technician to go to the site and manually operate one or more-line switches. The GOAB upgrade increases the number of remote-controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults.

Figure 3: DEF Manually Operated Switch

Overhead Ground Wire (OHGW)

Florida is known for a high concentration of lightning events, which continually stress the existing grid protection. Deteriorated overhead ground wire reduces the protection of the conductor and exposes the line to repeated lightning damage and risk of failure impacting the system. This initiative will also reduce the safety risk due to the required removal of OHGW prior to any restoration work on the system. By targeting deteriorated OHGW on lines with high lightning events, the benefit of this activity will be maximized. An added benefit is upgrading to fiber optic OHGW, facilitating high-speed relaying and enhanced communication and control between stations and centralized control centers.

Structure Inspections and Drone Inspections

The transmission system's inspection activities include all types of structures, line hardware, guying, and anchoring systems. Inspections include:

- Aerial helicopter Transmission Line Inspections
- Wood Pole Line Patrols
- Wood Pole Sound and Bore Line Patrol – 8-year cycle
- Non-wood Structure Line Patrols – 6-year cycle

Further, in 2021 DEF will conduct drone inspections on targeted lattice tower lines. The intent of this additional inspection is to identify otherwise difficult to see structure, hardware, or insulation vulnerabilities through high resolution imagery. DEF is incorporating drone patrols into the inspections because drones have the unique ability to provide a close vantage point with multiple angles on structures that is unattainable through aerial or ground patrols with binoculars.

Cost

DEF estimates the 10-year cost will be approximately $1.3B Capital and $41M O&M, and will entail approximately:

- 12,000 wood to non-wood poles;
- 400 tower replacements;
- CP protection for all towers;
- 100 GOABs;
- 500 miles of OHGW; and
- system inspection cycles, ground and aerial.

	DEF		
Structure Hardening*	2020	2021	2022
Totals	$ -	$ 41,395,564	$ 136,259,137
Capital	$ -	$ 40,000,000	$ 132,250,000
O&M	$ -	$ 1,395,564	$ 4,009,137
Total Units	0	521	1,482

**Pole and tower Inspection and Replacement details for years 2020 and 2021 are included in Exhibit JWO-1. Beginning in 2022 these activities will be incorporated into the Structure Hardening Program.*

Cost Benefit Comparison

The Structure Hardening Program will begin in 2021 and is estimated to take 30 years to complete. Based on today's cost, the program is estimated to cost $2.6B in Capital and $71M in Project O&M. At completion, approximately:

- 20,520 wood to non-wood poles;
- 720 tower replacements;
- CP protection for all towers;
- 305 GOABs;
- 4,300 miles of OHGW; and
- System inspections.

When the Structure Hardening Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Transmission system by approximately $19M to $24M annually based on today's costs. This represents a reduction of approximately 38% to 48% when compared to the average of 2016 to 2019 Transmission MED costs.

When the Structure Hardening Program is complete, DEF estimates it will reduce Transmission MED CMI by approximately 13 million to 16 million minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Transmission system damage can result in severe consequences in both cost and outage duration. The estimation of benefits represents an annual average expected value based on historical data and does not represent what could happen in individual events or scenarios in which severe damage occurs on critical parts of the Transmission system.

Prioritization Methodology

Work will be prioritized using the following processes:

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.
2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g. each pole, or segment of conductor on a line), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each asset, and the hardened configuration resulting from completion of the Program. The difference between the existing condition and the hardened configuration is the program impact.
3. Transmission subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Substation Flood Mitigation

Vision

Substation Flood Mitigation is a targeted program upgrading 20 sites identified as being at risk for significant flooding during extreme weather events.

Description

The Substation Flood Mitigation program builds in protection for substations most vulnerable to flood damage using flood plain and storm surge data. It includes a systematic review and prioritization of substations at risk of flooding to determine the proper mitigation solution, which may include elevating or modifying equipment, or relocating substations altogether.

Flood mitigation will be a targeted application of mitigation measures for substations. New assets could include control houses, relays, or total station rebuilds to increase elevation, etc.

Cost

It is expected that the 10-year cost will be approximately $27M Capital. This would cover approximately 14 substations on the DEF system.

Cost Benefit Comparison

The Substation Flood Mitigation Program is scheduled to start in 2023 and estimated to take 15 years to complete. Based on today's cost, the program will cost an estimated $38M in Capital. At the completion of the program 20 targeted substations will be hardened with flood mitigation strategies.

When the Substation Flood Mitigation Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Transmission system by approximately $400,000 to $500,000 annually based on today's costs. This represents a reduction of approximately 1% when compared to the average of 2016 to 2019 Transmission MED costs.

When the Substation Flood Mitigation Program is complete, DEF estimates it will reduce Transmission MED CMI by approximately 9 million to 11 million annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Transmission system damage can result in severe consequences in both cost and outage duration. The estimation of benefits represents an annual average expected value based on historical data and do not represent what could happen in individual events or scenarios in which severe damage occurs on critical parts of the Transmission system.

Prioritization Methodology

Work will be prioritized using the following processes:

1. <u>Probability of Damage</u>: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be

derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.

2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g. each pole, or segment of conductor on a line), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each asset, and the hardened configuration resulting from completion of the program. The difference between the existing condition and the hardened configuration is the program impact.
3. Transmission subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Loop Radially-Fed Substations

Vision

The Loop Radially-Fed Substation program will convert radially-fed substations to networked substations. The targeted program will address approximately 20 sites over 20 years.

Description

The Loop Radially-Fed Substations program builds a more resilient and networked transmission system by creating a secondary feed into substations that are more likely to experience long outage durations during extreme weather events. As part of the construction of the additional feed, other assets could include equipment such as breakers, switches, bus work, structures, insulators, potential transformers, lightning arresters, relays, control houses.

Cost

The estimated 10-year cost will be approximately $52M. This would cover approximately 5 substations on the system.

Cost Benefit Comparison

The Loop Radially-Fed Substations Program is scheduled to start in 2025 and estimated to take 20 years to complete. Based on today's cost, the program will cost an estimated $206M in Capital. At the completion of the program 20 targeted substations will be addressed.

When the Loop Radially-Fed Substations Program is complete, it will provide an alternate source of power to limit interruptions experienced by customers.

When the Loop Radially-Fed Substations Program is complete, DEF estimates it will reduce Transmission MED CMI by approximately 450,000 to 600,000 minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Transmission system damage can result in severe consequences in both cost and outage duration. The estimation of benefits represents an annual average expected value based on historical data and do not represent what could happen in individual events or scenarios in which severe damage occurs on critical parts of the Transmission system.

Prioritization Methodology

Work will be prioritized using the following processes:

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining

simulated weather patterns with historical asset failure through conditional probability methods.

2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g. each pole, or segment of conductor on a line), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each asset, and the hardened configuration resulting from program completion. The difference between the existing condition and the hardened configuration is the program impact.
3. Transmission subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Substation Hardening

Vision

The Substation Hardening Program started as part of DEF's Grid Investment Plan which was partially funded through the 2017 Revised and Restated Settlement Agreement. DEF plans to continue this program through the SPP. The Substation Hardening program will focus on upgrading oil breakers and electromechanical relays. The program will eliminate 443 oil breakers within 10 years. This program will also upgrade approximately 1,237 electromechanical relay groups to electronic relays to properly isolate line faults and reduce storm restoration duration by automating fault identification within 20 years.

Description

Substation Hardening will address two major components.:1) Upgrading oil breakers to state-of-the-art gas or vacuum breakers to mitigate the risk of catastrophic failure and extended outages during extreme weather events; and 2) Upgrading electromechanical relays to digital relays will provide communications and enable DEF to respond and restore service more quickly from extreme weather events.

Breaker Upgrades

Replacing oil circuit breakers with state-of-the-art breakers will result in the transmission system being able to more effectively and consistently isolate faults, reclose after momentary interruptions, and improve the customer experience through fewer interruptions. Oil circuit breakers are more unreliable than gas or vacuum breakers, especially in circumstances where they are operating numerous times over a short period, such as during extreme weather events. When oil circuit breakers are repeatedly called to operate, they can generate arcing gasses within the oil tank that can accumulate and result in catastrophic failure. Existing vintage oil breakers are less reliable when isolating line faults and can contribute to increased and longer customer outages when there is a failure.

Electronic Relays

The Electronic Relay upgrades eliminate noncommunicating electromechanical and solid-state relays with digital relays. Upgrading to modern relay designs with communication capabilities and microprocessor technologies will enable quicker restoration from outage events. Another benefit is increased overall system intelligence, which will improve restoration planning. One digital relay replaces a variety of legacy single-function electromechanical relays. Two-way communications and event recording capabilities allow them to provide device performance information following a system event to support continuous system design and operational improvements.

Grid automation will be implemented to reduce duration and impacts from system issues. Digital relays will be installed to add remote monitoring and operations to key assets, which allows for rapid service response and better protection and monitoring of equipment during extreme weather events. Restoration times will be reduced due to remote monitoring and control which will allow quicker pinpointing and resolution of issues.

Cost

The estimated 10-year cost for Substation Hardening Program is expected be approximately $109M Capital.

This would upgrade all oil filled breakers and approximately 600 relay groups on the DEF system.

	DEF		
Substation Hardening	**2020**	**2021**	**2022**
Totals	$ 5,004,000	$ 5,500,000	$ 7,500,000
Capital	$ 5,004,000	$ 5,500,000	$ 7,500,000
O&M	$ -	$ -	$ -
Total Units	26	29	39

Cost Benefit Comparison

The Substation Hardening Program is estimated to take 20 years to complete. Based on today's cost, the program will cost an estimated $199M in Capital.

When the Substation Hardening Program is complete, DEF estimates it will reduce the cost of extreme weather events on the Distribution system by approximately $70,000 to $90,000 annually based on today's costs.

When the Substation Hardening Program is complete, DEF estimates it will reduce Distribution MED CMI by approximately 14 million to 17 million minutes annually. CMI reduction is used as a proxy for reduction in extreme weather event duration for the average customer.

Transmission system damage can result in severe consequences in both cost and outage duration. The estimation of benefits represents an annual average expected value based on historical data and do not represent what could happen in individual events or scenarios in which severe damage occurs on critical parts of the Transmission system.

Prioritization Methodology

Work will be prioritized using the following processes:

1. Probability of Damage: To prioritize the work in the Florida regions, the Transmission and Distribution systems were modeled, and weather simulations were run to provide probabilistic exposure frequency for all asset locations. The weather modeling uses the FEMA Hazus and SLOSH models, which contain the weather data for storms over the last 200 years. Using the geographical locations of the Florida assets and the historic storm paths embedded in the Hazus model, a spatial correlation of future storm exposure can be derived. To determine probability of damage given that exposure, six years of historical outage data was provided and correlated with the closest weather tower to determine the conditions during historic failures recorded in the outage data. Then, the expected quantities of asset failure for simulated future weather exposure conditions was derived by combining simulated weather patterns with historical asset failure through conditional probability methods.
2. Consequence of Damage: Once the output of probabilistic damage is assessed, the probable impact to customers is considered. This step considers number of customers served by a given asset (e.g. each pole, or segment of conductor on a line), observed outage durations, the mix of customers, and critical facilities. This step is performed both for the existing configuration of each asset, and the hardened configuration at project completion. The difference between the existing condition and the hardened configuration is the program impact.

3. Transmission subject matter experts then use these outputs to determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability.

Transmission Vegetation Management

Vision

DEF will continue to utilize Integrated Vegetation Management (IVM) to minimize the impact of vegetation on the transmission assets.

Description

DEF's Transmission IVM program is focused on ensuring the safe and reliable operation of the transmission system by minimizing vegetation-related interruptions and adequate conductor-to-vegetation clearances, while maintaining compliance with regulatory, environmental, and safety requirements or standards. The program activities focus on the removal and/or control of incompatible vegetation within and along the right of way to minimize the risk of vegetation-related outages and ensure necessary access within all transmission line corridors. The IVM program includes the following activities: planned threat and condition-based maintenance, reactive work that includes hazard tree mitigation, and brush management (herbicide, mowing, and hand cutting operation).

Transmission utilizes LIDAR to generate a threat/condition-based Vegetation Management plan. NERC lines (200kV and above) are flown every year. A fourth of non-NERC lines are currently flown each year. After 4 years all lines will have been flown. Threat triggers target clearing for 6+ years of growth. The LIDAR program targets the entire Transmission system of approximately 5,200 miles.

Cost

The estimated contractor ratio is 91.5%. The estimated utility personnel ratio is 8.5%.

2020 -2022 Labor / Equipment Breakout		
	Labor	Equipment
Utility Personnel Totals	$ 4,010,124	$ 167,089
Capital	$ 1,965,352	$ 66,835
O&M	$ 2,044,773	$ 100,253
Contract Personnel Totals	$ 30,545,624	$ 14,374,411
Capital	$ 15,159,336	$ 7,133,805
O&M	$ 15,386,288	$ 7,240,606

	DEF		
VM - Transmission	2020	2021	2022
Totals	$ 12,522,040	$ 17,228,315	$ 19,346,891
Capital	$ 4,469,073	$ 8,995,999	$ 10,860,255
O&M	$ 8,052,967	$ 8,232,316	$ 8,486,636
Approximate Miles	398	404	404

Cost Benefit Comparison

It is expected that the 10-year cost will be approximately $108M Capital and $90M O&M. This would cover the inspection and vegetation remediation activities.

The IVM program's planned threat and condition-based maintenance include danger tree identification and mitigation, reactive work that includes hazard tree mitigation, and brush management (herbicide, mowing, and hand cutting operation) to reduce event possibilities during extreme weather events and enhance overall system reliability.

Prioritization Methodology

Planned work for DEF is scheduled and prioritized through a manual process using the date of previous work activities as well as threats and conditions identified through patrols, inspections and assessments. As systems and technologies can be developed and implemented, DEF intends to leverage those technologies/systems and analytics to evaluate numerous variables coupled with local knowledge to optimize the risk-based planning and scheduling of work.

Revenue Requirements and Rate Impacts

Rule 25-6.030(3)(g): An estimate of the annual jurisdictional revenue requirements for each year of the Storm Protection Plan.

Estimated Annual Jurisdictional Revenue Requirements for Each Year of the Storm Protection Plan										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
($ Millions)	$ -	$ 8.8	$105.6	$169.3	$241.1	$320.4	$404.9	$486.2	$560.9	$632.2

Rule 25-6.030(3)(h): An estimate of rate impacts for each of the first three years of the Storm Protection Plan for the utility's typical residential, commercial, and industrial customers.

Estimated SPP Rate Impacts Residential $/1,000 kWh	2020	2021	2022
(1) Total SPP Estimated Rate	$0.00	$0.27	$3.28
(2) Less: Amounts Historically Recovered in Base Rates	$0.00	$0.00	$2.06
(3) SPP Rate Impact Less Base Reduction	$0.00	$0.27	$1.22
(4) Typical Commercial % Increase from 2020 Bill	0.0%	0.2%	2.0%-2.3%
(5) Typical Industrial % Increase from 2020 Bill	0.0%	0.2%-0.3%	1.6%-4.2%

Notes:

(1) DEF's 2017 Settlement Agreement ends at the end of 2021. In 2022 line (1) shows the total estimated SPP rate. It assumes all spend that has traditionally been recovered in base rates for Storm Hardening activities (vegetation management for example) is now recovered through the SPPCRC. Line (2) shows the offsetting reduction estimated in base rates. Line (3) is the net SPP impact.

(2) Commercial & Industrial % Increase does not consider base rate reduction due to shift of existing spend in base rates to the SPPCRC in 2022.

Storm Protection Plan Project for Duke Energy Florida

Final Report

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April 2020 (Revised June 2020)

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Disclaimer

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Executive Summary

Duke Energy Florida (DEF) engaged Guidehouse Inc. (Guidehouse or the project team)[1] to help develop the DEF Storm Protection Plan (SPP). The SPP seeks to strengthen DEF's electric grid infrastructure to withstand extreme weather conditions and enhance overall reliability.

Guidehouse assisted DEF with developing and refining its analytical methods of project selection and prioritization to help target the most cost-effective grid strengthening solutions. This document provides Guidehouse's recommendations for a strategic 10-year investment plan and corresponding detailed 3-year capital investment plan for DEF's SPP. Program assumptions related to impacted assets, costs, and expected benefits are provided to support the recommendations. The project team used a wide range of data sources—both from DEF and from publicly available studies and sources—to complete the analysis and to develop a detailed bottom-up simulation of program impacts. Guidehouse used these data sources and others to model the locational impacts of extreme weather conditions and the anticipated reduction in restoration costs and outage times used to develop SPP program and investment recommendations.

The recommended plan focuses on core programs deployed on the distribution grid, within substations, on the transmission grid, and for vegetation management. These programs and associated projects will cost-effectively prevent or reduce the impacts of extreme weather events to DEF customers while enhancing the overall reliability of the electric system across DEF's service area.

SPP Full Deployment

In 2020, DEF will file its SPP for strengthening the electric grid infrastructure to withstand extreme weather conditions and enhance reliability within its service area. Full deployment of many SPP programs will span beyond the 10-year timeline defined in DEF's SPP regulatory filing. Some of the individual programs—e.g., distribution lateral hardening—may require 20 to 30 years to complete. For this assessment, the Guidehouse project team regarded completion of 3-year and 10-year plans as milestones towards achieving the greater benefits of a longer-range, fully hardened state of the DEF electric system.

When fully deployed, the extreme weather protection and reliability improvements offered by the SPP will produce significant ongoing benefits to DEF customers. The annual average benefits expected from the SPP investments include expected avoided restoration costs and projected reduced customer minutes of interruption (CMI).

[1] Guidehouse LLP completed its acquisition of Navigant Consulting, Inc, in October 2019. The two brands are now combined as Guidehouse.

Table-ES 1 and Table-ES 2 highlight the average annual avoided restoration costs and CMI reductions, respectively, given the average expected storm frequency and the potential for elevated storm frequency.

Table-ES 1. Estimated Annual Avoided Restoration Costs for Fully Deployed SPP

	Average Storm Frequency		Elevated Storm Frequency	
Program Category	Estimated Annual Avoided Restoration Costs (2020 Dollars)	(% Reduction)	Estimated Annual Avoided Restoration Cost (2020 Dollars)	(% Reduction)
Distribution	$104.6 million	51%	$130.8 million	64%
Transmission	$18.6 million	37%	$23.2 million	47%
Vegetation Management	NA	NA	NA	NA

Notes: % Reduction represents modeled restoration cost savings relative to average storm restoration costs from 2016 through 2019. Storm frequency assumptions are provided in Appendix B.
Source: Guidehouse, Inc.

Table-ES 2. Estimated Annual CMI Reduction with Fully Deployed SPP

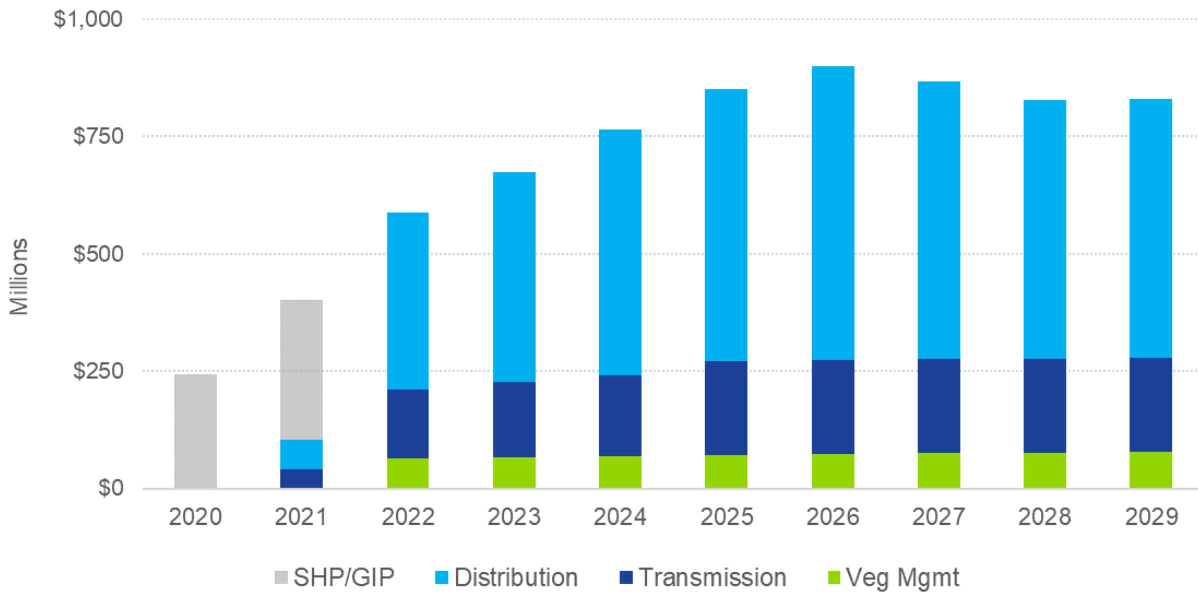
	Average Storm Frequency	Elevated Storm Frequency
Program Category	CMI Reduction Minutes	CMI Reduction Minutes
Distribution	666.6 million	833.2 million
Transmission	36.0 million	45.0 million
Vegetation Management	NA	NA

Notes: Storm frequency assumptions are provided in Appendix B.
Source: Guidehouse, Inc.

10-Year SPP Roadmap

DEF estimates a total investment of $6.4 billion in capital and associated O&M to deploy its proposed 10-year SPP. In this initial 10-year plan, SPP investments begin to ramp up in year 2 (2021) with additional investment in 2022 through 2029, as Figure-ES 1 depicts.

Figure-ES 1. SPP 10-Year Investment by Major Category



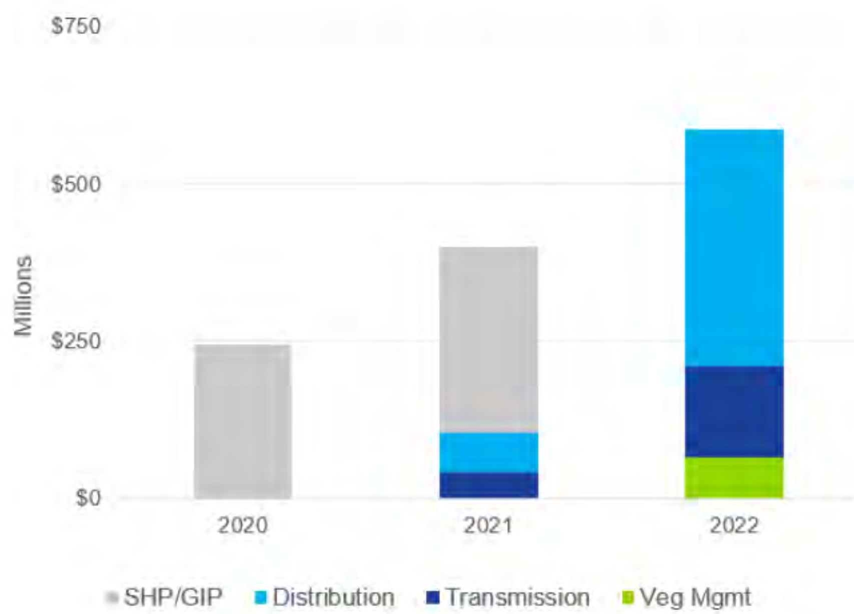
Source: Guidehouse, Inc.

In 2020 and 2021, DEF will invest approximately $540 million in capital and O&M for program investments as part of its previously approved Storm Hardening Plan (SHP) and for elements of its Grid Investment Plan (GIP). Hardening programs from these plans will become part of DEF's ongoing SPP. Beginning in 2021, DEF will add an incremental investment of approximately $100 million in capital and O&M as part of SPP implementation, with the full transition to the SPP investment program in 2022.

3-Year SPP Details

Over the first 3 years of the SPP, exclusive of investment associated with SHP/GIP in 2020 and 2021, DEF estimates a total SPP investment of approximately $690 million in capital and associated O&M, as depicted in Figure-ES 2.

Figure-ES 2. SPP 3-Year Investment by Major Category



Source: Guidehouse, Inc.

Within the SPP, DEF includes 10 programs. Table-ES 3 lists these programs by major investment category.

Table-ES 3. List of SPP Programs

Category	SPP Program
Distribution	D1: Feeder Hardening
	D2: Lateral Hardening
	D3: Self-Optimizing Grid
	D4: Underground Flood Mitigation
Transmission	T1: Structure Hardening
	T2: Substation Flood Mitigation
	T3: Loop Radially Fed Substations
	T4: Substation Hardening
Vegetation Management	VM1: Distribution Vegetation Management
	VM2: Transmission Vegetation Management

Source: Guidehouse Inc.

The body of this report details the estimated investment and expected activities associated with each of these SPP programs.

1. Introduction

Duke Energy Florida (DEF) engaged Guidehouse Inc. (Guidehouse or the project team)[2] to help develop the DEF Storm Protection Plan (SPP). The SPP seeks to strengthen DEF's electric grid infrastructure to withstand extreme weather conditions and enhance overall reliability. Guidehouse assisted DEF with developing and refining its analytical methods of project selection and prioritization to help target the most cost-effective grid strengthening solutions.

This document provides Guidehouse's recommendations for:

- Strategic 10-year investment plan for the DEF SPP (Section 2)
- Detailed 3-year capital investment plan for the DEF SPP (Section 3)

The recommended 10-year plan focuses on core programs deployed on the transmission grid, within substations, on the distribution grid, and for vegetation management. These programs and projects will cost-effectively prevent or reduce the impacts of extreme weather events to DEF customers while enhancing the overall reliability of the electric system across DEF's service area.

Program assumptions related to impacted assets, costs, and expected benefits are provided to support the recommendations. Guidehouse also assessed historical DEF, industry, and national weather data to model the locational impacts of various extreme weather conditions; the analysis estimates the anticipated reduction in restoration costs and outage times associated with the project team's SPP recommendations.

Guidehouse references the following data sources in the modeling and analysis of DEF's SPP programs.

- GIS data (DEF-specific)
- Asset management data (DEF-specific)
- Outage management system data (DEF-specific)
- Fragility analysis data[3]
- Inspection data (DEF-specific)
- Historic storm reports (DEF-specific)
- Vegetation coverage data (DEF-specific)

[2] Guidehouse LLP completed its acquisition of Navigant Consulting, Inc, in October 2019. The two brands are now combined as one Guidehouse.

[3] Panteli, Mathaios, et al. "Power system resilience to extreme weather: fragility modeling, probabilistic impact assessment, and adaptation measures." *IEEE Transactions on Power Systems* 32.5 (2016): 3747-3757.; Guikema, Seth, and Roshanak Nateghi. "Modeling power outage risk from natural hazards." *Oxford Research Encyclopedia of Natural Hazard Science*. 2018.

- Historic hourly National Oceanic and Atmospheric Administration (NOAA)[4] weather data from 199 weather stations
- Predictive windspeed frequency models
- Predictive flood frequency models
- Customer, load, and apparent power at risk data at (DEF-specific)
- Customer value of unserved energy
- Financial and other miscellaneous data[5]

Section 3 provides program-specific modeling assumptions included in Guidehouse's recommended investment plan. DEF engineering and planning personnel, regional staff, and other subject matter experts will be able to use the results of this analysis to inform the detailed planning and design-level analysis efforts needed to implement the SPP and realize its benefits.

The modeling methodology is discussed in Appendix A.

1.1 Full SPP Deployment Benefits

Full deployment of many SPP programs will span beyond the 10-year timeline defined in DEF's SPP regulatory filing. Some of the individual programs—e.g., distribution lateral hardening—may require 20 to 30 years to complete. For this assessment, the Guidehouse project team regarded completion of 3-year and 10-year plans as milestones towards achieving the greater benefits of a longer-range, fully hardened state of the DEF electric system. When fully deployed, the extreme weather protection and reliability improvements offered by the SPP will produce significant ongoing benefits to DEF customers. Table 1 and Table 2 highlight the estimated annual avoided restoration costs and reduced customer minutes of interruption (CMI), respectively, given the average expected storm frequency and the potential for elevated storm frequency.[6]

[4] NOAA is an agency within the US Department of Commerce that focuses on understanding, predicting, and information sharing on the conditions of the oceans, atmosphere, and related ecosystems.

[5] This includes inflation rates, DEF's weighted average cost of capital (WACC), valuation horizons, and more.

[6] Note that the given percentages are relative to a baseline of the 4-year average value for each benefit—that is, the 4-year average restoration cost and the 4-year average CMI. As such, it is possible for a percent reduction to be greater than 100%. For example, a 200% transmission-driven reduction in CMI indicates that the transmission programs proposed will reduce CMI by two times the average amount of CMI that has been experienced on the transmission system. This is possible given that the transmission system has not experienced large direct storm impacts over the past 4 years.

Table 1. Estimated Annual Avoided Restoration Costs for Fully Deployed SPP

	Average Storm Frequency		Elevated Storm Frequency	
Program Category	Estimated Annual Avoided Restoration Costs (2020 Dollars)	(% Reduction)	Estimated Annual Avoided Restoration Cost (2020 Dollars)	(% Reduction)
Distribution	$104.6 million	51%	$130.8 million	64%
Transmission	$18.6 million	37%	$23.2 million	47%
Vegetation Management	NA	NA	NA	NA

Notes: % Reduction represents modeled restoration cost savings relative to average storm restoration costs from 2016 through 2019. Storm frequency assumptions are provided in Appendix B.

Source: Guidehouse, Inc.

Table 2. Estimated Annual CMI Reduction with Fully Deployed SPP

	Average Storm Frequency	Elevated Storm Frequency
Program Category	CMI Reduction Minutes	CMI Reduction Minutes
Distribution	666.6 million	833.2 million
Transmission	36.0 million	45.0 million
Vegetation Management	NA	NA

Notes: Storm frequency assumptions are provided in Appendix B.

Source: Guidehouse, Inc.

Upon SPP full deployment, DEF can expect to avoid an estimated $123 million in storm restoration costs annually and an estimated annual reduction of about 703 million CMI.

Guidehouse used data from storm damage experienced since 2015 as well as customer outage data collected over this same period to support this analysis. The average storm frequency referenced in the tables above considers the weather conditions most likely to be experienced across the DEF service territory each year based on weather data from the past 200 years.[7] Should storm activity intensify or become more frequent, the SPP would deliver even more value in avoided restoration costs and CMI reduction.

Details on the 10-year and 3-year portions of Guidehouse's SPP recommendation are provided in the sections below.

[7] Storm frequencies were derived from HAZUS MH model runs. See www.fema.gov/hazus, msc.fema.gov/portal/home, and Schneider, Philip J., and Barbara A. Schauer. "HAZUS—its development and its future." Natural Hazards Review 7.2 (2006): 40-44.

1.2 Program Categorization

Guidehouse evaluated dozens of program elements and hundreds of assets as part of the SPP analysis and modeling. The project team categorized SPP programs into three program types: standards-based, targeted, and enabling, as defined in Table 3. The team used these program types in the analysis and modeling activities to drive how individual projects within each program are prioritized into the 10-year and 3-year investment plans.

Table 3. SPP Program Types

Program Type	Description
Standards-based	Programs that leverage standards to specify the hardening approach and to determine the conditions (including locational specifics, system characteristics, and vulnerabilities) that are eligible for deployment.
Targeted	Programs that seek to harden specific areas of the system that have specific characteristics (e.g., flood-prone areas) and merit deployment at those locations.
Enabling	Programs that are necessary to maintain the resilience of the system and that require continuous application to be effective.

Source: Guidehouse, Inc.

1.3 Program List

Table 4 lists the programs considered in the SPP analysis, the categories to which they belong, and their associated program types.

Table 4. DEF SPP Programs

Category	SPP Program	Program Type
Distribution	D1: Feeder Hardening	Standards-based
	D2: Lateral Hardening	Standards-based
	D3: Self-Optimizing Grid	Standards-based
	D4: Underground Flood Mitigation	Targeted
Transmission	T1: Structure Hardening	Standards-based
	T2: Substation Flood Mitigation	Targeted
	T3: Loop Radially Fed Substations	Targeted
	T4: Substation Hardening	Standards-based
Vegetation Management	VM1: Distribution Vegetation Management	Enabling
	VM2: Transmission Vegetation Management	Enabling

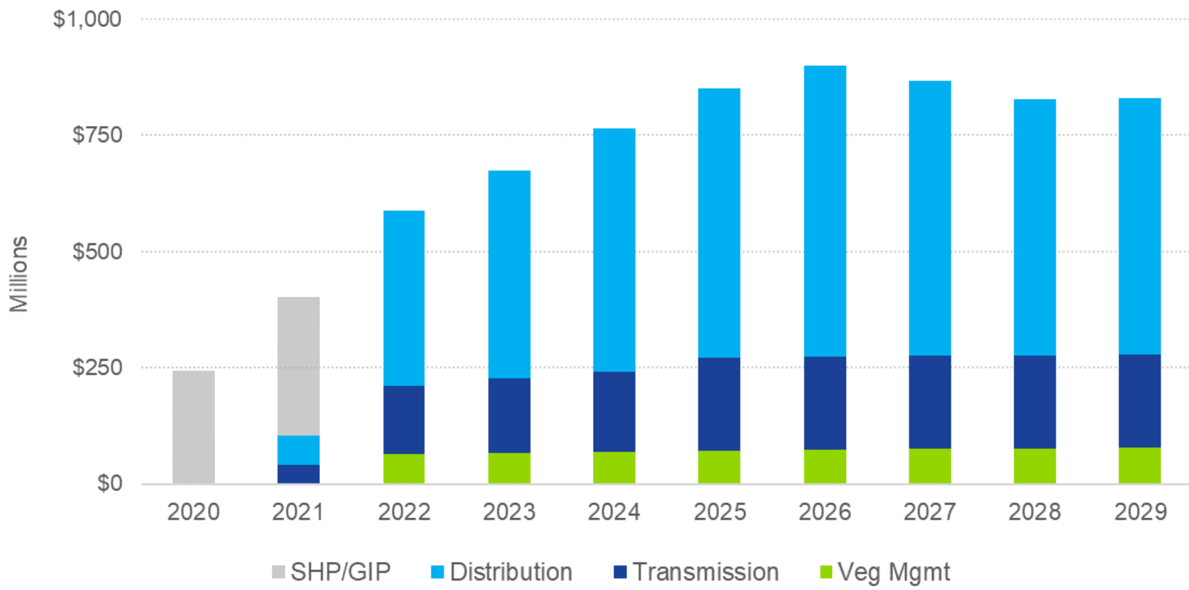
Source: Guidehouse, Inc.

Appendix C describes each program and how they were considered in the analysis process. Section 2 and Section 3 detail on Guidehouse's recommended 10-year and 3-year investment plan. Section 3 also offers additional details for each individual program and their associated extreme weather benefits.

2. Storm Protection Plan 10-Year Investment Plan

The recommended SPP, which spans 2020 through 2029, calls for a total investment of $6.4 billion in capital and associated O&M, with SPP-specific investment starting in year 2 (2021). Figure 1 shows this investment by year and investment category.

Figure 1. SPP Investment by Category Over 10 Years



Source: Guidehouse, Inc.

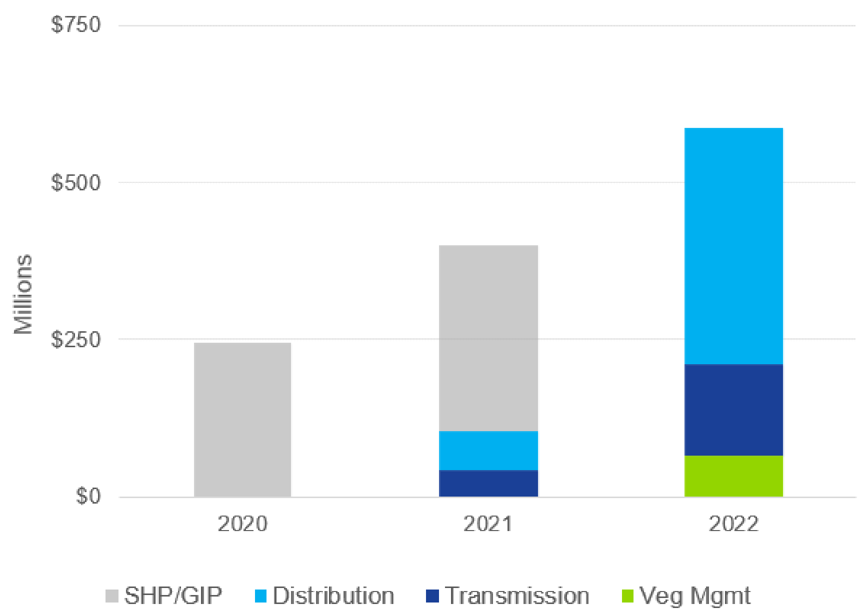
For 2020 and 2021, DEF has planned approximately $540 million in capital and O&M for storm hardening investments as part of its previously approved Storm Hardening Plan (SHP) and Grid Investment Plan (GIP) from the 2017 Settlement[8]. The amounts shown in Figure 1 include portions of the SHP and GIP programs that will become part of DEF's ongoing SPP. SPP will add approximately $100 million in incremental capital and O&M investment to these prior programs in 2021; in 2022, the first full year of SPP implementation, all investment shown is associated with SPP programs.

[8] Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170009-EI, In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.

3. Storm Protection Plan 3-Year Capital Plan

The following subsections provide a detailed program-level view of the first 3 years of the DEF SPP. A total of approximately $690 million in capital and O&M for SPP investments is estimated over the 3-year period, 2020 through 2022, as shown in Figure 2. This does not include the previously identified investment in 2020 and 2021 associated with the SHP/GIP.

Figure 2. SPP 3-Year Investment by Major Category



Source: Guidehouse, Inc.

Guidehouse used program definition details provided by DEF subject matter experts to define the program within its modeling and analysis approach. These details allowed the analysts to assess program costs, estimate benefits, and develop recommended program prioritization. A brief overview of program definitions is provided to facilitate understanding of the Guidehouse assessment teams' results.[9]

3.1 Distribution Programs

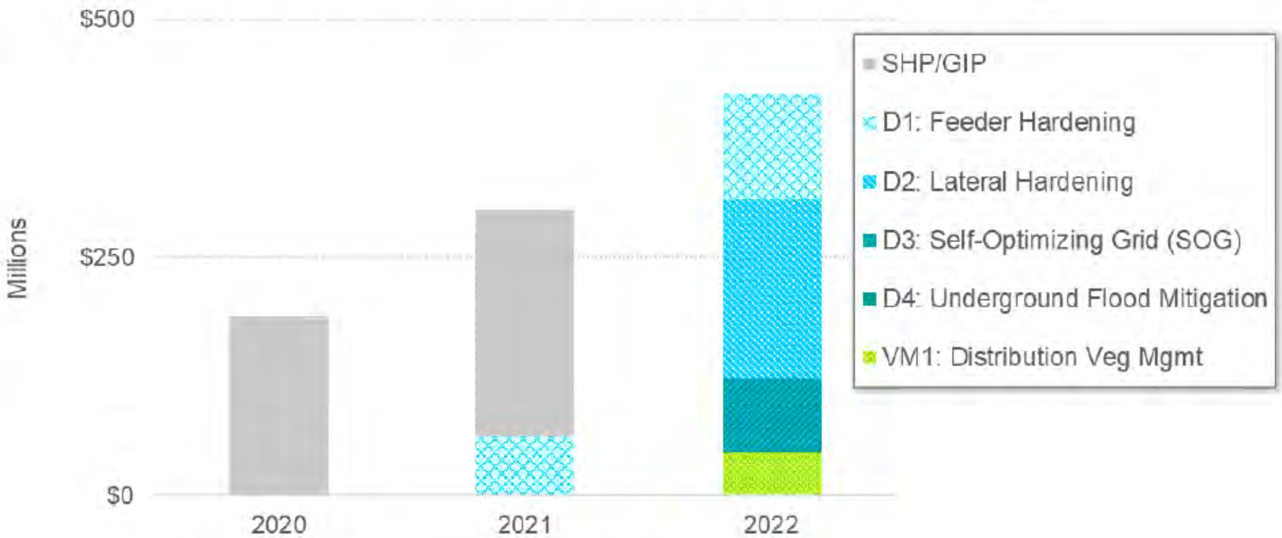
Distribution programs are proactive actions designed to upgrade the capabilities and resilience of distribution assets to reduce system and customer outages and susceptibility to extreme weather events. These actions can be generally categorized as one or more of the following:

- Accelerated replacement of prioritized infrastructure assets to lower the risk of in-service failures during extreme weather conditions.

[9] DEF will provide more complete definitions of each program in its filing materials; however, Appendix C defines the program characteristics that were captured specifically to facilitate the modeling and analysis activities presented in this report.

- Structure hardening to decrease susceptibility to extreme weather and wind damage to infrastructure through replacing and upgrading to current engineering standards, and relocation to more accessible locations for repair crews and undergrounding to avoid tree-related outages.
- Installation of automation technologies to improve system measurement, monitoring, and control and installation of alternate distribution line sources to provide system redundancy to reduce outages and improve operational efficiency.
- Proactive preventive and corrective maintenance programs to evaluate and mitigate asset deterioration to avoid in-service failures.

Figure 3. Distribution Programs Summary Spend by Year and Program



Source: Guidehouse, Inc.

Table 5. Distribution SPP Programs Investment for Years 1 to 3

Distribution SPP Programs	2020	2021	2022
D1: Feeder Hardening	-	$62.4 million	$111.4 million
D2: Lateral Hardening	-	-	$187.1 million
D3: Self-Optimizing Grid	-	-	$76.6 million
D4: Underground Flood Mitigation	-	-	$0.5 million
VM1: Distribution Vegetation Management	-	-	$45.8 million
SHP/GIP	$187.8 million	$237.2 million	-

Notes: *Amounts shown for each program reflect the capital investment and associated O&M spend required. Guidehouse's use of bottom-up modeling methodology may result in slight variations from reported budgeted spend amounts. Please see Appendix A for a description of Guidehouse's modeling methodology.*

Source: Guidehouse, Inc.

DEF anticipates a total of approximately $485 million in capital and O&M for SPP distribution investments (including distribution vegetation management) over the 3-year period, 2020 through 2022.

3.1.1 D1: Feeder Hardening

The Feeder Hardening program is a standards-based program that systematically upgrades the feeder backbone. This upgrade enables the feeder backbone to better withstand extreme weather events.

Work includes strengthening structures, updating basic insulation level to current standards, updating the conductor to current standards, relocating difficult-to-access facilities, and replacing oil-filled equipment. As part of this program, the poles supporting the feeder backbone line undergo strength testing, inspection. Poles showing signs of decay will be treated or replaced.

Table 6. Distribution Feeder Hardening Program (3-Year Plan)

D1: Feeder Hardening	2020	2021	2022
SPP Program Investment	**-**	**$62.4 million**	**$111.4 million**
Approx. No. of SPP Projects	**-**	**16**	**28**
Approx. No. of Line Miles	-	*64.1*	*89.2*
SHP/GIP Program Investment	$7.7 million	$7.5 million	-

Notes: *SHP/GIP Program Investments* reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology.
Source: Guidehouse, Inc.

3.1.2 D2: Lateral Hardening

The Lateral Hardening standards-based program identifies lateral segments to be placed underground that are most prone to outages during extreme weather events. Relocating lateral segments underground greatly reduces both damage costs and outage durations for DEF customers.

The Lateral Undergrounding strategy focuses on branch lines that historically experience the most outage events, contain significantly aged assets, are susceptible to damage from vegetation, and often have facilities that are inaccessible to trucks. These branch lines will be replaced with a modern, updated, and standard underground design of today.

The Overhead Hardening strategy will include structure strengthening, deteriorated conductor replacement, removing open secondary wires, replacing fuses with automated line devices, pole replacement (when needed), line relocation, and hazard tree removal.

Lateral branch line poles also receive inspection and preventive maintenance to identify wood poles that are showing signs of decay or that fall below the minimum strength requirements. Decayed poles with reduced structural integrity are identified for replacement or treated for pole life extension.

Table 7. Distribution Lateral Hardening Program (3-Year Plan)

D2: Lateral Hardening	2020	2021	2022
SPP Program Investment	**-**	**-**	**$187.3 million**
Approx. No. of SPP Projects	**-**	**-**	**134**
Approx. Underground Line Miles	-	-	*90.1*
Approx. Overhead of Line Miles	-	-	*99.5*
SHP/GIP Program Investment	$76.9 million	$104.0 million	-

Notes: *SHP/GIP Program Investments reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology.*
Source: Guidehouse, Inc.

3.1.3 D3: Self-Optimizing Grid

The Self-Optimizing Grid (SOG) program consists of three major components: capacity, connectivity, and automation and intelligence. SOG is a standards-based program that redesigns portions of the distribution system into a dynamic smart-thinking, self-healing network. SOG equips the grid with an ability to automatically reroute power around trouble areas, such as contact between a fallen tree and a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Completion of the SOG program will result in an overall reduction of the duration of outages stemming from extreme weather events.

Table 8. Self-Optimizing Grid Program (3-Year Plan)

D3: Self-Optimizing Grid	2020	2021	2022
SPP Program Investment	**-**	**-**	**$76.6 million**
Approx. No. of SPP Projects	**-**	**-**	**218**
SHP/GIP Program Investment	$56.5 million	$81.3 million	-

Notes: *SHP/GIP Program Investments reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology. The number of projects shown above represents the number of circuits impacted, not the number of automated devices.*
Source: Guidehouse, Inc.

3.1.4 D4: Underground Flood Mitigation

Underground Flood Mitigation is a targeted program which will harden existing underground lines and equipment to withstand a storm surge in flood prone areas. This involves the installation of specialized stainless-steel equipment and submersible connections. The primary purpose of this hardening activity is to minimize the damage caused by a storm surge to the equipment and thus expedite the restoration after the storm surge has receded.

Table 9. Underground Flood Mitigation (3-Year Plan)

D3: Underground Flood Mitigation	2020	2021	2022
SPP Program Investment	**-**	**-**	**$0.5 million**
Approx. No. of SPP Projects	**-**	**-**	**1**
SHP/GIP Program Investment	$0.3 million	-	-

Notes: *SHP/GIP Program Investments reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology. The number of projects shown above represents the number of circuits impacted, not the number of units.*

Source: Guidehouse, Inc.

3.2 Transmission Programs

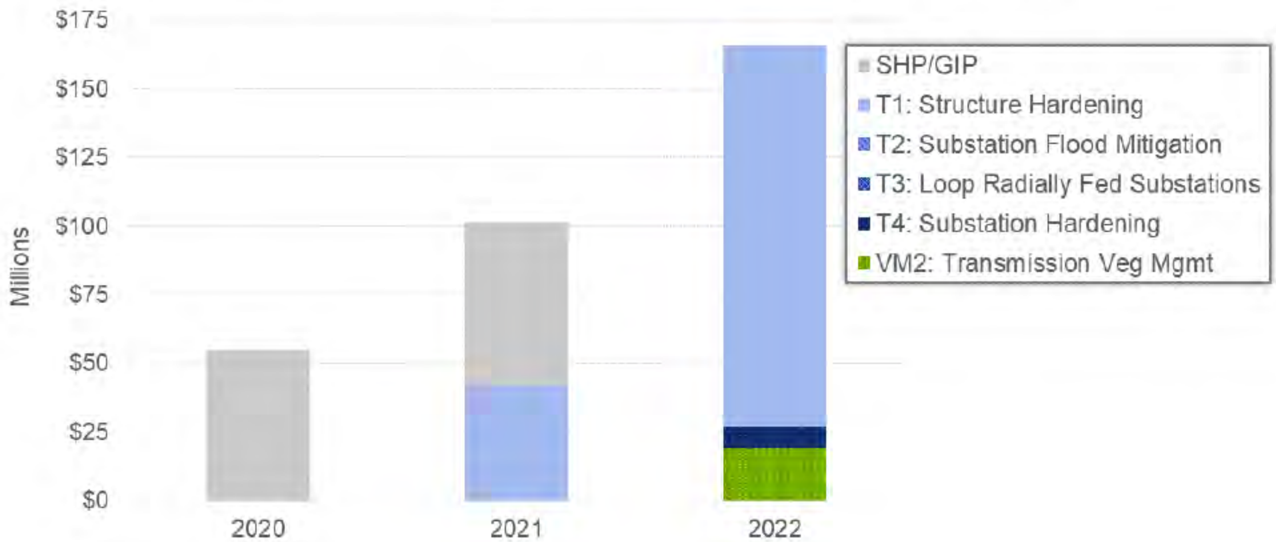
Transmission programs are designed to upgrade the capabilities and resilience of transmission assets to reduce system and customer outages and susceptibility to extreme weather events. These actions can be generally categorized as one or more of the following:

- Accelerated replacement of prioritized infrastructure assets to lower the risk of in-service failures during extreme weather conditions.
- Structure hardening to decrease susceptibility to extreme weather and wind damage to infrastructure through replacement and upgrading to current engineering standards.
- Installation of automation technologies to improve system measurement, monitoring, and control and installation of alternate transmission line sources to provide system redundancy to reduce outages and improve operational efficiency.
- Programmatic preventive and corrective maintenance programs to evaluate and mitigate asset deterioration to avoid in-service failures and capture detailed asset condition data. These comprehensive programs evaluate structures, foundations, insulators, conductor, and other hardware components. In cases where structures are difficult to access and/or more detailed inspection is required, fixed wing quadrotor drones are used.

Figure 4 shows a breakout of investment for the individual transmission programs.

Table 10 contains the specific investment dollars by year.

Figure 4. Transmission Programs Summary Spend by Year and Program



Source: Guidehouse, Inc.

Table 10. Transmission SPP Programs Investment for Years 1 to 3

Transmission SPP Programs	2020	2021	2022
T1: Structure Hardening	-	$42.0 million	$138.9 million
T2: Substation Flood Mitigation	-	-	-
T3: Loop Radially Fed Substations	-	-	-
T4: Substation Hardening	-	-	$7.5 million
VM2: Transmission Vegetation Management	-	-	$19.3 million
SHP/GHP	$54.8 million	$59.5 million	-

Notes: *Amounts shown for each program reflect the capital investment and associated O&M spend required. Guidehouse's use of bottom-up modeling methodology may result in slight variations from reported budgeted spend amounts. Please see Appendix A for a description of Guidehouse's modeling methodology.*

Source: Guidehouse, Inc.

DEF anticipates a total of approximately $208 million in SPP transmission investments (including transmission vegetation management) over the 3-year period, 2020 through 2022.

3.2.1 T1: Structure Hardening

Structure Hardening is a standards-based program that upgrades transmission wood pole H-frame structures with steel poles or other materials on overhead transmission lines. Where applicable, manual transmission gang-operated air-break (GOAB) switches are upgraded to supervisory control and data acquisition (SCADA) enabled GOAB switches.

Prioritized transmission towers are upgraded to the current design standard. Cathodic protection (CP) measures are applied as an effective method to control ongoing corrosion in the reinforced concrete structures supporting transmission towers.

On both types of structures, overhead transmission ground wires susceptible to damage or failure are upgraded to optical ground wire. Optical ground wires provide improved grounding and lightning protection as well as high-speed data transmission for system protection and control and communications.

Structure Hardening also includes several comprehensive programmatic structure inspections which capture condition data. Transmission system towers insulators, guying, anchoring, and foundations are ground inspected, and corrective maintenance activities are completed to correct deficiencies. Drone inspections are used to capture inspections data for structures in difficult to access areas and/ or instances where closer inspection is required to evaluate structure hardware condition.

Programmatic ground inspections identify transmission wood poles that are showing signs of decay or that fall below the minimum evaluation pole strength requirements. Insulators, conductors, guying, and other hardware is also inspected. Decayed poles with reduced structural integrity are identified for replacement or treated for pole life extension. If required, other corrective maintenance is completed, and decayed poles are identified for replacement.

Table 11 outlines the investments and scale of the Transmission Structure Hardening Program included in the SPP.

Table 11. Transmission Structure Hardening Program (3-Year Plan)

T1: Structure Hardening	2020	2021	2022
SPP Program Investment	**-**	**$42.0 million**	**$138.9 million**
Approx. No. of SPP Projects	**-**	**39**	**164**
Approx. No. of Poles Replaced	-	*645*	*1904*
Approx. No. of Towers Replaced	-	*19*	*9*
Miles of Overhead Ground Wire	-	-	*40.6*
SHP/GIP Program Investment	$37.3 million	$36.7 million	-

Notes: *SHP/GIP Program Investments reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology. The number of projects shown above represents the number of lines impacted.*

Source: Guidehouse, Inc.

3.2.2 T2: Substation Flood Mitigation

Transmission Substation Flood Mitigation is a targeted program that evaluates flood mitigation measures for substations. New assets may include containment curbing, pumps, pits, walls, and total station rebuilds to increase elevation or other measures.

Guidehouse's SPP recommendation did not include any Substation Flood Mitigation projects during the initial three-year period of the plan. While this program provides adverse weather hardening benefits, this targeted program scope begins after year 3.

3.2.3 T3: Loop Radially Fed Substations

The Loop Radially Fed Substations targeted program evaluates radially fed substations fed from a single transmission line source. When the radial transmission line assets are damaged during extreme weather events, customers may experience long outages during repair activities because an alternate feed is not present. Enabling transmission system redundancy and the ability to serve customers from an alternate power source can eliminate or shorten long outage durations. Assets required within a substation may include breakers, switches, buss work, structures, insulators, potential transformers, relays, and control houses. A transmission tie line may also be required.

Guidehouse's SPP recommendation did not include any Loop Radially Fed substation projects during the initial three-year period of the plan. While this program provides adverse weather hardening benefits, this targeted program scope begins after year 3.

3.2.4 T4: Substation Hardening

Substation Hardening is a standards-based program that will address two major components. 1) Upgrading oil breakers to state-of-the-art gas or vacuum breakers to mitigate the risk of catastrophic failure and extended outages during extreme weather events. 2) Upgrading electromechanical relays to digital relays with advanced system protection functions and communications to enable Duke Energy Florida to respond and restore service more quickly from extreme weather events.

Table 12. Transmission Substation Hardening Program (3-Year Plan)

T4: Substation Hardening	2020	2021	2022
SPP Program Investment	-	-	**$7.5 million**
Approx. No. of SPP Projects	-	-	**16**
SHP/GIP Program Investment	$5.0 million	$5.5 million	-

Notes: *SHP/GIP Program Investments reflect capital and O&M required for storm hardening investments that have been previously approved as part of DEF's Storm Hardening Plan (SHP) and/or Grid Investment Plan (GIP). The number of projects and number of units shown reflect SPP activity only. Guidehouse's prioritization methodology may result in variations from other reported estimated line miles and unit counts for future years. Please see Appendix A for a description of Guidehouse's modeling methodology. The number of projects shown above represents the number of substations impacted.*

Source: Guidehouse, Inc.

3.3 Vegetation Management Programs

Vegetation Management is an essential, widely accepted baseline practice for storm hardening electric transmission and distribution systems against severe weather events. Vegetation management (that is, tree pruning, cutting, danger tree removal, mowing, and chemical control of undesirable vegetation) is combined with other severe weather event hardening measures as part of DEF's overall SPP for electric transmission and distribution line systems.

Severe weather events, including high winds, heavy rain, and coastal surges, can cause trees to uproot and branches to break; this debris falls or flies into power lines, causing damage. For transmission systems, the primary cause of tree-related damage is weakened trees outside the utility easement falling into conductors and creating damage. For distribution systems, which often cross heavily vegetated areas, the primary cause of power outages and asset damage is trees within or outside the utility easement. Fallen trees and branches also impede service restoration and emergency service response due to blocked roadways and streets.

3.3.1 VM1: Distribution Vegetation Management Program

The Distribution Vegetation Management enabling program includes tree trimming, tree removals within easement, and associated activities on the distribution system. Also included are danger and hazard tree removals on the distribution system outside of easement requiring landowner permission.

Table 13. Distribution Vegetation Management Program (3-Yr Plan)

VM1: Distribution Vegetation Management	2020	2021	2022
SPP Program Investment	-	-	$45.8 million
SHP/GIP Program Investment	$46.4 million	$44.5 million	-

Source: Guidehouse, Inc.

3.3.2 VM2: Transmission Vegetation Management

The Transmission Vegetation Management-enabling program applies tree trimming, tree removals within easements, and associated activities on the transmission system. The program also includes right-of-way danger and hazard tree removals outside of easements on the transmission system.

Table 14. Transmission Vegetation Management Program (3-Yr Plan)

VM2: Transmission Vegetation Management	2020	2021	2022
SPP Program Investment	-	-	$19.3 million
SHP/GIP Program Investment	$12.5 million	$17.2 million	-

Source: Guidehouse, Inc.

Appendix A. Storm Protection Plan Methodology

This appendix provides the key approaches, methods, and assumptions Guidehouse used to develop its analysis for the Duke Energy Florida (DEF) Storm Protection Plan (SPP) investment plan.

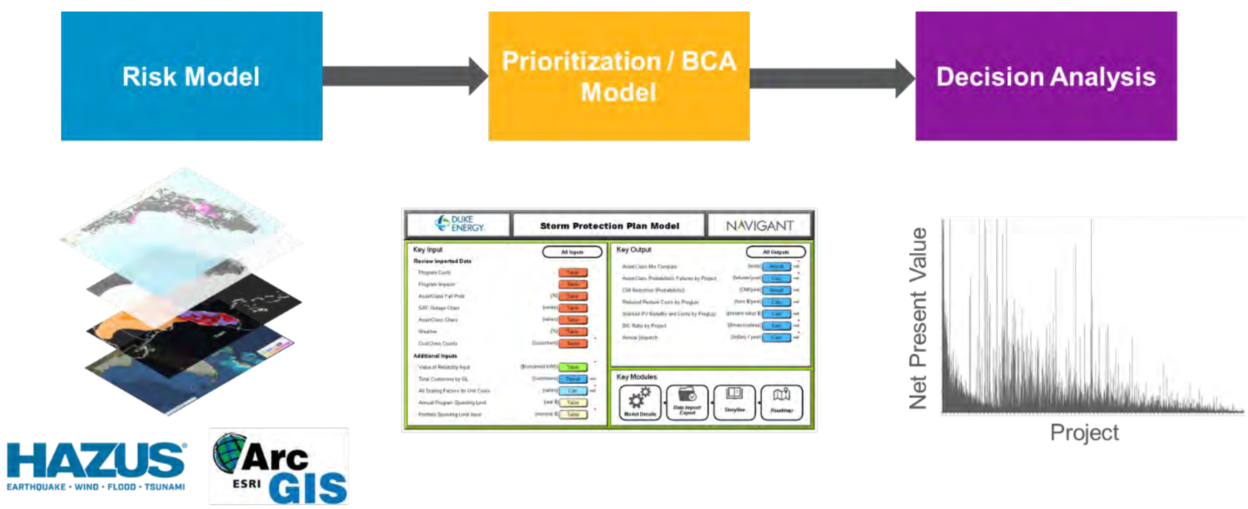
A.1 Overview of SPP Model

Guidehouse developed and employed a three-tiered modeling and analysis approach (referred to as the SPP model) to assess the effectiveness of proposed storm hardening programs and to inform the implementation prioritization process. The approach allowed the project team to simulate the deployment of these programs at every applicable location and under a range of weather conditions within the DEF service area. The following subsections describe the modeling approach and each of the three tiers of analysis (risk model, benefit-cost analysis, and decision analysis) incorporated into the SPP model to support the evaluation and prioritization of individual DEF SPP programs.

A.1.1 High Level Modeling Approach

Figure A-1 illustrates the data flow of program information through the three tiers of modeling and analysis.

Figure A-1. High Level Overview of DEF SPP Modeling Solution



Source: Guidehouse, Inc.

The first stage, the risk model, imports layers of data from the DEF GIS related to asset (e.g., asset type, age, condition), the latitudinal and longitudinal position of assets, and their relational configuration—that is, the way in which the assets interconnect. The risk modeling stage also imports probabilistic weather models to assess the risk exposure to grid assets in varying extreme weather conditions (storm surge, flooding, high winds). Each simulated location in the territory reflected DEF's asset mix at that location and the probability of experiencing a range of weather conditions. The output of the risk model stage characterizes the degree and associated cost of damage that would occur under a defined weather scenario.

The benefit-cost analysis (BCA) model analyzes the benefits and costs of each relevant combination of program and location. The model uses outputs from the risk model and other information to simulate the expected present value of costs and benefits associated with each program.

The decision analysis is a high-level prioritization of projects according to the BCA model's outputs. This high-level prioritization does not account for real-world constraints such as the availability of work crews, site-specific engineering considerations, and other prioritization factors.

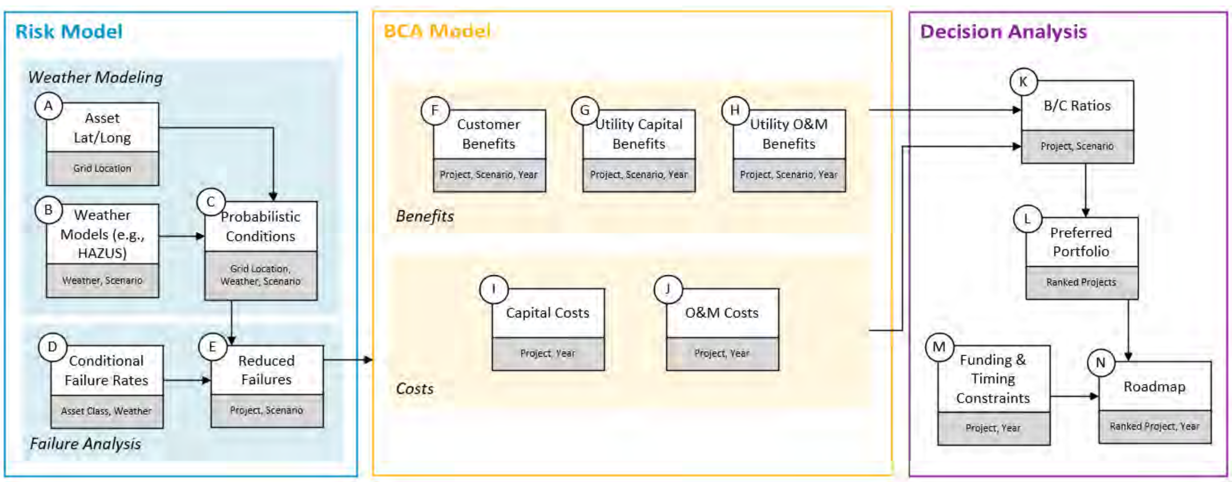
A.1.2 Detailed Modeling Approach

The SPP model characterizes individual transmission and distribution assets and storm hardening measures into broader categories, referred to as asset classes. Each program can then be defined based on the asset classes in place before and after the program is implemented. Programs are deployed at a locational level. Locations are defined as distribution circuits, transmission substations, and transmission lines. A project is one program deployed at a single location. The scope of the project depends on the number of assets present at the location.

Binning individual assets into asset classes is a practical method for estimating the value of each project without having to carry each individual asset (e.g., an individual utility pole) through the risk, BCA, and decision analysis modules. This method maintains the locational quantities of asset classes, the locational probability of weather conditions, and the relationship between customers and assets in the GIS.

The approach leverages a synthetic modeling technique to develop the portfolio of projects that are best suited to increase grid hardening and resiliency and to develop a high-level prioritized investment plan for project implementation. This solution is illustrated in Figure A-2, split by modules for risk, BCA, and decision analysis.

Figure A-2. Detailed Modeling Approach Flow Diagram



Source: Guidehouse, Inc.

The following sections summarize the concepts, logic, inputs, and outputs associated with each element of the flowchart in Figure A-2.

Risk Model

The primary purpose of the risk model is to estimate the expected frequency of asset failures under various weather conditions before and after the programs are implemented. The risk model is a bottom-up simulation of asset performance, calibrated to observed customer impacts and restoration costs in DEF territory. Components A through E from the risk model section in Figure A-2 are summarized as follows.

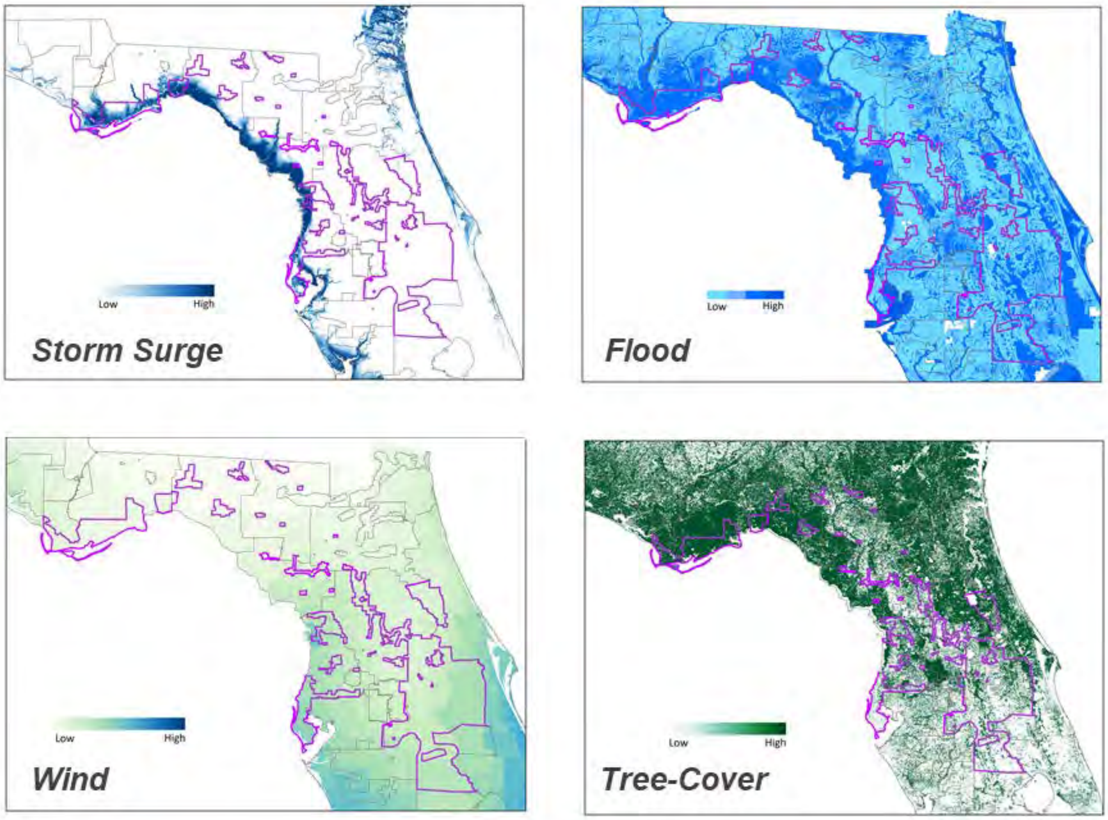
A	**Asset Lat/Long**	• Latitude and longitude of the asset (points), or latitude and longitude of vertices (line)
B	**Weather Models**	• Federal Emergency Management Agency (FEMA) and National Oceanic and Atmospheric Administration (NOAA) historic data and probability simulations of weather conditions (flood, storm surge, and wind speed) • FEMA HAZUS[10] model used for wind speed • FEMA SLOSH[11] model used for storm surge • NOAA and FEMA flood risk layers
C	**Probabilistic Conditions**	• Annual probability of occurrence for a given weather condition and location combination • Conditions are specific to each location
D	**Conditional Failure Rates**	• Probability of asset class failure when exposed to a given weather condition • Conditional failure rates applied to each location, thus picking up the location-specific probabilistic conditions in C
E	**Reduced Failures**	• Reduction in probability of asset class failure when a measure/program is applied • Dependent on the probabilistic conditions (weather) in C • Reduced outage time as well as equipment failure counts allow the value to reducing either or both to be incorporated into the BCA

Guidehouse simulated the weather conditions in the model through detailed environmental GIS data streams (Figure A-3).

[10] FEMA's Hazards US – Multi-Hazard (HAZUS) Model; https://msc.fema.gov/portal/resources/download

[11] FEMA's The Sea, Lake and Overland Surges from Hurricanes (SLOSH) Model; https://slosh.nws.noaa.gov/slosh/

Figure A-3. Environmental GIS Layers

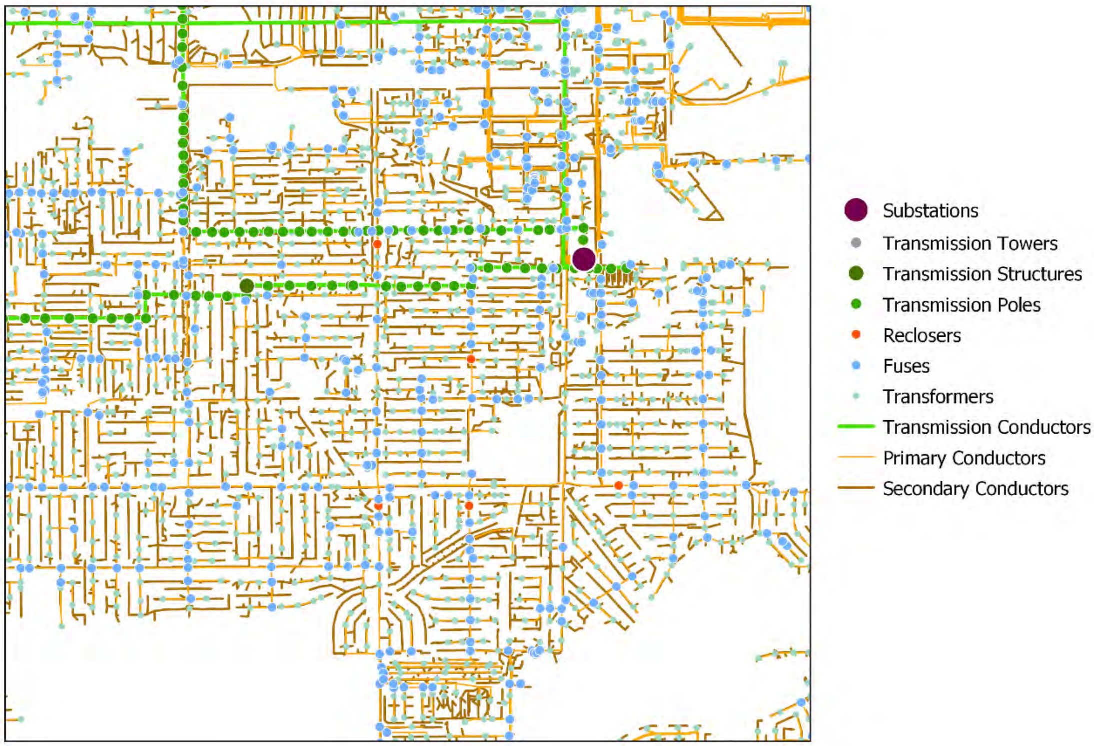


Source: HAZUS-MH, SLOSH, USGS, NOAA, Ventyx Energy Velocity

Guidehouse synthesized various data streams from the US Geological Survey (USGS), FEMA, and NOAA, including HAZUS simulations on storm surge and wind speeds, tree cover, and flood plains (Figure A-3), into a GIS. When formatted and regularized, the project team used these layers to generate probabilistic future conditions in DEF territory. Each combination of an asset location and weather scenario has an expected annual frequency of flooding, storm surge, and high wind conditions.

The impact of a program can then be estimated given the location-specific weather condition modeling and the mix of assets deployed. The asset mix is determined from DEF GIS and asset management system data (Figure A-4).

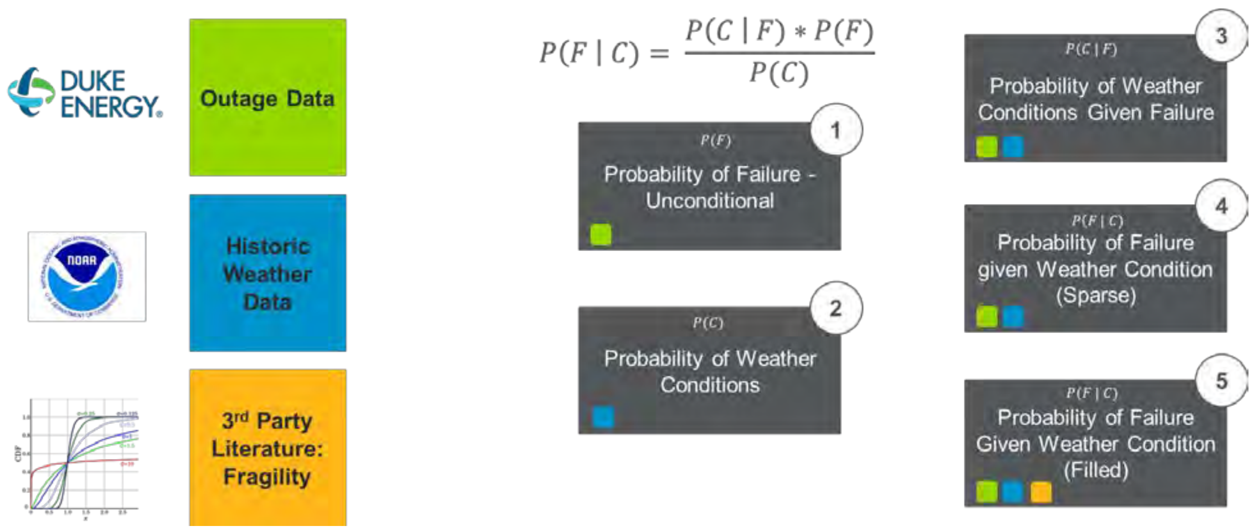
Figure A-4. Partial Illustration of GIS Asset Data



Source: Guidehouse, Inc., Duke Energy Florida

Guidehouse performed conditional failure analysis using historic DEF outage data, DEF asset data, and NOAA weather data. Each outage event was matched to historic data from the nearest weather station to the outage and the time of the outage. Figure A-5 illustrates the process for developing the probability of failure given weather conditions.

Figure A-5. Conditional Failure Analysis Approach



Source: Guidehouse, Inc.

The project team used five steps to derive conditional failure rates by asset class:

1. Count the total number of outages for each asset class divided by the total number of assets in each class, adjusted for the average event time, as described in Appendix B.
2. Count the frequency of each weather condition as recorded at each location.
3. Using data from local weather stations, match the conditions observed at each location to each outage.
4. Using conditional probability statistics, calculate the probability of failure (step 1) given the weather condition (step 2), and the condition probability (step 3).
5. Fill in any gaps (conditions not observed for a location and asset class combination) using fragility analysis literature.[12]

BCA Model

The BCA model is a tool used to calculate annual cash flows of each value stream relevant to the BCA. The model aggregates information and data from multiple sources and calculates results under different weather scenarios. Guidehouse assessed costs and benefits over a 30-year period for distribution programs and a 40-year period for transmission programs.

One of the core benefits assessed in the BCA model is customer outage benefits. This benefit is calculated based on the customer value of electricity (in terms of $/unserved kWh). The customer value of electricity varies based on the length of the outage and customer class.[13] The other benefits include utility capital and operations and maintenance (O&M) benefits associated with a hardened grid that experiences less asset failures relative to the conditions before the program implementation. The project team estimated the costs of program implementation on a location level based on the number of units deployed. The unit costs were developed by DEF and account for labor, material, indirect costs, staging and logistics, and contingency.

Referring back to Figure A-2, components F through J from the BCA model section are summarized below.

F	**Customer Benefits**	• Quantify reduction in outage time and associated downstream load by customer class. • Value of avoided outages is based on the value of an unserved kWh, which depends on the type of customer and the length of the outage. • The ICE calculator typically applies to outage times less than or equal to 16 hours. For outage times greater than 16 hours, Guidehouse applied the 16-hour outage values as a simplifying assumption.

[12] Panteli, Mathaios, et al. "Power system resilience to extreme weather: fragility modeling, probabilistic impact assessment, and adaptation measures." *IEEE Transactions on Power Systems* 32.5 (2016): 3747-3757.; Guikema, Seth, and Roshanak Nateghi. "Modeling power outage risk from natural hazards." *Oxford Research Encyclopedia of Natural Hazard Science*. 2018.

[13] The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. Available at https://icecalculator.com/home.

G	**Utility Capital Benefits**	• Calculated based on the reduced asset failures and the capital cost to replace those assets. • Value of deferring future capital replacement of existing assets by replacing them before the end of their expected useful lifetime with hardened equipment.
H	**Utility O&M Benefits**	• Calculated based on the reduction in O&M restoration costs associated with the reduction in asset failures.
I	**Capital Costs**	• The capital costs required to deploy the programs.
J	**O&M Costs**	• The O&M costs required to deploy the programs.

Decision Analysis

In the decision analysis portion of the model, the project-level BCA results were used to determine the prioritization and deployment plan for the programs. Thus, any prioritization shown in this report is driven only by the project BCA results; they do not include many crucial factors for project implementation. Guidehouse's analysis in this report does not consider other important factors that should be considered in program implementation that were outside the scope of this study, such as technology and regulatory risk, broader community benefits, customer inconvenience, viewshed, customer engagement, and local engineering expertise. This may mean that the actual implementation may differ from the BCA-based prioritization presented in this report.

Components K through N from the decision analysis section of Figure A-2 are summarized below.

K	**B/C Ratio**	• The costs and benefits of each project and scenario over the analysis period are converted into present values using discount rates for each cost test. Net present values and benefit-cost (B/C) ratios are then calculated for each project and scenario. • The B/C ratios are based on a theoretical deployment of the solution starting in the first year of the analysis period.
L	**Preferred Portfolio**	• Using the B/C ratios, the project team ranked each project from most preferred to least preferred. • Interactive effects were accounted for by counting the benefits of a program after other interacting programs' impact (e.g., self-optimizing grid impacts were estimated after feeder hardening). This ensured that program benefits were not double counted.
M	**Funding & Timing Constraints**	• Guidehouse applied program- and portfolio-level funding constraints, which DEF provided. These represent practical limits on program implementation.
N	**Roadmap**	• Projects were deployed algorithmically according to the ranking in step L and the constraints in step M. Annual program deployment analysis was guided by practical limitations on achievable implementation provided by the DEF project team and subject matter experts.

Appendix B. Weather Scenario Modeling

Guidehouse's model uses a detailed GIS representation of the Duke Energy Florida (DEF) service area to increase the accuracy and precision of the risk model and the benefit-cost analysis (BCA). This service area-specific GIS representation allows for simulated weather conditions and exposure probabilities to vary significantly depending on the latitude and longitude of each specific asset. The project team developed three weather scenarios (Average, Above Average, Increased Storm Frequency), with each weather scenario designed as discrete, consistent, representative outlooks on storm frequency and intensity applied at each asset location across the DEF service area throughout the planning horizon.

Saffir-Simpson Scale	
Category	**Wind Speed (mph)**
Blue Sky	0 – 40
Tropical Storm	40 – 74
Category 1	74 – 96
Category 2	96 – 111
Category 3	111 - 130
Category 4	130 - 157
Category 5	157+

To illustrate the team's methodology surrounding weather scenario development, Guidehouse built the tables below from total probabilities of storm events (tropical storm, Category 1 hurricane, Category 2 hurricane, etc.) across Florida, as informed by the Hurricane Research Division of the National Oceanic and Atmospheric Administration (NOAA) Atlantic basin hurricane database. While the tables illustrate the methodology applied across the entire state, in the GIS model, weather conditions were simulated at a detailed location level (latitude/longitude) before being applied to the BCA.

B.1 Scenario 1 – Average Storm Frequency

The average storm frequency scenario is defined by average conditions experienced in DEF territory: the frequency is the total number of events over all years, divided by the number of years. This is the annual average likelihood of each storm category to strike West Central Florida based on 1851-2018 NOAA data. The severity classes of events are based on the Saffir-Simpson scale (see above table) with the probability representing the likelihood that a windspeed event of at least that magnitude will occur in any given year. It is common to refer to a hurricane by the highest point on the Saffir-Simpson scale that it achieves, although the actual windspeeds at any given location affected by the hurricane will tend to be lower. As hurricanes achieve landfall and move inland, windspeeds typically decrease. These factors are accounted for in the detailed locational probabilities in the Guidehouse model.

To compute these numbers, Guidehouse first estimated the average duration of a storm event as approximately 22 hours using the historical NOAA data. The team then calculated the number of hours experienced historically in each range of wind speeds for all of DEF's territory, being careful to account for multiple station measurements in the same period. The probabilities below are relative to observed wind speed. The maximum windspeed present during a given 22-hour window was then used to assign those 22 hours to a severity class.

By summing the hours in each severity class and annualizing, the project team can obtain the probabilities $P_{S,22}$ of any given 22-hour event over the year belonging to severity class S. The team can then apply the following survival equation to compute the probability that no storm of that severity class occurs for the entire year:

$$P_{no\ S,year} = (1 - P_{S,22})^{(\frac{8760}{22})}$$

The probability that a storm of severity S does occur during any given year is $1 - P_{no\ S,year}$, producing the table below. Note that this is different than the expected frequency of events per year, which is a function of $P_{S,22}$.

Scenario 1

Blue Sky	Tropical Storm	Category 1	Category 2	Category 3	Category 4	Category 5
100.00%	98.92%	76.09%	40.77%	21.46%	6.62%	0.36%

Source: Guidehouse, Inc.

B.2 Scenario 2 – Above Average Storm Frequency

Above average storm frequency is defined by increasing the annual likelihood of storm strike by 10%. That is to say, the overall likelihood of storms increases by a factor of 0.1. Note that $P_{Blue\ Sky,22}$ is also reduced slightly, but the effect is negligible on the likelihood of getting a blue sky day in the year.

Scenario 2

Blue Sky	Tropical Storm	Category 1	Category 2	Category 3	Category 4	Category 5
100.00%	99.32%	79.28%	43.79%	23.33%	7.25%	0.39%

Source: Guidehouse, Inc.

B.3 Scenario 3 – Increased Storm Frequency

The increased storm frequency scenario is defined by increasing the annual likelihood of a storm event by 25% relative to the base scenario. Again, the effect on blue sky is negligible—there is still a nearly 100% chance (out to more than eight decimal places) to experience a 22-hour blue sky event.

Scenario 3

Blue Sky	Tropical Storm	Category 1	Category 2	Category 3	Category 4	Category 5
100.00%	99.65%	83.29%	48.04%	26.06%	8.20%	0.45%

Source: Guidehouse, Inc.

Appendix C. SPP Programs Descriptions for Modeling

This section describes the transmission, distribution and vegetation management programs evaluated in the Storm Protection Plan (SPP) model. Each description includes the following elements:

- **Program description:** Programs descriptions provide a general overview of the severe weather hardening actions and associated assets considered for model evaluation.
- **Extreme weather benefits:** Extreme weather benefits provide an overview of how each program provides benefits for outage prevention, system hardening, and outage reduction.
- **Program elements:** Program elements are the specific modeled assets added to or upgraded within each program that will provide severe weather storm hardening benefits.

Guidehouse developed these descriptions to facilitate the modeling and analysis activities. More complete program descriptions are provided by DEF.

C.1 D1: Feeder Hardening Program

C.1.1 Feeder Hardening (Overhead)

Description	The Feeder Hardening program is a standards-based program that systematically upgrades the feeder backbone. This upgrade enables the feeder backbone to better withstand extreme weather events. Work includes strengthening structures, updating basic insulation level to current standards, updating the conductor to current standards, relocating difficult-to-access facilities, and replacing oil-filled equipment. Feeder backbone line poles also receive preventive maintenance and undergo inspection to identify wood poles showing signs of decay or identify those falling below minimum strength requirements.
Extreme Weather Benefit	**Outage prevention**. Upgrading assets lowers the risk of in-service failure during extreme weather conditions. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage.
Elements	Rebuilds existing primary backbone non-hardened circuit assets with new upgraded construction. This project type includes upgrading assets: poles - Class 2 or greater, overhead conductor -- larger than 1/0, reclosers – self-healing, and overhead transformers – conventional.

C.1.2 Feeder Wood Pole Replacement and Treatment

Description	The Feeder Wood Pole Inspection and Treatment enabling activities are an inspection and preventive maintenance activity to determine if wood poles are showing signs of decay or if they fall below the minimum strength requirements. Poles with decay determined to be State 5 (Priority 1 - Replace immediately) or State 4 (Priority 2 - Replace as soon as practicable) are scheduled for replacement. Poles with minor deterioration (State 3) or deemed still serviceable (States 3, 2) may receive treatment to extend life of the pole.
Extreme Weather Benefit	**Outage prevention.** Identifying decayed poles more vulnerable to storm or severe weather damage and targeting them for strengthening measures, replacement, or treatment. Extreme weather benefits are not modeled for enabling activities.
Elements	Identifies decayed poles to be replaced or poles to be treated to extend the life of the pole.

C.2 D2: Lateral Hardening Program

C.2.1 Lateral Hardening (Underground)

Description	Lateral Hardening Undergrounding standards-based activity focuses on branch lines that historically experience the most outage events, contain significantly aged assets, are susceptible to damage from vegetation, and often have facilities that are inaccessible to trucks. These branch lines will be replaced with a modern, updated, and standard underground design of today.
Extreme Weather Benefit	**Outage prevention.** Reducing likelihood of outages caused by vegetation impacts during extreme weather **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage.
Elements	Replaces existing primary overhead branch line segments with new relocated underground line segments. All overhead assets are removed and replaced with underground distribution transformers, underground primary and secondary conductors, and a new overhead distribution fused riser pole is installed.

C.2.2 Lateral Hardening (Overhead)

Description	The Lateral Hardening Overhead standards-based activity identifies lateral segments to be placed underground that are most prone to outages during extreme weather events. Doing so will greatly reduce both damage costs and outage durations for DEF customers.
Extreme Weather Benefit	**Outage prevention.** Reducing outage frequency by moving the line to the front of the premise from the back, thus avoiding exposure to vegetation in high winds. This activity reduces outage duration by making the line more accessible to crews. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage.
Elements	Upgrades existing non-hardened primary branch lateral distribution overhead primary circuits with extreme wind load standard construction and other associated asset upgrades. This includes upgrading assets: poles - Class 2 or greater, overhead primary conductor – 1/0 or greater, overhead service – triplex, reclosers – self-healing, fuses – trip savers, and overhead transformers – conventional.

C.2.3 Lateral Wood Pole Inspection and Treatment

Description	The Lateral Wood Pole Inspection and Treatment enabling activity is an inspection and preventive maintenance activity to determine if wood poles are showing signs of decay or fall below the minimum strength requirements. Poles with reduced strength determined to be State 5 (Priority 1 - Replace immediately) or State 4 (Priority 2 - Replace as soon as practicable) are identified for replacement. Poles with minor deterioration (State 3) or deemed still serviceable (States 3, 2) may receive treatment to extend life of the pole.
Extreme Weather Benefit	**Outage prevention.** Identifying poles more vulnerable to storm or severe weather damage and targets them for strengthening/uplift measures, replacement, or treatment. Extreme weather benefits are not modeled for enabling activities.
Elements	Identifies decayed poles to be replaced or poles to be treated to extend the life of the pole.

C.3 D3: Self-Optimizing Grid Program

Description	The SOG program consists of three major components: capacity, connectivity, and automation and intelligence. The self-optimizing grid standards-based program redesigns portions of the distribution system into a dynamic smart-thinking, self-healing network. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. The benefit from completing this program is fewer customers affected by long duration outages as a result of extreme weather events.
Extreme Weather Benefit	**Outage reduction.** Adding the ability to reroute power during severe weather events reduces outage duration, frequency, and number of customers affected.
Elements	Adds one overhead self-healing recloser per approximately every 400 customers on primary overhead backbone circuits.

C.4 D4: Underground Flood Mitigation Program

Description	Within flood prone areas, Underground Flood Mitigation is a targeted program which will harden existing underground lines and equipment to withstand a storm surge through the use of the current Duke Energy Florida storm surge standards. This involves the installation of specialized stainless-steel equipment and submersible connections. The primary purpose of this hardening activity is to minimize the damage caused by a storm surge to the equipment and thus expedite the restoration after the storm surge has receded.
Extreme Weather Benefit	**Outage prevention.** Limiting equipment failures due to flood intrusion. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage.
Elements	Upgrades existing non-submersible underground distribution assets with new submersible underground assets and applies other flood proofing measures such as sealing ducts and equipment enclosures.

C.5 T1: Structure Hardening Program

C.5.1 Wood Pole Replacement

Description	The Wood Pole standards-based activity prioritizes replacing transmission wood pole H-frame structures with steel poles or other materials on transmission lines. Where applicable, the program targets replacing manual transmission gang-operated air-break (GOAB) switches with supervisory control and data acquisition (SCADA)-enabled GOAB switches.
Extreme Weather Benefit	**Outage prevention.** Providing for the acceleration of the replacement of wood poles, which lowers the risk of pole failure-related outages. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage. **Outage reduction.** Sensing voltage and current and enabling SCADA operators or master system software to perform remote switching. This capability eliminates the need to operate the devices locally from the control cabinet, as well as automatic sectionalizing operations. Compared to manual switching, remote switching can significantly reduce outage durations times.
Elements	• On transmission lines, replaces existing prioritized transmission wood pole H-frame structures with new steel poles or other materials • Upgrades existing manual GOAB switches with SCADA-enabled GOAB switches.

C.5.2 Structure Inspections

Description	Structure Inspections are an enabling activity providing programmatic inspection and corrective maintenance activities on overhead transmission steel towers and transmission wood poles. Through inspections, defective towers and poles are identified. Transmission system tower insulators, guying, anchoring, and foundations are ground inspected and corrective maintenance activities are completed to correct deficiencies. Programmatic ground inspections are performed to identify transmission wood poles that are showing signs of decay or fall below the minimum pole strength requirements. Conductors, insulators, and guying are also evaluated. If required, corrective maintenance is completed, and decayed defective poles are identified for replacement.
Extreme Weather Benefit	**Outage prevention.** Proactively evaluating tower and pole for deterioration, which lowers the risk of in-service failure during extreme weather conditions. Extreme weather benefits are not modeled for enabling programs.
Elements	Inspects towers, guying, and foundations; completes corrective maintenance; and identifies defective towers and poles for replacement.

C.5.3 Tower Replacements

Description	The Tower Replacements standards-based activity upgrades prioritized transmission towers to the current severe weather design. Cathodic protection (CP) measures are applied as an effective method to control ongoing corrosion in the reinforced concrete structures supporting transmission towers.
Extreme Weather Benefit	**Outage prevention.** Replacing prioritized steel, wood/steel towers with a new CP steel tower lowers the risk of in-service failure during extreme weather conditions. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to extreme weather and wind damage.
Elements	• Replacement of existing prioritized transmission towers with a new steel transmission tower • Installation of CP on upgraded transmission tower footers for ongoing corrosion control.

C.5.4 Tower Drone Inspections

Description	The Tower Drone enabling activity uses drones to capture inspections data for structures in difficult to access areas and/ or instances where closer inspection is required to evaluate structure hardware condition.
Extreme Weather Benefit	**Outage prevention.** Proactively evaluating towers for deterioration lowers the risk of in-service failure during extreme weather conditions. Extreme weather benefits are not modeled for enabling programs.
Elements	Provides detailed inspection and data collection of towers and associated hardware.

C.5.5 Overhead Ground Wires

Description	The Overhead Ground Wires standards-based activity targets replacement of transmission overhead ground wire susceptible to damage or failure with optical ground wire (OPGW). OPGW improves grounding and lightning protection and provides high speed transmission of data for system protection and control and communications.
Extreme Weather Benefit	**Outage prevention.** Lowering the risk of overhead ground wire in-service failure during extreme weather conditions due to lightning damage or mechanical failure. **System hardening.** Providing redundant sources of fiber optic communications for system protection and control.
Elements	Upgrades existing overhead ground wire with overhead OPGW.

C.6 T2: Substation Flood Mitigation Program

Description	The Substation Flood Mitigation targeted program evaluates substations for the application of flood mitigation measures. New assets may include containment curbing, pumps, pits, walls, and total station rebuilds to increase elevation or other measures.
Extreme Weather Benefit	**Outage prevention.** Reducing risk of prolonged outages caused by flooding. **System hardening.** Replacing or upgrading infrastructure to make it less susceptible to water intrusion and extreme weather conditions.
Elements	Removes existing non-flood mitigated substations and upgrades with flood mitigation substations (flood mitigation applied to existing non-flood mitigated substations).

C.7 T3: Loop Radially Fed Substations Program

Description	The Loop Radially Fed Substations targeted program evaluates radially fed substations that are fed from a single transmission line source. When the radial transmission line assets are damaged during extreme weather events, long customer outages may be experienced during repair activities because an alternate transmission feed is not present. Enabling transmission system redundancy and the ability to serve customers from an alternate power source can eliminate or shorten long outage durations. Assets required within a substation may include breakers, switches, buss work, structures, insulators, potential transformers, relays, and control houses. A transmission tie line may also be required.
Extreme Weather Benefit	**Outage reduction**. Enabling substation and customer load to be fed from an alternate source while repairs to damaged line segments are completed.
Elements	Adds new circuit segment (line tie) and required substation modifications/equipment and controls to an existing radially fed substation.

C.8 T4: Substation Hardening Program

Description	Substation Hardening is a standards-based program that will address two major components. 1) Upgrading oil breakers to state-of-the-art gas or vacuum breakers to mitigate the risk of catastrophic failure and extended outages during extreme weather events. 2) Upgrading electromechanical relays to digital relays with advanced system protection functions and communications to enable Duke Energy Florida to respond and restore service more quickly from extreme weather events.
Extreme Weather Benefit	**Outage reduction.** Reducing risk of in-service failures of breakers and relays during extreme weather conditions. Enabling more rapid identification and location of faults on transmission lines. **Outage prevention.** Supporting prompt and accurate diagnosis of grid events and operations to prevent recurrence.
Elements	Removes existing electromechanical relays and oil-filled substation breakers and upgrades with programmable electronic relays and gas-filled substation breakers.

C.9 VM1: Distribution VM Program

Description	The Distribution Vegetation Management enabling program includes tree trimming, tree removals within easement, and associated activities on the distribution system. Also included are danger and hazard tree removals on the distribution system outside of easement requiring landowner permission.
Extreme Weather Benefit	**Outage prevention.** Removal of vegetation likely to interfere with system operation during extreme weather reduces the likelihood of outages.
Elements	Application of cycle trimming, removal, demand trimming, herbicide, and hazard tree removal.

C.10 VM2: Transmission VM Program

Description	The Transmission Vegetation Management enabling program includes tree trimming, tree removals within easement, associated activities on the transmission line as well as right-of-way danger and hazard tree removals outside of easement on the transmission system.
Extreme Weather Benefit	**Outage prevention.** Removal of vegetation likely to interfere with system operation during extreme weather reduces the likelihood of outages.
Elements	Application of cycle trimming, removal, row mowing, herbicide, and hazard tree removal.