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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.	DOCKET NO. 20220049-EI ORDER NO. PSC-2022-0387-FOF-EI ISSUED: November 10, 2022

The following Commissioners participated in the disposition of this matter:

ART GRAHAM
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FINAL ORDER APPROVING, WITH MODIFICATIONS, FLORIDA PUBLIC UTILITIES COMPANY'S STORM PROTECTION PLAN

APPEARANCES:

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BY THE COMMISSION:

Background

Section 366.96, Florida Statutes (F.S.), requires each investor-owned electric utility (IOU) to file a transmission and distribution storm protection plan (SPP) that covers the immediate 10-year planning period. The plans are required to be filed with the Florida Public Service Commission (FPSC or Commission) at least 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. No later than 180 days after a utility files its plan containing elements required by our rule, we must determine whether it is in the public interest to approve, approve with modification, or deny the plan. Subsection 366.96(7), F.S., states that once a utility's SPP has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence. Under this section, we are also required to conduct an annual storm protection plan cost recovery (SPPCRC) proceeding to determine the utility's prudently incurred SPP costs.

IOUs were required to file their first SPPs by April 10, 2020. By motion filed on March 17, 2020, Florida Public Utilities Company (FPUC or Utility) sought to defer filing its SPP and refrain from participating in the SPPCRC proceeding due to circumstances affecting the utility as a result of Hurricane Michael. The Motion was granted by Order No. PSC-2020-0097-PCO-EI, issued April 6, 2020, and FPUC continued to operate under its Storm Hardening Plan.

On April 11, 2022, FPUC filed its first proposed SPP, which covers the period of 2022-2031 and included eight programs. FPUC's SPP includes the following programs:

- Distribution Overhead (OH) Feeder Hardening
- Distribution OH Lateral Hardening
- Distribution OH Lateral Underground
- Distribution Pole Inspection & Replacement
- Transmission & Distribution (T&D) Vegetation Management
- Future T&D Enhancements
- Transmission/Substation Resiliency
- Transmission Inspection and Hardening

The majority of these programs are a continuation of its previously approved Storm Hardening Plan and are described in Attachment A. The Office of Public Counsel (OPC) was granted intervention in this docket. An administrative hearing was held on August 2-4, 2022.[1] Post hearing briefs were filed on September 6, 2022. In its brief OPC included a procedural matter, which is addressed below.

[1] FPUC's docket was consolidated with the SPP dockets for TECO (20220048-EI), DEF (20220050-EI), and FPL (20220051-EI) for hearing purposes only.

Procedural Matter

On pages 27-36 of its post-hearing brief, OPC unilaterally inserted a "post-hearing legal issue" that was not listed in the Prehearing Order.[2] OPC argued that we should reverse the prehearing ruling set forth in Order No. PSC-2022-0292-PCO-EI, wherein the Prehearing Officer granted motions to strike portions of the prefiled testimony of OPC witness Lane Kollen. In our opinion, this legal argument does not raise a new substantive issue. The lack of legal relevance of witness Kollen's testimony was addressed in detail by the Prehearing Officer in Order No. PSC-2022-0292-PCO-EI. OPC requested reconsideration of that Order, which we denied. Because we have fully addressed the evidentiary concerns relating to the testimony of witness Kollen on the merits on two previous occasions, it is appropriate to discuss OPC's "post-hearing legal issue" here only to the extent it raises procedural concerns. For the reasons set forth below, there is no procedural error that we must consider at this time.

"The fundamental requirements of due process are satisfied by reasonable notice and a reasonable opportunity to be heard." *Florida Public Service Commission v. Triple "A" Enterprises, Inc.,* 387 So. 2d 940, 943 (Fla. 1980). At the administrative hearing held on August 2-4, 2022, in accordance with sections 120.569 and 120.57, F.S., all parties, including OPC, were given full opportunity to present argument on all relevant issues and to conduct cross-examination of all witnesses. Neither OPC nor any other party to this proceeding was precluded from making any legal arguments regarding rule interpretation by the exclusion of the testimony. The only effect of our action in striking the testimony was to exclude expert testimony on the ultimate legal issues, which are the sole province of the tribunal.

Many portions of Witness Kollen's prefiled testimony were not stricken. Those portions were moved into the record as though read, and exhibits LK-1 through LK-3 were admitted into evidence. OPC separately proffered the portions of Witness Kollen's testimony subject to the order granting the motion to strike, and the proffered testimony was also moved into the record as though read. On August 3, 2022, Witness Kollen provided a summary and was subject to cross-examination on both the testimony that was not stricken and the proffered testimony that had been stricken. Counsel for OPC also made its legal arguments about the rule interpretation at that time. Although we ultimately decided to strike portions of OPC Witness Kollen's testimony, OPC was provided an opportunity to make its legal argument at the administrative hearing, and in its motion for reconsideration. OPC made its arguments again in its post-hearing brief.

OPC also argued that a Commission Final Order applying Rule 25-6.030, Florida Administrative Code (F.A.C.), in a manner not consistent with their argument "could be seen as the agency interpreting its [statutory] mandate without an effective or complete delegation of authority." The cases cited by OPC in support of this argument address judicial review of the constitutionality of statutes.[3] As an agency, we have no jurisdiction to declare a statute unconstitutional. Moreover, following the passage of Article V, Section 21, of the Florida

[2] Order No. PSC-2022-0291-PHO-EI, issued August 1, 2022.
[3] Post-Hearing Brief at 23 (*citing Askew v. Cross Key Waterways*, 372 So. 2d 913 (Fla. 1978); *Microtel, Inc. v. Florida Pub. Serv. Comm'n,* 464 So. 2d 1189, 1191 (Fla. 1985); *Microtel, Inc. v. Florida Pub. Serv. Comm'n*, 483 So. 2d 415 (Fla. 1986)).

Constitution, our interpretation of a statute is not relevant to a court vested with jurisdiction to consider that constitutional question.

For these reasons, we do not agree with OPC's arguments that the actions taken with respect to witness Kollen's testimony were procedurally infirmed or negatively impacted the fairness of the proceeding.

We have jurisdiction over the issues set out below pursuant to Section 366.96 and Chapter 120, F.S.

Decision

I. Does FPUC's SPP contain all of the required elements of Section 366.96, F.S., and Rule 25-6.030, F.A.C.?

A. Parties' Arguments

FPUC stated that it worked closely with Pike Engineering to develop a SPP that included each component of Rule 25-6.030, F.A.C. FPUC used Rule 25-6.030(3), F.A.C., as a checklist to ensure it met each of the filing requirements.

OPC argued that FPUC did not comply with Rule 25-6.030, F.A.C., because OPC found the costs/benefits comparison in FPUC's SPP to be inadequate. OPC argued that FPUC's SPP filings are inadequate because the cost comparison did not quantify benefits pursuant to Paragraphs 3(c), (d), (e), (i), and (j) of Rule 25-6.030, F.A.C. OPC argues quantitative information, i.e., "a meaningful cost/benefit analysis" is required under the rule. OPC witness Kollen testified the context and juxtaposition of the terms "costs" and "benefits" strongly imply a comparison of dollar costs and dollar benefits, not a comparison of dollar costs and qualitative benefits.

B. Analysis

The first utility storm hardening programs were filed for our approval in 2007 and reviewed by us at least every three years thereafter. In 2019, the Florida Legislature emphasized the importance of storm hardening when it enacted Section 366.96, F.S., entitled "Storm Protection Plan Cost Recovery."[4] Subsection 366.96(3), F.S., requires each IOU to file a transmission and distribution SPP for our review and directs us to hold an annual proceeding to determine the IOUs' prudently incurred costs to implement the plan and allow recovery of those costs through the SPPCRC.

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[4] Subsection 366.96(1), F.S., provides that it is in the state of Florida's interest to strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities and the undergrounding of certain electrical distribution lines and vegetation management, and that it is in the state's interest for each utility to mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans.

We promulgated two rules, Rule 25-6.030, F.A.C., Storm Protection Plan, and Rule 25-6.031, F.A.C., Storm Protection Cost Recovery, to implement and administer Section 366.96, F.S. This is FPUC's first SPP filing.

This issue addresses the parties' arguments concerning the filing requirements pursuant to Rule 25-6.030, F.A.C. Throughout this docket, OPC's arguments have centered on whether qualitative or quantitative information is required pursuant to Rule 25-6.030, F.A.C. "Qualitative" information simply means descriptive or narrative information, as opposed to "quantitative" information, which is information that provides numeric (i.e., dollar) amounts.[5] Regardless of how information in a SPP filing is characterized, we will evaluate the information to determine if it meets the requirements of Section 366.96, F.S., and 25-6.030, F.A.C. For the reasons set forth below, we find that FPUC's SPP meets the requirements of Section 366.96, F.S., and Rule 25-6.030, F.A.C.

Section 366.96(4), F.S., provides:

> (4) In its review of each transmission and distribution storm protection plan filed pursuant to this section, the commission shall consider:
> (a) The extent to which the plan is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability, including whether the plan prioritizes areas of lower reliability performance.
> (b) The extent to which storm protection of transmission and distribution infrastructure is feasible, reasonable, or practical in certain areas of the utility's service territory, including, but not limited to, flood zones and rural areas.
> (c) The estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan.
> (d) The estimated annual rate impact resulting from implementation of the plan during the first 3 years addressed in the plan.

The rule implementing this statute identifies the types of information a utility is to submit for us to consider as part of our SPP review. *See* Rule 25-6.030(3), F.A.C. ("For each Storm Protection Plan, the following information must be provided . . . ."). By its plain language, this rule specifies only the informational content of the SPP filing. It does not establish a substantive standard for our decision on the SPP. We are to apply the considerations specified in Subsection 366.94(4), F.S., in making the ultimate determination whether it is in the public interest to approve, approve with modifications, or deny the SPP.

Under the rule, a utility must provide an estimate and comparison of the costs and benefits of each SPP program.[6] Specifically, Rule 25-6.0303(d), F.A.C., provides as follows:

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[5] Neither of the terms "qualitative" nor "quantitative" is contained within the SPP statute or SPP Rule; rather, these are terms that Commission staff and the Parties use to assist with the description of the categories of information that are at issue in this docket.
[6] Specific elements of Rule 25-6.030, F.A.C., such as areas for prioritization and rate impact, are discussed in more detail in Sections II through VI of this Order.

> 3(d) A description of each proposed storm protection program that includes:
> 1. A description of how each proposed storm protection program is designed to enhance the utility's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions;
> 2. If applicable, the actual or estimated start and completion dates of the program;
> 3. A cost estimate including capital and operating expenses;
> 4. A comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in subparagraph (3)(d)1.

Neither Section 366.96, F.S., nor Rule 25-6030, F.A.C., explicitly require a cost-effectiveness evaluation or quantitative cost-benefit analysis. Rule 25-6.030(3)(d)4., F.A.C., requires "…a comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in subparagraph 3(d)1." The crux of OPC's argument is those terms must be read together to mandate filings include a traditional cost-effectiveness evaluation or quantitative cost-benefit analysis that shows estimated benefits outweigh costs in a SPP. OPC argued that if no traditional cost-effectiveness evaluation or "quantitative" cost-benefit analysis is contained in the utility's SPP filings, we lack the information necessary to make a determination that a SPP can be approved in the public interest. In making this argument, however, the OPC makes the case for requirements that are outside the scope of the rule for two reasons.

First, the traditional use of the term, phrase, or concept of "cost-effectiveness evaluation" or "quantitative cost-benefit analysis," as promoted by OPC, is not expressly included in Section 366.96, F.S., nor Rule 25-6.030, F.A.C. An interpretive application of such term, phrase, or concept, as proposed by OPC, at a minimum would result in the imposition of new filing and analytical requirements that are not contained within the current rule, and therefore would arguably be beyond the scope of the current rule.

The more logical and practicable interpretation of the terms "costs" and "benefits" is found in a plain reading of 366.96, F.S., and Rule 25-6.030, F.A.C. Collectively these provisions require an investor-owned electric utility to provide information that demonstrates their program is likely to mitigate potential outages and reduce restoration time and the subsequent costs, regardless if such information is presented in a qualitative or quantitative format. These provisions also require that we consider the rate impact in order to approve a SPP. We will receive all the cost numbers necessary to make a rate impact determination. Thus, Rule 25-6.030, F.A.C., shall be interpreted to allow for both quantitative and qualitative information in the SPPs.

Second, OPC's argument is flawed given the real world nature of storm hardening. It is not a traditional utility function required for day-to-day service. Rather, creating a SPP is an activity that goes above and beyond the basic "sufficient, adequate, and efficient" standard of service to strengthen existing utility infrastructure to withstand potential extreme weather conditions. This means that storm hardening costs may or may not produce actual financial benefits during a given time, depending on a particular utility's circumstances, and qualitative information may provide an accurate analysis of the benefits of a SPP. [7]

Qualitative information can be meaningful when it demonstrates:

- How storm projects would impact the largest numbers of customers, such as transmission projects, and utility infrastructure serving critical customers such as hospitals, emergency responders, and water treatment plants.

- Whether a proposed SPP program or activity is something in addition to or above-and-beyond normal utility practices.

This means a particular SPP can effectively demonstrate how it meets the statutory criteria of mitigating outages and reducing restoration costs regardless if it is in a quantitative or qualitative format. Because we find the utility has the option to submit what it deems to be its most accurate data analysis of costs and benefits for our consideration, we find that Rule 25-6.030, F.A.C., shall be interpreted to allow for both quantitative and qualitative information in the SPPs.

However, a determination that a utility met the filing requirements of the SPP Rule, regardless of the type of information provided, does not mean automatic approval of its SPP programs and projects. In other words, meeting the filing requirements of the SPP Rule allows us to go forward with making a determination on approval, denial, or modification of a SPP.

In this case, we find the information FPUC provided is sufficient to ascertain a comparison of costs and benefits within its SPP, as well as rate impact of its SPP. FPUC met the filing requirements of Rule 25-6.030, F.A.C., because FPUC provided:

- The estimated costs for each proposed program.
- A description of how implementation of the plan will reduce restoration costs.
- Outage times and a description of how each program is designed to enhance the facilities.

While FPUC's filing did not include dollar amounts for benefits or a cost-effectiveness analysis in the format requested by OPC, the descriptions it provided were sufficient for a meaningful review of the SPP pursuant to Section 366.96, F.S. For example, as part of the program descriptions, FPUC identified that the program would achieve the desired objectives outlined in the SPP Rule of reducing restoration costs and outage times associated with extreme weather events. Additionally, FPUC witness Cutshaw argued that based on experience from Hurricane Michael, its proposed SPP programs would harden FPUC's system instead of FPUC facing

[7] Consider the following example: a utility spends $10 million to convert wooden poles to concrete poles. Based on the assumption that a Category 3 hurricane would strike the area every three years, the projected benefits are $15 million over 30 years for a net savings to customers of $5 million. However, if the utility does not experience extreme weather in these locations for a period of time (as was the case for the period 2005 through 2017) the customers may nonetheless be receiving qualitative benefits (the system is better prepared for when extreme weather does occur) that are consistent with the public interest requirements of Section 366.96, F.S.

restoration costs associated with bringing in outside crews and services following an extreme weather event.

C. Conclusion

FPUC satisfied the SPP Rule with its filing, and we have sufficient information necessary to make a public interest determination on its SPP.

II. Is FPUC's SPP expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability?

A. Parties' Arguments

FPUC argued that implementation of its SPP is expected to result in a significant reduction in outages, the length of outages, as well as reductions to future restoration costs from severe storms. FPUC argued that its SPP will ultimately result in less damage in a storm event, and therefore cost savings.

FPUC argued that its SPP is designed to meet the requirements of the SPP Statute and Rule by reducing outage times and restoration costs in order to improve the overall resiliency of FPUC's system. FPUC argued that it is not realistic and reasonable to quantify FPUC's reduction in restoration costs and outage times. FPUC provided a qualitative description for each of its SPP programs that included how each program met the statutory and rule requirements, as well as the benefits that could be expected from implementation of the program. The testimony of FPUC's witness Cutshaw emphasized the Utility's position that its SPP will reduce storm restoration costs based on lessons learned from Hurricane Michael.

OPC argued that FPUC only provided vague language on how its SPP would reduce restoration costs and FPUC did not provide any outage time reduction estimates. OPC argued that based on the information provided by the Utility in its SPP, the extent to which FPUC's SPP would reduce restoration costs and outage times cannot be determined.

B. Analysis

Subsection 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, we shall consider the extent to which the storm protection plan is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability. Rule 25-6.030(3)(d)(1), F.A.C., requires a utility to provide a description of how each proposed storm protection program is designed to enhance the utility's existing transmission and distribution facilities, including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions.

Because this is FPUC's first SPP filing, FPUC has operated to date under its current Storm Hardening Plan. FPUC utilized a Risk Resiliency Model that included historical post-storm data, and described the performance of hardened and non-hardened structures within its system.

OPC argued that FPUC did not include any monetized estimates of the reduction in restoration costs and outage times and instead provided vague language about reducing restoration costs. In rebuttal, FPUC witness Cutshaw explained that FPUC's programs provide economic benefit in multiple ways. For example, the witness explained that FPUC's poles are replaced with poles that have higher loading and strength factors, which in turn, would reduce restoration times and costs associated with extreme weather events. OPC did not specifically dispute the inputs or model utilized by FPUC.

FPUC provided sufficient support for us to determine that its SPP is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability.

C. Conclusion

FPUC demonstrated that its SPP is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability.

III. Does FPUC's SPP prioritize areas of lower reliability performance?

A. Parties' Arguments

FPUC argued that its SPP prioritizes areas of lower reliability. Critical load was categorized, service by circuit was assessed, and an Interruption Cost Estimate calculator was utilized to estimate the cost impact of outages. Weather patterns were also evaluated, as well as the societal impact of an electrical outage to a community.

FPUC stated that its Resiliency Risk Model used performance records from its system during extreme and non-extreme weather conditions as a key input in the development of its SPP. This information provided insight into the various causes of outages impacting the FPUC system and contributed to the prioritization of projects within key programs such as the Overhead Lateral Hardening Program and Overhead Lateral Undergrounding Program. For these key programs, FPUC focused on prioritizing feeders with the highest risk score and statistically worse performance, while also considering other factors.

OPC agreed that FPUC's model used historical reliability performance of its system under extreme and non-extreme weather events for areas of lower reliability performance, but argued it is unclear to what extent areas of lower reliability performance were prioritized over other areas for other reasons.

B. Analysis

Subsection 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, we shall consider the extent to which the plan is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability, including whether the plan prioritizes areas of lower reliability performance. Rule 25-6.030(3)(e)d, F.A.C., requires a description of the criteria used to select and prioritize proposed SPP projects be provided.

FPUC used Pike Engineering's Risk Resiliency Model to assess system risk and determine project prioritization for its SPP programs based on probability, response, and impact. The model performed an analysis of the Utility's historical reliability performance, both during extreme and non-extreme weather conditions, using quantitative data from available public sources as well as FPUC specific data. Model inputs included data such as wind probability, flood/storm surge potential, past performance, accessibility, critical load, and interruption cost estimates. FPUC took into consideration the model's prioritization portfolio along with other factors, such as external influences and resource availability, when determining the prioritization of its SPP.

OPC did not specifically address this issue with testimony or evidence, but rather discussed its preference for a more generalized adoption of a uniformed decision methodology. Because FPUC's SPP prioritizes areas of lower reliability based on its use of the Risk Resiliency Model and resulting criteria descriptions for each program, FPUC demonstrated its prioritization of SPP projects in areas of lower reliability performance. Thus, FPUC's SPP met the prioritization requirement of Section 366.96(4)(a), F.S.

C. Conclusion

FPUC's SPP prioritized areas of lower reliability performance.

IV. Is FPUC's SPP feasible, reasonable, or practical within the Utility's service territory?

A. Parties' Arguments

FPUC argued all of the programs in its SPP are feasible, reasonable, and practical for all areas and facilities that the Utility's SPP addresses. The Reliability Model used to develop the SPP considers, among other things, geographic location and population; thus, flood zones and rural areas have been considered. FPUC's use of the Resiliency Risk Model included data specific to FPUC's geographic location, customer population, rural areas, and flood zones. This information allowed the Utility to assess the resiliency and risks for each of the unique divisions of its system and develop its comprehensive SPP to address any issues.

OPC argued that efforts to identify excessive spending centered on projects do not meet what OPC calls its "two-prong" test, which is a construct OPC created in this docket to interpret the SPP statute to require that each program reduce both restoration costs and outage times.

B. Analysis

Subsection 366.96(4)(b), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, we shall 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. Rule 25-6.030(3)(c), F.A.C, requires a utility to provide a description of the utility's service area, including areas prioritized for enhancement and any areas where the utility has determined that enhancement of the utility's existing transmission and distribution facilities would not be feasible, reasonable, or practical. Integral to this description, the utility must include a general map, the number of customers served within each area, and its reasoning for prioritizing certain areas for enhanced performance and for designating other areas of the system as not feasible, reasonable, or practical.

As a part of its proposed SPP, FPUC provided a map of its service territory and the number of customers served within each area. In his testimony, OPC Witness Cutshaw did not identify any areas of FPUC's service territory in which it would not be feasible, reasonable, or practical to execute SPP projects. FPUC utilized a Resiliency Risk Model to gain awareness of system vulnerabilities to prioritize and assess overall risk and resiliency for each of the unique divisions within its overall system.

Because FPUC provided a map of its service area, the number of customers served within each area, and the methodology of prioritizing projects within its programs, we find that FPUC's SPP is feasible, reasonable, and practical in certain areas of the Utility's service territory including, but not limited to, flood zones, and rural areas.

C. Conclusion

FPUC's SPP is feasible, reasonable, and practical in the Utility's service territory.

V. What are the estimated costs and benefits of FPUC's SPP programs?

A. Parties' Arguments

FPUC estimated that implementation of its SPP for the 2022-2031 planning horizon would cost $263.14 million, including O&M, which equates to a revenue requirement of $147,181,829.[8] FPUC argued its proposed programs and subsequent projects provide an economic benefit in more than one way inclusive of reduced restoration costs from facilities, which will not require repair following extreme weather events and economic benefits to customers whose power availability either will be uninterrupted or be restored more expeditiously because of these initiatives.

FPUC argued that quantifying the costs in the manner OPC prefers is a complex, and arguably an impossible task. Some assumptions, such as cost per mile, cannot be fully validated

[8] Hearing Exh. 89, BATES 2103.

until projects are completed given that the price of materials and labor tend to fluctuate. The reduced amount of time without service is valued differently, because the value of that benefit varies by customer, customer type, location, and length of the outage. FPUC stated that OPC fails to consider these benefits and the cost savings that inure directly to customers from the elimination of outages and reduced restoration times when there is an outage.

OPC argued FPUC refused to quantify the costs and benefits of its programs and projects. OPC stated that the implementation of the SPP Rule requires an economic analysis in the form of a comparison of dollar benefits to dollar costs. Furthermore, the Rule requires the Utility to provide budgets for the programs and to provide the estimated reduction in restoration costs. OPC asserted that these amounts must be balanced against the benefits to the Utility's customers; as such, these two amounts allow us and the stakeholders to understand the benefits of the capital investments for storm hardening relative to the "reasonableness" of the costs.

B. Analysis

Subsection 366.96(4)(c), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, we shall consider the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan. Rule 25-6.030(3)(d)4., F.A.C., requires a utility to provide a comparison of the estimated program costs, including capital and operating expenses, and the benefits. For each SPP program, FPUC provided the estimated capital costs and operating expenses for 2022 through 2024, which are summarized in Table 1 below.

Table 1
FPUC's 2022-2024 SPP Program Cost

Program	2022 (millions)	2023 (millions)	2024 (millions)
Overhead Feeder Hardening	$0.30	$3.01	$3.07
Lateral Feeder Hardening	$0.06	$0.58	$1.01
Lateral Undergrounding	$0.11	$1.12	$1.67
Distribution Inspection and Replacement	$1.22	$1.52	$1.62
Transmission System Inspection and Hardening	$0.62	$0.62	$0.62
Transmission & Substation Resiliency	-	-	$9.35
Transmission & Distribution Vegetation Management	$9.5	$11.5	$14.0
Future Transmission & Distribution Enhancements	-	-	-
Total	$11.81	$18.35	$31.34

We find that FPUC provided a description of the benefits that will be brought about by its proposed SPP. The Utility also provided in its plan the program costs, including capital and operating expenses. Therefore, the estimated costs and description of benefits to FPUC customers, as a result of the proposed programs, were presented by the Utility in its SPP.

C. Conclusion

The estimated costs for all of FPUC's programs are reflected in Table 1.

VI. What is the estimated annual rate impact resulting from implementation of FPUC's SPP for the first three years?

A. Parties' Arguments

FPUC estimated the annual rate impact of its SPP, inclusive of amounts recovered through base rates. OPC argued that the cost increases for commercial and industrial customers are too high during this period of high inflation. OPC argued that the proposed programs and their costs will have significant incremental effects on the present customer rates, noting FPUC is proposing a 33% increase in revenues to pay for the 2022-2031 SPP programs. OPC argues that implementation of the SPP is estimated to cost at least $7,369 per customer in capital costs for the 10-year investment. OPC stated the estimated costs are much greater than the benefits from potential savings for nearly all of the programs and projects.

OPC argued that the cost of the SPP program is another addition to the customer bill, which already included a 2022 natural gas price increase, the current midcourse correction, and the Hurricane Michael surcharge. OPC recommended limitations on the expenditures of the Distribution Overhead Lateral Hardening and Undergrounding Programs, as well as elimination of the Future Transmission & Distribution (T&D) Enhancements Program and the Transmission & Substation Resiliency Program.

FPUC argued that OPC's testimony is misguided because it necessitates a lesser level of service for customers of smaller utilities and it does not consider investments based on overhead miles and the utility's service territory. Comparing customer impacts between large and small utilities with similar projects is flawed, as larger utilities are able to spread the costs over a larger pool of customers. FPUC's witness testified that it plans to delay certain projects to mitigate customer impacts, but those projects cannot be postponed indefinitely. FPUC argues that OPC's comparisons of costs across utilities on a per customer basis does not yield an "apples to apples" comparison.

B. Analysis

Subsection 366.96(4)(d), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, we shall consider the estimated annual rate impact resulting from implementation of the plan during the first three years addressed in the plan. Rule 25-6.030(3)(h), F.A.C., requires the utilities to provide an estimate of the rate impact for each of the first three years of its SPP for the utility's typical residential, commercial, and industrial customers. In addition, Rule 6.030(3)(i), F.A.C., requires the utilities to provide a description of any implementation alternatives that could mitigate the resulting rate impact. Here we address the annual rate impacts for the first three years of the Utility's SPP.

Pursuant to Rule 25-6.030(3)(h), F.A.C., FPUC provided the rate impact information for each customer type, which is shown in Table 2 below.

Table 2
SPP Estimated Rate Impact (2023-2025)

Customer Class	2023	2024	2025
Residential ($/1000kWh)	$6.60	$6.58	$15.21
Typical Commercial bill Increase	5.50%	5.50%	12.72%
Typical Industrial bill Increase	2.15%	2.20%	5.06%

FPUC's 10-year capital budget for its Overhead Lateral Hardening Program is $24.75 million. FPUC's 10-year capital budget for its Overhead Lateral Undergrounding Program is $63.35 million. OPC Witness Mara recommended reducing the capital budget for both programs.

On rebuttal, FPUC witness Cutshaw testified that reducing the capital budget for both programs would delay benefits to customers. He testified that overhead laterals make up a significant part of the FPUC distribution system and include 575 miles of overhead single-, two-, and three-phase circuits in both urban and rural settings. In fact, the witness stated laterals on the FPUC system are responsible for approximately 65 percent of the CMI over the analyzed period. Witness Cutshaw stated that the overhead laterals were reviewed based upon the Resiliency Risk Model within the SPP to determine which laterals met the criteria to be included in the early stages of the upgrades and undergrounding. FPUC's witness testified that it will take 30 years to accomplish the proposed hardening in the Overhead Lateral Hardening and Overhead Lateral Undergrounding programs; however, implementation of OPC witness Mara's proposed reductions would double that estimate. Witness Cutshaw stated that the resulting delay would deny FPUC's customers of the intended benefits they would otherwise receive from the proposed SPP, in reductions to outage times, given the historical impact of storms in recent years on areas of FPUC's system.

Rate mitigation is an important consideration; however, there is insufficient support for OPC's recommended reductions to the capital budgets for FPUC's Distribution Overhead Lateral Hardening and Distribution Overhead Lateral Undergrounding programs. Further, OPC's recommended reductions were based upon the total program costs for the 10-year period, which is impractical, considering the requirements that we review SPPs at least every three years, and cost-recovery proceedings annually.

C. Conclusion

The estimated annual rate impact to implement FPUC's SPP is provided in Table 2.

VII. Is FPUC's SPP in the public interest?

A. Parties' Arguments

FPUC argued that we should determine that FPUC's SPP meets the statutory objectives, complies with requirements of Rule 25-6.030, F.A.C., and as such, should be approved as being in the public interest.

FPUC witness Cutshaw testified that reductions to the costs of service outages could result from the installation of sectionalizing equipment with the use of its proposed Supervisory Control and Data Acquisition (SCADA) project, which falls within its Future T&D Enhancements program. Witness Cutshaw explained that Smart Grid technologies enable a utility to spend less time patrolling lines in search of damage that reduces manpower hours and cost. As such, time and cost savings associated with implementation of these devices can multiply exponentially. FPUC further stated OPC's argument against FPUC's proposal overlooks the cost savings that reduced outage times can produce from limiting business downtime, which results in realized dollar savings for customers when these types of enhancements are implemented. FPUC does not have Automated Metering Infrastructure (AMI) installed on its system, and must rely upon personnel to physically investigate the system in order to determine the location and cause of each service outage.[9] FPUC argued that the procurement of sectionalizing equipment will reduce outage times and manpower hours needed to locate and repair outages saving customers money and inconvenience.

FPUC testified that its existing 138 kV line project, within the FPUC's Transmission & Substation Resiliency Program, is designed to serve Amelia Island, where the current line is aging, which places customers at a significantly greater risk for lengthy and costly outages associated with severe weather. Therefore, the new proposed 138 kV line is necessary for gaining an alternative access point on FPL's system, which supplies power to FPUC. Another project within the FPUC's Transmission & Substation Resiliency Program involved the proposed hardening of an existing 69 kV line and upgrading the serving substation on the Island. This would allow access to existing generation owned by WestRock paper mill, and potentially would enable FPUC to restore service to a significant portion of Amelia Island within five to six hours after the loss of power due to a severe weather event, even if access to FPL's generation becomes damaged or destroyed.

OPC recommended that FPUC's SPP should be denied or modified to eliminate the 138 kV transmission line project and 69 kV line project, which comprise the FPUC's Transmission & Substation Resiliency Program, and to eliminate the Future T&D Enhancements Program. OPC witness Mara indicated FPUC's Future T&D Enhancement Program is supposed to be complete at some time in the future using some type of distribution automation or smart grid technology that can create a self-healing system; however, since this is a future program, the specific costs and

[9] FPUC witness Cutshaw stated that without a self-healing system, such as the proposed AMI, the Utility must rely upon a single individual known as a "bird-dog" to locate and identify the broken poles and downed lines, and then direct repair crews to that location. Witness Cutshaw admitted that they did not currently possess an AMI, so FPUC's Proposed Program would require adding new infrastructure, rather than improving existing infrastructure.

details on full deployment are not yet available. Further, witness Mara testified that this type of distribution automation or smart grid would not reduce restoration costs, even if it reduces and isolates the number of customers affected by an outage. In addition, OPC argued that FPUC failed to include any monetized value for reduction in outage cost or outage times. OPC also recommended that FPUC's Transmission and Substation Resiliency Program be removed from its SPP because these projects should not be considered as storm hardening.

B. Analysis

Subsection 366.96(5), F.S., states that we shall determine, no later than 180 days after a utility files its plan, "whether it is in the public interest to approve, approve with modification, or deny the plan." Unlike the Storm Hardening Plans, Section 366.96(7), F.S., states that once a storm protection plan is approved, a utility's "actions to implement the plan shall not constitute or be evidence of imprudence."

As previously discussed, this is the Utility's first SPP filing and covers the period of 2022-2031. FPUC's SPP includes the following programs:

- Distribution Overhead (OH) Feeder Hardening
- Distribution OH Lateral Hardening
- Distribution OH Lateral Underground
- Distribution Pole Inspection & Replacement
- Transmission & Distribution (T&D) Vegetation Management
- Future T&D Enhancements
- Transmission/Substation Resiliency
- Transmission Inspection and Hardening

T&D Enhancement Program

FPUC's future T&D Enhancement Program is designed to allow FPUC to explore the possible benefits of investing in distribution automation systems for future SPP program iterations and subsequent implementation. This includes distribution automation or "smart grid" type devices, which use technology to detect a fault in the system, automatically isolate the faulted section, and reroute power to restore undamaged areas of the grid. FPUC witness Cutshaw testified that the Utility is now studying options and future plans to develop and put into place a SCADA system for both its NE and NW divisions; however, FPUC does not know what equipment it wishes to deploy. The estimated Program costs are $30 million over the 10-year interval, but expenditures do not begin until after 2024.

OPC witness Mara testified against the inclusion of the Future T&D Enhancement Program for two reasons. First, the Program is ill-defined and lacks detail. To illustrate this point, he noted the Program would, at some time in the future, include some kind of distribution automation or smart grid technology; a SCADA would be part of this system, but since this is a "future" program, no specific costs or details on full deployment was provided. Second, witness Mara argued that that smart grid additions may reduce outage times, but do not reduce outage costs. As an example, he noted that the repair costs to remove a tree off a line and perhaps replace a pole are the same whether a fuse is on the lateral or not. Since outage costs would not be reduced, the witness asserted this Program should not be included in FPUC's SPP.

Although FPUC witness Cutshaw attempted to refute OPC's witness Mara, we agree with OPC that the Future T&D Enhancement Program is not fully developed and does not meet the objective of storm protection or hardening. Deploying distribution data gathering systems such as SCADA is a common utility practice to ensure reliable day-to-day service. Rule 25-6.030, F.A.C., defines a storm protection program as a collection of projects that "enhance the utility's *existing* infrastructure for the purpose of reducing restoration costs and reducing outage times...." (emphasis added). Utility storm protection or hardening is a discretionary activity that goes above and beyond the basic standard of service to strengthen a utility's existing infrastructure to withstand the potential for extreme weather. While certain automation systems may help identify and facilitate restoration efforts, we do not find that the underlying data gathering system is hardening of existing facilities. Therefore, we find that FPUC's T&D Enhancement Program is not a storm protection activity and should be excluded from FPUC's SPP.

Transmission & Substation Resiliency Program

FPUC's Transmission & Substation Resiliency Program consists of the construction of a new 138 kV transmission line, the construction of a new substation, and the upgrade of a 69 kV transmission line to improve electrical resiliency and redundancy to Amelia Island. FPUC stated that these projects are necessary to facilitate restoration during extreme weather events and ensure the continued reliability of service to its NE Division.

FPUC witness Cutshaw testified that Amelia Island is currently served by a FPUC-owned, dual-circuit 138 kV transmission line that extends from an off-island interconnection point with the FPL transmission system across the Amelia River. The FPUC witness testified that Amelia Island could experience extended outages due to some inaccessible areas of its existing transmission system if subjected to storm damage. FPUC proposed to construct the new 138 kV line along a separate route from a separate FPL substation, consisting of approximately 10.75 miles of cable (2.03 miles subaqueous). FPUC witness Cutshaw recognized that while the construction of a redundant 138 kV line would improve electrical resiliency, the proposed placement of the new line is not optimal because the NE Division is a barrier island, which limits the number of areas where interconnections with other sources are available. As part of this Program, FPUC also proposed to upgrade a 4.5 mile segment of an existing 69 kV line and construct a new substation interconnection to the WestRock paper mill on Amelia Island to allow FPUC to leverage the paper mill's cogeneration capacity in times of need. FPUC Witness Cutshaw testified that the estimated costs for the Transmission/Substation Resiliency Program are $88.7 million dollars over the 10-year interval, but with costs to be incurred in 2024.

OPC witness Mara asserted the Transmission and Substation Resiliency Program should not be included in FPUC's SPP because it is not necessary or prudent. His testimony was that the existing double circuit transmission line is a hardened structure, built on concrete poles, with a few lattice steel towers at the river crossing. While FPUC states the location of this transmission system makes access to it very challenging, witness Mara pointed out it is adjacent to a four-lane highway providing better access than to most transmission lines in Florida. The OPC witness added that research by this Commission found that very few non-wood poles failed during hurricanes. Witness Cutshaw testified that by employing the good maintenance practices described in its 2022-2031 SPP, the existing dual-circuit line would be hardened against extreme wind speeds of 120 mph with Grade B strength factors.

OPC witness Mara also testified that the upgrades to the 69 kV line and new substation are not storm hardening, but rather, it is an investment to access an alternate power source. The capacity increase for interconnection of a co-generation plant should be analyzed from a power supply cost perspective and not based on storm hardening, especially since there are no guarantees that the plant will be operational when most needed by the FPUC to serve its customers. This evidence revealed that the 69 kV line project is not storm hardening, but is instead a regular Utility activity.

Utility storm protection or hardening is a discretionary activity that goes above and beyond the basic standard of service to strengthen a utility's existing infrastructure to withstand the potential for extreme weather. As such, we agree with OPC witness Mara that the Transmission and Substation Resiliency Program should be removed from FPUC's SPP. Rule 25-6.030(1)(a), F.A.C., defines a storm protection program as a collection of projects that "enhance the utility's *existing* infrastructure" (emphasis added). Looping substations is a common utility practice to ensure reliable service and the new 138 kV transmission line involves the construction of new redundant infrastructure, rather than the enhancement or hardening of existing facilities. While we agree that such activity may enhance a utility's transmission system, it does not strengthen existing transmission facilities. Therefore, new redundant infrastructure projects, such as looping substations, are not storm protection pursuant to Rule 25-6.030(1)(a), F.A.C. In addition, as asserted by OPC witness Mara, the upgrades to the 69 kV line and new substation are not storm hardening, but rather an investment to access an alternate power source. The owner of a qualifying facility is required to pay all costs associated with interconnection to a utility. Rule 25-17.087(9), F.A.C., states:

> [T]he qualifying facility is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers, lines, services, meters, switches, and associated equipment and devices beyond that which would be required to provide normal service to the qualifying facility if the qualifying facility were a non-generating customer. These costs shall be paid by the qualifying facility to the utility for all material and labor that is required. Therefore, we find that the projects included in FPUC's Transmission and Substation Resiliency Program shall not be characterized as storm protection activities.

We find that the projects included in FPUC's Transmission and Substation Resiliency Program should not be characterized as storm protection activities and should be excluded from FPUC's SPP. In addition, FPUC should remove the Future T&D Enhancement Program and the Transmission & Substation Resiliency Program from its proposed SPP. With these two modifications, FPUC's proposed SPP is in the public interest.

C. Conclusion

FPUC's SPP, with the following modifications, is in the public interest and is approved: (1) removal of the Future T&D Enhancement Program, and (2) removal of the Transmission & Substation Resiliency Program. FPUC shall file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff.

Based on the foregoing, it is

ORDERED that Florida Public Utilities Company's Storm Protection Plan met the requirements of Rule 25-6.030, F.A.C., and with the following modifications, is in the public interest and shall be approved: (1) removal of the Future Transmission & Distribution Enhancement Program; and (2) removal of the Transmission & Substation Resiliency Program. It is further

ORDERED that Florida Public Utilities Company shall file a modified Storm Protection Plan the reflecting the above ordered changes within 30 days of issuance of the final order for administrative approval by Commission staff. It is further

ORDERED that this docket shall remain open for Commission staff's verification that the modified Storm Protection Plan has been filed and complies with our order. Once these actions are complete, this docket shall be closed administratively.

By ORDER of the Florida Public Service Commission this 10th day of November, 2022.

ADAM J. TEITZMAN
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

WLT/JDI

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Florida Public Utilities Corporation
Proposed 2022 – 2031 Storm Protection Plan Programs

Distribution Overhead Feeder Hardening
This 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.

Distribution Overhead Lateral Hardening
Upgrading 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.

Distribution Overhead Lateral Undergrounding
This program's focus is to address undergrounding existing overhead laterals 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.

Distribution Pole Inspection and Replacement
While continuing to follow the eight year wood pole inspection program currently in place, poles will be replaced as needed following their cyclical inspection. Replacement poles will comply with NESC standards.

Future Transmission & Distribution Enhancements
FPUC's existing Supervisory Control and Data Acquisition (SCADA) system does not have the capability to initiate commands for the remote control of grid devices. This SPP program proposes to conduct analysis of possible benefits of investing in distribution automation systems for future SPP program iterations and subsequent implementation. These investments may include substation equipment, software systems, and distribution equipment/devices.

T & D Vegetation Management
Vegetation management is currently conducted on a three-year cycle for all main feeders and a six-year cycle on all laterals but FPUC is proposing to convert to a 4-year, cyclical, circuit-based vegetation management plan. Each circuit will have its own designated cycle and be prioritized based on customer count, critical infrastructure, and vegetation-related customer interruptions.

Transmission & Substation Resiliency
This program includes the construction of an additional 138 KV transmission line, the upgrade of one 69 KV transmission line, and the construction of one substation to improve the electrical redundancy and resiliency to Amelia Island. FPUC proposes a redundant transmission line to ensure continued reliability of service to the Northeast Division. Additionally, this program proposes to upgrade an existing 69 KV transmission line from an existing paper mill.

<u>Transmission System Inspection and Hardening</u>

Transmission facilities (six-year cycle) and substation equipment (annual cycle) will be inspected consistent with their respective inspection cycles. This program also includes the inspection and full replacement of 69kV wood poles with concrete poles that are compliant with NESC code requirements.

–New 2-18-20.