BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20250014-EI

Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.
_______________________________________/

DOCKET NO. 20250015-EI

Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida.
_______________________________________/

DOCKET NO. 20250016-EI

Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.
_______________________________________/

DOCKET NO. 20250017-EI

Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.
_______________________________________/

VOLUME 1 OF 1
PAGES 1 - 258

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO SMITH

DATE: Tuesday, May 20, 2025

TIME: Commenced: 9:30 a.m.
Concluded: 10:05 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
TALLAHASSEE, FLORIDA
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BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301; appearing on behalf of Florida Public Utilities Company (FPUC).

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APPEARANCES CONTINUED:

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I N D E X

WITNESS:	PAGE
MICHAEL JARRO (FPL)	
Prefiled Direct Testimony inserted	36
BRIAN LLOYD (DEF)	
Prefiled Direct Testimony inserted	52
ALEXANDRA M. VAZQUEZ (DEF)	
Prefiled Direct Testimony inserted	65
CHRISTOPHER MENDEZ (DEF)	
Prefiled Direct Testimony inserted	77
KEVIN PALLADINO (TECO)	
Prefiled Direct Testimony inserted	81
A. SLOAN LEWIS (TECO)	
Prefiled Direct Testimony inserted	102
JASON D. DESTIGTER (TECO)	
Prefiled Direct Testimony inserted	112
MARK CUTSHAW (FPUC)	
Prefiled Direct Testimony inserted	152
KEVIN J. MARA (OPC)	
Prefiled Direct Testimony inserted	168
MICHAEL JARRO (FPL)	
Prefiled Rebuttal Testimony inserted	180
BRIAN LLOYD (DEF)	
Prefiled Rebuttal Testimony inserted	194
ALEXANDRA M. VAZQUEZ (DEF)	
Prefiled Rebuttal Testimony inserted	201
KEVIN PALLADINO (TECO)	
Prefiled Rebuttal Testimony inserted	221
A. SLOAN LEWIS (TECO)	
Prefiled Rebuttal Testimony inserted	241
P. MARK CUTSAHW (FPUC)	
Prefiled Rebuttal Testimony inserted	248

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	255	255
2-86	As identified in the CEL	255	
2-73	As identified in the CEL		256

P R O C E E D I N G S

CHAIRMAN LA ROSA: Good morning, everybody. Today is May 20th, 2025. It is a little after 9:30, 9:31, and I would like to call this hearing conference to order.

Staff, will you go ahead and start us off and please read the notice?

MR. IMIG: By notice issued on April 28th, 2025, this time and place has been set for a hearing in Docket Nos. 20250014, 20250015, 20250016 and 20250017. The purpose of the hearing is set out more fully in the notice.

CHAIRMAN LA ROSA: Excellent. Thank you.

Let's go ahead and take appearances.

MR. IMIG: Staff notes that there are four dockets today in this consolidated proceeding. Staff suggests that all appearances be taken at once. All parties should enter their appearances and declare the dockets for which they are entering an appearance. After the parties make their appearances, staff their make theirs.

CHAIRMAN LA ROSA: Thank you.

Let's go ahead now and take appearances. Let's start with FPL.

MR. WRIGHT: Good morning, Chairman and

Commissioners. Christopher Wright on behalf of Florida Power & Light in the 14 docket.

CHAIRMAN LA ROSA: Thank you.

MR. BERNIER: Good morning, Commissioners, Matt Bernier for Duke Energy Florida. I would also like to enter an appearance for Stephanie Cuello and Dianne Triplett in the 15 docket.

MR. MEANS: Good morning, Commissioners. Malcolm Means with the Ausley Law Firm appearing on behalf of Tampa Electric. And I would also like to enter appearances for Jeff Wahlen and Virginia Ponder, and we are appearing in the 16 docket.

Thank you.

MS. KEATING: Good morning, Commissioners, Beth Keating with the Gunster Law Firm, here this morning for Florida Public Utilities in the 17 docket.

CHAIRMAN LA ROSA: Thank you.

MS. BAKER: Good morning, Commissioners, Laura Baker with the law firm Stone, Mattheis, Xenopoulos & Brew on behalf of White Springs Agricultural Chemicals, Inc., doing business as PCS Phosphate-White Springs. I am appearing in the 15 docket. And I would also like to make an appearance on behalf of my colleagues James Brew and Sarah Newman.

Thank you.

CHAIRMAN LA ROSA: Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel and Walt Trierweiler with the Office of Public Counsel. We are appearing in all four dockets.

CHAIRMAN LA ROSA: Thank you.

Staff.

MR. IMIG: Jacob Imig, Commission staff, in the 14, 15 and 16 dockets. I would also like to enter an appearance for Timothy Sparks in the 14 docket, Jennifer Augspurger in the 15 and 17 dockets, Saad Farooqi in the 16 docket, and Carlos mark in the 17 docket.

MS. HELTON: And Mary Anne Helton is here as your Advisor in all the dockets.

CHAIRMAN LA ROSA: Great. Thank you.

Staff, are there any preliminary matters that we need to address?

MR. IMIG: Staff notes that there are -- that stipulations have been reached on all issues in every docket. All witness testimony and exhibits have been stipulated to in all dockets, and all witnesses have been excused from this proceeding.

CHAIRMAN LA ROSA: Okay. Let's go through each docket, and we will take a vote accordingly, starting with FPL, would the parties like to speak about the stipulations, starting with FPL?

MR. WRIGHT: Yes, Chairman, we have a brief opening.

CHAIRMAN LA ROSA: Sure. You are recognized.

MR. WRIGHT: Thank you.

FPL's 2026 Storm Protection Plan continues the same eight existing Storm Protection Plan programs that were approved in the 2023 Storm Protection Plan and affirmed by the Florida Supreme Court.

For purposes of the '26 Storm Protection Plan, FPL has not proposed any material modifications to any of the programs; rather, we have updated certain costs for some of the programs. We have reflected reduction in the average cost per project for our lateral hardening program, and we have identified additional substations to be added to our substation program to reflect recent storm events.

FPL and Office of Public Counsel worked collaboratively to evaluate FPL's storm protection programs, and as a result of these constructive efforts, on April 25th, FPL and OPC jointly filed proposed stipulations and resolutions that, if approve, would fully resolve all issues in this case.

The stipulations slightly modify the annual targets for certain programs, specifically the lateral feeder and transmission hardening programs. These proposed modifications are to be annual targets, not hard caps. And any variances from those targets would be explained in our Storm Protection Plan Cost Recovery Clause docket.

Modifications agreed to in the stipulations are reasonable and thoughtful compromise and resolution of competing positions set forth in FPL and OPC's testimony and exhibits introduced into this docket.

To put this into perspective, the agreed on modifications will reduce the estimated total ten-year plan costs by approximately 809 million over ten-year planning period.

As set forth in the joint stipulations, FPL and OPC agreed that FPL's 2026 Storm Protection Plan, as modified by the stipulations, meets the requirements of the Storm Protection Plan statute, this Commission's Storm Protection Plan rule, and in the public interest and should be approved. FPL would like to thank Public Counsel for its constructive and collaborative efforts to reach a full resolution in this case.

In closing, FPL respectfully requests that the Commission approve the pending joint stipulation and find that FPL's 2026 Storm Protection Plan, as modified by the proposed stipulations, is in the public interest.

Thank you.

CHAIRMAN LA ROSA: Thank you.

OPC?

MR. REHWINKEL: Thank you, Mr. Chairman. And just as an intro, I am going to make remarks that generally cover all four dockets. I will make them only in this docket, and ask that you consider them in the remaining three, if that's okay.

CHAIRMAN LA ROSA: If something else pops up in one of those other dockets, I am just going to look your direction.

MR. REHWINKEL: Thank you.

I want to start off by thanking the Commission staff and the office of the Prehearing Officer especially. This docket, because of the schedule, could have gotten off to rocky start, but it was worked out and it made things work well for Public

Counsel, the parties throughout, and we really appreciate that.

We also want to thank the companies. This docket involves serious matters and significant money, but the professionalism, the cordiality and the cooperation by all four companies and their representatives was outstanding from day one, and we appreciate it. It made for a better outcome.

Public Counsel has joined in four settlements, including the one in this docket, of the triennial storm protection plans for the investor-owned electric utilities, and we believe in the settlements that we have entered into.

We contend that the resolutions in the settlements in this docket, and the others, are fair and strike a reasonable balance that supports the public interest finding that is required by law, and advances the Legislature's goals of creating a more resilient Florida.

Make no mistake about it, there are significant differences among the parties; but out of these differences, we found common ground that we believe yields a result that is at least as good as a litigated outcome. I just want to give you a little bit of background in support of the compromise and the settlement that you have before you.

In this docket, and the other dockets, we hired a nationally known expert who filed testimony in each docket. The company submitted their plans backed by their own renowned experts. We conducted several rounds of written discovery, and we conducted four depositions, one for each company.

This is all done on a very accelerated timeframe that's laid out by the Legislature, and everyone worked together to make sure it worked. In the aftermath of the recent Florida Supreme Court decision of the proper scope of these hearings, the Public Counsel is satisfied that we received a thorough opportunity to fully litigate this case.

Each settlement, including the one in this docket, represents a fair compromise of the positions of the company and the Public Counsel. Overall, we view the agreement, here and in the other dockets, as providing the potential for moderation in the near-term growth of the bill impacts for customers, our clients, while giving the companies flexibility to meet specific needs and adjust to circumstances in contracting, construction, the economy and weather, among others.

I am happy to answer any questions that you have in this docket or the others about these settlements, but we commend them for your approval because we think it is the right thing to do.

Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Staff?

MR. IMIG: The parties in this docket have stipulated to all issues, and the docket is in the posture for a bench decision by the Commission.

CHAIRMAN LA ROSA: Okay. Commissioners, are there any questions?

Commissioner Smith.

COMMISSIONER PASSIDOMO SMITH: Thank you, Mr. Chair. Just briefly. I just have a few comments similar to Mr. Rehwinkel that will kind of encapsulate for all the dockets, at least as far as the first three that we are going to go over.

I know three years ago, when this -- the distribution lateral hardening program was brought before us, that I dissented because I was just concerned about the rate impact on customers, so I appreciate the stipulation just tempering the pace of these programs, and fully support it.

So that will also -- this comment kind of goes as far as Duke and TECO's lateral hardening programs as well. I just appreciate you guys coming together and bringing forth a very well thought out stipulation for us to consider, so thank you.

CHAIRMAN LA ROSA: Great.

Commissioners, any further questions?

Commissioner Clark, you are recognized.

COMMISSIONER CLARK: I did have one question for each of the parties that I have not been able to find is, have we ran the customer impacts, the actual final customer impact on the bill for each of the -- under the terms of the stipulations -- settlement, I am sorry?

CHAIRMAN LA ROSA: And specifically -- so we will go to FPL, and then I have no problem going to questions on each of one of the parties as we get to, I know Mr. Rehwinkel has discussed talking in general, but we can also go to him for questions on each one of the dockets as that party is ready to present. I just want to clarify that.

COMMISSIONER CLARK: That's fine.

CHAIRMAN LA ROSA: So, yeah, let's hear from

FPL since they are up.
MR. WRIGHT: Yeah, thank you, and great question. Commissioner.
So as part of the stipulation, we focused more on number of projects rather than a cost, or trying to target sort of a bill impact range. So you will see an adjustment over the 10 years, it kind of ramps down after the first three years.
Because it's a cumulative revenue requirement, including, you know, what you already have on your books so far, the rate impacts -- there will be some reduction in the rate impacts. I do not have those numbers off the top of my head here. But starting in about 2028, I believe, is where you will start to see a slight reduction in the rate impacts. That's just due to the effect of it being a cumulative revenue requirement.
So it does take some time to feel to the effect of this reduction. But as I said in my opening remarks, the agreed upon stipulations result in, over the ten-year plan, a reduction of approximately $809 million in total costs.
COMMISSIONER CLARK: Thank you.
CHAIRMAN LA ROSA: Commissioners, any further questions? Any comments?

All right. Yeah, I will just say, you know, similar to what Commissioner Smith had mentioned, obviously, these programs are the things that we have approved in the past, but I do appreciate maybe pulling back a little bit on the velocity specifically to the lateral program. I think it's certainly, you know, a discussion point that we have seen and we have discussed. Certainly a lot of other folks are also talking about that.

So I think we are ready for a vote if there is no other further comments on the FPL docket. Open for a motion.

COMMISSIONER CLARK: Move to approve the settlement agreement, Mr. Chairman.

COMMISSIONER GRAHAM: Second.

CHAIRMAN LA ROSA: Hearing a motion, and hearing a second.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Yay.

Opposed no?

(No response.)

CHAIRMAN LA ROSA: Show that Docket 20250014 is approved as stipulated.

Let's go -- let's go move on to Duke. Would the parties like to speak on the stipulated proposals that are before us?

MR. BERNIER: Yes, Mr. Chairman, just briefly.

CHAIRMAN LA ROSA: Sure. You are recognized.

MR. BERNIER: Matt Bernier for Duke Energy Florida. And I don't usually have the luxury of going after Public Counsel, so I will say I appreciate their comments and agree.

CHAIRMAN LA ROSA: That was their choice, by the way.

MR. BERNIER: Presented for your consideration today are the joint stipulations DEF entered with OPC, and I would note that PSC Phosphate, the other intervenor party, has not voiced any objection to, and I believe supports, even though they did not sign on, the stipulations and the resulting plan are supported by the evidence in the record, and they are in the public interest as we are urge your approval.

Our plan is designed to achieve the goals that have been outlined by the Legislature of strengthening and protecting these transmission and distribution systems in order to reduce outage times, costs and restoration efforts.

The stipulated plan before you, as you heard from Power & Light is very similar. It continues on in the programs and the goal of the previous iterations of the plan, and the previous iterations of the plan have already started to deliver some very serious benefits for our customers.

In the 2024 storm season, we were impacted by Hurricanes Debby, Helene and Milton, we lost zero hardened structures. We saved over 300 million minutes of customer outage times, and we restored service to 95 percent of our customers in one, three and four days respectively after those storms.

So these are real benefits that our customers are seeing. And not just our customers, but the communities at large, right. Those are hospitals that are able to continue operating, government services that are able to continue, schools that can reopen, businesses, those are real tangible benefits for customers, and with this continued plan, with your approval, will be able to keep building on that success.

I would like to thank, again, your staff for shepherding through this process. Obviously, the Prehearing Officer for good work on it. Public Counsel for being willing to sit and talk with us and reach an amicable resolution.

And I would also like to thank, because I am sure they are probably watching, the DEF team who put together this filing. I know it's a short window after we file before we come to a hearing, but work begins on this well in advance, months, maybe a year in advance of this, and there are untold amount of people who spend countless hours working on this. Many of their names don't appear anywhere in the filing, but they do an incredible amount of work, and we could not do it without them. So if they are listening hoping I don't say anything stupid, we really appreciate that work.

But with that, we are available to answer any questions you may have, but otherwise we urge your approval.

Thank you.

CHAIRMAN LA ROSA: Great.

OPC?

MR. REHWINKEL: Just briefly. I would readopt my remarks made in the 15 docket. And I would like to point out to the Commission, each of these agreements was negotiated independently of any other companies. Certainly, one company came in first, I mean on a timeline, and other companies brought different proposals that met their individual circumstances.

There were companies who were more advanced in terms of their rollout of hardening activities, so what worked for one company wouldn't necessarily be appropriate for another. So we did not try to do that. We worked with each company to find an individual solution that met our criteria of moderation on the bill, and accomplishing the legislative goals, so thank you.

CHAIRMAN LA ROSA: PCS Phosphate?

MS. BAKER: Yes, just briefly, Commissioners.

I wanted to thank OPC and Duke. We obviously supported OPC's positions in this case. We were concerned about customer rate impacts. And we appreciate OPC and Duke working together and coming up with some good stipulations that we can facilitate today, so thank you very much.

CHAIRMAN LA ROSA: Great. Thank you.

Staff?

MR. IMIG: The parties in this docket have stipulated to all issues, and the docket is in the posture for a bench decision by the Commission.

CHAIRMAN LA ROSA: Before we do that, let's open it back up to us.

Commissioners, any questions? Commissioner Clark has a standing question.

MR. BERNIER: Apologies. I meant to answer it as I was rambling on before.

We just reached this stipulation on Friday. I have not seen any projected rate impact calculations based on it. I do know, however -- or I would note that we have the SPPCRC docket that is going on right now, and that we could absolutely provide our expectation in that docket before for you, but I am sorry I don't have it here today.

CHAIRMAN LA ROSA: That's just kind of a general question, right, and not necessarily picking on Duke, although, you know, you guys were greatly impacted by these storms this past season, and you did a good job of talking about how, you know, some of the hardening that had been done before held up throughout those storms, and when the storms hit this year, or, you know, last year, last hurricane season. I got on the ground. Your team was very hospitable in showing me some of the damages, and kind of pointing me in certain the directions. I wanted to see some of the things myself.

Did the storm impact change the approach at all to what was presented this year in regards to maybe things that we have seen in recent years? It does seem like every storm has a different impact.

MR. BERNIER: Yeah. Thank you, Mr. Chairman.

I can't say that it changed the actual filing, but it definitely changed the way we are thinking about it, and the prioritization, and some of the thoughts about, I think, concerns that we probably hadn't really maybe fully baked until we saw how it worked. So I think you will probably see that change borne out, you know, in execution as we are going through in the clauses and, you know, where we are concentrating some of those efforts, but the plan had been baked by the time of the storms.

CHAIRMAN LA ROSA: Okay. Understood.

Commissioners, any further questions or thoughts? Any discussion on this docket?

If none, I am open for a motion on the Duke docket.

COMMISSIONER CLARK: I move to approve the settlement agreement, Mr. Chairman.

COMMISSIONER GRAHAM: Second.

CHAIRMAN LA ROSA: Hearing a motion, and hearing a second.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Yay.

Opposed no?

(No response.)

CHAIRMAN LA ROSA: Show that the settlement passes.

Let's now move to TECO. Would the parties like to speak?

MR. MEANS: Yes. Thank you, Mr. Chairman Malcolm Means, speaking on behalf of Tampa Electric, and good morning, Commissioners.

Tampa Electric seeks approval of joint stipulations between the company and the Office of Public Counsel. These joint stipulations will resolve all issues in this docket, and approve a modified version of Tampa Electric's proposed 2026 to 2035 Storm Protection Plan.

The joint stipulations are supported by extensive testimony and exhibits from Tampa Electric, and are the results of discovery and hard work by Tampa Electric, the Office of Public Counsel and your staff.

Tampa Electric followed a rigorous process to prepare its proposed SPP. The company updated its previous SPP based on analysis by outside consultants, lessons learned from implementing prior SPPs and restoration experiences from recent major storms.

The company's testimony and exhibits demonstrate that the four largest capital programs are cost-effective for customers, and the company's proposed vegetation management program is optimized for customer benefit.

Tampa Electric voluntarily reduced the annual mileage target for the distribution lateral undergrounding program from 75 to 100 miles in its previous plan to 65 to 85 miles in the proposed plan. The company's reductions to the speed of lateral underground conversions were made to mitigate customer bill impacts and help maintain affordable rates.

Tampa Electric's proposed plan also includes two new programs based on lessons learned from last year's hurricanes. These include a distribution storm surge heartening program, which is a small but important new program that will harden distribution switch gear and transformers in areas at risk of flooding, and a transmission switch program, which will allow the company to remotely reconfigure its transmission system and reduce outage time during extreme weather. Each of the programs in the company's proposed plan will cost-effectively reduce restoration costs and outage times for all Tampa Electric customers when major storms hit.

The joint stipulations before you today modify the company's proposed plan by further reducing the company's annual distribution lateral undergrounding mileage target to 75 miles per year, and state the intent of the parties to proceed with the proposed plan in all of their respects.

OPC's ability to challenge the company's transmission switch program in the next SPP approval cycle is not limited or affected by the stipulation.

The parties have stipulated that the company's modified proposed SPP is in the public interest and should be approved. We request that the Commission agree and approve the joint stipulations and the company's modified proposed SPP. Your approval will allow the company to continue the important work of making its transmission and distribution system more resilient during extreme weather, while mitigating bill impacts for customers.

Tampa Electric would like to thank you for your time this morning, thank the Office of Public Counsel for working with the company on a beneficial resolution to this docket, and thank your staff for their work in reviewing the company's plan.

Thank you.

CHAIRMAN LA ROSA: Thank you.

OPC?

MR. REHWINKEL: The Public Counsel reiterates our remarks in the prior two dockets.

Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Staff?

MR. IMIG: The parties in this docket have stipulated to all issues, and the docket is in the posture for a bench decision by the Commission.

CHAIRMAN LA ROSA: Excellent. Great.

Commissioners, it's in our hands. Commissioner Clark.

MR. MEANS: Yeah, the same as my colleagues for Florida Power & Light and Duke. I don't have a new estimated rate impact for you, but I can say that it will reduce the project revenue requirement of the plan. We just haven't run that through the rate impact calculation yet.

CHAIRMAN LA ROSA: Commissioners, any further questions. All right, discussion in our hands.

Seeing no further questions or discussion, open for a motion, Commissioners.

COMMISSIONER CLARK: Move approve the settlement agreement, Mr. Chairman.

COMMISSIONER GRAHAM: Second.

CHAIRMAN LA ROSA: Hearing a motion, and hearing a second.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Opposed no?

(No response.)

CHAIRMAN LA ROSA: Show that the settlement agreement is approved.

Thank you, let's move to FPUC.

MS. KEATING: Thank you, Mr. Chairman, Commissioners. Beth Keating speaking on behalf of FPUC.

Commissioners, FPUC and OPC have agreed to stipulations regarding FPUC's 2026 Storm Protection Plan that we believe are consistent with Section 366.96, and are also in the public interest.

Approval of these stipulations will resolve all disputed issues between the company and OPC in this docket, and will promote regulatory certainty, administrative efficiency and avoid litigation costs.

FPUC's plan this year is very much like the last plan. The only differences were that the work is ramped up and there was an additional program. So the stipulation between OPC and FPUC primarily addresses those changes.

First, the parties agree and stipulate that a decision on FPUC's proposed distribution connectivity and automation program, or the DCA for short, which is the topic of Issue 1 in this docket, can be deferred until FPUC's next SPP filing.

If the stipulation is approved, the DCA program would not be voted on in this proceeding, and would, therefore, not be deemed an approved program for purposes of this 2026 SPP, or for cost recovery through the SPPCRC, and the company would not, however, be precluded from seeking approval of the DCA in the next program, and, likewise, OPC would not be precluded from opposing the program the next time around.

This leads me to the second key stipulation the parties have reached, which are the reductions of company's annual spend for its SPP that are reflected in Attachment 1. The amounts reflected in the attachment are not viewed as targets or firm caps, but any significant deviation by FPUC will be explained in the SPPCRC filing.

Having reviewed its project timelines, work schedules and inventory, PFUC believes it can implement its proposed SPP without the DCA and still maintain the intended benefits for the public consistent with the statute.

I note for clarification that Attachment 1 to the stipulations does reflect costs beginning to be incurred in 2028 for the DCA. This is merely because the chart used was taken from the original filing, and the reference to the DCA program in that chart shouldn't be interpreted to indicate that FPUC would seek to recover costs for the DCA program before it's approved.

Thus, with deferral of the DCA portion of FPUC's SPP, and the revisions to the estimated cost to implement the plan, FPUC asks that the Commission approve the programs subject to the stipulations.

And we would also like to thank OPC for working with us, and particularly on a shortened timeframe, and for staff for their review of the program.

Thank you.

CHAIRMAN LA ROSA: Thank you.

OPC?

MR. REHWINKEL: Thank you, Mr. Chairman. We reincorporate and reiterate our remarks from the prior dockets.

CHAIRMAN LA ROSA: Great. Thank you.

Staff?

MR. IMIG: The parties in this docket have stipulated to all issues, and the docket is in the posture for a bench decision by the Commission.

CHAIRMAN LA ROSA: Great. Commissioners, it's back over to us.

Commissioner Clark, are you satisfied, or -- let's open up the question that is on the table.

MS. KEATING: To respond to Commissioner Clark's question, the projections are projections. And as the other companies noted, it's difficult to give a definitive reduction, but we did run the numbers, and for 2026, it would be approximately a $2.22 reduction in the SPPCRC factor, but that doesn't include the true-up.

COMMISSIONER CLARK: Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Commissioners, any further questions?

Commissioner Smith.

COMMISSIONER PASSIDOMO SMITH: Thanks, Mr. Chair. No question. Just wanted to just put out there, again, supporting the stipulation, in particular the deferral of the DCA program. Reading through it, it's -- adding feeder ties to the distribution system, to me, was -- I had some concerns about that seeming like a normal course of business activity. So I would just, you know -- of course, if this program comes before us in three years, that there might be a better explanation, at least for my understanding, about how this would fall under storm hardening. I am not obviously prejudging anything, I just when this -- if this brings back before us again, I would probably like to get a better understanding of that.

But with that, I fully support the stipulation.

CHAIRMAN LA ROSA: Excellent. Great.

Questions? Any other discussions?

Seeing none, we are open for a motion.

COMMISSIONER CLARK: Move to approve the settlement agreement, Mr. Chairman.

COMMISSIONER GRAHAM: Second.

CHAIRMAN LA ROSA: Hearing a motion, and hearing a second hearing.

All those in favor signify by saying yay.

(Chorus of yays.)

CHAIRMAN LA ROSA: Yay.

Opposed no?

(No response.)

CHAIRMAN LA ROSA: Show that the settlement agreement is approved.

Thank you.

Let's go ahead and I will move back over to staff -- or let me ask, do the parties have any other preliminary matters that need to be addressed?

Seeing none, then let's go to of staff. Staff, can you address the prefiled testimony?

MR. IMIG: Staff asks that the prefiled testimony of all witnesses identified in Section VI of the Prehearing Order be entered into the order as though read.

CHAIRMAN LA ROSA: Okay. Then the prefiled testimony of all witnesses are entered into the record, then, as though read.

(Whereupon, prefiled direct testimony of

Michael Jarro (FPL) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250014-EI

FLORIDA POWER & LIGHT COMPANY

2026-2035 STORM PROTECTION PLAN

DIRECT TESTIMONY OF

MICHAEL JARRO

Filed: January 15, 2025

TABLE OF CONTENTS

I. INTRODUCTION 3

II. OVERVIEW OF THE 2026 STORM PROTECTION PLAN 5

III. ADDITIONAL DETAILS FOR THE 2026 STORM PROTECTION PLAN 11

IV. CONCLUSION 12

EXHIBIT MJ-1 – FPL's 2026-2035 Storm Protection Plan

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael Jarro. My business address is Florida Power & Light Company, 15430 Endeavor Drive, Jupiter, FL, 33478.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Vice President of Distribution Operations.

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

A. My current responsibilities include the operation and maintenance of FPL's distribution infrastructure that safely, reliably, and efficiently delivers electricity to 6 million customer accounts representing approximately 12 million people in 43 counties in peninsular and Northwest Florida. FPL's service area is divided into nineteen (19) distribution management areas with a total of approximately 80,400 miles of distribution lines and 1.4 million distribution poles. The functions and operations within my area are quite diverse and include distribution operations, major projects and construction services, power quality, meteorology, and other operations that together help provide the highest level of service to FPL's customers.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Miami with a Bachelor of Science Degree in Mechanical Engineering and Florida International University with a Master of Business Administration. I joined FPL in 1997 and have held several leadership positions in distribution operations and customer service, including serving as distribution reliability manager, manager of distribution operations for the south Miami-Dade area, control center general manager, director of network operations, senior director of customer strategy and analytics, senior director of power delivery central maintenance and construction, and vice-president of transmission and substations.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to sponsor and provide an overview of FPL's updated Storm Protection Plan ("SPP") for the ten-year period of 2026-2035 (hereinafter, the "2026 SPP"), which is attached to my direct testimony as Exhibit MJ-1. The 2026 SPP provides, among other things, a description of each SPP program and demonstrates how the programs have enhanced and will continue to enhance the existing transmission and distribution system to reduce restoration costs and outage times. The 2026 SPP also provides an estimate of the annual jurisdictional revenue requirement for the 2026-2035 plan period and additional details on each program for the first three years of the SPP (2026-2028), including estimated rate impacts.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit MJ-1 – FPL's Storm Protection Plan 2026-2035, which was prepared at my request and under my supervision. I note that FPL used the same approach for the proposed 2026 SPP that was used for both the 2020-2029 Storm Protection Plan ("2020 SPP") approved by Commission Order No. PSC-2020-0293-AS-EI and the 2023-2032 SPP ("2023 SPP) approved by Commission Order PSC-2022-0389-FOF-EI.

II. OVERVIEW OF THE 2026 STORM PROTECTION PLAN

Q. What is the purpose of FPL's 2026 SPP?

A. The purpose of FPL's 2026 SPP is to meet the statutory directives "to strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management" and "for each utility to mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans." *See* Sections 366.96(1)(c)-(e), Fla. Stat. FPL's 2026 SPP provides a comprehensive approach to achieve these legislative objectives.

Safe and reliable electric service is essential to the life, health, and safety of the public, and has become a critical component of modern life. While no electrical system can be made completely resistant to the impacts of hurricanes and other extreme weather conditions,[1] the programs included in the 2026 SPP will collectively provide increased resiliency and faster restoration to the electric infrastructure that FPL's approximately 6 million customers and Florida's economy rely on for their electricity needs.

Q. What programs are included in FPL's 2026 SPP?

A. The 2026 SPP will continue the following eight existing storm hardening and storm preparedness programs that were included in both the 2020 SPP and 2023 SPP:

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[1] It is important to note that, despite the implementation of the SPP programs, outages will still occur when severe weather events impact Florida.

- Distribution Inspection Program
- Transmission Inspection Program
- Distribution Feeder Hardening Program
- Distribution Lateral Hardening Program
- Transmission Hardening Program
- Distribution Vegetation Management Program
- Transmission Vegetation Management Program
- Substation Storm Surge/Flood Mitigation Program

A detailed description for each of these eight existing SPP programs is provided in Section IV of Exhibit MJ-1.

Q. Is FPL proposing any new SPP programs as part of its 2026 SPP?

A. No.

Q. Is FPL proposing any substantive or material modifications to any of these existing SPP programs?

A. No. FPL has projected three additional years for the 2026-2035 plan period, but has not proposed any material modifications to any of these existing programs previously approved in the 2023 SPP. Rather, FPL has updated the projected costs for certain programs to better reflect current data and pricing, reduced the estimated average cost per project under the Distribution Lateral Hardening Program, and identified additional substations that require storm surge and flood mitigation through the Substation Storm Surge/Flood Mitigation Program.

Q. Please summarize the program updates included in the 2026 SPP.

A. Distribution Inspection Program – FPL is forecasting an increase in the projected capital costs for the Distribution Inspection Program to better reflect current material and labor costs associated with the program, as well as to address the volume of pole replacements, remediations, or removals, including to poles to be removed as a result of hardening projects. This increase will be partially offset by a reduction in the estimated average cost per project under the Distribution Lateral Hardening Program over the 2026-2035 plan period.

Distribution Feeder Hardening Program – FPL is forecasting an increase in the projected capital costs for the Distribution Feeder Hardening Program to better reflect current material and labor costs associated with the program, as well as a reclassification of approximately 850 miles of feeders in the panhandle region of FPL's service area that were previously categorized as laterals. This increase will be partially offset by a reduction in the estimated average cost per project under the Distribution Lateral Hardening Program over the 2026-2035 plan period.

Distribution Lateral Hardening Program – FPL is forecasting a reduction in the estimated average cost per project under the Distribution Lateral Hardening Program over the 2026-2035 plan period to reflect the efficiencies realized from the implementation of program improvements further described in Section IV(D)(1)(a) of Exhibit MJ-1. This decrease will partially offset the increase in capital costs projected for the Distribution Inspection Program, Distribution Feeder Hardening Program, and

Substation Storm Surge/Flood Mitigation Program.

<u>Distribution Vegetation Management Program</u> – FPL is forecasting an increase in the projected costs for the Distribution Vegetation Management Program to better reflect: current labor and equipment market pricing; reduction in projected number of laterals to be converted from overhead to underground as part of the Distribution Lateral Hardening Program (*i.e.,* comparatively more overhead facilities remaining and need to be maintained); and to ensure that FPL is able to maintain the required vegetation maintenance cycles.

<u>Transmission Vegetation Management Program</u> – FPL is forecasting an increase in the projected costs for the Transmission Vegetation Management Program to better reflect current labor and equipment market pricing and an increase in both North American Electric Reliability Corporation's ("NERC") and non-NERC transmission miles on FPL's system.

<u>Substation Storm Surge/Flood Mitigation Program</u> – Finally, FPL will continue the work on two substations previously included in the 2023 SPP and has identified five additional substations to be addressed through the Substation Storm Surge/Flood Mitigation Program based on recent extreme weather events. The seven substation projects included in the 2026 SPP result in a projected increase in the capital costs to be incurred under the Substation Storm Surge/Flood Mitigation Program. This increase will be partially offset by a reduction in the estimated average cost per project under

the Distribution Lateral Hardening Program over the 2026-2035 plan period.

Q. Please provide an overview of the benefits of continuing the existing programs as part of the 2026 SPP.

A. The majority of these storm hardening programs have been in place since 2007 and the performance of FPL's system during historical extreme weather events demonstrates that these existing SPP programs have and will continue to provide increased transmission and distribution ("T&D") infrastructure resiliency, reduced restoration time, and reduced restoration costs when FPL's system is impacted by severe weather events. For example, a prior analysis of Hurricanes Matthew and Irma indicated the restoration construction man-hours, days to restore, and storm restoration costs for these storms would have been significantly higher without FPL's existing storm hardening programs. In the case of Hurricane Matthew, FPL estimated that without hardening, restoration would have taken two additional days (50% longer) and resulted in additional restoration costs of $105 million (36% higher than actual costs). In the case of Hurricane Irma, FPL estimated that without hardening, restoration would have taken four additional days (40% longer) and resulted in additional restoration costs of $496 million (40% higher than actual costs).

Also illustrative are the results of FPL post-storm forensic analyses of the performance of FPL's system during the 2020-2023 storm seasons as compared to performance during Hurricane Wilma, which occurred in 2005 before FPL began implementing its current existing SPP programs. Further details on the performance of FPL's system during these extreme weather events is provided in Sections II and IV of Exhibit MJ-1.

Although FPL's storm preparedness and hardening programs to date have produced a more storm resilient and reliable T&D electrical grid, continuing the previously approved SPP programs in the 2026 SPP is appropriate and crucial to achieve the legislative directives in Section 366.96, Florida Statutes. Indeed, Florida remains the most hurricane-prone state in the nation and, with the significant coast-line exposure of FPL's system and the fact that the vast majority of FPL's customers live within 20 miles of the coast, a robust storm protection plan is critical to maintaining and improving grid resiliency and storm restoration.

FPL submits that continuing these previously approved storm hardening programs in the 2026 SPP will continue to provide significant and important benefits to the customers and the communities served by FPL both now and for many years to come, including years with multiple extreme weather events, such as the 2022 and 2024 hurricane seasons. A description of the benefits of continuing the existing SPP programs as part of the 2026 SPP is provided in Sections II and IV of Exhibit MJ-1.

Q. Does FPL's 2026 SPP address recovery of the costs associated with the SPP programs and projects?

A. No. Cost recovery of the costs associated with the 2026 SPP will be addressed in the separate annual Storm Protection Plan Cost Recovery Clause ("SPPCRC") docket.

III. ADDITIONAL DETAILS FOR THE 2026 STORM PROTECTION PLAN

Q. Has FPL provided project-level detail and information for the first year (2026) of the 2026 SPP?

A. Yes. Project level detail for the first year (2026) is provided in Appendix D of Exhibit MJ-1. I note that FPL's distribution and transmission annual inspection and vegetation management programs do not lend themselves to identification of specific projects and, therefore, project level detail for these programs is not included in Appendix D.

Q. Does the 2026 SPP provide the estimated number of projects and costs for each SPP program over the 2026-2035 plan period?

A. Yes. This information is provided in Appendix C of Exhibit MJ-1.

Q. Does the 2026 SPP provide a description of the vegetation management activities for the first three years (2026-2028)?

A. Yes. The following additional information for the first three years (2026-2028) of the vegetation management activities under the SPP is provided in Sections IV(F) and IV(G) and Appendix C of Exhibit MJ-1: the projected frequency (trim cycle); the projected miles of affected transmission and distribution overhead facilities; and the estimated annual labor and equipment costs for both utility and contractor personnel.

Q. Does the 2026 SPP provide the annual jurisdictional revenue requirements for the ten-year plan period?

A. Yes. FPL has provided the estimated annual jurisdictional revenue requirements for years 2026-2035 in Section VI of Exhibit MJ-1.

Q. Does the 2026 SPP provide estimated rate impacts for each of the first three years of the plan (2026-2028)?

A. Yes. An estimate of overall rate impacts for years 2026-2028 based on the total program costs included in the 2026 SPP are provided in Section VII of Exhibit MJ-1.

Q. Has FPL identified any reasonable alternatives that could mitigate the resulting rate impact for each SPP program?

A. FPL has not identified lower-cost alternative programs that would achieve the legislative directives of Section 366.96, Florida Statutes, to reduce costs and outage times associated with extreme weather events by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management. However, all SPP projects will be based on competitive solicitations and other contractor and supplier negotiations to ensure that FPL selects the best qualified contactors and equipment suppliers at the lowest evaluated costs, which will help to mitigate the associated rate impacts of the SPP programs. Additionally, FPL continually evaluates the SPP programs to identify and, where appropriate, implement lessons learned, best practices, and improvements to further the efficient administration of each program.

IV. CONCLUSION

Q. Does FPL believe the 2026 SPP is in the public interest?

A. Yes. The FPL 2026 SPP will continue the existing storm hardening and storm preparedness programs that were included in both the FPL 2020 SPP and 2023 SPP previously approved by the Commission. These existing SPP programs have already demonstrated that they have and will continue to achieve the legislative objectives in Section 366.96, Florida Statutes, to increase T&D infrastructure resiliency, reduce restoration times, and reduce restoration costs when FPL's system is impacted by extreme weather events. I note that the Commission has previously found and determined that each of the eight programs included in the 2026 SPP are in the public interest.

FPL submits that the existing programs included in the 2026 SPP remain in the public interest and will continue to strengthen FPL's electric utility infrastructure to better withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management. Although there is the significant variability and subjectivity required to forecast future storms and estimated benefits of future SPP programs over a ten-year period, the performance of FPL's storm hardened system during historical extreme weather events demonstrates that these existing SPP programs have and will continue to provide increased T&D infrastructure resiliency, reduced restoration time, and reduced restoration costs when FPL's system is impacted by severe weather events.

Safe and reliable electric service is essential to the life, health, and safety of the public and has become a critical component of modern life. While no electrical system can be made completely resistant to the impacts of hurricanes and other extreme weather conditions, the continuation of the existing SPP programs included in the 2026 SPP will collectively provide increased resiliency and faster restoration to the electric infrastructure that FPL's approximately 6 million customers and Florida's economy rely on for their electricity needs.

Q. Does this conclude your direct testimony?

A. Yes.

Florida Power & Light Company

Storm Protection Plan
2026-2035

Docket No. 20250014-EI

Filed: January 15, 2025

(Whereupon, prefiled direct testimony of Brian Lloyd (DEF) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVIEW OF 2026-2035 STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20250015-EI

DIRECT TESTIMONY OF BRIAN M. LLOYD

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

JANUARY 15, 2025

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Brian M. Lloyd. My current business address is 3250 Bonnet Creek Road, Lake Buena Vista, FL 32830.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as General Manager, PGO Projects.

Q. What are your responsibilities as General Manager, PGO Projects?

A. My duties and responsibilities include planning for Distribution grid upgrades, system planning, and overall Distribution asset management strategy across Duke Energy Florida, as well as the Distribution Project Management for executing the work identified. Additionally, I manage organizations that execute the subdivision and apartments developer interactions and engineer large residential developments across the DEF territory.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Science degree in Mechanical Engineering from Clemson University and am a registered Professional Engineer in the state of Florida. Throughout my 18 years at Duke Energy, I have held various positions within Distribution ranging from Engineer to General Manager focusing on Asset Management, Asset Planning, Distribution Design, and Project Management. My current position is General Manager of PGO Projects for Power Grid Operations.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide and support the Company's Storm Protection Plan 2026-2035 ("SPP 2026"). The SPP 2026 is consistent with and complies with all the requirements of both Section 366.96, Florida Statutes ("SPP statute"), and Rule 25-6.030, F.A.C. ("SPP rule"). My testimony will show that DEF's SPP 2026 utilizes the same analysis methodology and ultimately carries forward the same Programs from the most-recently approved Storm Protection Plan, the 2023-2032 Storm Protection Plan ("SPP 2023"). The results of this analysis are presented in DEF's SPP 2026, which is attached to my testimony.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. (BML-1), DEF SPP Program Descriptions;
- Exhibit No. (BML-2), DEF SPP Support; and
- Exhibit No. (BML-3), DEF Service Area

Exhibits BML-1 and BML-3 were prepared by the Company under my direction, while BML-2 was prepared by Guidehouse, Inc., with input from the Company, and they are all true and correct to the best of my information and belief. Mrs. Alexandra M. Vazquez is co-sponsoring the Transmission Programs portion of Exhibit No. (BML-1), the Transmission Programs portion of Exhibit No. (BML-2), and the Transmission customers portion of Exhibit No. (BML-3). Mr. Christopher A. Menendez is co-sponsoring the Revenue Requirements and Rate Impacts component of Exhibit No. (BML-1).

Q. Please summarize your testimony.

A. My testimony presents DEF's Storm Protection Plan for the planning period of 2026 through 2035 and shows that DEF's SPP 2026 meets the requirements of both the SPP statute and rule. As directed by the Legislature, the SPP 2026 is designed to cost-effectively "strengthen [the Company's] infrastructure to withstand extreme weather conditions by promoting overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management." DEF's SPP 2026 is built upon the previously approved DEF SPP 2020 and SPP 2023, taking into consideration updated reliability, asset, storm, and cost data.

III. OVERVIEW OF SPP 2026

Q. How did DEF approach the development of the SPP?

A. SPP 2026 was developed in a similar manner as the previously approved SPP 2020 and SPP 2023 by building a cross functional team of Company experts from various business functions, many that were directly involved in DEF's previous SPPs and by utilizing the professional services of Guidehouse to provide modeling and analysis support. Much like the DEF team, many of the Guidehouse experts were key participants in the formation of SPP 2020 and SPP 2023. The Guidehouse experts' deep level of industry experience in the Distribution and Transmission systems, climate resilience, risk mitigation, benefits-cost analysis, and predictive analytical techniques provide the expert support necessary to build a comprehensive Storm Protection Plan that meets the requirements of the SPP statute and rule. Guidehouse's previous experience with both SPP 2020 and SPP 2023 made for an efficient start-up process and provided continuity between the three iterations of the Plan.

Q. Please describe how the SPP is organized.

A. DEF's SPP 2026 is attached as three Exhibits. As required by Rule 25-6.030, Exhibit No. (BML-1) includes a summary of each Program included in SPP 2026;

estimated spend and units for the first three years of implementation (2026 to 2028); detailed information for the first-year projects (2026); vegetation management information; and the estimated benefits. Exhibit No. (BML-2) is a write-up of the prioritization methodology and estimated Program benefits. A map of DEF's service area with associated customer count is provided in Exhibit No. (BML-3).

Q. Has DEF determined that there are any areas of its service territory that Storm Protection Plan projects would not be feasible, reasonable, or practical?

A. No, DEF has not determined there are any areas of its service territory in which it would not be feasible, reasonable, or practical to execute SPP projects.

IV. OVERVIEW OF PROGRAMS EVALUATED IN THE SPP

Q. Are the Programs in SPP 2026 the same as SPP 2023?

A. Yes, the DEF and Guidehouse teams selected the same portfolio of Programs for SPP 2026 as the previously approved SPP 2023. These nine Programs are tried, true and built from DEF's and Guidehouse's experience. The nine Programs are: Distribution Feeder Hardening; Distribution Lateral Hardening; Distribution Self-Optimizing Grid; Distribution Underground Flood Mitigation; Transmission Structure Hardening; Transmission Substation Flood Mitigation; Transmission Substation Hardening; Distribution Vegetation Management; and Transmission Vegetation Management. Detailed descriptions of these Programs can be found in Exhibit No. (BML-1).

Q. How did DEF develop the list of Programs for the SPP?

A. As mentioned above, DEF first started with the existing SPP 2023 Programs and sub-programs. These Programs are a combination of those that were previously included in DEF's Storm Hardening Plans (under the since repealed Storm Hardening rule) and those that were developed by internal subject matter experts to meet the requirements of the SPP rule and statute. Then, subject matter experts ("SMEs") with knowledge of the Transmission and Distribution systems and asset performance evaluated whether any new system performance trends were observed that would meet the intent and requirements of Section 366.096, Florida Statutes and Rule 25-6.030, F.A.C. A complete list of the Program names and descriptions selected for inclusion in SPP 2026 can be found in Exhibit No. (BML-1).

Q. Are there any new Programs included in DEF's SPP 2026 when compared to DEF's approved SPP 2023?

A. No.

Q. Are there any new Subprograms contained in DEF's SPP 2026 continuing Programs?

A. Yes. DEF is proposing to include Insulator Upgrades within the Transmission Structure Hardening Program. Mrs. Alexandra M. Vazquez discusses this Subprogram in her testimony.

Q. Are any Programs or Subprograms completing deployment within the SPP 2026 10-Year planning period?

A. Yes. As discussed in Mrs. Vazquez's testimony, DEF expects to complete its Transmission Wood Pole Replacements subprogram during this planning period. DEF also expects to reach the originally planned saturation goal of 80% deployment of the Self-Optimizing Grid Program during the planning horizon. However, the team is continuing to evaluate data from the 2024 storm season and DEF believes there may be additional value to be gained from continuing the Program to a greater portion of the distribution system.

Q. Are there other potential Programs or Subprograms that DEF may consider in the future for inclusion in the SPP?

A. Yes, DEF will continue to monitor emergent technologies and other asset hardening opportunities informed by post-storm forensic studies that may warrant further review and consideration. For example, DEF assets were heavily impacted by 2024's trio of significant storms in Debby, Helene and Milton, but the results from the post storm forensics have not been evaluated for the purposes of informing DEF's SPP. DEF will also continue to assess its proposed deployment of its current Programs and Subprograms to ensure customers are served most effectively by those investments, such as potentially continuing the Self-Optimizing Grid beyond 80% of DEF's feeders as alluded to above.

C2-105

V. PROGRAM EVALUATION, PRIORITIZATION, AND SELECTION

Q. Are there differences in program evaluation and prioritization between SPP 2026 and SPP 2023?

A. Yes. Similar to the development of SPP 2020 and SPP 2023, DEF provided Guidehouse with asset, outage, project costs, and storm damage cost data sets to support the Program evaluation and prioritization. These data sets were updated with information through 2023. As part of the refinement process from SPP 2023 to SPP 2026, DEF and Guidehouse updated values and model details such as asset location data, outage information and others which resulted in an enhanced model.

Q. Are there differences in how Programs were analyzed within the Guidehouse model?

A. No, the same analysis was performed by Guidehouse for SPP 2026 as SPP 2023. For each Program, Guidehouse estimated a reduction in storm damage and outage duration, using CMI as a proxy for duration, for each possible project location. The model enables DEF to prioritize the work over the life of the Program based on performing the highest benefit work first. As discussed in more detail in Exhibit No. (BML-2), the Guidehouse model prioritized work by looking at the probability of damage to particular assets (including consideration of information from various FEMA-produced models) and the consequences of that damage, including for example the number and/or type of customers served by particular assets. That information was then evaluated by DEF subject matter experts in the Distribution and Transmission functions for further analysis and prioritization.

Q. How did the DEF Distribution subject matter experts select the specific targets for implementation in 2026?

A. DEF's Distribution subject matter experts utilized the Guidehouse benefits-to-cost prioritized list of projects to select the highest ranked project. For the Feeder Hardening program and Lateral Hardening Overhead subprogram, DEF subject matter experts then evaluated other projects served from the same substation bank to determine if there were any opportunities with deployment years within the next three to five years. If a project or projects served by a substation bank met this criteria, DEF selected those projects to execute with the initiating target which allows DEF engineering, project management, and construction resources to work more efficiently and reduce overall construction driven disturbance duration to the customers in the area. That is; by grouping together qualifying projects from a particular substation bank, DEF aims to minimize any necessary work-related outages and reduce costs through the efficient use of resources. Other projects are worked individually and are not grouped with other projects. DEF notes that it is always working to identify efficiencies and other available means to lower costs related to all Programs. If efficiencies can be identified and costs lowered, those lower costs may allow for DEF to identify and complete additional Program scope within the Planning horizon.

C2-107

Q. Does DEF believe there are any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan?

A. No, DEF does not believe there are any implementation alternatives that could mitigate the rate impact without negatively impacting the benefits the SPP 2026 is designed to deliver. In order to mitigate rate impact, SPP 2026 would need to be reduced or delayed which would result in a reduction or delay of the benefits.

VI. BENEFITS THAT DEF'S SPP IS INTENDED TO BRING TO DEF'S CUSTOMERS

Q. What benefits does DEF believe its proposed SPP 2026 will provide its customers?

A. As mentioned above, DEF proposes to implement the activities included in Exhibit No. (BML-1). While DEF agrees with the Commission's recognition that "[n]o amount of preparation can eliminate outages in extreme weather events,"[1] DEF is confident that the activities included in this Plan will strengthen its infrastructure, reduce outage times associated with extreme weather events, reduce restoration costs, and improve overall service reliability.

[1] *See Review of Electric Utility Hurricane Preparedness and Restoration Actions,* Docket No. 20170215-EU, p. 6.

Q. Has DEF experienced extreme weather events since it began deployment of SPP 2020 and SPP 2023 Programs?

A. Yes. DEF had the following named storms impact its service territory and customers: Hurricanes Ian and Nicole in 2022; Hurricane Idalia in 2023, Hurricane Debby in August 2024, Hurricane Helene in September 2024 and most recently, Hurricane Milton in October 2024.

Q. Has DEF reviewed how its distribution storm hardened assets performed during the hurricanes mentioned above?

A. Yes. Immediately following an extreme weather event, forensic damage assessment teams are dispatched to a subset of DEF's storm hardened assets to review how the assets performed under the extreme conditions. These inspections have identified that the hardening efforts are effective as no hardened assets have been identified as damaged due to the storms. Additionally, DEF assesses a sample of all distribution poles that are damaged during an extreme weather event to determine if there are opportunities in DEF's hardening and maintenance programs. These forensic assessments are then analyzed by an outside consultant to look for trends or risks and, for the storms with completed reports, initial forensic analyses have shown thus far that the sampled distribution storm hardened assets have performed as intended during these extreme weather events.

DEF's Self-Optimizing Grid investments have helped Florida customers avoid over half a billion minutes of interruptions during the extreme weather events mentioned above, covering just three years (2022-2024). The approximate avoided customer minutes of interruption (CMI) attributable to SOG by named storm are:

Storm	CMI Avoided
Ian	196 million
Nicole	13 million
Idalia	8 million
Debby	13 million
Helene	100 million
Milton	220 million

Mrs. Vazquez discusses the transmission hardened asset performance in her testimony, but overall, as demonstrated above, DEF's ongoing preparedness practices and SPP investments continue to contribute to excellence in restoration following hurricanes and other major events.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Alexandra M. Vazquez (DEF) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: REVIEW OF 2026-2035 STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20250015-EI

DIRECT TESTIMONY OF ALEXANDRA M. VAZQUEZ

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

JANUARY 15, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Alexandra M. Vazquez. My current business address is 3300 Exchange Place, Lake Mary, FL. 32746.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Manager, Transmission Asset Management.

Q. What are your responsibilities as Manager, Transmission Asset Management?

A. My duties and responsibilities include strategic planning of Transmission reliability projects, completion of Transmission system outage investigations, management of Transmission asset health, and assurance of immediate Transmission engineering and technical support.

C4-270

Q. Please summarize your educational background and work experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the University of Central Florida. Additionally, in 2017, I received a Senior Reactor Operator certification at the Duke Energy Catawba Nuclear station. I have been with the Company, and its predecessor companies, since 2008. Throughout my 16 years at Duke Energy, I have held various leadership roles within both the nuclear generation and transmission organizations including Manager of Transmission Asset Management, Engineering Manager, Project Manager, Maintenance Supervisor, and Maintenance Superintendent. My current position, as described previously, is Manager of Transmission Asset Management in Power Grid Operations.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's filing of its Storm Protection Plan 2026-2035 ("SPP 2026"). My testimony will provide details of the Transmission investments, which includes the same Programs as previously approved in DEF's Storm Protection Plan 2023-2032 ("SPP 2023").

Q. Do you have any exhibits to your testimony?

A. No, but I am co-sponsoring the Transmission portions of the following exhibits:

- Exhibit No. (BML-1), DEF SPP Program Descriptions,

- Exhibit No. (BML-2), DEF SPP Support; and
- Exhibit No. (BML-3), DEF Service Areas.

Q. Please summarize your testimony.

A. My testimony presents the Transmission portion of the Company's SPP for the planning period 2026 through 2035. The Transmission Programs included in DEF's SPP 2026 build upon the previously approved DEF SPP 2020 and SPP 2023 Programs, taking into consideration updated reliability, asset, storm, and cost data. The Programs present a holistic approach to further strengthening the Company's infrastructure with the goal of reducing outage frequency and duration during extreme weather events and enhancing overall reliability.

III. OVERVIEW OF TRANSMISSION SPP 2026

Q. Please provide an overview of Duke Energy Florida's Transmission System.

A. A. The Company's transmission system includes approximately 5,300 circuit miles of transmission lines, which includes 500 kV, 230 kV, 115 kV and 69 kV lines. The Transmission system has more than 520 transmission substations and over 49,500 towers, poles and other related equipment and material that support a peak load of approximately 13,000 MWs. These assets deliver electric service to approximately 2 million retail customers located throughout a 20,000 square mile area including the densely populated areas around Orlando, St. Petersburg, and Clearwater, as well as rural north Florida and west central Florida.

DEF's transmission system is part of the Florida interconnected power grid that enables utilities to exchange power. Within Florida, the Company's system is extensively networked and interconnected with other investor-owned utilities, municipal electric utilities, and rural electric cooperatives.

In addition to power lines and substations, the system includes various other equipment and facilities such as control houses, computers, structures, transformers, regulators, capacitors, breakers, communication devices, and protective relays. Together, these assets provide the Company with considerable operational flexibility with its transmission system and allow DEF to provide safe and reliable power to DEF's customers.

Q. Please provide an overview of the Transmission Programs withing the SPP 2026.

A. DEF's Transmission plan addresses defined grid investment through hardening programs to withstand the impacts of extreme weather events to reduce restoration costs and customer minutes interrupted. The Transmission Programs referenced in Mr. Brian Lloyd's testimony and Exhibit No. (BML-1) are categorized into four (4) Programs (with associated sub-programs): Transmission Structure Hardening, Substation Hardening, Substation Flood Mitigation, and Transmission Vegetation Management.

IV. OVERVIEW OF PROGRAMS EVALUATED IN THE SPP

Q. Are the Programs in SPP 2026 the same as SPP 2023?

A. Yes, the DEF and Guidehouse teams selected the same portfolio of Programs for SPP 2026 as the previously approved SPP 2023. Detailed descriptions of these Programs can be found in Exhibit No. (BML-1).

Q. How did DEF develop the list of Programs for the SPP?

A. DEF first started with the existing SPP 2023 Programs and sub-programs and then consulted subject matter experts ("SMEs") with knowledge of the Transmission system and asset performance to evaluate whether any new system performance trends were observed that would meet the intent and requirements of Section 366.096, Florida Statutes and Rule 25-6.030, F.A.C. DEF reviewed the Transmission proposals in the other company's SPPs and industry trends to identify and validate potential programs. A complete list of the Program names and descriptions selected for inclusion in SPP 2026 can be found in Exhibit No. (BML-1).

Q. Are there any new Subprograms contained in DEF's SPP 2026 continuing Programs?

A. Yes, DEF is proposing to include Insulator Upgrades within the Transmission Structure Hardening Program. This subprogram will bring an accelerated enhancement of line insulators to decrease outage events and improve operation of the grid during extreme weather events. Line insulators will be prioritized based on inspection data and enhanced weather modeling. This sub-program is further discussed in Exhibit No. (BML-1).

Q. Are there any other adjustments to DEF's continuing SPP 2026 Programs?

A. Other than the subprogram addition discussed above, there are no additional modifications to the SPP 2026 Transmission Programs.

Q. Are any Programs or Subprograms completing deployment within the SPP 2026 10-Year planning period?

A. DEF expects to complete its Transmission Wood Pole Replacements subprogram during this 10-year planning period. This subprogram is estimated to be completed by the end of 2028.

Q. What benefits and other impacts will be experienced with the completion of the Transmission Wood Pole Replacement subprogram?

A. Wood poles are among the transmission assets most susceptible to damage, and completing their replacement with hardened assets will allow more customers to experience the immediate benefits of a hardened system (i.e., reduced and minimized outages). Completion of this subprogram will also allow DEF to focus on other structure hardening subprograms (e.g., tower upgrades). However, because other structure hardening subprograms such as Overhead Ground Wire replacement will no longer be performed in conjunction with wood pole replacements, the costs associated with those other subprograms (which are not increasing) will now be fully allocated rather than shared with the wood pole replacement. As always, DEF will continue to explore other opportunities for optimization.

Q. Are there other potential programs that DEF may consider in the future for inclusion in the SPP?

A. Yes, DEF will continue to monitor emergent technologies and system performance for other asset hardening opportunities that may warrant further review and consideration.

V. PROGRAM EVALUATION, PRIORITIZATION, AND SELECTION

Q. Are there differences in program evaluation and prioritization between SPP 2026 and SPP 2023?

A. Yes. Similar to the development of SPP 2020 and SPP 2023, DEF provided Guidehouse with asset, outage, and cost data sets to support the Program evaluation and prioritization. These data sets were updated with information current through 2023. As part of the refinement process from SPP 2023 to SPP 2026, DEF and Guidehouse updated values and model details which resulted in an enhanced model.

Q. Are there differences in how Programs were analyzed within the Guidehouse model?

A. No, as discussed in Mr. Lloyd's testimony, Guidehouse performed the same analysis for SPP 2026 as SPP 2023, the only modifications were to the inputs as discussed above.

Q. How were the Transmission projects selected to provide the greatest value to DEF's customers?

A. The Guidehouse model utilizes a benefit-cost analysis (BCA) approach, based on probability of damage and consequence of damage. This enhanced model ensued a prioritized list of projects. Utilizing this list, DEF's Transmission SMEs evaluated Programs for targeted opportunities for optimization, considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability. The optimization process further involved evaluating Programs for remaining projects either on the same line segment or at the same substation with scheduled deployment within the next two years that would require the same outage. If a project or projects on the line segment or at the substation met this criterion, DEF selected this work to be completed alongside the initiating project. This targeted optimization provides synergies to minimize disruptions to our communities and customers, improve resource utilization and efficiency, and reduce the cost of execution. DEF continuously works to identify efficiencies and other available means to lower costs related to all Programs. If efficiencies can be identified and costs lowered, those lower costs may allow for DEF to identify and complete additional Program scope within the Planning horizon.

Q. Have you completed the substation flood mitigation evaluation, and what were the results?

A. Yes, DEF completed its program reevaluation. Utilizing the updated FEMA flood maps and additional detailed flood studies, DEF reviewed all substations within its territory. Site elevations were determined and compared with the FEMA flood elevations and historical flooding to determine potentially impacted sites and how the sites could be mitigated.

As a result of this review, six (6) sites are no longer deemed flood impacted sites, leaving five (5) sites within the program from the original SPP 2023 site list. An additional six (6) sites were newly identified to have flood impacts based on the recent analysis. The updated mitigation plan now includes a total of eleven (11) sites. These sites were input into the updated SPP 2026 model to determine prioritization.

VI. BENEFITS THAT DEF'S SPP INTENDS TO BRING TO DEF'S CUSTOMERS

Q. What benefits does DEF intend its SPP 2026 to deliver to its customers?

A. As Witness Lloyd has mentioned, DEF proposes to implement activities included in Exhibit No. (BML-1). DEF is confident that the activities included in this 10-Year plan will strengthen its infrastructure, reduce outage times associated with extreme weather events, reduce restoration costs, and improve overall service reliability.

Q. Has DEF experienced extreme weather events since it began deployment of SPP 2020 and SPP 2023 Programs?

A. Yes. DEF had the following named storms impact its service territory and customers: Hurricanes Ian and Nicole in 2022; Hurricane Idalia in 2023, Hurricane Debby in August 2024, Hurricane Helene in September 2024 and most recently, Hurricane Milton in October 2024.

Q. How have DEF's transmission storm hardened assets performed during the hurricanes mentioned above?

A. Immediately following an extreme weather event, damage assessment teams are dispatched to review how all transmission assets (hardened and otherwise) performed under these extreme weather conditions. Following this initial assessment, forensic analysis services are rendered. An outside contractor collects and analyzes damaged facilities and components after an extreme weather event. Sufficient data is collected at the failure sites to determine the nature and cause of the failure. Data includes the following: Asset identification, photographs, sample of damaged components as necessary, field technical assessment (soil conditions, exposure, vegetation, etc.), and inventory of associated hardware. Over the last few years, the results of this analysis provide correlation of the damaged assets to (1) storm intensity, (2) storm location, (3) asset condition, and (4) asset design.

Forensic analyses have shown thus far that the transmission storm hardened assets have performed as intended during these extreme weather events. Zero SPP hardened assets have failed due to extreme weather events. In reviewing our wood pole subprogram, DEF has seen a steady and consistent decline in number of failures over the years. During Hurricane Irma DEF had 139 non-hardened poles fail and Hurricane Michael DEF had 130 structures (towers) fail. Most recently, during a similar storm (Hurricane Milton), DEF had eighteen (18) non-hardened poles, and zero (0) structures (towers) fail.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Christopher Menendez (DEF) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: REVIEW OF 2026-2035 STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20250015-EI

DIRECT TESTIMONY OF CHRISTOPHER A. MENENDEZ

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

JANUARY 15, 2025

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is Duke Energy Florida, LLC, 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Director, Rates and Regulatory Planning.

Q. What are your responsibilities as Director, Rates and Regulatory Planning?

A. I am responsible for the Company's regulatory planning and cost recovery, including the Company's Storm Protection Plan ("SPP") filing.

Q. Please summarize your educational background and work experience.

A. I joined the Company on April 7, 2008. Since joining the Company, I have held various positions in the Florida Planning & Strategy group, DEF Fossil Hydro Operations Finance, and DEF Rates and Regulatory Strategy. I was promoted to my current position in April 2021. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. I received a Bachelor of Science degree in Accounting from the University of South Florida, and I am a Certified Public Accountant in the State of Florida.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an estimate of the annual revenue requirements for the Company's 2026-2035 Storm Protection Plan ("SPP"), as required by Rule 25-6.030(3)(g), F.A.C., as well as an estimate of rate impacts for each of the first three years of the SPP for DEF's typical residential, commercial, and industrial customers, as required by Rule 25-6.030(3)(h), F.A.C.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, exhibits in this proceeding?

A. Yes. I am co-sponsoring the Revenue Requirements and Rate Impact section of Exhibit No. (BML-1) attached to the direct testimony of Mr. Lloyd. This section of Exhibit No. (BML-1) is true and accurate to the best of my knowledge and belief.

Q. What are the estimated annual revenue requirements for the Company's 2026-2035 SPP?

A. That information is found on page 56 of Exhibit No. (BML-1).

Q. What are the estimated rate impacts for each of the first three years of the SPP for DEF's typical residential, commercial, and industrial customers?

A. That information is found on page 56 of Exhibit No. (BML-1).

Q. Has DEF complied with the requirements of Rule 25-6.030(3)(g) and (3)(h)?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

C3-269

(Whereupon, prefiled direct testimony of Kevin Palladino (TECO) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KEVIN E. PALLADINO

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

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

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

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

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

Q. Please describe your educational background and professional experience.

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

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

A. No.

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

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

Q. Are you sponsoring any exhibits in this proceeding?

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

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

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

TAMPA ELECTRIC'S SPP ACHIEVEMENTS TO DATE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please describe the new Transmission Switch Hardening Program.

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

The Transmission Switch Hardening Program is a four-year initiative to evaluate the upgrade of 153~~250~~ transmission switch locations with modern switches enabled with Supervisory Control and Data Acquisition ("SCADA") communication and remote-control capabilities. Operating these switches from a control center and avoiding sending technicians to the switch sites will allow for faster isolation of trouble spots on the transmission system and more rapid restoration following line faults, thereby increasing the resiliency of the transmission system. Additional information regarding this Program is provided in Tampa Electric's proposed 2026-2035 Plan.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SUMMARY

Q. Please summarize your direct testimony.

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

Commission.

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

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

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of A. Sloan Lewis (TECO) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

A. SLOAN LEWIS

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

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Manager, Rates in the Regulatory Affairs Department.

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

A. As the Manager, Rates, I am responsible for Tampa Electric's Storm Protection Plan ("SPP") and the Storm Protection Plan Cost Recovery Clause ("SPPCRC"). My duties and responsibilities include the oversight of the revenue requirements, rates, and all Florida Public Service Commission ("Commission") filings related to the SPP and SPPCRC.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in accounting from Florida State University in 1994 and a Master of Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 24 years, expanded my cost recovery clause oversight and leadership to include all of the clauses for Tampa Electric and People's Gas. I led a team of Accountants with the responsibility over the clause-related financial transactions in the company's accounting system, the proper classification of recoverable and non-recoverable expenses, the accurate reporting of clause expenses in Commission filings, and the annual Commission clause audits. In 2024, I moved into the role of Manager, Rates overseeing the regulatory aspects of the SPP and SPPCRC.

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

A. The purpose of my testimony in this proceeding is to present the estimate of rate impacts for each of the first three years of the Tampa Electric's proposed 2026-2035 SPP for the utility's typical residential, commercial, and industrial customers required by Rule 25-6.030(g)-(h) of the Florida Administrative Code. My testimony also explains the methodology used to calculate these estimates.

Q. Have you prepared an exhibit to accompany your direct testimony?

A. Yes. Exhibit No. ASL-1, entitled "Tampa Electric's 2026-2035 SPP Total Revenue Requirements by Program" was prepared under my direction and supervision. This exhibit shows the annual revenue requirement for the company's proposed 2026-2035 SPP programs.

CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS FOR TAMPA ELECTRIC'S 2026-2035 SPP

Q. What are the estimated annual jurisdictional revenue requirements for each year of the company's proposed 2026-2035 SPP?

A. The estimated annual jurisdictional revenue requirements for each year of the company's proposed 2026-2035 SPP are included in the following table. The revenue requirements for each proposed SPP programs are set out in my Exhibit No. ASL-1.

Total SPP Revenue Requirements (2026-2035)

Year	Revenue Requirements
2026	$142,270,601
2027	$169,739,854
2028	$191,967,403
2029	$211,267,410
2030	$233,188,276
2031	$254,939,680
2032	$275,718,765
2033	$294,281,562
2034	$312,752,491
2035	$331,105,799

Q. How were the estimated annual jurisdictional revenue requirements for the proposed plan developed?

A. The estimated annual jurisdictional revenue requirements were developed with cost estimates for each of the proposed 2026-2035 SPP programs, with the addition of depreciation and return on the SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the SPP Cost Recovery Clause Rule. Tampa Electric used the weighted average cost of capital and depreciation rates established by the Commission in the company's most recent base rate case. See Vote Sheet, DN 10091-2024, filed December 3, 2024, in Docket No. 20240026-EI.

The revenue requirement calculation is further reduced by the depreciation savings that result from the retirement of assets as part of SPP projects. The revenue requirement calculation does not include Allowance for Funds Used During Construction ("AFUDC") because none of the projects in Tampa Electric's proposed 2026-2035 SPP qualify for AFUDC under Rule 25-6.0141, F.A.C.

Q. Do these revenue requirements include any costs that are currently recovered in base rates?

A. Yes. The annual revenue requirements shown in the table above reflect all the investments and expenses associated with the activities in the plan without regard to whether the costs are recovered through the company's existing base rates and charges or through the company's SPPCRC. In the "2020 Agreement," approved by the Commission in Order No. PSC-20200224-AS-EI, issued on June 30, 2020, Tampa Electric agreed to recover the costs of some existing storm hardening activities that were previously recovered through base rates through the SPPCRC, while others remain recovered through base rates.

Q. Will Tampa Electric seek recovery of the appropriate estimated SPP costs through the separate annual SPPCRC proceeding, in accordance with Rule 25-6.031, F.A.C.?

A. Yes, Tampa Electric will continue to file for cost recovery of the estimated SPP costs through the separate annual SPPCRC proceeding. The revenue requirement presented in the company's proposed 2026-2035 SPP is an estimated revenue requirement for all of the programs in the plan. The Commission will address the estimated annual revenue requirement for the clause recoverable programs, and cost recovery for that revenue requirement, in the separate SPPCRC proceeding.

CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2026-2028 OF THE PROPOSED STORM PROTECTION PLAN

Q. Please provide an estimate of rate impacts for each of the first three years of Tampa Electric's proposed 2026-2035 SPP for typical residential, commercial, and industrial customers.

A. The estimated rate impacts for each of the first three years of the proposed 2026-2035 SPP for a typical residential, commercial, and industrial Tampa Electric customer are listed in the table below.

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

Q. How were the estimated rate impacts for each of the first three years of the proposed 2026-2035 SPP for a typical residential, commercial, and industrial customer determined?

A. For each year, the programs were itemized and identified as either substation, transmission, or distribution costs. Each of those functionalized costs was then allocated to rate class using the allocation factors for that function. The company used the allocation factors from the Tampa Electric 2024 base rate case approved in the company's most recent base rate case. See Vote Sheet, DN 10091-2024, filed December 3, 2024, in Docket No. 20240026-EI.

Once the company derived the total SPP revenue requirement recovery allocation to the rate classes, the rates were determined in the same manner. For residential customers, the charge is a per-kWh charge. For commercial and industrial customers, the charge is a per-kW charge. The estimated charges were derived by dividing the rate class allocated SPP revenue requirements by the 2026 energy billing determinants for residential and small commercial customers and by the 2026 demand billing determinants for large commercial and industrial customers. Those charges were then applied to the billing determinants associated with typical bills for each group to calculate the impact on those bills. The company performed this analysis using the costs for 2026, 2027, and 2028.

Q. Will the rates established through the SPPCRC differ from those presented in the rate impact calculations in the SPP?

A. Yes. The rate impacts presented above reflect the "all-in" costs of the company's SPP without regard to whether the costs are or will be recovered through the SPPCRC or through the company's base rates.

In addition, when it makes its SPPCRC filing, the company will use more recent billing determinants based on the most current load forecast available at that time.

SUMMARY

Q. Please summarize your direct testimony.

A. My testimony and exhibit demonstrate that Tampa Electric's estimated annual jurisdictional revenue requirements for each of the 10 years of the 2026-2035 SPP and rate impacts for each of the first three years of the 2026-2035 SPP for the utility's typical residential, commercial, and industrial customers comply with Rule 25-6.030(3)(g)-(h). These calculations were performed in accordance with the requirements of Section 366.96, Florida Statutes, and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Jason D. DeStigter (TECO) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF TAMPA ELECTRIC COMPANY

1. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q. By whom are you employed and in what capacity?

A. I am employed by 1898 & Co. as a Director and lead the Utility Investment Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 250 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 8,300 engineers, architects, construction professionals, scientists, consultants and entrepreneurs with more than 40 offices across the country and throughout the world.

Q. Briefly describe your educational background and certifications.

A. I received a Bachelor of Science Degree in Engineering and a Bachelor’s in Business Administration from Dordt College, now called Dordt University. I am also a registered Professional Engineer in the state of Kansas.

Q. Please briefly describe your professional experience and duties at 1898 & Co.

A. I am a professional engineer with 16 years of experience providing consulting services to electric utilities. I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients. These studies have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a project manager, I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside their Asset Management Practice performing similar studies to the effort performed for Tampa Electric Company ("Tampa Electric").

Q. Have you previously testified before the Florida Public Service Commission or other state commissions?

A. I provided written and rebuttal testimony on behalf of Tampa Electric Company for the 2020-2029 and 2022-2031 Storm Protection Plans ("SPP") before the Florida Public

Service Commission (Docket Nos. 20200067-EI and 20220048-EI). I have also provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light, Baltimore Gas & Electric, Oklahoma Gas and Electric, Entergy Louisiana, Entergy New Orleans, Entergy Texas, AEP Texas, and Texas New Mexico Power. A complete list of testimony I have provided before other regulatory bodies is included with Exhibit JDD-1.

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

A. The purpose of my testimony is to summarize the results and methodology developed using 1898 & Co.'s Storm Resilience Model, with the following objectives:

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

Through my testimony I will describe the major elements of the Storm Resilience Model, which includes a Major Storm Event Database, Storm Impact Model, Resilience Benefit Module, and Budget Optimization & Project Prioritization. Specifically, I will define resilience, review historical major storm events to impact Tampa Electric service territory, describe the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explain how to understand the resilience benefit results. Additionally, I will outline the key updates to the Storm Resilience Model for the 2026-2035 SPP. Throughout my testimony I will describe both how the assessment was performed and why it was performed as such. Finally, I will describe the calculations and results of the Storm Resilience Model.

Q. Are you sponsoring any attachments in support of your testimony?

A. Yes, I am sponsoring the 1898 & Co, Tampa Electric's 2026 – 2035 Storm Protection Plan Resilience Benefits Report that is being included as Appendix "I" in Tampa Electric's proposed 2026-2035 SPP.

Q. Were your testimony and the attachment identified above prepared or assembled by you or under your direction or supervision?

A. Yes.

Q. What was the extent of your involvement in the preparation of Tampa Electric's proposed 2026-2035 SPP?

A. I served as the 1898 & Co. project director on the Tampa Electric 2026-2035 Storm Protection Plan Assessments and Benefits Assessment. The evaluation utilized a Storm Resilience Model to calculate benefits. I worked directly with the Tampa Electric Team involved in the resilience-based planning approach. I was directly involved in the development of the Storm Resilience Model, the assessment and results, as well as being the main author of the report.

2. RESILIENCE-BASED PLANNING OVERVIEW

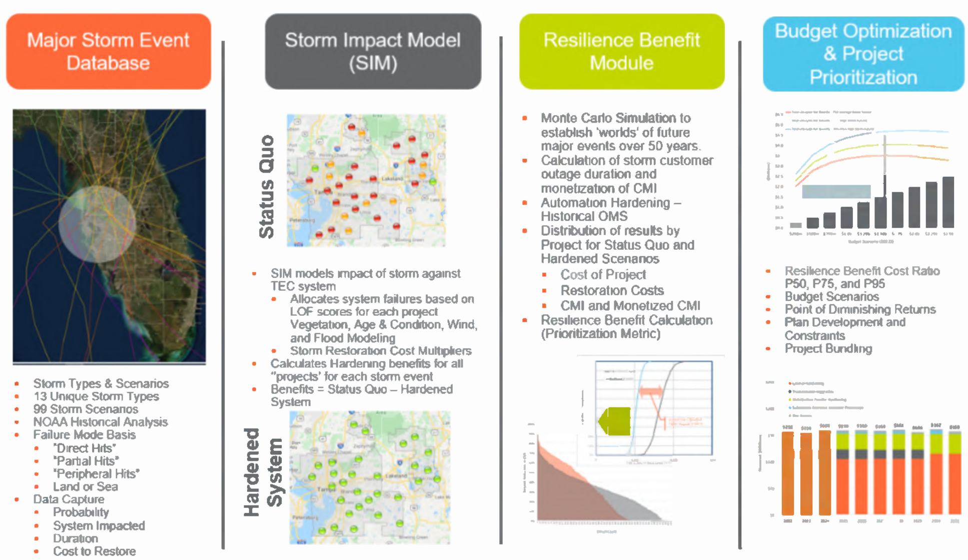
Q. Please describe the analysis 1898 & Co. conducted for Tampa Electric.

A. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the Tampa Electric Transmission & Distribution ("T&D") system utilizing a Storm Resilience Model. The Storm Resilience Model models the benefits of all potential hardening projects for an 'apples to apples' comparison across the system. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level. The results of the Storm Resilience Model are:

- Decrease in the Storm Restoration Costs
- Decrease in the customers impacted ("CI") and the duration of the overall outage, calculated as Customer Minutes Interrupted ("CMI")

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit. Figure 1 provides an overview of the Storm Resilience Model used to calculate the project benefit and prioritize projects.

Figure 1: Storm Resilience Model Overview



The storm database includes the future "universe" of potential storm events to impact the Tampa Electric service territory. The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios.

Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone the asset is in. The Storm Impact Model also estimates the restoration costs and CMI for each of the projects. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per Tampa Electric's hardening standards. The CMI benefit is monetized using the U.S. Department of Energy's ("DOE") Interruption Cost Estimator ("ICE") for project prioritization purposes.

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

The Budget Optimization and Project Scheduling model prioritizes the projects based on the highest resilience benefit cost ratio. The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates Tampa Electric's technical and operational realities (Transmission outages) in scheduling the projects.

This resilience-based prioritization facilitates the identification of the critical hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers get the "biggest bang for the buck."

Q. Which of the Storm Protection Plan programs are evaluated within the Storm Resilience Model?

A. The Storm Resilience Model includes project benefits results, budget optimization, and project prioritization for the following Storm Protection Plan programs:

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

Q. Please outline the key updates there were made to the Storm Resilience Model from the 2022-2031 SPP to the 2026-2035 SPP assessment.

A. The Storm Resilience Model was used in the development of the 2022-2031 SPP as well as the 2026-2035 SPP. The following are the key updates to the 2026-2035 Storm Resilience Model:

1. General - these updates include shifting of the time horizon, additional years of storms to the historical analysis, and accounting for completed projects.
2. Capital Cost Assumptions - based on actual completed projects and communicated increases in commodity prices, the cost assumptions for all project types were adjusted.
3. Lateral Undergrounding Approach - Based on continued lessons learned from the lateral undergrounding program, Tampa Electric has refined its lateral undergrounding project approach for this SPP. Tampa Electric has determined that the analysis should assume all laterals on a circuit will be undergrounded as part of the 1898 & Co. Analysis. This change will enhance the ability for Tampa Electric to contract out work and deliver benefits to all Tampa Electric customers on a circuit. Although the model assumes each lateral on a circuit will be undergrounded, during detailed distribution planning and engineering review, Tampa Electric may determine some lateral sections need not be undergrounded (e.g., feeds abandoned meters, crosses waterway, crosses railroads). By undergrounding all the electrically connected protection zones off a circuit feeder/mainline Tampa Electric will more easily be

able to anticipate costs and design work to minimize the number of new underground miles. It should be noted that Tampa Electric still has lateral undergrounding projects being designed and constructed as part of the 2022-2031 SPP. The analysis has been designed to assume these segments will be completed as planned so as not to duplicate costs or benefits.

Q. Please outline the type and count of hardening projects evaluated in the Storm Resilience Model.

A. Table 1 contains the list of potential hardening projects by program evaluated in the Storm Resilience Model.

Table 1: Potential Hardening Project Count

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

Q. How were these potential hardening projects identified?

A. The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of Tampa Electric's system during major storm events. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. Additionally, hardening approaches for parts of the system were based on the balance of the resilience benefit they provide with the overall costs. Table 2 shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

Table 2: Tampa Electric Asset Base

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

All of the assets that benefit from hardening are strategically grouped into potential hardening projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse. For lateral projects, all protection zones eligible for undergrounding were grouped together.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '1' were also included in these projects. The combination of physical hardening and automation hardening provides significant resilience benefit for feeders.

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

For substations, Tampa Electric conducted a detailed assessment of extreme weather risk. Based on this, nine substations were identified that included flooding risk to the level that could justify investment, of which six were prioritized for this 2026-2035 SPP.

Q. Why is this approach to hardening project identification important?

A. This approach to hardening project identification is important for several reasons.

- The approach is comprehensive. As Table 2 shows, the approach evaluates nearly all of Tampa Electric's T&D system. By considering and evaluating the entire system on a consistent basis, the results of the hardening plan provide confidence that portions of the Tampa Electric system are not overlooked for potential resilience benefit.
- By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and

industrial, and priority customers. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all weak links in the circuit and for capturing the full benefit for customers.

- The granularity at the asset and project levels allows Tampa Electric to invest in portions of the system that provide the most value to customers from a restoration cost reduction, CI, CMI perspective. The adopted approach provides confidence that the overall plan is investing in parts of the system that provide the most value for customers.
- These types of hardening projects enhance resilience by providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows Tampa Electric to provide a higher level of system resilience.
- The approach balances the use of robust data sets with Tampa Electric experience with storm events to develop storm hardening projects. Data-only approaches may

provide decisions that don’t match reality, while people-driven only solutions can be filled with bias. The approach balances the two to better identify types of hardening projects.

Q. Why is it necessary to model storm hardening projects benefits using this resilience-based planning approach and Storm Resilience Model?

A. The Storm Resilience Model was architected and designed for the purpose of calculating storm hardening project benefit in terms of reduced restoration costs and CMI to build a SPP with the right level of investment that provides the most benefit for customer. It was necessary to model storm hardening projects using the resilience-based planning approach shown in Figure 1 for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms to impact the Tampa Electric service territory. For this reason, the resilience-based planning approach includes the “universe” of potential major events that could impact Tampa Electric over the next 50 years, this is the Major Storm Event Database.

2. The cost to restore the failed assets is dependent on the extent of the damage and resources used to fix the system. The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. Modeling this series of events for the entire system at the asset and project level for both Status Quo and Hardened scenarios is needed to accurately model hardening project benefits. Therefore, the resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 99 storm events for both scenarios.
3. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life cycle of the assets. The Monte Carlo Simulation creates a 1,000-future storm "worlds." From this, the life-cycle resilience benefit of each hardening project can be calculated.
4. The Budget Optimization algorithm develops a long-term Storm Protection Plan that optimizes cost, maximizes customers' benefit, and does not exceed Tampa Electric technical execution constraints.

3. MAJOR STORM EVENT DATABASE

Q. Please provide an overview of the Major Storm Event Database and how it was developed.

A. The Major Storm Event Database includes the "universe" of storm events that could impact Tampa Electric's service territory over the next 50 years. It was developed collaboratively between Tampa Electric and 1898 & Co. It utilizes information from the National Oceanic and Atmospheric Administration ("NOAA") database of major storm events, Tampa Electric historical storm reports, available information on the impact of major storms to other utilities, and Tampa Electric experience in storm recovery. From that information, 13 unique storm types were observed to impact the Tampa Electric service territory. For each of the storm types, various storm scenarios were developed to capture the range of probabilities and impacts of each storm type. In total, 99 storms scenarios were developed to capture the "universe" of storm events to impact the Tampa Electric service territory. Table 3 provides a summary of the Major Storm Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration of the event.

Table 3: Major Storm Event Database Overview

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

Q. How were the storm impact ranges developed?

A. The range of system impacts for each storm scenario were developed based on historical storm reports from Tampa Electric and augmented by Tampa Electric's team experience with historical storm events. The approach followed an iterative process of filling out more known impact information from recent events and developing impacts for those events without impact data based on their relative storm strength to the more known events.

4. STORM IMPACT MODEL

Q. Please provide an overview of the Storm Impact Model.

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

Q. How are restoration costs allocated to the asset base for each major storm events?

A. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration cost multipliers above planned replacement costs. These multipliers were developed by Tampa Electric and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF and the overall restoration costs outlined in the Major Event Storm Database.

Q. How are customer outage durations calculated in the model for each major storm event?

A. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset and project in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefits are also monetized.

Q. Why were CMI benefits monetized?

A. The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed. Since CMI is in minutes and restoration costs are in dollars, the resilience-based planning approach monetized CMI. The monetized CMI benefit is combined with the restoration cost benefit for each project to calculate a total resilience benefit in dollars.

Q. How was the CMI benefit monetized?

A. CMI was monetized using DOE's ICE Calculator. The ICE Calculator is an electric outage planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability or resilience improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE. The ICE calculator includes the cost of an outage for different types of customers. The calculator was extrapolated for the longer outage durations associated with storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

5. RESILIENCE BENEFIT MODULE

Q. Please provide an overview of the Resilience Benefit Calculation Module

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

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 20 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

Q. What economic assumptions are used in the life-cycle Resilience Benefit Module?

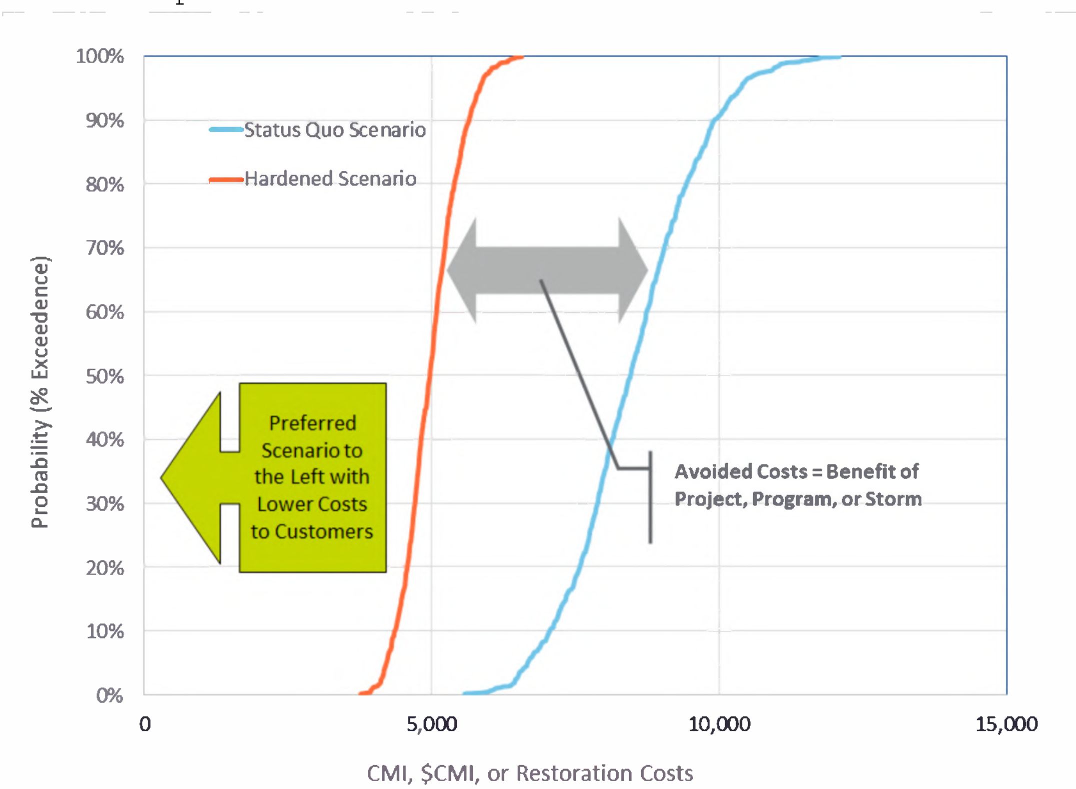
A. The resilience net benefit calculation includes the following economic assumptions.

- 50-year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years.
- 2% escalation rate
- 6% discount rate

Q. How are the resilience results of the Monte Carlo Simulation displayed and how should they be interpreted?

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

Figure 2: Status Quo and Hardened Results Distribution Example



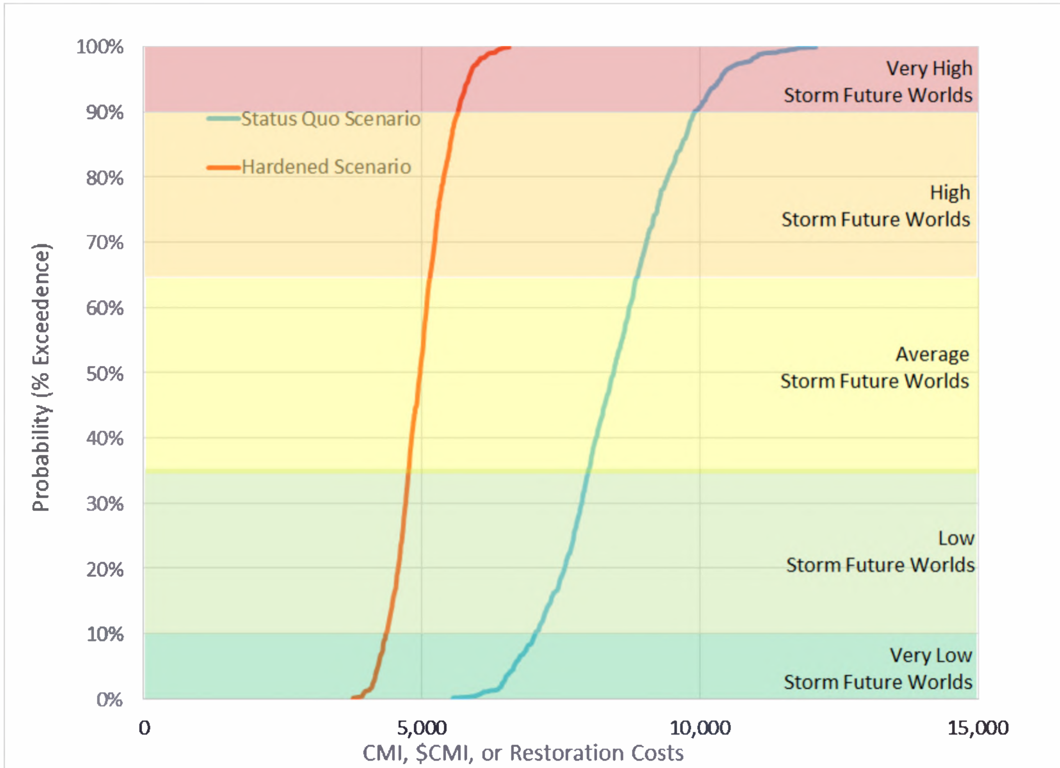
Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e., vertical) the less range in the result. The more horizontal the slope, the wider the range and variability in the results.

Q. How do S-Curves map to potential Future Storm Worlds?

A. Figure 3 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

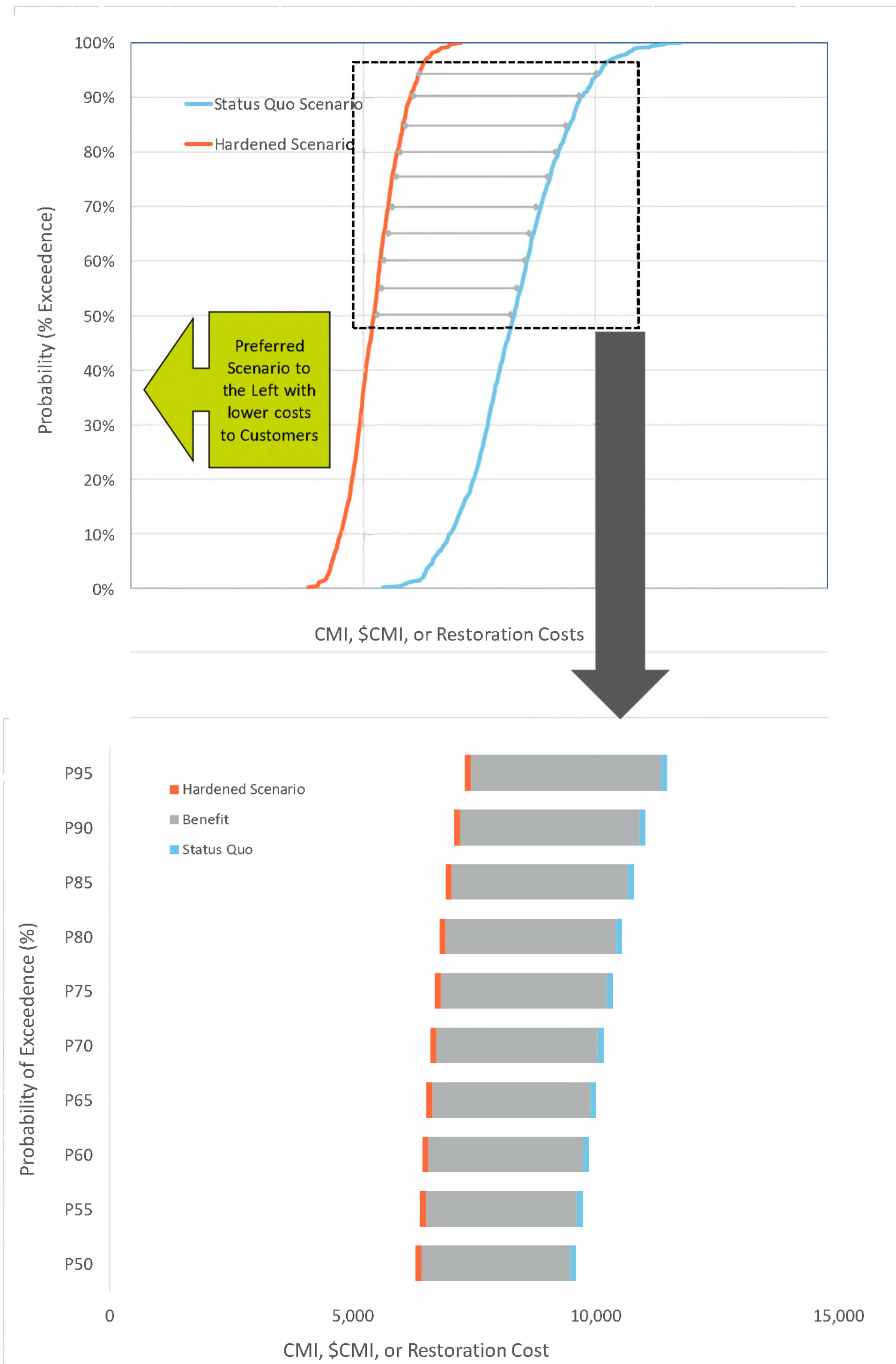
Figure 3: S-Curves and Future Storms



Q. How are the S-Curves used to display the resilience benefit results?

A. For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the resilience results will show specific P-values to highlight the gap between the Status Quo and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 4 illustrates this concept of looking at the top part of the S-curves and showing the P-values.

Figure 4: S-Curves and Resilience Focus



Q. Please describe the analysis to calculate resilience benefit for automation hardening projects.

A. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event.

The resilience benefit for feeder automation was estimated using historical Major Event Day ("MED") outage data from the OMS. MED is often referred to as "grey-sky" days as opposed to non-MED which is referenced as "blue-sky" days. Tampa Electric has outage records going back 20 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 20 years.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. The Storm Resilience Model extrapolates the 20 years of benefit calculation to 50 years to match the time horizon of the other projects. Additionally, the CMI was monetized and discounted over the 50-year time horizon to calculate the net present value (NPV). The NPV calculation assumed a replacement of the reclosers in year

25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Q. Please provide an example of this calculation.

A. A historical outage may include a down pole from a storm event, causing the substation breaker to lock out resulting in a four-hour outage for 1,500 customers, or 360,000 CMI (4*1500*60). The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70%.

6. BUDGET OPTIMIZATION AND PROJECT SCHEDULING

Q. How were hardening projects prioritized?

A. All the projects are evaluated and prioritized using the same criteria allowing all 1,588 projects to be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50-year NPV gross benefit value listed above. The ranking is performed for each of the P-values (P50, P75, and P95) as well as a weighted value.

Performing prioritization for each of the four benefit cost ratios is important since each project has a different rate of benefit change between the P50 to P95 values. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. Tampa Electric and 1898 & Co. settled on a weighting of the three values for the base prioritization metric, however, investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

Q. How was the overall investment level set and projects selected?

A. In developing the Tampa Electric Storm Protection plan project identification and schedule, the Tampa Electric and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction

- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (e.g., project A before project B, project Y at the same time as Project Z)
- Remaining transmission structures left to be converted from wood to non-wood (Transmission Asset Upgrades program)
- Remaining substations (six) identified for extreme weather protection measures

7. RESILIENCE BENEFIT RESULTS

Q. What is the investment profile of the Storm Protection Plan?

A. Table 4 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.62 billion, although this table omits a small amount of cost that extends into 2036. Lateral undergrounding makes up most of the total, accounting for approximately 77.7% of the total investment. Feeder Hardening is second, accounting for 17.2%. Transmission upgrades make up approximately 3.74% of the total, with substations making up 1.4%.

Table 4: Storm Protection Plan Investment Profile by Program (Nominal $000)

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

Q. What are the restoration cost benefits of the plan?

A. The 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $460 million to $1,480 million. With the Storm Protection Plan, the costs decrease by approximately 28% to 30%. The decrease in restoration costs is approximately $130 to $450 million. From a NPV perspective, the restoration costs decrease benefit is approximately 8% to 28% of the project costs.

Q. What are the customer outage benefits of the plan?

A. The customer outage benefits are projected to consist of approximately a 10% decrease in the storm CMI over the next 50 years.

Q. What are the key take-aways from how resilience-based planning assessment was performed?

A. The following are the key take-aways from how the resilience-based planning assessment was performed in the Storm Resilience Model:

- Customer and Asset Centric: The model is foundationally customer and asset centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset weak links that serve customers shows that the Storm Resilience Model is directly aligned with the intent of the statute to identify hardening projects that provide the most benefit to customers. With this customer and asset centric approach, the specific restoration cost saving and impact to customers in terms of CMI benefit, which are required by the statute, can be calculated more accurately.

- Comprehensive: The comprehensive nature of the assessment is best practice; by considering and evaluating nearly the entire T&D system the results of the hardening plan provide confidence that portions of the Tampa Electric system are not overlooked for potential resilience benefit.
- Consistency: The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits calculation between asset types. For example, the model can compare a substation hardening project to a lateral undergrounding project. This is a significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios.
- Rooted in Cause of Failure: The Storm Resilience Model is rooted in the causes of asset and system failure from two perspectives. Firstly, the Major Storm Event Database outlines the range of storm stressors and the high-level impact to the system. Secondly, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail, mainly

vegetation density, asset condition, wind zone, and flood modeling. With this basis, hardening investment identification and prioritization provides a robust assessment to focus investment on the portions of the system that are more likely to fail in the major storm.

- Drives ~~Prudency~~Reasonableness: The assessment and modeling approach drives ~~prudency~~reasonableness for the Storm Protection Plan in that the business case allows Tampa Electric to invest in the portions of the system that provide the model value to customers.
- Balanced: Since storm events cannot be fully eliminated, the diversification of hardening measures allows Tampa Electric to provide a higher level of system resilience for customers.

Q. What conclusions can be made from the results of the resilience analysis?

A. The conclusions of Tampa Electric's Storm Protection plan evaluated within the Storm Resilience Model are:

- The overall investment level of $1.62 billion for Tampa Electric's Storm Protection Plan is reasonable and provides customers with maximum benefits. The projects selected have favorable project economics for the duration of the SPP.

- Tampa Electric's Storm Protection Plan results in a reduction in storm restoration costs of approximately 28% to 30%. In relation to the plan's capital investment, the restoration costs savings range from 8% to 28% depending on future storm frequency and impacts.
- The CMI decreases by approximately 10% over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted by individual outages, and decreasing the length of the outage time.
- The cost associated with purchasing the reduction in storm CMI (that is, the total Investment less the Restoration Cost Benefits) is in the range of $1.98 to $3.46 per minute. This entire range is less than the outage costs derived from the DOE ICE Calculator and less than the typical 'willingness to pay' found with customer surveys.
- Tampa Electric's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.

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

8. CONCLUSION

Q. Does this conclude your prepared verified direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Mark Cutshaw (FPUC) was inserted.)

Before the Florida Public Service Commission

Direct Testimony of P. Mark Cutshaw

On Behalf of

Florida Public Utilities Company

Docket 20250017-EI

I. Background

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw. My business address is 780 Amelia Island Parkway, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering. My electrical engineering career began with Mississippi Power Company in June 1982. I spent nine years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During January 2024, I moved into my current role as Manager, Electric Operations.

Q. Have you previously testified before the Commission?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case addressed in Docket No. 20140025-EI, rebuttal testimony in Docket No. 20180061-EI, direct and rebuttal testimony in Docket No. 20190156-EI, which was the limited proceeding to recover storm costs associated with Hurricane Michael, as well as testimony in numerous years for the Fuel and Purchased Power Cost Recovery proceeding. Most recently, I provided testimony in Docket No. 20220049-EI, the initial filing for approval of FPUC's Storm Protection Plan, as well as Dockets Nos. 20220010-EI, 20230010-EI, and Docket No. 20240010-EI for the Storm Protection Plan Cost Recovery Clause proceeding.

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

A. The purpose of my testimony is to provide an overview of the 2026 – 2035 Storm Protection Plan ("SPP"), pursuant to Rule 25-6.030, F.A.C. for Florida Public Utilities Company ("FPUC")

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Attached to my direct testimony is Exhibit PMC-01, which is FPUC's proposed, updated 2026-2035 SPP.

II. Overview of the FPUC SPP

Q. What is the purpose of the FPUC SPP?

A. The purpose of the FPUC SPP is to comply with Florida Public Service Commission Rule 25-6.030 F.A.C., Storm Protection Plan, which was established in accordance with Section 366.96, F.S. Section 366.96, F.S. requires each investor-owned electric utility (IOU) to file a transmission and distribution Storm Protection Plan that covers the immediate 10-year planning period. The plans are required to be filed with the Florida Public Service Commission ("Commission") every three years and must explain the systematic approach the utility will follow to achieve the objectives of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." s. 366.96(3). The Commission adopted Rule 25-6.030, Florida Administrative Code (F.A.C.), Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, to implement the new statute.

FPUC filed its first SPP on April 11, 2022, which was approved with modifications by Order No. PSC-2022-0387-FOF-EI, issued in Docket No. 20220049-EI.

FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. To the extent that there are existing programs that are continuations of the Company's legacy Storm Hardening Plan, there are some costs associated with these programs currently included in the base rates approved for the Company during its last rate proceeding. As such, in years past, the Company has identified these costs that are in base rates at the time the Company makes

C8-592

its SPP cost recovery filing, and calculates its costs recovery factors to exclude costs recovered in base rates such that only incremental investments are included for SPPCRC recovery factor as required by Rule 25.6.031, F.A.C.

On August 8, 2024, FPUC filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI in which among other things, includes a request to remove all Storm Protection Plan costs from base rates and transfer recovery of all SPP programs to the SPPCRC. If approved, all costs associated with currently approved SPP Programs will be recovered through the SPPCRC.

Q. Please describe what was considered in the development of the updated FPUC SPP.

A. FPUC, with the assistance of Pike Engineering, has updated its Storm Protection Plan to ensure that projects undertaken through the Plan will strengthen the utility's electric utility infrastructure to withstand extreme weather conditions. Key aspects of the SPP include the hardening of overhead electrical facilities and the undergrounding of certain electrical distribution lines, which will result in a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. This ensures FPUC's implementation of its SPP will achieve the statutory objectives of reducing restoration costs and outage times associated with extreme weather events, while also enhancing reliability.

Q. Were there unique considerations in the initial development of FPUC's SPP?

A. Yes, to a degree, given FPUC's territory and its position as a non-generating utility. While the two FPUC service territories are separated and geographically diverse, FPUC and Pike Engineering analyzed FPUC's historical reliability performance, both during extreme and non-extreme weather conditions. The analysis of the data provided insight into the various drivers (causes) of the outages impacting the FPUC system along with the frequency and relative geographical location.

The resulting, approved FPUC SPP is a combination of previously Commission-approved storm hardening initiatives, some of which contain incremental investments due to program modifications, as well as a newly proposed Program, all of which are grounded on a methodology of resiliency risk scores across FPUC's Distribution system.

Q. Is FPUC proposing significant changes to its updated SPP?

A. No. This plan proposes the continuation of six (6) previously approved SPP Programs and the introduction of a new Program, Distribution Connectivity and Automation. This newly proposed Program reduces outages and their associated restoration times by enhancing the ability to reroute power and by leveraging intelligent grid devices to isolate areas of damage and automatically reroute power from unaffected areas of the grid.

Q. Are there any areas in FPUC's service territory where it has determined, since implementation of its 2022 Plan, that SPP projects are not feasible or practical?

A. No. Though implementation strategies may differ between projects due to geographical or other concerns, all currently approved and proposed SPP Programs are feasible and practical across FPUC's entire service territory. Some of these project-to-project variations may include combining multiple Programs within a single project in order to achieve the statutory objectives.

Q. Please provide a description of what programs are included in the updated FPUC SPP?

C8-594

A. This updated plan proposes the continuation of six (6) previously approved SPP Programs and the introduction of a new Program, Distribution Connectivity and Automation. These programs include:

Overhead Feeder Hardening

The Overhead Feeder Hardening program upgrades backbone overhead lines to extreme winds requirements outlined in the National Electric Safety Code ("NESC").

Overhead Lateral Hardening

Like the Overhead Feeder Hardening program, the Overhead Lateral Hardening program upgrades existing overhead facilities along key lateral lines off the feeder to withstand extreme wind requirements outlined in the NESC.

Overhead Lateral Undergrounding

The Overhead Lateral Undergrounding program addresses undergrounding laterals in place or the relocation and undergrounding of these overhead electric facilities.

Distribution Pole Inspections and Replacements

This Distribution Pole Inspections and Replacements Program will continue the eight-year wood pole inspection and replacement of poles that do not meet NESC strength requirements.

Transmission System Inspection and Hardening

This Transmission System Inspection and Hardening Program will continue transmission inspections on all transmission facilities and replacement of the remaining transmission wood poles with concrete poles.

Transmission & Distribution Vegetation Management Program

The Transmission & Distribution Vegetation Management Program will continue to address vegetation management activities related to FPUC transmission and distribution lines under a the currently approved 4-year trim cycle.

Distribution Connectivity and Automation Program

The Distribution Connectivity and Automation Program proposes improvements to the topology of the Distribution system that will facilitate reduced outage times through the addition of feeder ties as well as intelligent protection and automation equipment.

Q. Please describe the benefits associated with the FPUC SPP.

A. The major benefit of the FPUC SPP is to provide increased resiliency and faster restoration times to the FPUC customers. Although the total number of customers served by FPUC is relatively small in comparison to other utilities, our customers nonetheless rely on FPUC to provide safe and reliable electric service which is essential to the life, health, and safety of the public, and has become a critical component of modern life. Both divisions of FPUC's service territory are notably hurricane-prone given that the Northeast Division consists of Amelia Island and as confirmed by the impact of Hurricane Michael on our Northwest Division in 2018. As such, FPUC's SPP reflects a robust storm protection plan, which is critical to maintaining and improving grid resiliency and storm restoration as contemplated by the Legislature in Section 366.96 F.S.

FPUC's SPP programs will provide increased infrastructure resiliency, reduced restoration time, and reduced restoration cost should FPUC be impacted by hurricanes or other extreme weather events.

Q. Has FPUC changed the evaluation or prioritization of any of the projects under its proposed Plan from its 2022 Plan?

A. The Risk Resiliency Model has been updated to take into consideration the age of the distribution feeders as well as historical districts. In addition, model inputs were updated to reflect current system characteristics. The lateral undergrounding criteria was also adjusted to better reflect expected benefits resulting in a reduction of proposed undergrounding projects over the life of the Program. Finally, the divisions have been separated and examined independently from one another allowing for more efficient mobilization of resources.

Q. How did FPUC determine the prioritization for the projects under this proposed, updated SPP?

A. FPUC's utilizes the Risk Resiliency Model which leverages data inputs from various sources to evaluate and risk rank scenarios based on a balance of Probability, Response, and Impact. Projects representing the highest risk among the analyzed scenarios are represented with a higher risk resiliency score and are prioritized over projects with lower risk resiliency scores. It is important to note that the prioritization process described does not account for other factors that may influence FPUC's decision regarding the order of execution of these projects such as the availability of resources or material.

III. Storm Protection Plan Programs

Q. What information is provided for each program in the FPUC SPP?

A. The information provided, consistent with Rule 25-6.030(3) (d), F.S., is as follows:

- A description of how each program is designed to enhance FPUC's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions;
- Identification of the actual or estimated start and completion dates of the program;
- A cost estimate including capital and operating expenses;
- A comparison of the costs and the benefits; and
- A description of the criteria used to select and prioritize proposed storm protection programs.

Each of the above-listed descriptions is provided in Section 3.0 of FPUC's SPP.

Q. Please describe the Overhead Feeder Hardening Program?

A. The Overhead Feeder Hardening program will upgrade backbone overhead lines to extreme winds requirements outlined in the NESC. The backbone of a feeder resembles the major arteries of the distribution circuit that services a particular community. When a fault occurs on a backbone of the feeder, upwards of 2,500 customers can be immediately impacted.

Q. Please describe the Overhead Lateral Hardening Program.

A. Like the Overhead Feeder Hardening program, the Overhead Lateral Hardening program will upgrade existing overhead facilities along key lateral lines off the feeder to withstand extreme wind requirements outlined in the NESC. Laterals are separately protected sections of the feeder providing service to upwards of 200 to 300 customers.

Q. Please describe the Overhead Lateral Undergrounding Program.

A. The Overhead Lateral Undergrounding program will address undergrounding overhead laterals in place or the relocation and undergrounding of these overhead electric facilities, many of which are located in heavily vegetated areas, environmentally sensitive areas, or in areas where upgrading the overhead construction to NESC extreme wind standards is not practical or consistent with industry design standards. The program is also proposed to include the undergrounding of overhead facilities crossing major thoroughfares (I-10, A1-A, and SR-200). Undergrounding primary and secondary overhead facilities reduces obstructions to roadways that are essential for providing access to restoration crews and other emergency response personnel, thus accelerating power restoration and community access to these vital resources.

Q. Please describe the Distribution Pole Inspection and Replacement Program as included in the FPUC SPP.

A. This Distribution Pole Inspection and Replacement program will continue the eight-year wood pole inspection program currently in place. Should a pole fail the inspection process, it will be scheduled to be replaced. The most current edition of the NESC serves as a basis for the design of replacement poles for wood poles that fail inspection. Grade 'B' construction, as described in Section 24 of the NESC, has been adopted as the standard of construction for designing new pole installations and the replacement of reject poles. Also, extreme wind loading, as specified in rule 250C and figure 250-2(a) of the NESC, has been adopted.

Q. Please describe the Distribution Connectivity and Automation Program as included in the FPUC SPP.

A. The Distribution Connectivity and Automation Program proposes improvements to the topology of the Distribution system that will facilitate reduced outage times through the addition of feeder ties as well as intelligent protection and automation equipment. Additional feeder ties reduce outage times by providing alternates feeds, facilitating the rerouting of power to unaffected areas of the grid. Combined with intelligent devices, these feeder ties can be used to mitigate outages to unaffected areas of the grid.

Q. Please describe the Transmission System Inspection and Hardening Program as included in the FPUC SPP.

A. The Transmission System Inspection and Hardening program will continue transmission inspections on all transmission facilities which includes patrols of the 138 KV and 69 KV transmission lines owned by FPUC. This inspection ensures that all structures have a detailed inspection performed at a minimum of every six years. In addition to the six-year inspections mentioned above, wood transmission poles are also included in the 8-year distribution wood pole ground-line condition inspection and treatment program. Should a wood transmission pole be identified during the inspection as not meeting the minimum strength requirements, this pole will be replaced with a concrete pole that meets the current NESC codes and extreme wind loading standards. The Transmission Wood Pole Replacement program accelerates the full replacement of existing wood poles on FPUC's 69kV system with concrete poles proven more resilient to extreme weather conditions. Transmission substation equipment will also be inspected annually to document the integrity of the facility and identify any deficiencies that require action.

Q. Please describe the Transmission & Distribution Vegetation Management Program

A. This Transmission & Distribution Vegetation Management program continues the approved four-year vegetation management cycle on the transmission lines and distribution main feeders and laterals on the system. FPUC completed a study regarding its vegetation management cycle and has determined that this four-year cycle is an efficient and cost-effective trim cycle that will reduce outages and restoration times during extreme weather events.

Q. Will there be any internal staffing changes that will result from the development and administration of the FPUC SPP reflected in this filing?

A. No. There will be no additional internal staffing changes as a result of the proposed, updated FPUC SPP.

IV. Details for the Storm Protection Plan First Three Years

Q. What information has been provided for the initial three-year period of the FPUC SPP?

A. The information required by Rule 25-6.030(3)(e)(1), F.A.C., for the first year (2026) of the updated FPUC SPP is provided in Sections 3.0, 5.0 and 6.0 of FPUC's SPP as follows:

- The actual or estimated construction start date and completion dates;
- A description of the affected existing facilities, including number and type(s) of customers served, historic service reliability performance during extreme weather conditions, and how this data was used to prioritize the proposed storm protection project;
- Cost estimates, including capital and operating expenses, along with a description of the criteria used to select and prioritize proposed projects is included in the description of each proposed FPUC SPP program provided in Section 6.0 of the FPUC SPP.

For the second and third years, the following information has been provided.

C8-601

- The estimated number and costs of projects under each specific SPP program;
- Information used to develop the estimated rate impacts.

This information is provided in Section 3.0 through Section 3.8 of FPUC's SPP.

Q. What vegetation management information is provided for the initial three-year period of the FPUC SPP?

A. Information required by Rule 25-6.030(3)(f), F.A.C., for the first three years of the vegetation management activities under the updated FPUC SPP is provided in Sections 1.3 and 3.8 of FPUC's SPP and additional information included in Appendix C to FPUC's SPP. Included are the projected trim frequency, the projected trim miles of transmission and distribution overhead facilities, and the estimated annual labor and equipment costs for both utility and contractor personnel. Also included are descriptions of how the vegetation management activities will reduce outage times and restoration costs due to extreme weather conditions in Sections 1.3 and 3.8 and Appendix C of FPUC's SPP.

Q. Are the jurisdictional revenue requirements for the 2026 – 2035 period included in the SPP?

A. Yes. This information regarding the estimated jurisdictional revenue requirement is included in Section 4.0 of the SPP. This estimate is based on the proposed SPP programs and current operating environment.

Q. Is information provided in the SPP that shows the estimated rate impact detail?

A. Yes. This information regarding the estimated rate impact detail is included in Section 5.0 of the FPUC SPP. This estimate is based on the proposed SPP programs and the current economic and operating environment. The cost recovery filing for FPUC's expenditures under its currently approved SPP, as well as projected costs associated with the updated SPP, will continue to be submitted for approval of cost recovery in Docket No. 20250010-EI. Again, as noted above, FPUC has filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI, which includes a request to remove SPP-related costs from base rates and to transfer recovery of all costs associated with approved SPP programs to the SPPCRC. If approved, all costs associated with SPP Programs currently recovered through base rates, such as Transmission & Distribution Vegetation Management, Distribution Pole Inspections and Replacements and Transmission System Inspection and Hardening programs will be transferred to the SPPCRC for recovery, which will reduce upward pressure on base rates, but will inflate the SPPCRC factor.

Q. Are there any implementation alternatives that could mitigate the rate impact?

A. FPUC has not identified any implementation alternatives that could mitigate the resulting rate impact of the proposed SPP. FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. Alternate implementation plan(s) beyond what is proposed in the SPP would delay the realization of benefits, and thus result in higher storm restoration costs associated with extreme weather events. As part of the currently approved plan, FPUC implemented a methodical ramp up of investments during the first three years of the SPP of which, in addition to other benefits, this methodical ramp up of investments mitigated the resulting rate impact in the first three years of the plan and allows for the Hurricane Michael cost recovery surcharge to expire.

Q. What benefits does the Company anticipate will result from implementation of its updated SPP?

A. Implementation of FPUC's updated SPP will result in a reduction of storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions.

V. <u>Conclusion</u>

Q. Does FPUC anticipate that the SPP will meet all the legislative requirements of Section 366.96, F.S. and FPSC Rule 25-6030, F.A.C.?

A. Yes. The FPUC SPP and the information contained does comply with all the legislative requirements contained within Section 366.96, F.S. and Rule 25-6.030, F.A.C.

Q. Based on the details of the SPP, does FPUC anticipate a continued reduction in outages and restoration cost associated with extreme weather events?

A. Yes. The SPP contains a number of programs that will enhance the resiliency of FPUC's electric distribution and transmission infrastructure. The previously approved SPP builds on what had already been accomplished through the Storm Hardening Plan and enhances those efforts through additional programs that will further enhance the reliability and resiliency of FPUC's electric system in a cost-effective manner. This SPP is largely a continuation of FPUC's previously approved plan and also contemplates an additional program that will further reduce the Company's response and outage times when events do occur.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Kevin J. Mara (OPC) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.	**DOCKET NO.: 20250014-EI**
In re: Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.	DOCKET NO.: 20250015-EI
In re: Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.	DOCKET NO.: 20250016-EI
In re: Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.	DOCKET NO.: 20250017-EI
	FILED: March 12, 2025

DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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TABLE OF CONTENTS

I. INTRODUCTION 1

II. DISCUSSION 5

EXHIBITS

Curriculum Vitae KJM-1

DEF Response to Staff's First Set of Interrogatories, No. 7.................................... KJM-2

FPL Response to Staff's First Set of Interrogatories, No. 16 .... KJM-3

Excerpt from FPL Response to OPC's First Request for Production of Documents,

Nos. 3-4 .... KJM-4

DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO. 20250014-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS?

A. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am the Executive Vice President of the firm GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering. I am a registered professional engineer (P.E.) in Florida and 22 additional states.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of

GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC. In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Bedford, New Hampshire; Augusta, Maine; Orlando, Florida; Folsom, California; Redmond, Washington; and Madison, Wisconsin. GDS has over 180 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have submitted testimony before the following regulatory bodies:

- Vermont Department of Public Service;

- Federal Energy Regulatory Commission ("FERC");
- District of Columbia Public Service Commission;
- Public Utility Commission of Texas;
- Maryland Public Service Commission;
- Corporation Commission of Oklahoma;
- Public Service Commission of South Carolina; and
- Florida Public Service Commission.

I have also submitted expert opinion reports before United States District Courts in Alabama, California, South Carolina, and New Mexico.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit KJM-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. GDS was retained by the Florida Office of Public Counsel ("OPC") to provide technical assistance and expert testimony regarding the Florida Power & Light Company's ("FPL" or "Company") 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, Florida Administrative Code ("F.A.C."). Accordingly, I am appearing on behalf of the Citizens of the State of Florida. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting my expert opinion regarding the reasonableness of FPL's proposed 2026 - 2035 Storm Protection Plan ("SPP" or "Plan") and its consistency with the applicable standards for the Commission to consider the SPP.

The fact that I do not address any specific element of the company's SPP or address any other particular issues in my testimony or am silent with respect to any portion of the company's direct testimony in this proceeding should not be interpreted as an approval of any position taken by that company in the testimony to which I have had an opportunity to respond.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARATION OF YOUR TESTIMONY?

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery (including deposition testimony), the Company's responses to the Florida Public Service Commission ("PSC" or "Commission") Staff's discovery, and other materials pertaining to the SPP and its impacts on the Company. In addition, I reviewed section 366.96, Florida Statutes ("F.S."), which requires the filing of the SPP and authorized the Commission to adopt the relevant rules, including Rule 25-6.030, F.A.C., which addresses the Commission's approval of a Transmission and Distribution SPP that covers a utility's immediate 10-year planning period.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I have no specific recommended adjustments to any program. I do make a recommendation regarding the ability of the company to make moderate reductions in its SPP spending while maintaining the objectives of the SPP standards. In my opinion, it is not unreasonable and would be consistent with the public interest for the Commission to order a reduction in the pace of the SPP which limits feeder hardening to 75 feeders, limits lateral undergrounding to 1,100 laterals annually, and limits transmission structure replacement to 350 annually.

II. DISCUSSION

Q. WITH REGARD TO THE FLORIDA SUPREME COURT'S 2024 DECISION IN CITIZENS OF STATE V. FAY, 396 SO. 3D 549 (FLA. 2024), THAT A PRUDENCE OR COST EFFECTIVENESS DETERMINATION WAS NOT REQUIRED AND THUS NOT A PROPER SUBJECT OF INTERVENOR TESTIMONY, WAS THERE ANY ANALYSIS THAT YOU BELIEVED WAS THUS BARRED THAT WOULD HAVE OTHERWISE BEEN HELPFUL OR NECESSARY TO THE COMMISSION TO DETERMINE WHETHER THE SPP OF FPL IS IN THE PUBLIC INTEREST AND MEETS THE INTENT OF THE LEGISLATURE AS EXPRESSED IN THE SPP STATUTE?

A. Rule 25-6.030, F.A.C. ("SPP Rule"), sets forth comprehensive requirements for a Utility's Storm Protection Plan. Specifically, Rule 25-6.030(3)(d)(1), F.A.C., and Rule 25-6.030(3)(d)(3), F.A.C., calls for benefit and cost estimates for each Program within the Plan, and Rule 25-6.030(3)(d)(4), F.A.C., calls for cost to benefit comparison for each Program. In light of the Florida Supreme Court's interpretation of section 366.96, F.S., and the SPP Rule, I believe it is necessary for me to express my opinion that without the requirement of an up-front prudence or cost-effectiveness determination, consumers are at risk of exposure to runaway budgets and expenditures over the life of these plans. With no evidence allowed or taken on prudence or cost effectiveness, substantial changes in SPP

Programs and Program budgets may be overlooked and may not be considered, resulting in an increased burden on the rate payers. This scenario effectively cuts the Commission off from determining whether enormous sums of money are being spent to achieve diminishing returns both in the form of benefits to customers and in the interest of the State of Florida as a whole.

Q. DID FPL INCLUDE ANY NEW OR MODIFIED PROGRAMS IN THE 2026 SPP?

A. No. FPL did not modify their approach to their program, and they did not add any new programs. They have substantially increased in the budget for two programs: Distribution Feeder Hardening and Substation Flood Mitigation.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE SUSBTATION FLOOD MITIGATION PROGRAM?

A. No. The increase in cost is in response to flooding to five additional substations based on recent extreme weather events.[1]

Q. WHAT IS YOUR UNDERSTANDING OF THE INCREASE IN COSTS FOR THE DISTRIBUTION FEEDER HARDENING PROGRAM?

A. FPL updates the construction costs based on experience, but more importantly, in the proposed Feeder Hardening program, FPL reclassified 850 miles of laterals as feeders.[2] In addition, FPL's 2023 SPP had the Feeder Hardening program ending in 2031 with the average capital cost per year of $103.3 million for the years 2026 to 2031. In the proposed 2026 SPP, the Feeder Hardening program with 850 miles of additional laterals classified

[1] Exhibit MJ-1 Page 43 of 50.
[2] Exhibit MJ-1 Page 23 of 50.

as feeders with a projected completion date of 2034 projected an average annual cost of $216.6 million.[3] This is a significant increase in spending for this program.

Q. DOES FPL EXPLAIN HOW THIS INCREASE IN COSTS FOR FEEDER HARDENING IS OFFSET BY ANOTHER PROGRAM?

A. Yes, FPL contends that this increase will be partially offset by a reduction in the estimated average cost per project under the Distribution Lateral Hardening Program over the 2026-2035 plan period.[4] FPL is forecasting a reduction in the cost per lateral.[5] So the cost of underground laterals appears to have gained efficiencies, but FPL is proposing to increase the number of laterals to be undergrounded at a rate which reduces the annual spend to help mitigate the increase in the Feeder Hardening program cost.

Q. CAN YOU DESCRIBE STAFF'S FIRST SET OF INTERROGATORIES NO. 16?

A. Staff inquired about reducing the SPP by the following parameters:

1. Limiting the number of feeders to be hardened to 75 feeders per year,
2. Limiting the Lateral Hardening to 1,100 laterals per year, and
3. Limiting transmission structure upgrades to 350 structures per year.

FPL's Feeder Hardening program proposed a significant number of feeders to harden in the first two years of the program and then tailed off to a pace of 25 to 75 feeders per year.[6] For the Lateral Hardening program, FPL projected hardening between 900 to 1,600 laterals per year. For Transmission structure replacements, FPL budgeted for the replacement of roughly 400 to 550 structures per year.

[3] Exhibit MJ-1, Appendix C.
[4] Direct Testimony of Michael Jarro, p. 7, lines 6-8.
[5] Direct Testimony of Michael Jarro, p. 7, lines 18-20.
[6] Exhibit MJ-1, Appendix C.

In my opinion, the slow down scenario suggested by the Staff's interrogatory has merit.

Q. DID FPL PROVIDE THE RATE IMPACT FOR THE REDUCTION IN SCOPE POSED IN THE STAFF'S FIRST SET OF INTERROGATORIES, NO. 16?

A. No. FPL did not provide the rate impact.[7] I will note that the Staff had a similar interrogatory for Duke Energy Florida who was able to clearly respond with a rate impact as shown in Exhibit KJM-2.[8]

Q. WOULD YOU SUPPORT A REDUCTION IN PACE FOR ROLL OUT OF THE FPL SPP?

A. Yes. A reduction in the pace will not materially affect the response to major events in the near term and will tend to make electric service for all FPL customers more affordable.

Q. DO YOU HAVE ANY OBSERVATIONS ABOUT FPL'S ASSERTIONS ABOUT THE CORRELATION BETWEEN STORM HARDENING EFFORTS TO-DATE AND THE RESTORATION TIMES REPORTED BY THE COMPANY OVER THE LAST FEW YEARS?

A. Yes. Based on my review of FPL's storm analyses and forensic reports[9] and from my experience, I agree that efforts to harden the grid have undoubtedly lent themselves to reducing outage times and perhaps restoration costs. I would caution the Commission to carefully evaluate the claims of reductions based solely on the hardening efforts. Although I am not an expert in the logistics of storm restoration activity, I am aware that it is often a

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[7] *See* Exhibit KJM-3, FPL Response to Staff's First Set of Interrogatories, No. 16.
[8] *See* Exhibit KJM-2, Duke Energy Florida, LLC's Response to Staff's First Set of Interrogatories, No. 7.
[9] *See, for example,* Exhibit KJM-4, Excerpt from FPL Response to OPC's First Production of Documents, Nos. 3-4.

very labor-intensive process. The cost of labor for restoration efforts may or may not be directly correlated to the level of hardening of the system. There may be occasions where a major event impacts systems that have not been significantly hardened and additional resources are needed to achieve a reasonable restoration time. However, in other situations where the expected impact is less severe, significant labor costs for restoration may be incurred but little or no facilities damage occurs. The takeaway here is that apparent improvement in restoration time and cost cannot always be attributed to storm hardening efforts. Likewise, depending on the objective, storm restoration costs could actually increase even if restoration time decreases and facilities hardening is substantially increased, depending on the number of contractors temporarily brought into the territory to assist with restoration.

Q. ARE THERE ANY OTHER ELEMENTS OF THE FILING AND OR INFORMATION PROVIDED THAT YOU BELIEVE THE COMMISSION SHOULD TAKE INTO ACCOUNT FOR FPL'S SPP?

A. Yes. In the petition, FPL states, "[t]hus, the Florida Legislature has already found and determined that storm hardening the T&D system is a *prudent* action for the Florida electric utilities to undertake." (Emphasis added.) In accord with the aforementioned Florida Supreme Court decision, I will not substantively respond to this assertion. However, if the Commission allows the Company to nevertheless introduce the concept of "prudence" in the decision making, I believe it would be necessary for me to provide supplemental testimony in that regard.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Whereupon, prefiled rebuttal testimony of Michael Jarro (FPL) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250014-EI

FLORIDA POWER & LIGHT COMPANY

2026-2035 STORM PROTECTION PLAN

REBUTTAL TESTIMONY OF

MICHAEL JARRO

Filed: April 2, 2025

Q. Please state your name and business address.

A. My name is Michael Jarro. My business address is Florida Power & Light Company, 15430 Endeavor Drive, Jupiter, FL, 33478.

Q. Have you previously submitted testimony in this docket?

A. Yes. My direct testimony in support of Florida Power & Light Company's ("FPL") 2026-2035 Storm Protection Plan (hereinafter, the "2026 SPP") was filed in this docket on January 15, 2025. The 2026 SPP was attached to my direct testimony as Exhibit MJ-1.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony and exhibits submitted by Kevin J. Mara on behalf of the Office of Public Counsel ("OPC"). Specifically, my rebuttal testimony responds to OPC witness Mara's recommendations that the Commission should order the following reductions to FPL's 2026 SPP: (1) limit the Distribution Feeder Hardening Program projects to 75 feeders per year; (2) limit the Distribution Lateral Hardening Program underground projects to 1,100 per year; and (3) limit the Transmission Hardening Program projects to the replacement of 350 structures per year. I also address certain comments by OPC witness Mara regarding FPL's storm hardening and its impact on storm restoration.

Q. Are you sponsoring any exhibits in your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits attached to my rebuttal testimony:

- Exhibit MJ-2 – Appendices C from FPL's 2026 SPP and 2023 SPP
- Exhibit MJ-3 – FPL's Response to OPC's Second Set of Interrogatories No. 33
- Exhibit MJ-4 – FPL's Response to Staff's First Set of Interrogatories No. 12
- Exhibit MJ-5 – FPL's Response to Staff's First Set of Interrogatories No. 9

- Exhibit MJ-6 – FPL's Response to Staff's First Set of Interrogatories No. 7
- Exhibit MJ-7 – FPL's Response to Staff's First Set of Interrogatories No. 10
- Exhibit MJ-8 – Annual and Total SPP Costs for OPC Proposed Adjustments
- Exhibit MJ-9 – Rate Impacts of OPC's Proposed Adjustments
- Exhibit MJ-10 – FPL's Response to OPC's Third Set of Interrogatories No. 42

Q. On page 5 of his direct testimony, OPC witness Mara expresses an opinion that there is a risk of "runaway budgets and expenditures over the life of these plans." Do you have a response?

A. Yes. FPL's 2026 SPP is a continuation of the same storm hardening programs that were included in both the 2020 SPP and 2023 SPP approved by the Florida Public Service Commission ("Commission"). As explained in my direct testimony, and as acknowledged by OPC witness Mara on page 6, lines 8-9 of his direct testimony, FPL has not proposed any material modifications to any of the existing eight programs previously approved in the 2023 SPP. Rather, FPL has updated the projected costs for certain programs to better reflect current data and pricing, reduced the estimated average cost per project under the Distribution Lateral Hardening Program, reclassified laterals as feeders to be addressed under the Distribution Feeder Hardening Program, and identified additional substations that require storm surge and flood mitigation through the Substation Storm Surge/Flood Mitigation Program.

Attached as Exhibit MJ-2 are the Appendices C from both the proposed 2026 SPP and previously approved 2023 SPP, which show the estimated program costs and activities for the applicable ten-year planning periods. Attached as Exhibit MJ-3 is FPL's response to OPC's Second Set of Interrogatories No. 33, which provides a comparison of the programs included in the 2023 SPP and the 2026 SPP. As shown in Exhibits MJ-2 and MJ-3, the programs included in the 2026 SPP are generally consistent with those included in the previously approved 2023 SPP. In fact, the difference in the average annual spend for the first three years of the 2026 SPP (2026-2028) is a decrease of approximately $56 million compared to the 2023 SPP despite the fact that costs of labor and materials have increased since the 2023 SPP, and the 2026 SPP includes five additional substations under the Substation Storm Surge/Flood Mitigation Program.

Finally, I note that the projected, actual/estimated, and actual SPP costs are submitted for review and approval by the Commission in the annual Storm Protection Plan Cost Recovery Clause ("SPPCRC") dockets. Thus, the Commission has the opportunity to review and approve both the SPP budgets and expenditures on an annual basis, which mitigates OPC witness Mara's claimed risk of "runaway budgets and expenditures."

Q. Before addressing his specific recommendations, do you have any general observations regarding OPC witness Mara's proposed adjustments?

A. Yes. I note that OPC witness Mara's proposed adjustments to the Distribution Lateral Hardening Program, Distribution Feeder Hardening Program, and Transmission Hardening Program are, with the limited exception of the feeder hardening in calendar year 2026, each within the estimated annual range of projects proposed in FPL's 2026 SPP as shown in the table below.

TABLE 1

Distribution Feeder	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
2026 SPP # Feeders:	225-325	75-175	25-75	25-75	25-75	25-75	25-75	25-75	25-75	0	475-1025
OPC # Feeders:	75	75	75	75	75	75	75	75	75	75	750
Distribution Lateral	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
2026 SPP # Laterals:	900-1,300	900-1,300	900-1,300	1,100-1,600	1,100-1,600	1,100-1,600	1,100-1,600	1,100-1,600	1,100-1,600	1,100-1,600	10,400-15,100
OPC # Laterals:	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	11,000
Transmission	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
2026 SPP # Poles:	300-350	400-500	450-550	450-550	450-550	300-350	150-200	0	0	0	2,500-3,050
OPC # Poles:	350	350	350	350	350	350	350	325	0	0	2,775

However, if the number of projects to be completed under the Distribution Lateral Hardening Program, Distribution Feeder Hardening Program, and Transmission Hardening Program were decreased and subject to a hard cap as proposed by OPC witness Mara, all things being equal, FPL projects there will be a delay in when customers would realize the important benefits of reductions in outages, outage times, and restoration costs associated with extreme weather events, as well as a delay of ancillary non-hardening benefits, such as improved day-to-day reliability. Notably, the impacts associated with delaying these SPP projects (*i.e.*, delay when customers and communities would realize these important benefits) could be significant for years with multiple extreme weather events, such as the 2022 and 2024 hurricane seasons. Such delays would likely also bring negative individual customer and local community impacts as a result of halting uncompleted work associated with these multi-year hardening projects.

Q. Do you have any observations regarding OPC witness Mara's proposal to use a hard cap on the number of projects to be completed each year under the Distribution Lateral Hardening Program, Distribution Feeder Hardening Program, and Transmission Hardening Program?

A. Yes. It appears OPC witness Mara is proposing a hard cap on the annual number of projects to be completed under each of these programs rather than a range of estimated annual projects. As to be expected with any major construction project, project schedules and cost estimates may change due to events and circumstances that are largely beyond the utility's control, which may result in variances in the construction schedules, number of projects, and the associated costs of the SPP projects to be undertaken during a calendar year. Importantly, FPL manages the SPP projects at the program level to ensure that resources are being utilized appropriately and efficiently. For example, if a crew completes a project, FPL moves that crew onto the next project based on the Commission-approved prioritization and selection criteria for the applicable SPP program.

If, however, there was a hard cap on the number of SPP projects that could be completed in a given year, FPL would lose efficiency by being forced to shut down SPP program work once the cap was reached, release the crews from FPL's system, and then incur additional costs to bring crews back onto the system to restart SPP program work in the next calendar year. Rather than lose this efficiency, FPL submits that it is appropriate to continue to use an estimated annual range of projects for each SPP program, which is consistent with the approach approved in both FPL's 2020 SPP and 2023 SPP.

Q. On page 5, OPC witness Mara recommends that FPL's Distribution Lateral Hardening Program should be limited to 1,100 laterals per year. Do you have a response?

A. Yes. OPC witness Mara overlooks that the number of estimated projects for the Distribution Lateral Hardening Program reflects that the program was initially started as a very limited pilot program in 2018, was continued as a limited pilot program in FPL's Commission-approved 2020 SPP, and was implemented as a permanent program in FPL's 2023 SPP with a ramp-up in the number of projects to be completed each year over the ten-year period, which ramp-up included the new Management Region selection criteria beginning in 2025. As can be seen in Exhibit MJ-2, the Distribution Lateral Hardening Program included in FPL's 2026 SPP is consistent with the ramp-up and number of estimated projects under the previously approved 2023 SPP. In fact, the ramp-up in number of estimated lateral projects over the period 2026 through 2028 is slightly less in the 2026 SPP (3-year average estimated range of 900 to 1,300) than in the 2023 SPP (3-year average estimated range of 967 to 1,333).

The Distribution Lateral Hardening Program is a significant contributing factor to FPL's success in reducing outages, outage times, and restoration costs when FPL's system and customers are impacted by extreme weather events. FPL's laterals make up the majority of FPL's distribution system, with 1.9 times as many miles of overhead laterals as there are overhead feeders, and many overhead laterals are rear-located facilities that are more difficult and take longer to access and more likely to be near vegetation. As shown in FPL's response to Staff's First Set of Interrogatories No. 9, which is provided as Exhibit MJ-5, FPL's underground facilities have performed significantly better during recent extreme weather events than overhead facilities that are exposed to damages and outages caused by vegetation and debris. OPC witness

Mara's proposed adjustment to the Distribution Lateral Hardening Program would result in a delay in when the customers and communities served by FPL would realize these important hardening benefits. This delay should be considered by the Commission when evaluating OPC witness Mara's proposal.

Q. On page 5 of his direct testimony, OPC witness Mara recommends that FPL's Distribution Feeder Hardening Program should be limited to 75 feeders per year. Do you have a response?

A. As shown on Exhibit MJ-2, FPL's Distribution Feeder Hardening Program is winding down over 2026 (225-325 projects) and 2027 (75-175 projects) to an annual range of 25 to 75 feeders estimated to be completed each year from 2028 through 2034. As acknowledged by OPC witness Mara on pages 6-7 of his direct testimony, the increase in miles of feeders to be hardened is primarily the result of the need to reclassify approximately 850 miles of feeders in the panhandle region of FPL's service area (former Gulf Power Company service area) that were previously categorized as laterals.

Although OPC witness Mara's proposal of 75 feeders per year is consistent with the 25-75 project range proposed in the 2026 SPP for calendar years 2028 through 2034, it would require an adjustment to the number of estimated projects to be completed in 2026 and 2027, as well as when the program is estimated to be completed. Importantly, these feeder hardening projects are multi-year projects that span several years from initial engineering and permitting stages through final construction and in-service. The projects require coordination with the affected municipalities to mitigate traffic and other impacts to the customer and communities in the areas of the projects. If FPL were to limit the feeder hardening projects to 75 each for 2026 and 2027, FPL would be required to shut down existing multi-year projects that have already started. The impact would be greatest for communities where the work has already begun and may necessitate the immediate stop of these hardening efforts and leaving equipment in a temporary, compromised condition. As these are active work sites, FPL would need to demobilize the corresponding materials and workforce, which would result in additional costs for the impacted projects. As part of the permit process for SPP projects, FPL makes commitments (with the caveat that the SPP projects are subject to Commission approval) to finish the projects in a timely manner to mitigate the disruption from road closures/limitations. Furthermore, restarting the projects that would need to be paused to meet OPC's proposed annual cap of 75 feeders may require additional coordination and acquisition of new permits, which would result in additional costs for the impacted projects.

Finally, I note that FPL's hardened feeders have performed significantly better than non-hardened feeders during recent extreme weather events. As shown in FPL's response to Staff's First Set of Interrogatories No. 7, which is provided as Exhibit MJ-6, FPL's Distribution Feeder Hardening Program has led to a significant reduction in the number of distribution poles that failed and needed replacement due to impacts of recent extreme weather events. OPC witness Mara's proposed adjustment to the Distribution Feeder Hardening Program would result in a delay in when the customers and communities served by FPL would realize these important hardening benefits. This delay should be considered by the Commission when evaluating OPC witness Mara's proposal.

Q. On page 5 of his direct testimony, OPC witness Mara recommends that FPL's Transmission Hardening Program should be limited to the replacement of 350 structures per year. Do you have a response?

A. Yes, the recommendation by OPC witness Mara fails to account for the impacts associated with stopping a project partway if the hard limit for the year is reached. Similar to the Distribution Feeder Hardening Program, FPL's Transmission Hardening Program is winding down with all existing transmission structures estimated to be hardened by the end of 2032. As can be seen from Exhibit MJ-2, the estimated range of transmission structures to be replaced during calendar years 2026 through 2032 are almost identical in the proposed 2026 SPP and the previously approved 2023 SPP. In fact, the only difference is the range of projects estimated for calendar year 2026 is slightly less in the 2026 SPP (300-350 structures) than in the 2023 SPP (400-500 structures).

While an outage associated with distribution facilities can impact up to several thousands of customers, a transmission-related outage can result in an outage affecting tens of thousands of customers. Additionally, an outage on a transmission facility could cause cascading loss of service for hundreds of thousands of customers. Thus, the prevention of transmission-related outages is essential. As shown on page 32 of Exhibit MJ-1 and in FPL's Response to Staff's First Set of Interrogatories No. 10, which is provided as Exhibit MJ-7, the performance of FPL's system during recent storm events indicates that FPL's Transmission Hardening Program has contributed to the overall storm resiliency of the transmission system and provided savings in storm restoration costs.

As of year-end 2022, all the existing transmission structures in the legacy FPL service area have been hardened and the transmission structures remaining to be hardened serve the customers located in the panhandle region of FPL's service area (*i.e.*, the former Gulf Power service area). FPL submits that it is important to continue and complete the Transmission Hardening Program to ensure that all FPL customers, including those in the panhandle region of FPL's service area, receive these important hardening benefits.

Q. Does OPC witness Mara provide a justification for his recommended adjustments to the Distribution Lateral Hardening Program, Distribution Feeder Hardening Program, or Transmission Hardening Program?

A. On page 7 of his direct testimony, OPC witness Mara cites to a Staff interrogatory inquiring about reducing the number of annual feeder, lateral, and transmission hardening projects. The only other support provided by OPC witness Mara appears to be his statement on page 8, line 13, that the proposed reductions will make electric service for all FPL customers more affordable.

Q. Has FPL evaluated OPC witness Mara's claim?

A. Yes. After receiving his direct testimony, the FPL Power Delivery team estimated the annual and total SPP costs based on OPC witness Mara's proposed adjustments, which estimates are provided in Exhibit MJ-8 in the same format as Appendix C to FPL's

2026 SPP. FPL's Rates team then used this information to calculate the ten-year revenue requirements and three-year rate impacts of OPC witness Mara's proposed adjustments, using the same methodology and assumptions used to calculate the revenue requirements and rate impacts provided in FPL's 2026 SPP.[1] A comparison of the estimated ten-year revenue requirements and three-year rate impacts under OPC witness Mara's proposal and FPL's proposed 2026 SPP is provided in Exhibit MJ-9. As shown therein, OPC witness Mara's proposed adjustments would have little impact on customer rates. Importantly, however, OPC witness Mara's proposed adjustments would delay when customers receive the important storm hardening benefits from these programs and result in additional costs to stop and restart projects.

Q. On page 9, lines 6-11 of his direct testimony, OPC witness Mara appears to imply that storm restoration costs could actually increase even if storm hardening is substantially increased. Do you agree with his position?

A. No. Storm restoration costs are a product of the construction man hours ("CMH") required to repair the transmission and distribution facilities damaged during an extreme weather event. The greater the damage on the system the more CMH required to restore that damage, and the more CMH required to restore service the greater the storm restoration costs. Although the number of overhead line crews responding to a storm on FPL's system is an important factor in the time to restore power following an extreme weather event (*i.e.*, all things being equal, more crews would restore faster than less crews completing the same number of CMH), the number of crews does not

[1] The revenue requirements and rate impacts for the 2026 SPP are provided on pages 48-50 of Exhibit MJ-1 attached to the direct testimony of FPL witness Jarro.

directly impact the total CMH required to repair the transmission and distribution facilities damaged during an extreme weather event. Rather, FPL's storm hardening initiatives are the single biggest factor to reducing damage to the system from an extreme weather event, which, in turn, reduces the total CMH required to restore power to the customers and communities served.

FPL's response to OPC's Third Set of Interrogatories No. 42, which is attached as Exhibit MJ-10, demonstrates that the performance of FPL's system during recent storm seasons has significantly improved as compared to the performance of the system during Hurricane Wilma, which occurred in 2005 before FPL began implementing its current SPP programs. While no electrical system can be made completely resistant to the impacts of hurricanes and other extreme weather conditions, the performance of FPL's system during recent storm events demonstrates that continuing the existing storm hardening plans included in the 2026 SPP will continue to reduce damage to FPL's system, reduce outages, reduce outage times, and reduce restoration costs associated with extreme weather events.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Brian Lloyd (DEF) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVIEW OF STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20250015-EI

REBUTTAL TESTIMONY OF BRIAN M. LLOYD

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

APRIL 2, 2025

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Brian M. Lloyd. My current business address is 3250 Bonnet Creek Road, Lake Buena Vista, FL 32830.

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony supporting the Company's SPP on January 15, 2024.

Q. Has your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to provide the Company's rebuttal to certain assertions and conclusions contained in the direct testimony of OPC's witness Mara. Mrs. Vazquez also presents rebuttal of the testimony of Witness Mara.

Q. Do you have any exhibits to your testimony?

A. No, I do not.

Q. Please summarize your testimony.

A. My testimony will explain the adverse consequences of adopting Witness Mara's recommended reduction in the pace at which DEF would deploy Distribution Feeder Hardening and Lateral Hardening work.

III. SPP DEPLOYMENT PACE

Q. Does Witness Mara make a recommendation to reduce the pace at which DEF deploys certain SPP subprograms in his testimony?

A. Yes. Mr. Mara recommends DEF slow the deployment pace of subprograms within the Feeder and Lateral Hardening Programs to the level Staff inquired about in its seventh interrogatory.

Q. Can you describe Witness Mara's recommendation for Distribution subprogram deployment?

A. Yes. Witness Mara recommended limiting "the number of feeders to be hardened from 120 to 105 feeders and lateral hardening from 130 laterals per year to 122 laterals per year."[1] I'd like to first point out that DEF's response, as shown in Exhibit No. (KJM-5), stated "hardening only 105, instead of approximately 150, miles of feeders per year..." and not the "120 miles" Witness Mara incorrectly included in his testimony. Like Mrs. Vazquez's response to his recommendation on the Transmission subprogram deployment, the recommended reduction in the Distribution subprogram deployment also requires a much larger than roughly 4% reduction in units.

If the Commission were to adopt his recommendation, it would translate to a reduction in unit deployment of around 20% in 2027 and 2028. As I explain below, based on my experience with storm restoration efforts, I believe an approximately 20% reduction in this important work, for the relatively small reduction in revenue requirements of approximately 3.9%, is short-sighted and will have a larger impact on storm restoration efforts than Mr. Mara recognizes.

Q. Do you agree with Witness Mara's assertion that this reduction will not materially affect the response to major events in the near term?

A. No, I do not. First of all, as I explained in my direct testimony, DEF's has not had a hardened distribution structure fail during a storm event. As DEF stated in response to the Staff's interrogatory, limiting the feeder and lateral hardening work to the units suggested would extend Feeder Hardening and Lateral Hardening deployment timelines by approximately 20 and 10-15 storm seasons, respectively. Of course, delays in deployment would translate into a delay of the benefits these

[1] Mara testimony, pg. 14

hardening efforts provide to customers who are and will be served by these hardened assets.

The near-term impacts of this proposed reduction in pace would be seen in 2027 and 2028. Limiting the number of miles hardened could reduce the number of customers benefitting from hardened distribution feeders and laterals by over 20,000 customers in 2027 alone, a figure that would then grow in 2028 as DEF falls even farther behind the deployment pace established in the Plan.

Q. Can you please describe your "storm role"?

A. My "storm role" is Planning Section Chief for Duke Energy Florida. In this storm role, which is activated during the Company's response to an extreme weather event, I oversee a team of Duke Energy employees who are responsible for collecting, evaluating, disseminating, and using incident information to forecast the impact an extreme weather event could have on the DEF distribution system; estimate the number of resources needed to respond to the forecasted damage; provide vital information to the resources responding to the event; and tracking progress of restoration. This critical information is shared with other storm response teams to ensure that the communities we serve are restored to normalcy as safely and efficiently as possible following an extreme weather event. The team that I lead also conducts the forensics damage assessment and reviews the data to determine how DEF's distribution system and its hardening measures fared against the weather.

Q. Have your experiences shaped your views on the value of storm hardening efforts?

A. Yes, definitely. My experiences not only as a long-time Florida resident but also as someone responsible for assisting the Company in storm restoration activities have provided key insights into the value storm hardened assets can bring to the communities DEF serves.

Seeing the destruction extreme weather events inflict on residents and businesses further underscores the importance of DEF's storm hardening measures. A lasting memory of mine following Hurricane Michael is hearing customers cheer when the first streetlight illuminated after being out of commission for a length of time. After such an impactful storm that destroyed so much for those communities, seeing a simple streetlight return to service was enough to illicit that response.

Lastly, in my brief review of Witness Mara's testimony in FPL's SPP 2026-2035 docket, I noticed he commented that he is "not an expert in logistics of storm restoration activity."[2] If he had the experience in storm restoration activities that I have, he would not have come to the short-sighted conclusion that his recommended reduction in DEF's SPP deployment pace would not materially impact the Company's response to major events in the near term. Further, I doubt the 20,000 customers impacted by the delayed hardening efforts in 2027 would agree with Mr. Mara, as they may well be the ones cheering when that first streetlight comes back on.

[2] *See* doc. no. 01539-2025, pg. 8, Docket No. 20250014-EI.

IV. CONCLUSION

Q. Mr. Lloyd did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. Mr. Mara's testimony involved numerous assertions, opinions and conclusions and I could not reasonably respond to each and, therefore, I focused on the issues that I thought were most important. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion, opinion, or conclusion.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Alexandra M. Vazquez (DEF) was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVIEW OF STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20250015-EI

AMENDED REBUTTAL TESTIMONY OF ALEXANDRA M. VAZQUEZ

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

APRIL 11, 2025

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Alexandra M. Vazquez. My current business address is 3300 Exchange Place, Lake Mary, FL. 32746.

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony supporting the Company's SPP on January 15, 2025.

Q. Has your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes. My title has changed to Manager, Power Grid Operations Asset Management Governance, but my job responsibilities are the same.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to provide the Company's rebuttal to certain assertions and conclusions regarding the Transmission specific aspects of DEF's 2026-2035 Storm Protection Plan ("SPP 2026" or "Plan") contained in the direct testimony of OPC's witness Mara. Mr. Lloyd presents additional rebuttal of Mr. Mara's testimony.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibit to my testimony:

- Exhibit No. (AV-1): Excerpt from Amy Howe's Second Amended Rebuttal Testimony, specifically page 10, line 19 through page12, line 12, regarding Witness Mara's Testimony in Docket No. 20220050-EI.

Q. Please summarize your testimony.

A. My testimony focuses on Witness Mara's testimony as it relates to Transmission specific programs and subprograms and rebuts the incorrect conclusions contained within. In sum, when the Transmission programs are properly understood, it is clear the programs are rightfully included in the Company's SPP and should be approved. OPC's witness' arguments to the contrary demonstrate a lack of understanding of the programs themselves and are based on a narrow interpretation of Rule 25-6.030 (the "SPP Rule") that, in DEF's belief, unnecessarily curtails the scope of the SPP contrary to what appears to be the legislature's intent. Witness Mara's recommendations should be rejected by the Commission.

Q. At a high level, did anything stand out to you in your review of Mr. Mara's testimony?

A. Yes. After reviewing Witness Mara's Curriculum Vitae provided in Exhibit No. (KJM-1), it does not appear that Mr. Mara has experience operating a Transmission system. Based on my experience working on DEF's Transmission assets, I will address why I disagree with Witness Mara's opinion regarding each Transmission subprogram he discussed and further explain how they are designed to accomplish the goals of reducing outages and restoration costs resulting from extreme weather events.

Q. Have you fully described the Transmission programs within the SPP?

A. Yes. The Transmission programs were described in Exhibit No. (BML-1) – Program Descriptions and further explained in my previously filed direct testimony. In this rebuttal testimony, I will only address certain specific contentions raised by OPC's witness, Mr. Mara.

III. INSULATOR UPGRADES

Q. Please describe how the Transmission Insulator upgrades subprogram meets the intent of the SPP Statute and Rule.

A. The Transmission Insulator Upgrades subprogram is intended to upgrade targeted equipment that is more vulnerable during extreme weather events to protect the integrity of the grid. Simply put, this subprogram of Structure Hardening will mitigate outages during extreme weather events. Structure hardening in its entirety is focused on reduction of outage times and restoration costs, however, the primary benefit of the Insulator upgrades subprogram is reduction in outages, thus improving operation of the grid during extreme weather events.

Q. Does this subprogram's scope include various types of insulators?

A. Yes. DEF's Insulator upgrade subprogram is not limited to a specific type of insulator or application. Criteria for this subprogram is based on material properties and not insulator application or configuration (e.g., post). Post insulator refers to the application and use of the insulator, not the material. Therefore, post insulators are included.

Q. OPC Witness Mara pointed out that DEF did not include certain information regarding this subprogram in its Exhibit No. (BML-1). Do you agree?

A. Yes, Witness Mara is correct. DEF inadvertently omitted the Insulator upgrades subprogram Year 1 location information in its Exhibit No. (BML-1) and filed a revised version on March 13, 2025. The Year 1 Project List for Insulator Upgrades subprogram is included in this corrected version on page 45 of 56.

Q. Can you explain why the Year 1 Project List for Insulator upgrades shows a customer count of 0 for the locations identified?

A. Yes. Service for all customers originates from the transmission system, which acts as a bridge between the generation and the distribution system. The transmission system consists of different voltages with the highest voltage portion (100kv and above) being the bulk electric system ("BES"). The BES is subjected to mandatory reliability standards published and administered by the North American Electric Reliability Council ("NERC") under the authority of the Federal Energy Regulatory Commission ("FERC"). These standards require sufficient redundancy within the BES to allow continued operation even when one or more elements of the system is out of service.

Therefore, most of DEF's BES assets do not directly serve customers but instead serve as critical infrastructure maintaining power flow within and between DEF, neighboring utilities, and Independent Power Producers. As a result, failure of a single BES element will often not cause a direct outage to our customers but removes a level of resiliency for the entire BES. Sequential failures within the system can cause significant disruption to power flows and cause extensive customer interruptions, including during an extreme weather event.

Imagine a highway facilitating long-distance travel, much like Transmission lines carry power over long distances at higher voltages. Both are designed for high-volume, long-distance transport. The substations are like rest stops along a highway, where the voltage can be adjusted (stepped up or down) to match the needs of the distribution system, similar to how rest stops provide amenities for travelers. If there is an issue along the highway (i.e., accident, closed path, etc.), the driver has alternative exits and routes to continue navigating to their destination; however, the driver is still impacted by the incident. Similarly, if there is a failure on a transmission line, power may have an alternate path, but the grid is still impacted and ultimately the customer may be impacted. Thus, it is critical to harden these facilities against the effects of extreme weather events as the hardening will have a positive impact on the overall level of service provided to our customers even if, as described above, a given line is shown as "serving" 0 customers.

Q. Referencing the Insulator upgrades subprogram, Witness Mara states that “this program replaces a system component with another component with similar strength and purpose” and “this is not an upgrade.” Do you agree with Witness Mara’s statements?

A. No, I do not agree with Witness Mara’s assertions. Mr. Mara may have overlooked the section in Exhibit No. (BML-1) where it states that the line insulator subprogram is targeting porcelain insulators which show pin erosion ‘penciling’ of the connections between the insulators. The glass replacement insulators utilize a more uniform matrix than porcelain, with a design change that includes a zinc sleeve to mitigate the pin erosion for a better mechanical connection. The implementation of the improved design in the bell and connection is to reduce the effects of penciling over time, ultimately mitigating failure during extreme weather events and minimizing outage events.

Additionally, in DEF’s response to Staff’s First Set of Interrogatories, DEF shared that ceramic/porcelain is made from a combination of different raw materials, and this affects grain structure, void formation, and consequently long-term performance of porcelain bells. The uniformity of glass insulator material and better control of the manufacturing process produces insulators that do not have as much variation in strength as ceramic/porcelain insulators. This material has lower failure rates during extreme weather events, constituting a major upgrade in resilience during storms. Therefore, Mr. Mara is incorrect to say that the hardened insulators have similar strength.

Q. Can you describe the prioritization methodology for the Insulator upgrade subprogram?

Yes, but first let me state that Mr. Mara is incorrect in suggesting that "DEF did not indicate prioritization." Like other equipment upgrade subprograms within DEF's SPP, the prioritization of the insulators is conducted in a rigorous 2-step process, as documented in Exhibit Nos. (BML-1) and (BML-2). In the first step, the SPP model is run against the existing conditions under simulated weather modeling including extreme weather events and against a hardened condition for every location on the grid in DEF's territory. Failures of all equipment types are calculated, and downstream costs and benefits are estimated quantitatively through this detailed simulation.

The output of the modeling is a data driven list of locations, by sub-program, prioritized by the projects' benefit-cost ratios, such that the most cost-effective locations are placed earlier in time. In the second-step, DEF engineers carefully conduct a desk-review to evaluate the data driven generated prioritization based on their experience and knowledge of the location to determine if there are on-ground conditions that were not captured in the model that would change the rank of the location within the plan. Please see Appendix A of Exhibit No. (BML-2) for further details on this methodology.

Q. Witness Mara also states that DEF "did not provide a comparison of costs and benefits for the new program" and "it is not possible to make a comparison necessary for the PSC to determine if implementation of the program is in the public interest." Do you agree with Witness Mara's claims?

A. No. I do not agree with Witness Mara's claims. Insulator upgrades is a subprogram of the Transmission Structure Hardening program. DEF provided cost and benefit details at the program level, as required by Rule 25-6.030, F.A.C. Furthermore, specifically for the Insulator upgrades subprogram, benefits are described on page 39 of Exhibit No. (BML-1). Additionally, as requested, costs were provided for Insulator Upgrades in response to OPC's First Set of Interrogatories (No. 44).

This subprogram will help to harden the system against the effects of extreme weather and should be included in DEF's SPP.

IV. TOWER UPGRADES AND OVERHEAD GROUND WIRE

Q. Mr. Mara recommends that the Tower Upgrade and Overhead Ground Wire subprograms should be removed from the SPP because, in his opinion, these subprograms are "like for like" replacements that serve the same purpose without improving system performance. Has Witness Mara expressed similar or equivalent sentiments regarding DEF's Transmission Tower Upgrades and Overhead Ground Wire subprograms?

A. Yes. Witness Mara filed testimony in DEF's SPP 2023-2032 docket, Docket No. 20220050-EI. He advocated for similar conclusions based on similar reasoning as in this docket including recommending the Commission eliminate Transmission Tower Upgrades and Overhead Ground Wire from DEF's SPP.

Q. Did DEF file rebuttal testimony in Docket No. 20220050-EI?

A. Yes. DEF's Witness Amy Howe filed extensive rebuttal testimony rebutting many of Witness Mara's assertions.

Q. Do you agree with Witness Howe's previous statements regarding these two subprograms?

A. Yes, Exhibit No. (AV-1) identifies the portions of Ms. Howe's Second Amended Rebuttal Testimony on these points, specifically page 10, line 19 through page 12, line 12,in addition to my testimony below regarding the appropriateness of the subprograms.

Q. Describe why the Transmission Tower Upgrades subprogram meets the requirements of Rule 25-6.030, F.A.C.

A. As stated in Exhibit No. (BML-1), the Transmission Tower Upgrades subprogram will replace tower types that have previously failed during extreme weather events, as well as those identified by inspections. Prior experience has shown that, after wood poles are removed from the system, that next point of vulnerability are the identified towers. As described in Exhibit No. (BML-2), Tower Upgrades is a standards-based activity, in which towers are upgraded to the current design standard. Existing transmission towers will be upgraded with a new steel tower or a steel/concrete structure. Upgrading prioritized steel, wood/steel towers with a new cathodic protection steel tower lowers the risk of in-service failure during extreme weather conditions. The system is also hardened, as the upgraded tower is less susceptible to extreme weather and wind damage.

Q. Witness Mara references the number of towers DEF expects to replace as part of its Tower Upgrade subprogram noting that it appears DEF's current proposed Plan anticipates replacing a greater number of towers, can you explain the change?

A. Yes. As stated in DEF's Response to OPC's First Set of Interrogatories (No. 52), the Transmission Tower Upgrade subprogram's overall intent and selection criteria has not changed over the iterations of DEF's Storm Protection Plan filings. DEF's SPP 2023 stated that there were over 700 towers identified as having a similar design type to those that had previously failed during extreme weather (e.g., hurricanes Irma and Michael) and thus would be prioritized for upgrade under the subprogram. This number represents a subset, not the full complement, of the towers within the subprogram's criteria. DEF believes that Witness Mara's understanding is not complete.

Q. Do you agree with Witness Mara's recommendation that the Transmission Tower Upgrade subprogram should be eliminated from DEF's SPP?

A. No, I do not agree with Witness Mara's recommendation that the Transmission Tower Upgrade subprogram should be eliminated from the SPP because, as I explain below, his conclusion is based upon a number of faulty premises.

First, Mr. Mara states "The replacement of towers is a like-for-like replacement. This is different than replacing a wood transmission pole with a metal or concrete pole with greater resiliency to extreme winds."[1] Mr. Mara fails to recognize that tower upgrades are designed to the latest standards. Equipment standards, both internal and external, are continuously reviewed and updated. Thus, new equipment installations include the improvements as part of DEF's updated standards, meaning the towers are not being replaced "like for like" at all.

[1] Mara Testimony, p. 11, ll. 9-11.

Mr. Mara continues, "If age is a criterion and the towers are beyond their useful life, then replacement of the towers is an aging infrastructure project and therefore should not be included in the SPP."[2] This argument ignores reality by seeming to believe that the resiliency of the system is somehow a static measure that does not change over time, that infrastructure should rationally be expected to retain all its strength throughout its service life. The reality is that resiliency of an aging system decreases over time. Replacing these aging towers to today's design standards increases reliability by reducing risks of infrastructure damage. "Aging" infrastructure, but not yet beyond its useful life (still accomplishing its purpose), performs better when replaced with a new component, thereby strengthening the overall system relative to the status quo, which I believe is the goal of the SPP. Accelerated change outs of aging infrastructure increases resiliency and reliability, as less damage occurs during extreme weather events with upgraded equipment. Finally, DEF inspects its infrastructure pursuant to Commission-approved schedules and towers identified as beyond their useful life would be replaced as part of DEF's standard maintenance work (i.e., base rate work) and not pursuant to this subprogram.

Mr. Mara also states, "Transmission lines have been required by the NESC to be built for extreme wind events since at least 1977. . . . Replacing towers with new towers that meet the same weather loading condition will not add to resiliency."[3] The National Electric Safety Code ("NESC") establishes minimum requirements to ensure safety and reliability. This national standard changes over time and therefore the standards as they existed in 1977 are not identical to the standards adopted in 2023. In some cases, NESC-mandated

[2] *Id.* at ll. 14-15.
[3] *Id.* at ll. 12-17.

wind speed tolerances may decrease. DEF, however, does not decrease wind speed tolerances when the NESC allows. DEF extreme wind design standards meet and exceed the current and past NESC requirements which of course cover more criteria than wind-loading. This assures designs balance meeting safety minimums, construction variables, reliability, costs, and long-term performance based on project locations and circuit criticality. To the extent Mr. Mara is basing his understanding of DEF's design standards on responses provided in Mr. Lloyd's deposition, I would note that I am sponsoring the Transmission-specific portions of the SPP, and that Mr. Lloyd's job responsibilities do not encompass transmission work – as he noted in that deposition.[4]

Witness Mara continues "If the tower design was flawed, it would have been imprudent for DEF to have originally constructed the tower in which case the cost should also be denied from the SPP." To DEF's knowledge, no such towers exist, nor does Witness Mara opine that the design *was* flawed but merely states "if" it was flawed it should not have been accepted. As mentioned above, tower construction has always been and continues to be driven by design standards. This includes designs before and after the adoption of the 1977 NESC extreme wind criteria. Mr. Mara chose to ignore that the lattice towers in question predate 1977, or possibly did not know because he failed to ask. And (by his own admission), there was no NESC extreme wind loading requirement at the time of design. Therefore, the towers do not suffer from a "design" flaw any more than any component that has been updated over time (or which was built to a given standard that has been subsequently modified).

[4] *See, e.g.*, Lloyd Deposition, p. 12, ll. 7-15; p. 33, ll. 4-8; p. 34, ll. 15-21; p. 40, ll. 20-21.

Mr. Mara next states that "Replacing a tower with another tower of the same strength does not increase resiliency. Rather it simply maintains the status quo in terms of strength. . . . Clearly replacing new towers with the same strength and same materials is not a clear improvement in outage cost or times, therefore the project does not meet the requirements" of the Rule. As I previously noted, this opinion ignores reality by assuming the system's strength is static and infrastructure retains its original strength throughout its operational life – unfortunately, that is just not the case. Moreover, as stated above, DEF upgrades towers to DEF extreme wind guidelines that exceed NESC requirements, providing increased strength and resiliency. Additionally, as a result of past extreme weather event performance, DEF engineering criteria for tower construction was enhanced to not only satisfy NESC minimum requirements, but to also mitigate cascading failure.

This subprogram should be retained.

Q. Witness Mara states neither Florida Power & Light nor Tampa Electric include the replacement of lattice towers in their respective SPPs. Do you think this should prevent DEF from including this hardening activity in its own SPP?

A. No. I am not aware of any requirement that all utilities have the exact same programs included in their respective SPPs - for good reason - each utility's system is unique. DEF's SPP is specific to its system's needs and includes programs designed to strengthen *that* system to provide customers the benefits the legislature has identified while meeting the requirements of the SPP Rule.

Q. Describe how the Transmission Overhead Ground Wire subprogram meets the requirements of Rule 25-6.030, F.A.C.

A. As described in Exhibit No. (BML-2), the Transmission Overhead Ground Wire ("OHGW") subprogram is a standards-based activity that targets replacement of transmission OHGW susceptible to damage or failure with optical ground wire ("OPGW"). OPGW provides improved grounding and lightning protection as well as high-speed data transmission for system protection, control, and communications. As stated in Exhibit No. (BML-1), deteriorated OHGW reduces the protection of the conductor and exposes the line to repeated lightning damage and risk of failure impacting the system. By targeting deteriorated OHGW on lines with high lightning events, the benefits of this subprogram will be maximized. Additionally, the redundant sources of fiber optic communications for system protection and control supports faster identification of trouble spots on the transmission system and enables faster restoration following line faults, thus reducing outage restoration times.

Q. Witness Mara asserts DEF is "simply replacing old overhead ground wire with another conductor that serves the same purpose without any increase in performance of the transmission line during extreme weather events." Can you please explain what was meant by the term "deteriorated OHGW" used in Exhibit No. (BML-1) and why the subprogram is appropriate for SPP?

A. Yes, but first I would stress that, in my opinion, programs or subprograms aimed at replacing aging infrastructure – whether due to wear over time or because they have simply been performing as intended but cannot realistically be expected to do so indefinitely – are properly included in the SPP. The OHGW subprogram is a contributor to system interruptions during extreme weather events and therefore, its enhancement serves to strengthen the system and provide a more resilient grid as intended by the SPP statute and rule.

With that said, deteriorated OHGW is static conductor that has lost some of its strength but still performs the designed function, albeit at reduced capacity. This deterioration occurs when the protective galvanization has been sacrificed; static in this condition is more prone to failure. It is known and accepted that all static sizes and material combinations will lose their galvanization and eventually rust, thus reaching end of life. When this occurs, not only is the static more susceptible to failure from both wind and lightning events, but the grounding qualities become compromised. The OHGW is not "deteriorated" in the sense of having been poorly designed or maintained; rather, it is simply an asset that, when replaced, will strengthen the system against the effects of extreme weather relative to the state of the system as it exists today.

Q. Do you agree with Witness Mara that DEF may or may not use the communication capabilities of the optical overhead ground wire it is installing?

A. No, nor do I know the factual basis upon which Mr. Mara based this speculative conclusion, other than his correct recognition that fiber optic cable must be integrated in a system of like cables – but that is one of the purposes of the subprogram – to accelerate the completion of that system. We have every intention of using the communication capabilities of OPGW. In some cases, we may need other upgrades to occur on adjacent transmission stations and circuits before allowing use of the communication. Once all upgrades are completed, we will have full communication capability. OPGW serves both purposes of shielding and offering communication, and as previously provided in DEF's response to OPC's First set of Interrogatories (No. 40), OPGW is our standard for new construction and replacements. This fiber optic cable enables the migration to fiber-based protection and control logic which strategically offers short- and long- term infrastructure bandwidth solutions. Fiber enables fast, reliable, and advanced protection and control system functionality for the transmission grid. Additionally, it minimizes the impacts to customers by reducing incidents of grid operations while also reducing grid restoration times. From a construction standpoint, it is more cost effective and less customer invasive to install OPGW while performing other work rather than going back again to install it when the need arises.

Q: Can you describe the prioritization methodology for OHGW?

A: Fundamentally, OPGW aims to increase the resilience of the grid over the existing baseline by improving grounding. The risk of outages due to lightning strikes and mechanical failures are heightened during extreme weather conditions due to higher magnitude and frequency lightning events. Advanced replacement of functional wire that is susceptible to failure (e.g., degraded) under extreme weather conditions with new optical wire provides an effective solution to mitigate these risks.

The prioritization of locations for OPGW follows the two-step methodology described for insulators above and in Appendix A of Exhibit No. (BML-2), which includes rigorous weather modeling and detailed engineering desk-review. For OPGW, the prioritization modeling focuses on the main purpose of the hardening activity, by modeling benefits from reduction in customer minutes of interruption ("CMI") due to increased resilience to lightning strikes.

Q. Would you characterize the benefits of installing OPGW as "a minor side benefit?"

A. I would not characterize the benefits of installing OPGW as a "minor side benefit."[5] DEF is replacing the existing OHGW following the current Duke Energy OPGW standards, provided in DEF's response to OPC's First Set of Interrogatories (No. 40) and Production of Documents Request (No. 12). These standards are cost-effective, as the additional material cost is negligible compared to the total construction cost and provide additional benefits to the system. Installing OPGW not only provides the benefit of communication, but it also provides additional strength of the element (higher breaking strength). As mentioned above, communication enablement is a large benefit. Fiber optic cable installed in the overhead static wire position on transmission lines enables the migration to a fiber-based protection and control logic. This strategically offers DEF an optimum short- and long-term infrastructure bandwidth solution. Fiber enables fast, reliable, and advanced protection and control system functionality for the transmission grid and strategically impacts reliability by reducing incidences of grid operations, while reducing grid restoration times.

[5] Mara Testimony, p. 13, l. 13.

Q. Do you agree with Witness Mara's allegation "the new OHGW will meet the same NESC loading limits for extreme wind, so there is no increase in strength and thus no reduction in restoration costs."?[6]

A. No. I do not agree with Witness Mara's assertion. Design standards are reviewed and revised over time and components replaced through this program (including OHGW) are reviewed and checked to these current design standards for compliance. Replacing OHGW to today's design standards minimizes the probability of failures during extreme wind events, minimizing future restoration times.

For all these reasons, I disagree with Mr. Mara's conclusion that this subprogram should be removed from the SPP.

Q. Are Transmission Tower Upgrades and Overhead Ground Wire currently included in DEF's SPP approved by the Florida Public Service Commission?

A. Yes. These two subprograms have been approved by the Florida Public Service Commission in both DEF's SPP 2020-2029, Docket No. 20200069-EI, as well as DEF's SPP 2023-2032, Docket No. 20220050-EI.

V. SPP DEPLOYMENT PACE

Q. Does Witness Mara make a recommendation to reduce the pace at which DEF deploys certain SPP subprograms in his testimony?

A. Yes. Witness Mara recommends DEF reduce its deployment of certain SPP subprograms to a level Staff inquired about in its seventh interrogatory.

[6] *Id.* at p. 13, ll. 19-20.

Q. Can you describe Witness Mara's recommendation for Transmission subprogram deployment?

A. Yes. Witness Mara recommended "limiting transmission structure upgrades to 462 structures per year."[7] This translates to a unit deployment reduction of around 75% in 2026 and 2027 for these affected subprograms. Witness Mara seemingly ignores, or at least does not acknowledge, that a roughly 4% reduction in revenue requirements he recommends would be a much more dramatic decrease in subprogram deployment.

Q. Do you agree with Witness Mara's assertion that this reduction will not materially affect the response to major events in the near term?

A. No, I do not. First of all, as I explained in my direct testimony, DEF has not had a hardened transmission structure fail during a storm event. As described in DEF's response to the Staff's Interrogatory, limiting deployment to 462 transmission structures (i.e., poles and towers) over the entire 10-year plan (2026 through 2035) would delay these proven benefits to customers by extending the risk of non-hardened structure failures through an additional 6 to 7 storm seasons and at the conclusion of the first three-years of the proposed SPP (i.e., end of year 2028) this recommended reduction would result in close to 3,000 wood transmission poles remaining on the system rather than 0 as proposed by DEF.

In sum, adoption of this proposed reduction in work scope could lead to prolonged system impacts during extreme weather events, affecting a multitude of critical customers such as urgent care and medical centers, fire stations, law enforcement facilities and prisons, cell

[7] *Id.* at p. 14, l. 8.

towers, fueling stations, and water treatment plants, assisted living and hospice facilities, schools, shelters, and financial institutions – not to mention the impacts to other customers of all classes and types.

VI. CONCLUSION

Q. Ms. Vazquez, your rebuttal covers a lot of ground, but did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. Mr. Mara's testimony involved numerous assertions, opinions and conclusions and I could not reasonably respond to each and, therefore, I focused on the issues that I thought were most important. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion, opinion, or conclusion.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Kevin Palladino (TECO) was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250016-EI
FILED: APRIL 2, 2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

KEVIN E. PALLADINO

INTRODUCTION:

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

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

Q. Are you the same Kevin E. Palladino who filed direct testimony in this proceeding?

A. Yes, I am.

Q. Have your duties, responsibilities, or experience changed since the direct testimony was submitted?

A. No.

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

A. The purpose of my rebuttal testimony is to respond to issues raised in the direct testimony of Kevin J. Mara, who is testifying on behalf of the Office of Public Counsel ("OPC").

My rebuttal testimony will explain why OPC witness Mara's proposed rejections of the Distribution Storm Surge Hardening Program ("DSSH Program") and Transmission Switch Hardening Program ("TSH Program") are based on inaccurate statements about the contents of Tampa Electric's 2026-2035 Storm Protection Plan ("SPP" or "Plan") and would result in reduced storm resiliency benefits for Tampa Electric's customers.

PLAN COMPLIANCE WITH RULE 25-6.030

Q. Mr. Mara asserts that Tampa Electric did not provide "a general map" in its 2026-2035 SPP for either the DSSH Program or TSH Program as required by Rule 25-6.030(3)(c) of the Florida Administrative Code ("SPP Rule"). Do you agree with this assertion?

A. No. I reviewed the SPP Rule while preparing Tampa

Electric's 2026-2035 SPP. To my knowledge, the SPP Rule does not require Tampa Electric to prepare a map for each SPP Program. Rule 25-6.030(3)(c) requires the company to provide a "description of the utility's service area" that includes "a general map" and the number of customers served in each area. This part of the SPP Rule does not mention a separate map for each proposed SPP Program. Rule 25-6.030(3)(d)1-5 requires Tampa Electric to provide a description of each proposed SPP Program and then lists five categories of information that the company is required to provide as part of that description. None of the requirements listed include a program-specific map.

Q. Did Tampa Electric provide a description of the utility's service area that includes a map and the number of customers served in each area as required by the SPP Rule?

A. Yes. Tampa Electric provided a description of the company's service area on Bates stamped pages 25 and 26 of the 2026-2035 SPP. This description includes both a "general map" and the number of customers served in each of the company's seven service areas.

Q. Mr. Mara further asserts that Tampa Electric did not comply with the SPP Rule because it did not provide the number of customers served by either the DSSH Program or TSH Program. Do you agree with this assertion?

A. No. To my knowledge, the SPP Rule does not require Tampa Electric to identify the number of customers served by a SPP Program. Rule 25-6.030(3)(d)1-5 requires Tampa Electric to provide a description of each proposed SPP Program and then lists five categories of information that the company is required to provide as part of that description. None of those requirements includes the number of customers served by a Program. Additionally, it would be impractical for Tampa Electric to provide a customer count at the Program level for several reasons, including that a Program may extend beyond the ten-year horizon of the current Plan, and because the company has not identified each project that it may complete under a Program during its entire lifespan.

Q. Rule 25-6.030(2)(e)1 requires a utility to provide a description of each project in the first year of the plan that includes "number and type(s) of customers served." Did Tampa Electric provide this information for the TSH Program?

A. No. Tampa Electric is not required to provide this information for the TSH Program because the company does not have any projects planned for that Program in the first year of the plan.

Q. Rule 25-6.030(2)(e)1 requires a utility to provide a description of each project in the first year of the plan that includes "number and type(s) of customers served." Did Tampa Electric provide this information for the DSSH Program?

A. Yes. The company initially provided the number of switchgear replacements it plans to engineer for the DSSH Program in 2026 in Appendix H to the company's 2026-2035 SPP and a description of the number of customers that can be served by a switchgear on Bates stamped page 49 of the SPP. Once Tampa Electric completes the detailed engineering work for the replacement of the 174 switchgear planned in 2026, the company will have the information to develop more detailed customer counts for DSSH projects. Since Mr. Mara asserts that the information provided in the plan is insufficient, Tampa Electric developed a more specific customer count estimate for the Program and provided it in the revised Appendix H submitted in this docket on March 31, 2025.

Q. Mr. Mara asserts that Tampa Electric did not provide a "designation of any areas of the system not feasible, reasonable, or practical [sic]," for either the DSSH Program or TSH Program. Did Tampa Electric include this information in its 2026-2035 SPP?

A. Yes. Bates stamped page 26 of the 2026-2035 SPP states, "Tampa Electric developed the proposed 2026-2035 SPP and its supporting Programs and initiatives by examining the company's entire service area for the most cost-effective storm hardening opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities from the storm hardening evaluation due to concerns regarding the feasibility, reasonableness, or practicality of storm hardening." Bates stamped page 49 of the 2026-2035 SPP also explains that the DSSH Program is limited to replacement of switchgears in flood evacuation zones A, B, and C. Finally, Bates stamped pages 42 and 43 of the 2026-2035 SPP explain that the TSH Program will evaluate all manual GOAB switches on the company's system, meaning the entire transmission system is feasible for hardening under that program.

Q. Mr. Mara also asserts that Tampa Electric failed to provide "a description of implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the SPP" for either the DSSH Program or TSH Program, as required by Rule 25-6.030(3)(i) of the Florida Administrative Code. Did Tampa Electric provide the required description of implementation alternatives?

A. Yes. Tampa Electric provided a description of implementation alternatives on Bates stamped page 76 of the 2026-2035 SPP.

Q. Mr. Mara claims that Tampa Electric did not comply with Rule 25-6.030(3)(a) of the Florida Administrative Code by providing a description of how the TSH Program will strengthen infrastructure to withstand extreme weather conditions because the "description provided by TECO only addresses normal operation of switches." Did Tampa Electric provide this description?

A. Yes. Tampa Electric's 2026-2035 SPP explains how this SPP Program will provide benefits during extreme weather. Bates stamped page 42 of the 2026-2035 SPP states, "Based on the company's experience with Hurricane Milton, Tampa Electric is proposing the replacement of the GOAB switches with automated, remotely controlled switches that will greatly improve isolation and restoration times following extreme weather events."

Q. Mr. Mara states that Tampa Electric failed to provide a description of how the TSH Program will reduce restoration costs and outage times. Did Tampa Electric provide this description?

A. Yes. Revised Bates stamped page 42 states, "The Transmission Switch Hardening Program is a four-year initiative that aims to evaluate the upgrade of 153 switch locations with modern switches enabled with Supervisory Control and Data Acquisition("SCADA") communication and remote-control capabilities. This upgrade will allow for switches to be operated from a control center and avoid sending a technician to a site to operate the switch. This will allow for faster isolation of trouble spots on the transmission system and more rapid restoration following line faults, thereby increasing the resiliency of the transmission system." Bates stamped page 71 of the 2026-2035 SPP also states, "The company expects that the benefits of this program will include faster isolation of trouble spots on the transmission system, fewer truck rolls and less technician time in the field, and more rapid restoration following line faults."

Q. Mr. Mara asserts that Tampa Electric did not provide a comparison of the costs and benefits of the TSH Program. Did Tampa Electric provide this comparison in its 2026-2035 SPP?

A. Yes. Section 5 of the 2026-2035 SPP, which is titled "Storm Protection Plan Projected Costs and Benefits," includes approximately seven pages that set out this comparison. The projected costs for the TSH Program are included on Bates stamped page 69 of the 2026-2035 SPP, and the benefits of the program are described on Bates stamped page 71 of the 2026-2035 SPP.

TRANSMISSION SWITCH HARDENING

Q. Mr. Mara asserts that Tampa Electric offers only a "vague notion of confidence that the [TSH Program] will provide benefits." Do you agree with this characterization?

A. No. On Bates stamped page 71 of the 2026-2035 SPP, Tampa Electric explained that replacement of manually operated switches with remote operated switches will result in "faster isolation of trouble spots on the transmission system, fewer truck rolls and less technician time in the field, and more rapid restoration following line faults." On Bates stamped page 42 of the 2026-2035 SPP, Tampa Electric also explained that it can use transmission switches to "section portions of the transmission system" to "isolate trouble spots to minimize impacts to customers."

It also takes less time to isolate a trouble spot and restore power to some customers through remote switching than it would take for a technician to travel to the location of that same switch and manually operate it. This is especially true during or immediately after an extreme weather event, when transmission access may be compromised and technicians cannot gain access to the switch to isolate the faulted section. It is also evident that remotely operating a switch avoids the costs associated with a truck roll and the labor cost to manually operate the switch. Tampa Electric has a high level of confidence that this Program will provide restoration cost and outage time benefits in extreme weather conditions.

The TSH Program will reduce outage times by installing communication and remote-control capabilities on transmission switches that result in quicker response times and sectionalizing. This upgrade will allow Tampa Electric to remotely operate switches from a control center and avoid sending a qualified line technician to a site to operate the switch. This will allow for faster isolation of trouble spots on the transmission system, allowing non-damaged areas of line to be energized.

Q. Mr. Mara asserts that "It is necessary for line personnel to patrol a section of line prior to operating a switch remotely to restore service; therefore, having remote control over the switch limits its effectiveness during major events." Do you agree with this characterization?

A. No. The remote capabilities of the switch are most effective during major events by allowing for quicker isolation of damaged transmission lines. The control room operator can isolate damaged lines remotely without line personnel patrols in the field. Remote operation will allow the company to re-route power around damaged transmission line segments and restore power to the grid even before line crews go into the field.

Q. Mr. Mara asserts that "these remote-controlled switches are required by OSHA to have manual overrides to protect workers who may be working in the vicinity." Please

D5-95

describe the manual override procedure required by OSHA for the remote-controlled switches.

A. The remote-controlled transmission switch has a manual override in which the clutch mechanism is decoupled, effectively disconnecting the motor from the switch. When the workers are working on the line, it is locked and tagged in the disconnected position to eliminate the possibility of reengaging while work is being performed. The control center can still remotely operate a switch, isolate system damage, and restore power if there are no workers in the vicinity of the damage.

Q. Would there ever be a circumstance where automated functionality would not be available under OHSA-regulated circumstances?

A. No. All remote-controlled transmission switches have a clutch assembly to allow for the appropriate manual override, if required, for the automated functionality not to be available. Furthermore, this OSHA requirement is applicable when line technicians are working on an energized line. Since the goal of the program is to expedite and perform switching prior to restoration, without sending personnel on site, the requirement does not apply.

Q. Mr. Mara asserts "during a major event, the effectiveness of remote-control switches is diminished due to the potential for confusion of many different crews working in an area including crews from out of town assisting TECO in restoration efforts." Do you agree with this characterization?

A. No. The remote-control switches are very effective as they are used to isolate the damaged area remotely from the Energy Control Center ("ECC"). Without the remote-controlled switches, identifying and isolating the damaged area takes significantly longer. Additionally, line crews must notify and coordinate with ECC to obtain "clearance" allowing the line workers to perform work on the damaged area. This process ensures the ECC is aware of all line work being performed in that area and avoids any "potential confusion."

Q. Does the company currently "deploy" the same switches proposed in the TSH Program?

A. Yes. However, without the inclusion of the TSH Program in the SPP, these switches would be replaced at end-of-life under the company's asset management program. Therefore, the timeline for completing the replacement would be significantly longer than it would be through the proposed TSH Program and would not provide the benefits of the upgraded switches including quicker isolation of damaged transmission lines during major events. If the Commission rejects the TSH Program, Tampa Electric's customers would not receive the full benefits of remotely operable transmission switches for years or even decades.

Q. If approved, does the company plan to recover the TSH program costs through the company's Storm Protection Plan Cost Recovery Clause?

A. Yes, Tampa Electric plans to recover costs for the TSH Program through the company's Storm Protection Plan Cost Recovery Clause if it is approved by the Commission.

Q. Please explain why the TSH Program should be included in the company's 2026-2035 SPP?

A. The Commission should approve inclusion of the TSH Program in the company's 2026-2035 SPP because it will provide storm resiliency by reducing outage time. The transmission system is the primary feed of all distribution systems, and without it, entire substations and the distribution circuits they power would be left de-energized for longer during outages. Reducing outage time on the transmission system improves resiliency for all downstream systems such as substations and distribution circuits.

OTHER TOPICS

Q. Mr. Mara raises a concern with Tampa Electric's inclusion of the word "prudent" in the 2026-2035 SPP and supporting testimony. How do you respond to Mr. Mara's concern?

A. Although Tampa Electric disagreed with Mr. Mara's claims since the company used the word "prudent" in its general context, not a legal context, on March 31, 2025 the company filed revised pages to remove all references to "prudent" or "prudence" from the company's direct testimony and exhibits in this docket.

Q. Mr. Mara asserts that utilities "should not be modifying the programs by means of testimony or responses to data requests." Has Tampa Electric proposed any changes to the SPP Programs contained in its 2026-2035 SPP through discovery responses or through testimony?

A. No. Tampa Electric is not proposing any modifications to the programs included in its 2026-2035 SPP through rebuttal testimony, discovery responses, or any other filing.

Q. Mr. Mara's testimony refers to Staff interrogatories that asked Tampa Electric about "options for delaying" the DSSH and TSH Programs and includes the company's responses in his Exhibit KJM-2. What would be the effects of delaying these programs?

A. Delaying these programs would not be beneficial for Tampa Electric customers. First, slowing the pace of implementation for these programs would delay the storm resiliency benefits of these programs. Second, slowing the pace of work would also result in higher costs in total over time, to complete the same SPP projects, since the current work pace allows for greater efficiency for contractors, which is reflected in lower bids for the work.

Q. If the Commission rejects the DSSH and TSH Programs as Mr. Mara suggests, how would that affect Tampa Electric's customers?

A. The DSSH and TSH Programs are designed to proactively replace portions of our transmission and distribution system with assets that will reduce restoration costs and outage times associated with extreme weather. As I previously explained, Tampa Electric would not replace these assets in the regular course of business unless they have reached the end of their useful life. If the Commission rejects these SPP Programs, Tampa Electric's customers would not receive these benefits for years or even decades.

Q. Should the Commission approve Tampa Electric's 2026-2035 SPP?

A. Yes. The Commission should reject Mr. Mara's arguments and find that it is in the public interest to approve Tampa Electric's 2026-2035 SPP without modification. The company's proposed SPP was prepared as a customer-focused program using rigorous analytical tools and engineering and operational judgment. It strikes a reasonable balance between the costs of the SPP, customer benefits such as the reduction in restoration cost and outage time, and the impact on customers' bills.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of A. Sloan Lewis (TECO) was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250016-EI
FILED: APRIL 2, 2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

A. SLOAN LEWIS

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

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Manager, Rates in the Regulatory Affairs Department.

Q. Are you the same A. Sloan Lewis who filed direct testimony in this proceeding?

A. Yes, I am.

Q. Have your duties, responsibilities, or experience changed since the direct testimony was submitted?

A. No.

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

A. The purpose of my rebuttal testimony is to respond to the testimony of Kevin J. Mara, who is testifying on behalf of the Office of Public Counsel ("OPC").

My rebuttal testimony explains that Tampa Electric's accounting treatment and inclusion of the costs for the Legacy Storm Hardening Initiatives and Distribution Pole Replacement Programs in the 2026-2035 SPP is appropriate and in accordance with the 2020 Settlement Agreement and Rule 25.6030 of the Florida Administrative Code ("SPP Rule").

Q. Please describe the 2020 Settlement Agreement.

A. In April 2020, Tampa Electric, OPC, and several other parties entered into a settlement agreement to resolve issues in several dockets, including the Commission's docket for review of the company's 2020-2029 Storm Protection Plan ("SPP"). The Commission approved the 2020 Agreement in Order No. PSC-2020-0224-AS-EI, issued June 30, 2020. The 2020 Agreement required Tampa Electric to recover the costs of some existing storm hardening activities through the Storm Protection Plan Cost Recovery Clause ("SPPCRC"), and to recover the costs of other existing activities through base rates. The activities that remain in base rates include Distribution Pole Replacements, Distribution Unplanned Vegetation Management, Transmission Unplanned Vegetation Management, and the Legacy Storm Hardening Plan Activities.

Q. Mr. Mara asserts in his testimony that not all of the costs associated with Legacy Storm Hardening Initiatives are recovered through base rates, and states: "It is my understanding that TECO will recover O&M expenses through the SPPCRC." Is Mr. Mara's understanding correct?

A. No. None of the O&M costs associated with Legacy Storm Hardening Initiatives have been or will be included in the company's annual SPPCRC filing. The 2020 Agreement requires Tampa Electric to recover the costs associated with the Legacy Storm Hardening Initiatives through base rates.

Mr. Mara's confusion is likely related to the inclusion of the Legacy Storm Hardening Initiatives in the company's 2026-2035 SPP, and the inclusion of Legacy Storm Hardening Initiative-related expenses in the estimated revenue requirement for the 2026-2035 SPP. Tampa Electric, however, does not recover the costs of all SPP activities through the SPPCRC. As I explained on page 6 of my Direct Testimony: "The annual revenue requirements [in the SPP] reflect all the investments and expenses associated with the activities in the plan without regard to whether the costs are recovered through the company's existing base rates and charges or through the company's SPPCRC." The company's inclusion of all the SPP costs in the Plan is consistent with the requirements of the SPP Rule.

Q. Mr. Mara also asserts in his testimony that: "for the Distribution Pole Replacement program, the capital costs will be assigned to the SPP with the exception of plant additions and retirements associated with all distribution pole replacement which will remain through base rates." Is Mr. Mara's understanding correct?

A. No. Mr. Mara's statement confuses the inclusion of the capital costs related to the Distribution Pole Replacement program in the 2026-2035 SPP with cost recovery through the SPPCRC. Tampa Electric included all of the company's SPP activities in its 2026-2035 SPP even though not all of the costs of those activities are recovered through the SPPCRC. This approach is consistent with the 2020 Agreement and Rule 25.6030 of the Florida Administrative Code.

Page 7 of the 2020 Settlement Agreement states: "TECO's Distribution Pole Replacement program is a legacy storm hardening activity that is included in TECO's SPP. However, cost recovery for the plant additions and retirements associated with all distribution pole replacements will remain through base rates. This includes O&M expenses from asset transfers related to distribution pole replacements." All costs related to the Distribution Pole Replacement program are appropriately included in the company's estimated 2026-2035 SPP revenue requirement because this Program is part of the company's approach to storm hardening. Distribution Pole Replacement Program costs are appropriately excluded from the company's annual SPPCRC filing.

Q. Does Tampa Electric intend to seek recovery of the Legacy Storm Hardening Initiatives and Distribution Pole Replacement Program in its annual SPPCRC filing?

A. No. None of the costs for the Legacy Storm Hardening Initiatives or Distribution Pole Replacement Program have been or will be included in the company's annual SPPCRC filing.

Q. Mr. Mara asserts in his testimony that the 2020 Agreement "calls for exclusion from the SPPCRC of retirements and additions to the poles." Is Mr. Mara's statement correct?

A. Yes. This is the correct characterization of the treatment of the capital costs in the Distribution Pole Replacement program. Tampa Electric does not include the capital cost for the Distribution Pole Replacement program in the SPPCRC.

Q. Please summarize your testimony.

A. Tampa Electric's accounting treatment for the Legacy Storm Hardening Initiatives and Distribution Pole Replacement Programs in the 2026-2035 SPP are appropriate and in accordance with the 2020 Settlement Agreement and the SPP Rule.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of P. Mark Cutshaw (FPUC) was inserted.)

Before the Florida Public Service Commission

Rebuttal Testimony of P. Mark Cutshaw

On Behalf of

Florida Public Utilities Company

Docket 20250017-EI

I. Background

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw. My business address is 780 Amelia Island Parkway, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony on behalf of Florida Public Utilities Company ("FPUC" or "Company").

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Not at this time.

II. Purpose

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut various conclusions contained in the direct testimony of the Office of Public Counsel's ("OPC") witness Kevin Mara pertaining to his analysis of FPUC's updated Storm Protection Plan ("SPP") and particularly, the proposed Distribution Connectivity and Automation Plan. I will also briefly address

Mr. Mara's comments regarding the changes to the budget for the overhead feeder hardening program.

III. Responses

Q. Is Mr. Mara correct that FPUC "does not have a set of written planning criteria for their distribution system?"[1]

A. No. That is not correct. Mr. Mara appears to misconstrue FPUC's response to the Office of Public Counsel's ("OPC") Interrogatory 10a. As stated in response to Interrogatory 10a, although "FPUC does not have any documented distribution planning criteria", there are other written criteria that are utilized when developing distribution and transmission projects. Primarily, the National Electric Safety Code (NESC) is utilized when project planning and design occurs. The NESC includes many written details including crucial requirements that must be considered. As situations require more detailed planning and engineering, consultants and other software resources are used for situations such as distribution pole loading, transmission pole design, conductor sag calculations, etc. Being that the FPUC system is comprised of less than 34,000 customers, across two geographically separated small service territories, extensive planning criteria are not necessary to ensure that voltage, thermal and contingency limitations are adhered within both the planning and operation of the system. Rather than having remote personnel performing planning activities, FPUC has experienced engineering and operations staff out in the field on a consistent basis ensuring the system planning and operational criteria complies with standard utility practice.

[1] Direct Testimony of Kevin J. Mara, p.9, lines 16-20.

Q. Does Witness Mara have a complete understanding of FPUC's proposed new program, the Distribution Connectivity and Automation Program (or "DCA Program")?

A. No. Witness Mara makes several incorrect assumptions regarding the proposed Program and the FPUC system. For instance, his comparison of our distribution program to a transmission program, his suggestion that the program's scope is incomplete, and his assertion that FPUC's system has intertie capabilities that do not exist, as well as his seeming misapplication of one of the Plan filing requirements, indicate a misunderstanding of both what FPUC was required to file and what it is proposing to do.[2] I address each of these in more detail below.

Q. Is Witness Mara correct in stating that, "FPUC does not yet know the number of automated devices to be installed nor the details of the communications"?[3]

A. No, he is not. Likewise, his comment that "FPUC has not developed the concept of the Program enough to describe the communication of the automation system nor the number or type of devices to be used" is also not accurate.[4] The installation of devices and their integrated communication system is outside the 3-year detailed planning period; thus, specific numbers and quantities were not included in the filing. However, this technology and communication system is well-documented, and supported by case studies by several U.S. and Canadian utilities, including one large Florida-based utility. The technology the FPUC is proposing to implement is not new; instead, it has

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[2] Direct Testimony of Kevin J. Mara, at pages 11, 10, 11, and 12.
[3] Direct Testimony of Kevin J. Mara, p.10, lines 14-15.
[4] Direct Testimony of Kevin J. Mara, p.11, lines 28-30.

been well studied, documented and successfully deployed. FPUC provided articles with these details as part of our response to Staff's first Interrogatory.

Q. Is his statement that all "feasible and practical" feeder connections have already been made, correct?[5]

A. No. As reflected in the discovery response cited by Witness Mara, FPUC indicated that feeder ties had been made when feasible and practical but did not indicate that all feasible and practical feeder connections have already been established. The referenced feeder ties have been established over time as part of a multitude of new service connection projects when the opportunities presented itself. In other words, prior to the proposed DCA Program, FPUC had no program specifically geared at establishing feeder ties. However, in order to mitigate restoration costs and outage times for our customers, as contemplated by the Legislature, we have determined that the reasonable and feasible way to address that issue is through the DCA Program, which begins with identifying and constructing other tie points.

Q. Is the Distribution Connectivity and Automation Program identical to Duke's Transmission LFRS program?[6]

A. No. The referenced Duke Transmission LFRS Program, as I understand it, is not identical nor similar to the FPUC Distribution Connectivity and Automation Program. FPUC's program is more similar to Duke Energy's Self-Optimizing Grid Program, which contains similar distribution system strengthening enhancements as FPUC's proposed program.

[5] Direct Testimony of Kevin J. Mara, p.11, lines 27-28.
[6] Direct Testimony of Kevin J. Mara, p.11, lines 7-24.

Q. Did FPUC comply with Rule 25-6.030(3)(c), F.S., as it pertains to the Distribution Connectivity and Automation Program?[7]

A. Yes. The maps and description of customers served, as required by the referenced Rule, can be found in pages 10 through 13 of FPUC's Plan, which is my exhibit PMC-01. It appears that Mr. Mara reads this paragraph of the rule to apply to individual programs. While I am not a lawyer, I read that particular paragraph to apply to the overall Plan, not individual programs. Furthermore, the Distribution Connectivity and Automation Program, like all other Programs FPUC proposed, is applicable across the entirety of FPUC's service territory. That is, FPUC has not identified any areas within its service territory where enhancement of the existing transmission and distribution facilities would not be feasible, reasonable, or practical.

Q. Does the program harden existing facilities, or instead, simply construct new, redundant infrastructure?[8]

A. I believe the former is more accurate. This program will enable hardened overhead feeders, overhead laterals and underground laterals the ability to maintain service when extreme weather conditions or accidents impact an area. This is achieved in different ways, some of which involve reconductoring existing facilities so that they have the adequate capacity for two-way power flow, extending an existing line to create new tie point to another existing line, segmenting the feeder to allow for the rerouting of power, and installing automated devices to detect faults, isolate areas of damage, and automatically reroute power to the unaffected areas of the grid.

[7] Direct Testimony of Kevin J. Mara, p.12, lines 1-3.
[8] Direct Testimony of Kevin J. Mara, p.11, lines 18-24.

Q. Mr. Mara indicated that FPUC's Overhead Feeder Hardening budget increased for the three-year horizon (2026-2028) relative to same three-year horizon budget presented in 2022.[9] Is that accurate?

A. Yes. The numbers described by Witness Mara are correct.

Q. Was the increase expected?

A. Due to some uncertainties and our lack of experience with our initial Storm Protection Plan in general, we had a reasonable expectation that costs would likely increase as we gained experience and honed the details of our Plan. Specifically, FPUC's initial SPP reflected the best projections known to us at that time. However, when we developed our first Plan to be filed in 2022, we had a level of uncertainty around several things, including how to appropriately manage the plan and how to handle supply chain issues, among other things. Our goal was to develop a plan that was manageable, but met the Rule requirements, and then make reasonable and practical adjustments as we gained experience. With experience, we learned that adjustments to the undergrounding criteria were necessary, as noted in our filing, and we incorporated the lessons we learned during the first 3 years of implementation into the adjustments we incorporated in our updated Plan.

Q. Witness Mara also indicates that the Overhead Feeder Hardening program originally had a "slow roll-out" but that now it is on track to be completed in 10 years.[10] Is that accurate?

A. Witness Mara is partially correct. Like all of the programs in FPUC's initial SPP, the Overhead Feeder Hardening Program was contemplated to ramp up slowly in terms of

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[9] Direct Testimony of Kevin J. Mara, p.6, lines 5-11.
[10] Direct Testimony of Kevin J. Mara, p.6, lines 8-9.

activity and, therefore, costs. In our initial SPP, this program was planned as a 30-year program. Due to our experience in implementing this program, we refined our projection to reflect completion in 20 years from the filing of this updated SPP, or 24 years total based upon the initial start date. Witness Mara's is not correct that it will be completed in 10 years.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN LA ROSA: How about exhibits?

MR. IMIG: Staff has compiled a comprehensive exhibit list, which includes the prefiled exhibits attached to the witnesses' testimony in this case. The list has been provided to the parties, the Commissioners and the court reporter. The list is marked as the first hearing exhibit, and the other exhibits should be marked as set forth in the chart.

CHAIRMAN LA ROSA: Okay. Then the exhibits then will be as so marked.

(Whereupon, Exhibit Nos. 1-86 were marked for identification.)

MR. IMIG: Staff asks that the comprehensive exhibit list, marked as Exhibit No. 1, be entered into the record.

CHAIRMAN LA ROSA: Exhibit 1 is then entered.

(Whereupon, Exhibit No. 1 was received into evidence.)

MR. IMIG: Staff requests that Exhibits 2 through 73 be moved into the record as set forth in the comprehensive exhibit list.

CHAIRMAN LA ROSA: Have the parties had a chance to review the exhibit list? Seeing nodded heads. Okay. Excellent. Are there any objections to them? Seeing none.

If there is no objections, then Exhibits No. 2 through 73 will then being entered into the record.

(Whereupon, Exhibit Nos. 2-73 were received into evidence.)

CHAIRMAN LA ROSA: Are there any other matters?

MR. IMIG: There are no other matters at this time, Mr. Chairman.

CHAIRMAN LA ROSA: Okay. Excellent.

Thank you, parties.

Any other additional matters to discuss?

Seeing none, I would just kind of say this quickly, is that, you know, there has been a lot of discussion downtown from the Legislature about the SPP process specifically, and just kind of our industry in general. If there are suggestions to changes, and kind of going to OPC on this, to create efficiencies, I would certainly encourage that and to open those discussions between you and them, and whatever may happen there. But certainly, as we start to do more and more of this, I think we are all seeing this a little clearer. So I know there were some discussions in a committee, and I just wanted to kind of put that out there.

If -- seeing no other matters before us, Commissioners, are we good? I think so. Then we will go ahead and call this meeting adjourned.

Thank you all very much for your time.

(Transcript continues in sequence in Volume *.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 3rd day of June, 2025.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028