Table of Contents
Commission Conference Agenda
October 4, 2022

Item 1

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Office of Industry Development and Market Analysis (Deas, Williams)
Office of the General Counsel (Imig, Jones)

RE: Applications for Certificate of Authority to Provide Telecommunications Service

AGENDA: 10/4/2022 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

Please place the following Applications for Certificate of Authority to Provide Telecommunications Service on the consent agenda for approval.

DOCKET NO.	COMPANY NAME	CERT. NO.
20220132-TX	Cablevision Lightpath, LLC	8976
20220129-TX	Peering Hub Inc.	8977

The Commission is vested with jurisdiction in this matter pursuant to Section 364.335, Florida Statutes. Pursuant to Section 364.336, Florida Statutes, certificate holders must pay a minimum annual Regulatory Assessment Fee if the certificate is active during any portion of the calendar year. A Regulatory Assessment Fee Return Notice will be mailed each December to the entities listed above for payment by January 30.

Item 1

FILED 9/22/2022
DOCUMENT NO. 07566-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (D. Buys, Mouring) ALM
Office of the General Counsel (Watrous, Sandy) JSC

RE: Docket No. 20220133-EI - Application for authority to issue and sell securities during calendar years 2023 and 2024, pursuant to Section 366.04, F.S., and Chapter 25-8, F.A.C., by Florida Power & Light Company and Florida City Gas.

AGENDA: 10/4/2022 - Consent Agenda - Final Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

Please place the following application for authority to issue and sell securities on the consent agenda for approval.

Docket No. 20220133-EI - Application for authority to issue and sell securities during calendar years 2023 and 2024, pursuant to Section 366.04, F.S., and Chapter 25-8, F.A.C., by Florida Power & Light Company and Florida City Gas.

Florida Power & Light Company (FPL or Company) requests authorization to issue and sell and/or exchange any combination of long-tern debt and equity securities and/or to assume liabilities or obligations as guarantor, endorser or surety in an aggregate amount not to exceed $8.1 billion during calendar year 2023.

In addition, FPL requests authorization to issue and sell short-term securities during the calendar years 2023 and 2024 in an amount or amounts such that the aggregate principal amount of short-term securities outstanding at the time of and including any such sale shall not exceed $5.15 billion.

Florida City Gas (FCG) requests authorization to make long-term borrowings from FPL in an aggregate amount not to exceed $300 million during 2023 and make short-term borrowings from FPL in an aggregate principal amount not to exceed $150 million at any one time during calendar years 2023 and 2024.

In connection with this application, FPL confirms that the capital raised pursuant to this application will be used in connection with the regulated activities of FPL and FPL's subsidiaries, including FCG, and not the nonregulated activities of its subsidiaries and affiliates.

Staff has reviewed FPL's projected capital expenditures. FPL's construction budget forecast for 2023 is $8.036 billion for FPL and $53 million for FCG. The amount requested by the Company ($13.25 billion, of which $450 million is for FCG) exceeds its expected capital expenditures ($8.089 billion in 2023). The additional amount requested exceeding the forecasted capital budget expenditures allows for financial flexibility for unexpected events such as hurricanes, financial market disruptions, and other unforeseen circumstances. Staff believes the requested amounts are appropriate. Staff recommends FPL's application for authority to issue securities during calendar years 2023 and 2024 be approved.

For monitoring purposes, this docket should remain open until May 3, 2024, to allow the Company time to file the required Consummation Report.

Item 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (D. Buys, Mouring) ALM
Office of the General Counsel (Watrous, Sandy) JSC

RE: Docket No. 20220146-PU – Joint application for authority to issue and sell securities for year ending December 31, 2023, by Tampa Electric Company and Peoples Gas System.

AGENDA: 10/04/22 – Regular Agenda – Final Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On August 24, 2022, Tampa Electric Company (Tampa Electric or Company) filed a joint application with Peoples Gas System (PGS) for authority to issue and sell securities. In its petition, Tampa Electric stated it is preparing to transfer the assets used by its PGS division into a separate corporation named Peoples Gas System, Inc. (PGS, Inc.). PGS, Inc. intends to access the third-party lending market during 2023 but cannot predict when during 2023 that it will do so. To assist its affiliate and to facilitate an orderly transfer of its gas assets, Tampa Electric has agreed to continue to be responsible for providing capital as needed to PGS, Inc. under an Intercompany Debt Agreement until December 31, 2023.

In its joint application, Tampa Electric bifurcated its securities application into two separate sections; one for Tampa Electric and another for PGS, Inc. Therefore, in this recommendation, Issue 1 will address Tampa Electric's application, Issue 2 will address PGS, Inc.'s application, and Issue 3 will address the filing of the consummation reports and the closure of this docket. To be clear, in this docket the Commission is only voting on the legality of the companies' securities application and not on the spin-off of PGS.

The Commission has jurisdiction over the application for authority to issue securities pursuant to Section 366.04, Florida Statutes..

Discussion of Issues

Issue 1: Should the Commission approve Tampa Electric Company's application for authority to issue and/or sell securities for the calendar year ending December 31, 2023?

Recommendation: Yes. The amount of all equity and long-term debt securities issued during calendar year 2023 should not exceed $1.5 billion, and the maximum amount of short-term debt outstanding at any one time during calendar year 2023 should not exceed $2.2 billion. (D. Buys)

Staff Analysis: In its joint application with PGS to issue securities during calendar year 2023, Tampa Electric stated that on January 1, 2023, the Company is planning to transfer the assets, liabilities, and equity that have been recorded on the books of its PGS division into a separate corporation called Peoples Gas System, Inc. The new company will be a wholly owned subsidiary of a newly formed gas operations holding company, TECO Gas Operations, Inc., which would be a subsidiary of TECO Energy, Inc.

Included in the liabilities transferred will be PGS's allocation of outstanding unsecured notes issued by Tampa Electric and outstanding short-term borrowings that are planned to be converted into an Intercompany Debt Agreement with Tampa Electric, with interest rates on each allocation being maintained accordingly. During 2023, Tampa Electric will provide additional short-term debt funding to PGS, Inc. through the Intercompany Debt Agreement at Tampa Electric's prevailing cost of short-term debt borrowings. The Intercompany Debt Agreement will remain outstanding until PGS, Inc. pays Tampa Electric all principal and interest due on the Intercompany Debt Agreement. PGS, Inc. plans on paying off the debt associated with the Intercompany Debt Agreement in 2023 by issuing its own long-term and short-term debt. The initial obligation of PGS, Inc. under the Intercompany Debt Agreement is expected to be approximately $800 million. The total amount of borrowing available to PGS, Inc. under the Intercompany Debt Agreement will be approximately $1.2 billion.

Tampa Electric requests the authority to issue, sell and/or exchange equity securities and issue, sell, exchange and/or assume long-term or short-term debt securities and/or to assume liabilities or obligations as guarantor, endorser or surety during calendar year 2023. The Company also seeks authority to enter into interest rate swaps or other derivative instruments related to debt securities. Any exercise of the requested authority will be for the benefit of the Tampa Electric or its affiliate PGS, Inc. under the Intercompany Debt Agreement.

The amount of all equity and long-term debt securities issued, sold, exchanged, or assumed and liabilities and obligations assumed or guaranteed as guarantor, endorser, or surety should not exceed in the aggregate $1.5 billion during the calendar year 2023, including any amounts issued to retire existing long-term debt securities. The maximum amount of short-term debt outstanding at any one time during calendar year 2023 will not exceed $2.2 billion.

In connection with this application, the Company confirms that the capital raised pursuant to this application will be used in connection with the activities of the Company's regulated electric and gas divisions, or its affiliate PGS, Inc. under the Intercompany Debt Agreement, and not the unregulated activities of the utilities or their affiliates.

Staff has reviewed Tampa Electric's projected capital expenditures. Tampa Electric's projected construction budget for 2023 is $1.151 billion. The amount requested by the Company ($3.7 billion) exceeds its projected capital expenditures ($1.151 billion in 2023). The additional amount requested exceeding the projected capital budget expenditures allows for funding of the Intercompany Debt Agreement with PGS, Inc. ($800 million) and financial flexibility for unexpected events such as hurricanes, financial market disruptions, and other unforeseen circumstances. Staff believes the requested amounts are appropriate. Staff recommends Tampa Electric's application for authority to issue securities during calendar year 2023 be approved.

Issue 2: Should the Commission approve Peoples Gas System, Inc.'s application for authority to issue and/or sell securities for the calendar year ending December 31, 2023.

Recommendation: Yes. The amount of all equity and long-term debt securities issued during calendar year 2023 should not exceed $1.4 billion, and the maximum amount of short-term debt outstanding at any one time during calendar year 2023 should not exceed $1.2 billion. (D. Buys)

Staff Analysis: As discussed in Issue 1, on January 1, 2023, PGS, Inc., a new wholly owned subsidiary of TECO Energy, Inc., is planned to be established and the assets, liabilities, and equity that have been recorded on the books of PGS and reported in its Annual Report to the Florida Public Service Commission and Earnings Surveillance Reports are planned to be legally moved from Tampa Electric to the newly formed Peoples Gas System, Inc. During 2023, short-term debt funding will be provided to PGS, Inc. through an Intercompany Debt Agreement at Tampa Electric's prevailing cost of short-term debt. The Intercompany Debt Agreement will remain outstanding until PGS, Inc. pays Tampa Electric all principal and interest due on the Intercompany Debt Agreement. PGS, Inc. plans on paying off the debt associated with the Intercompany Debt Agreement in 2023 by issuing its own long-term and short-term debt.

The initial obligation of PGS, Inc. under the Intercompany Debt Agreement is expected to be approximately $800 million. PGS, Inc. intends to access the third-party lending market during 2023 but cannot predict when during 2023 it will do so. If necessary, PGS, Inc. may obtain temporary short-term bank borrowings (used to retire the Intercompany Debt Agreement principal and interest) that would be replaced with a combination of long-term debt and short-term debt borrowings.

PGS, Inc., through Tampa Electric, requests the authority to issue, sell, and/or exchange equity securities and issue, sell, exchange, and/or assume long-term or short-term debt securities and/or to assume liabilities or obligations as guarantor, endorser or surety during the period covered by this Application. PGS, Inc. also requests authority to enter into interest rate swaps or other derivative instruments related to debt securities. Any exercise of the requested authority will be for the benefit of PGS, Inc.

In connection with this application, PGS, Inc. confirms that the capital raised pursuant to this application will be used in connection with the activities of PGS, Inc.'s regulated gas distribution services and not the unregulated activities of the utility or its affiliates

The amount of equity (excluding equity moved from Tampa Electric to the new Peoples Gas System, Inc. on January 1, 2023, as described above) and long-term debt securities issued, sold, exchanged, or assumed and liabilities and obligations assumed or guaranteed as guarantor, endorser, or surety (excluding the initial obligation assumed by PGS, Inc. on January 1, 2023 under the Intercompany Debt Agreement of approximately $800 million) will not exceed in the aggregate $1.4 billion during the period covered by this Application (2023), including any amounts issued to retire the Intercompany Debt Agreement with Tampa Electric and amounts needed for potential long-term emergency funding. The maximum amount of short-term debt, as described above to potentially retire the Intercompany Debt Agreement with Tampa Electric, outstanding at any one time and to avail PGS, Inc. of short-term emergency funding and other purposes, will not exceed $1.2 billion.

Staff has reviewed PGS, Inc.'s request and its projected capital expenditures. PGS Inc.'s projected construction budget for 2023 is $333 million. The amount requested by the Company ($2.6 billion) exceeds its projected capital expenditures ($333 million in 2023). The additional amount requested exceeding the projected capital budget expenditures allows for the repayment of the Intercompany Debt Agreement with Tampa Electric ($800 million) and financial flexibility for unexpected events such as hurricanes, financial market disruptions, and other unforeseen circumstances. Staff believes the requested amounts are appropriate. Staff recommends PGS Inc.'s application for authority to issue securities during calendar year 2023 be approved.

Issue 3: Should this docket be closed?

Recommendation: No. This docket should remain open to allow the Companies time to file the required Consummation Reports. (Watrous)

Staff Analysis: For monitoring purposes, this docket should remain open until May 3, 2024, to allow the Companies time to file the required Consummation Reports. Tampa Electric and Peoples Gas System, Inc. should be required to file separate consummation reports within 90 days after the end of calendar year 2023.

Item 3

FILED 9/22/2022
DOCUMENT NO. 07562-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (D. Buys, Mouring) ALM
Office of the General Counsel (Sandy) JSC

RE: Docket No. 20210153-EI – Application for authority to issue and sell securities for 12 months ending December 31, 2022, by Tampa Electric Company.

AGENDA: 10/04/22 – Regular Agenda – Final Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On September 3, 2021, Tampa Electric Company (Tampa Electric or Company) filed an Application for Authority to Issue and Sell Securities (Initial Application) with the Commission. Tampa Electric's Initial Application requested authority to assume up to $800 million in outstanding short-term debt at any one time during calendar year 2022. On November 5, 2021, the Commission issued Order No. PSC-2021-0414-FOF-EI, approving the Company's Initial Application.[1] On December 15, 2021, Tampa Electric filed a petition requesting that the Commission amend Order No. PSC-2021-0414-FOF-EI by increasing the Company's maximum amount of short-term debt outstanding for 2022 from $800 million to $1.0 billion. On March 15, 2022, the Commission issued Order No. PSC-2022-0114-FOF-EI approving the Company's Petition to amend the initial Order and increase the Company's maximum amount of short-term

[1]Order No. PSC-2021-0414-FOF-EI, issued November 05, 2021, in Docket No. 20210153-EI, *In re: Request for approval of authority to issue and sell securities for 12 months ending December 31, 2022, by Tampa Electric Company.*

debt outstanding for 2022 from $800 million to $1.0 billion.[2] On August 24, 2022, Tampa Electric filed a second petition requesting that the Commission amend Order No. PSC-2022-0114-FOF-EI by increasing the Company's maximum amount of short-term debt outstanding for 2022 from $1.0 billion to $2.2 billion.

The Commission has jurisdiction over this matter pursuant to Chapter 366, Florida Statutes (F.S.), including Section 366.04, F.S

[2]Order No. PSC-2022-0114-FOF-EI, issued March 15, 2022, in Docket No. 20210153-EI, *In re: Request for approval of authority to issue and sell securities for 12 months ending December 31, 2022, by Tampa Electric Company*

Discussion of Issues

Issue 1: Should the Commission approve Tampa Electric's petition to amend the authority granted in Order No. PSC-2022-0114-FOF-EI by increasing Tampa Electric's limit on the maximum amount of short-term debt outstanding during calendar year 2022 from $1.0 billion to $2.2 billion?

Recommendation: Yes. Tampa Electric's petition to amend the authority granted in Order No. PSC-2022-0114-FOF-EI to increase the Company's maximum amount of short-term debt outstanding at any one time during calendar year 2022 from $1.0 billion to $2.2 billion should be approved. (D. Buys)

Staff Analysis: On August 24, 2022, Tampa Electric filed a petition seeking to amend its authority to issue and sell securities during calendar year 2022. The Company is requesting to increase the maximum amount of short-term debt outstanding at any time during calendar year 2022 from $1.0 billion to $2.2 billion. Tampa Electric explained in its petition that due to rising natural gas prices, the Company will incur a significant under-recovery of its fuel costs for 2022. As a result, Tampa Electric is requesting that the Commission amend the previously granted authority in Order No. PSC-2022-0114-FOF-EI to issue $1.0 billion in short-term debt and raise that limit to $2.2 billion. This will provide the Company with sufficient flexibility to manage volatile fuel costs through the remainder of 2022. Tampa Electric is not requesting modification or amendment of any of the other terms set out in Order No. PSC-2022-0114-FOF-EI which approved the first Petition to Amend.

In compliance with paragraph (2)(d) of Rule 28-106.201, F.A.C., Tampa Electric stated that they are not aware of any disputed issues of material fact at this time, and do not believe any disputed issues of material fact will arise in this docket but acknowledge the possibility that other parties could assert disputed issues of material fact during this proceeding.

Based on its review, staff believes that the Company's request to increase the maximum amount of short-term debt outstanding at any one time during calendar year 2022 from $1.0 billion to $2.2 billion is appropriate and recommends it be approved.

Issue 2: Should this docket be closed?

Recommendation: For monitoring purposes, this docket should remain open until May 5, 2023, to allow the Company time to file the required Consummation Report. (Sandy)

Staff Analysis: For monitoring purposes, this docket should remain open until May 5, 2023, to allow the Company time to file the required Consummation Report.

Item 4

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 26, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Buys, King, Maloy, Ramos) TB
Office of the General Counsel (Trierweiler, Imig) AH

RE: Docket No. 20220048-EI – Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.

AGENDA: 10/04/22 – Regular Agenda – Post Hearing Decision - Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: October 8, 2022 - 180-day Statutory Deadline Per 366.96(5), Florida Statutes.

SPECIAL INSTRUCTIONS: Please place Dockets Nos. 20220048-EI, 20220049-EI, 20220050-EI, and 20220051-EI in consecutive order on the Agenda.

Table of Contents

Case 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 a plan, that contains all the elements required by Commission rule, the Commission must determine whether it is in the public interest to approve, approve with modification, or deny the plan. Section 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. Further, this section requires the Commission conduct an annual proceeding, referred to as the storm protection plan cost recovery clause (SPPCRC), to determine the utility's prudently incurred SPP costs.

Tampa Electric Company (TECO) filed its first SPP on April 10, 2020, in Docket No. 20200067-EI. The Office of Public Counsel (OPC), Walmart, Inc. (Walmart), and Florida Industrial Power Users Group (FIPUG) were granted intervention. These matters were set for an administrative hearing; however, prior to the hearing TECO entered into a Settlement Agreement with FIPUG, OPC, and Walmart. An administrative hearing was held on August 10, 2020 for the Commission to hear oral argument from the parties in support of the Settlement Agreement, to admit testimony and documentary evidence into the record, and to consider the Settlement Agreement. The Commission approved the Settlement Agreement by Order No. PSC-2020-0293-AS-EI, issued August 28, 2020, in Docket No. 20200067-EI.

Key provisions of the 2020 Settlement are:

- Approval of the SPP and programs shall not include or imply any determination of prudence for any project in a program approved under the settlement. Except as provided in paragraphs 19-26 of the TECO Settlement Agreement, the Signatories retain the right to challenge the prudence or reasonableness of any project or costs for any project submitted through the SPPCRC during a true-up proceeding in 2021 or thereafter.
- TECO will file an updated SPP in early 2022. If approved by the Commission, the Signatories intend that the 2022 updated SPP will form the basis for cost recovery of SPP activities in 2023, 2024, and 2025, and that TECO will then next be required to file an updated SPP for approval again in 2025.

On April 11, 2022, TECO filed its proposed SPP for Commission approval which covers the period of 2022-2031 and included eight programs. The majority of these programs are a continuation of its 2020 SPP and are described in Attachment A. FIPUG, OPC, and Walmart were 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. OPC and FIPUG (Joint Parties) filed a joint brief which included a procedural matter which is addressed below.

Procedural Matter

On pages 14-24 of their post-hearing brief, the Joint Parties unilaterally inserted a "post-hearing legal issue" that was not listed in the Prehearing Order.[2] The Joint Parties argue in this post-hearing issue that the Commission should reverse a prehearing ruling, set forth in Order No. PSC-2022-0292-PCO-EI, where the Prehearing Officer granted motions to strike portions of the prefiled testimony of OPC witness Lane Kollen. In staff's opinion this legal argument raises a new substantive issue not previously ruled upon. 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 request was denied by the full Commission. Because the evidentiary concerns relating to the testimony of witness Kollen have twice been addressed on the merits, staff believes it is appropriate to discuss the Joint Parties' "post-hearing legal issue" here only as it raises procedural concerns. For the reasons set forth below, staff believes there is no procedural error that that Commission 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 the Joint Parties, were given full opportunity to present argument on all relevant issues in the case and to conduct cross-examination of all witnesses on the case's relevant issues both in the case in chief and in the portions of the hearing where proffered testimony was admitted into the record. (TR 44).

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 the Commission's action in striking the testimony was to exclude expert testimony on the ultimate legal issues, which is within the sole province of the tribunal.

Many portions of Witness Kollen's testimony were not stricken. Those portions were moved into the record as though read, and his prefiled exhibits LK 1 through LK 3 were admitted into evidence. (TR 824-853). (TR 824-853). OPC separately proffered the portions of Witness Kollen's testimony subject to the order granting the motion to strike and the prefiled testimony was also moved into the record as though read. (TR 854-886). 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. OPC also made its legal arguments about the rule interpretation at that time. (TR 802-808). Although the Commission ultimately decided to strike the OPC Witness testimony, OPC was provided an opportunity to make its legal argument at the administrative hearing (TR 798-810), and in its motion for reconsideration. Counsel for OPC made its arguments again in its post-hearing brief.

[1] TECO's docket was consolidated with the SPP dockets for FPUC (20220049-EI), DEF (20220050-EI), and FPL (20220051-EI) for hearing purposes only.

[2] Order No. PSC-2022-0291-PHO-EI, issued August 1, 2022.

The Joint Parties also argue that a Commission Final Order applying Rule 25-6.030, 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." (Joint Parties BR 23)The cases cited by the Joint Parties in support on this argument all address judicial review of the constitutionality of statutes.[3] As an agency, the Commission has no jurisdiction to declare a statute unconstitutional. Moreover, following the passage of Article V, Section 21, of the Florida Constitution, the Commission's interpretation of a statute will not be relevant to a court vested with jurisdiction to consider that constitutional question.

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

There are 8 issues for the Commission to consider in this docket.[4] The Commission has jurisdiction in this matter pursuant to Section 366.96, F.S. and Chapter 120, F.S.

[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)).

[4] TECO's issues are 1A-6A, 10A, and 11A. Issues 7-9 are FPL only issues.

Discussion of Issues

Issue 1A: Does TECO's Storm Protection Plan contain all of the elements required by Rule 25-6.030, Florida Administrative Code?

Recommendation: Yes. TECO appears to have met the criteria and intent of Rule 25-6.030, F.A.C., Storm Protection Plan, with its filings. Thus, the Commission has adequate information in order to make a determination on the TECO SPP. (Trierweiler, Imig, Maloy)

Position of the Parties

TECO: Yes.

JOINT PARTIES: Yes, TECO's SPP does include the requisite comparison of the costs and dollar benefits of the proposed programs and projects; however, the Joint Parties do not agree with the analysis, which, among other things, includes subjective estimates of the value to customers of avoided outages.

WALMART: Yes. Walmart adopts the position of the Office of Public Counsel ("OPC").

PARTIES' ARGUMENTS

TECO

TECO asserted that the competent substantial evidence in the record shows that TECO's SPP includes all elements required by the SPP Rule. TECO argued that its witness Plusquellic's direct testimony elaborated on how the company's 2022 SPP complies with the SPP Rule. See Tr. 523-525. (TECO BR 3-4)

JOINT PARTIES

The Joint Parties argued that TECO's comparison of costs and benefits was flawed. (Joint Parties BR 2) Further, the Joint Parties argued that the consulting firm that TECO retained to monetize the value of SPP benefits to customers, improperly used excess dollar amounts to calculate that benefit. (Joint Parties BR 3) The Joint Parties argued that societal value of customer interruptions was improperly included in the estimates of avoided damages and restoration costs, and that it is a highly subjective measure. (Joint Parties BR 3) The Joint Parties argued that the societal value of customer interruptions should be excluded from the justification of SPP programs and projects. (Joint Parties BR 3)

WALMART

Walmart adopted the position of OPC. (Walmart BR 3)

ANALYSIS

<u>History</u>

The first utility storm hardening programs were filed for Commission approval in 2007 and were reviewed by the Commission 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."[5] Subsection 366.96(3), F.S., requires each IOU to file a transmission and distribution SPP for the Commission' review and directs the Commission 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.

The Commission promulgated two Rules, 25-6.030, F.A.C., Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Cost Recovery, to implement and administer Section 366.96, F.S. The full text of Section 366.96, F.S., and Rule 25-6.030, F.A.C., are provided as Attachment B. In 2020, TECO's first storm protection plan, which was primarily an extension of the utility's existing storm hardening plan, was approved.

Issue

The primary issue raised by the Joint Parties is that TECO's comparison of costs and benefits was flawed. For the reasons set forth below, Staff believes TECO's SPP filings meet the requirements of 366.96, F.S., and Rule 25-6.030, F.A.C.

Law

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

> 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 Statute further articulates that the Commission must use the public interest standard when considering a SPP. *See* § 366.96(5), stating that the Commission shall determine whether it is in the public interest to approve, modify, or deny the plan. Accordingly, Rule 25-6.030, F.A.C., requires utilities to file certain minimum information in order for the Commission to determine if it is in the public interest to approve, approve with modifications, or deny a utility's storm protection plan. In other words, Rule 25-6.030, F.A.C., is a filing requirement rule, not a standard for the Commission's decision. As such, the rule allows the utilities to have the flexibility to submit and manage their hardening plans while simultaneously requiring a utility file the information necessary for the Commission to make a determination about whether it is in the public interest to approve a plan, approve a plan with modifications, or deny a plan.

[5] 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 facilitates, 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.

Rule 25-6.030(3), F.A.C., Storm Protection Plan, identifies the specific information to be included in each IOU's SPP.[6] Rule 25-6.030(3)(d), F.A.C., requires, in relevant part, a comparison of costs and benefits:

> 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 25-6.030, F.A.C., explicitly require a prescriptive or specific kind of analysis or comparison of costs or benefits in an SPP.

Staff Analysis

Rule 25-6.030(3)(d), F.A.C., requires "...a comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in 3(d)1." The Joint Parties alleged that TECO improperly calculated certain benefits. (Joint Parties BR 3) By arguing that TECO did not provide an adequate "comparison of costs and benefits" (Joint Parties BR 2, 4), the Joint Parties' arguments in Issue 1 are about the methodology of TECO's alleged benefits. Staff believes that TECO provided adequate information for the Commission to evaluate TECO's SPP.

While the nature of cost data is objective, benefits in the context of storm hardening specifically, may require various forms description and analysis to ascertain. Staff believes that a utility should have the flexibility to use a methodology that it believes most clearly demonstrates the benefits of a SPP. The Joint Parties' argument, however, does not take into account 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. Section 366.03, F.S. This means that storm hardening costs may or may not produce actual financial benefits that exceeds costs during a given time, depending on a particular utility's circumstances.[7]

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[6] Specific elements of Rule 25-6.030, F.A.C., such as areas for prioritization and rate impacts, are discussed in more detail in Issues 2A through 6A.

[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) there are no monetized benefits to the general body of customers. 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.

This is why Section 366.96(4)(a), F.S., provides the flexibility for IOUs to submit and manage their hardening plans so long as the plans include projects that effectively "reduce restoration costs and outage times associated with extreme weather events and enhance reliability" for customers. For these reasons, staff believes that a utility should have the option to submit what it deems is its most accurate data or analysis of costs and benefits for the Commission's consideration.

In this case, staff believes that TECO provided the information necessary for the Commission to make a determination on TECO's SPP. This information included the expected benefits in the form of avoided restoration costs and customer outages and a monetization of avoided customer outages. (TR 331-332) For example, TECO provided the Distribution Feeder Hardening Program would decrease restoration costs by approximately 54 percent and reduce customer minutes of interruption by approximately 46 percent. (EXH 9, P 103) This information allows the Commission to evaluate the potential of the SPP to mitigate outages and reduce restoration costs.

CONCLUSION

Staff recommends that TECO provided sufficient information for the Commission to make a public interest determination pursuant to Section 366.96, F.S.

Issue 2A: To what extent is TECO's Storm Protection Plan expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability?

Recommendation: TECO utilized a Storm Resilience Model to support its proposed 2022 SPP program evaluation and prioritization. The results of this model estimate that TECO's SPP is projected to reduce restoration costs and outage times associated with extreme weather events. (Maloy)

Position of the Parties

TECO: Tampa Electric's SPP is expected to significantly reduce restoration costs and outage times associated with extreme weather events and enhance reliability. The five programs analyzed by 1898 & Co. are expected to reduce restoration costs by $380-$531 million and reduce CMI by 29 percent over the next 50 years. The company's Vegetation Management Program is expected to improve SAIFI by 15.3 percent, SAIDI by 9.6 percent, and reduce restoration costs by 22.2 percent.

JOINT PARTIES: Some of TECO's proposed programs and projects will have a better impact on reducing outages times and lowering restoration costs than others. Additionally, several programs and projects are not extreme weather storm hardening programs but rather routine maintenance responsibilities of any electric utility and should not be included in TECO's SPP.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

TECO

In its brief, TECO stated that its proposed SPP programs will reduce restoration costs by $380-$531 million and reduce CMI by 29 percent over the next 50 years, depending on the intensity and frequency of extreme weather events. TECO hired an outside consultant to evaluate the vegetation management activities and the analysis showed a reduction in vegetation-caused outages by 29 percent. (TECO BR 4-5) TECO refuted OPC's assertion that TECO improperly calculated CMI by including societal values in its calculation. The Company's model calculated the benefits of each project in terms of reduced minutes of customer interruptions and reduced restoration costs, and then calculated an estimation of the monetized CMI in order to prioritize projects. (TECO BR 6) TECO argued that the programs OPC challenged will both reduce restoration costs and outage times.

Last, TECO argued against OPC's recommended budget reduction of 50 percent, stating that the proposed cuts would result in a 60 percent reduction in expected restoration cost savings and approximately 80 percent reduction in avoided CMI benefits. TECO stated that since OPC witness Mara misinterpreted the Company's analysis and data, the Commission should reject his proposed cuts and approve TECO's SPP without modification. (TECO BR 15-17)

JOINT PARTIES

In their joint brief, OPC and FIPUG stated that two of TECO's SPP programs will not result in decreased outage times and costs, as required by Rule 25-6.030, F.A.C., specifically, the Transmission Access Enhancement Program and a project within the Overhead Feeder Hardening Program. The Joint Parties' arguments regarding its recommendations on TECO's specific SPP programs are discussed in Issues 6A and 10A. (Joint Parties BR 4-5)

WALMART

Walmart adopts the position of OPC on this issue. (Walmart BR 3)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. As discussed in Issue 1A, 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. TECO provided this information in Section 3 of its SPP. (EXH 9, P 103)

TECO witness Pickles testified that a similar analysis was completed for its 2020 and 2022 SPPs by 1898 & Co. on the same eight storm protection programs. (TR 332) The analysis and modeling performed by the Storm Resilience Model included:

- Major Storm Event Database
- Storm Impact Model (SIM)
- Resilience Benefit Module
- Budget Optimization & Project Prioritization

(TR 389-390)

The Major Storm Event Database contained 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios utilizing National Oceanic and Atmospheric Administration (NOAA) historical analysis, capturing data of probability, system impacted, duration, and cost to restore the system. The SIM models calculates the hardening benefits for all projects for each storm event. The Resilience Benefit Module simulated future major events over 50 years, calculating the storm customer outage duration and monetization of customer minutes of interruption (CMI), as well as resilience benefit calculation used to prioritize the projects. The Budget Optimization & Project Prioritization used different budget scenarios to determine the point of diminishing return and bundled projects, to name a few. (EXH 9, P 138-140)

The estimated benefits of a reduction in restoration costs and outage times are calculated as a percentage improvement expected during extreme weather or major event days when compared to the status quo. (TR 529-530) TECO's proposed SPP projected cost versus benefit or decreased restoration cost and reduced CMI is shown in Table 2A-1:

Table 2A-1
TECO's SPP Projected Cost versus Benefit

Storm Protection Program	Projected Reduction in Restoration Costs (Approximate benefits in percent)	Projected Reduction in Customer Minutes of Interruption (Approximate benefits in percent)
Distributed Lateral Undergrounding	32	45
Transmission Asset Upgrades	85	14
Substation Extreme Weather Hardening	20-25	12-45
Distribution Feeder Hardening	54	46
Transmission Access Enhancement	28	55

Source: EXH 9, P 103

The Joint Parties argued in their brief that although some of TECO's programs will have an impact on reducing outages times and lowering restoration costs, several of the programs are not storm hardening and do not meet the requirements of the SPP Rule. (Joint Parties BR 4) The Joint Parties' arguments and staff's analysis on the requirements of the SPP Rule are discussed in more detail in Issue 1A. The Joint Parties also argued that these programs were merely routine maintenance projects for an electric utility and should not be included in TECO's SPP. This argument by the Joint Parties will be addressed in Issue 10A. Walmart adopted the position of OPC and, as such, no other argument was raised by an intervening party for this issue.

Staff believes that TECO provided the necessary information to meet the requirements of the SPP Statute and Rule related to this issue. Using the Storm Resilience Model to incorporate data specific information to its transmission and distribution facilities, the Company estimated the reduction in outage times and restoration costs that could result from the implementation of its proposed SPP programs. Based on the results of the model, TECO demonstrated that its proposed programs are projected to reduce restoration costs and outage times associated with extreme weather events.

CONCLUSION

Similar to its 2020 SPP, TECO utilized a Storm Resilience Model to support its 2022 SPP program evaluation and prioritization. The results of this model estimate that TECO's SPP is projected to reduce restoration costs and outage times associated with extreme weather events.

Issue 3A: To what extent does TECO's Storm Protection Plan prioritize areas of lower reliability performance?

Recommendation: TECO's SPP appears to prioritize areas of lower reliability performance. (Maloy)

Position of the Parties

TECO: The company's methodology for prioritizing projects incorporates reliability performance. The projects that are anticipated to deliver the highest customer benefit at the lowest relative cost are prioritized higher. Furthermore, historical outage data and trim data were incorporated into the Vegetation Management Program design.

JOINT PARTIES: TECO has several proposed projects that prioritize areas of lower reliability performance; however, many of those programs and projects either do not qualify as permissible SPP programs or projects and/or are not economically justifiable.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

TECO

TECO prioritized its SPP projects using models designed by 1898 & Co. The models utilized by the Company considered multiple factors to determine each asset's potential to fail during various extreme weather events. The models estimated the restoration costs and outage times for each asset in different storm types, coupled with the reduction in those costs and times if those assets were hardened. TECO refuted OPC's arguments that critiqued TECO's prioritization methodology and argued that its SPP properly prioritizes areas of lower reliability performance. (TECO BR 17-18)

JOINT PARTIES

In their joint brief, OPC and FIPUG stated that TECO inflated the projected benefits of its SPP projects because its calculations contained societal value and the analysis is therefore, flawed. (Joint Parties BR 8)

WALMART

Walmart adopts the position of OPC on this issue. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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)1.d., F.A.C., requires a description of the criteria used to select and prioritize proposed SPP projects to be provided.

TECO's witness De Stigter testified that the Storm Resilience Model was used to perform an analysis of the 2022-2031 SPP resiliency benefits. The model was developed by 1898 & Co. and was used to: (TR 389-390).

- Calculate the customer benefits 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 an overall investment level that maximized customers' benefits while not exceeding TECO's technical execution constraints.

Witness De Stigter stated that all projects were evaluated and prioritized using the same criteria in order to be ranked against one another and then compared. (TR 445-446) The model calculated benefits consistently for all projects, allowing project prioritization across the entire asset base for a range of budget scenarios. (TR 454-455) The witness testified that the Storm Resilience Model utilized a resilience-based planning approach to calculate hardening benefits and prioritize projects. The model's database included the probability of major storm events occurring as well as the magnitude of impact, and the duration to restore the system, as well as the restoration cost to return the system back to normal after the event. The model uses a probability-weighted basis to determine which specific portions of the TECO system would be impacted, and their contribution to the overall restoration costs. The witness stated that the model evaluates the storm's impact for each portion of the system based on the status of the system and if the portion of the system is already hardened. (TR 401) The witness also stated that the major storm event database utilizes information from the NOAA database of major storm events, TECO's historical storm reports, available information on the impact of major storms to other utilities, and TECO's experience in storm recovery. (TR 413)

OPC provided extremely limited testimony specific to this issue. Its witness Mara testified that, contrary to TECO's analysis, prioritizing equipment that is most susceptible to extreme weather events delivers a larger impact at the beginning of each program. (TR 730) Also, OPC's witness Kollen stated that TECO's cost/benefit analysis is flawed due to the inclusion of societal value in the calculations and the view that societal value is a highly subjective measurement. (TR 966-967) TECO argued that OPC misunderstands how monetized CMI was considered in the analysis. TECO explained that its model first calculated the benefits of each SPP project in terms of reduced restoration costs and reduced minutes of customer interruption. (TR 408) After this calculation was performed, the model next monetized the estimated CMI savings so that projects could be ranked against each other by one metric, which is dollars. (TR 431) Therefore, as discussed above, it appears TECO does prioritize assets that would have a likelihood of failing during a storm and those that have the greatest impact on CMI. Therefore, staff recommends that TECO's SPP does prioritize areas of lower reliability performance.

CONCLUSION

TECO's SPP appears to prioritize areas of lower reliability performance.

Issue 4A: To what extent is TECO's Storm Protection Plan regarding transmission and distribution infrastructure feasible, reasonable, or practical in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas?

Recommendation: With the exceptions discussed in Issues 6A and 10A, TECO's SPP appears feasible, reasonable, and practical within the Company's service territory. (Maloy)

Position of the Parties

TECO: There are no areas of the company's service area where it would be impractical, unfeasible, or imprudent to harden. All components of the transmission and distribution system can be hardened to achieve resiliency benefits.

JOINT PARTIES: A number of programs and projects in flood zones that DEF has proposed for SPP inclusion would, absent the 2021 Stipulation, be more appropriately addressed in a base rate case since they do not harden the system from extreme storm events. Many of these programs fail the two-prong test. (Note: It appears that the Joint Parties made a scrivener's error in their brief, providing a position for DEF rather than TECO.)

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

TECO

In its brief, TECO stated that its 2022 SPP reflects that it is feasible, reasonable, and practical to harden all components of the company's transmission and distribution system in all areas. TECO argued that customers should benefit from the SPP investments, so TECO took steps to ensure that all parts of the Company's service territory will receive storm protection investments. TECO stated that the intervenors did not present facts to the contrary. (TECO BR 19)

JOINT PARTIES

In their joint brief, OPC and FIPUG stated that some projects do not meet the two-prong test and included excessive spending. OPC and FIPUG also stated that some projects should be addressed in base rates instead of the SPP, since they do not harden the system. (Joint Parties BR 9)

In addition, the Joint Parties argued about the inclusion of two substations included in the Substation Extreme Weather Hardening Program: South Gibsonton 230/69 kV Substation and the Skyway 69 kV Substation. The Joint Parties stated both substations should already be upgraded to address storm surge and flooding concerns since portions of them were upgraded between 1999 and 2006. Since the flood maps have been available since 1973, the hardening of these substations should have been completed during their most recent improvements. (Joint Parties BR 7-8)

WALMART

Walmart adopts the position of OPC on this issue. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(b), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. Such description must include a general map, number of customers served within each area, and the utility's 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 TECO's SPP, the Utility provided a map of its service territory, which included the number of customers served within each area. (EXH 9) TECO witness Pickles testified that all components of the Company's transmission and distribution system can be hardened to achieve resiliency benefits. (TR 340-341) The Company's plan does include some consideration of geography, incorporating elements such as wind speed zones, flood zones, localized vegetation cover, and accessibility of assets. (TR 340) Overall, TECO did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness, or practicality concerns. (EXH 9, P 39)

In their joint brief, OPC and FIPUG stated that some projects do not meet the two-prong test and included excessive spending. These programs are discussed in Issues 10A and 6A respectively. OPC also questioned the reasonableness of TECO's Substation Extreme Weather Hardening Program, designed for flood prone areas. OPC argued this Program should only include substations that have a history of flooding and all substations with alternate feeds should be excluded. (TR 734-737; 740-742) To support its position, OPC witness Mara testified that flood maps were issued in 1973; therefore, substations constructed after 1973 should have been designed to account for potential flood waters. Additionally, in instances where a transformer is de-energized due to flooding, the load from that substation could likely be switched to an adjacent substation that is not flooded. In such a case, OPC argued that TECO's Substation Extreme Weather Hardening Program would not reduce outage times.

TECO witness Plusquellic rebutted OPC's arguments and testified that TECO designs all assets to meet or exceed standards in effect at the time of construction. Also, TECO brings equipment up to the current standards when it is replaced or upgraded, but the Company does not upgrade the remainder of the substations to keep control of costs. The witness stated that the referenced flooding standards were not developed to address storm surge and TECO evaluated storm surge potential of its projects using the Sea, Land and Overland Surges from Hurricanes ("SLOSH") Model to determine which substations were at greater risk. (TR 1507-1508) The witness also testified that the nine substations included in this Program were selected because they serve critical load. The loss of some of these substations could trigger the loss of interconnected transmission lines or risk a loss of service to a critical facility if that load could not be switched to another substation. (TR 1508-1509)

Staff recommends TECO has met the requirements of Rule 25-6.030(3)(c), F.A.C, by providing a map of its service area, the number of customers served within each area, and the methodology of prioritizing projects within its programs. For the Substation Extreme Weather Hardening Program, staff agrees with TECO that witness Mara did not present any specific outage or performance data for substations with alternate feeds. He stated that these substations could "likely" be switched to an adjacent substation not experiencing flood conditions; however, witness Mara did not identify any specific substations where this had occurred or could occur in the future. Given the variability of extreme weather events, it is not clear that a scenario as described by witness Mara of an available, unaffected, adjacent substation is reasonable to assume given the limited information. In view of the information presented in TECO's SPP and witness testimony, specifically on the Substation Extreme Weather Hardening Program, staff believes TECO's SPP is reasonable in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas.

CONCLUSION

With the exceptions discussed in Issues 6A and 10A, TECO's SPP appears feasible, reasonable, and practical within the Company's service territory.

Issue 5A: What are the estimated costs and benefits to TECO and its customers of making the improvements proposed in the Storm Protection Plan?

Recommendation: The estimated costs of TECO's SPP programs are shown in Table 5A-1. The estimated benefits, ranging from 12 percent to 55 percent reduction in customer minutes of interruption, are discussed in Issue 2A. (Maloy)

Position of the Parties

TECO: Tampa Electric estimates that the total costs for the 2022-2031 SPP are $2,076 million, resulting in a total revenue requirement of $1,371 million. The five programs analyzed by 1898 & Co. are expected to reduce restoration costs by $380-$531 million and reduce CMI by 29 percent over the next 50 years. The company's Vegetation Management Program is expected to improve SAIFI by 15.3 percent, SAIDI by 9.6 percent, and reduce restoration costs by 22.2 percent.

JOINT PARTIES: While TECO has presented a cost/benefit analysis, none of the incremental costs of the expanded or new SPP programs have benefits that exceed the costs when the cost/benefit analyses are corrected. If the programs and projects are not economically justified, then the programs and projects cannot be prudent and the costs would be imprudent and unreasonable.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

TECO

TECO's 2022 SPP estimated costs are reasonable when compared to the estimated benefits. TECO argued that the net cost of its SPP equates to $0.65 to $0.78 per minute to reduce a minute of customer interruption. (TECO BR 19-20) The Company stated that OPC did not present evidence that TECO's data was inaccurate; but instead, discussed inflation. TECO stated that its cost/benefit analysis did prioritize projects and programs that included the highest benefits with the investment. (TECO 20-21)

JOINT PARTIES

In its joint brief, OPC and FIPUG stated that since TECO included societal value within their analysis, the actual benefits are uncertain. The Joint Parties also argued that if the Commission should recognize the Company's estimated benefits as correct, the Commission should reduce TECO's SPP costs to its customers by approximately half, which would still provide customers with most of the benefits of the Company's SPP. (Joint Parties BR 9-10)

WALMART

Walmart adopts the position of OPC on this issue. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(c), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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, as identified and discussed in Issue 2A.

For each SPP program, TECO listed the estimated capital costs and operating expenses, which are summarized in Table 5A-1. TECO compared these costs with the estimated benefits that could be achieved from the completion of its programs. The benefits included the reduction in outage times (CMI reduction), as discussed in Issue 2A. (EXH 9, P 103)

Table 5A-1
TECO's 2022-2024 SPP Program Costs

Program Name	2022 (millions)	2023 (millions)	2024 (millions)
Distribution Lateral Undergrounding	$105.8	$104.7	$105.2
Distribution Overhead Feeder Hardening	$33.4	$30.7	$30.7
Vegetation Management	$26.2	$29.1	$28.7
Transmission Asset Upgrades	$17.0	$18.0	$18.1
Substation Extreme Weather Hardening	$0	$0.7	$4.3
Infrastructure Inspections	$1.6	$1.6	$1.6
Transmission Access Enhancement	$2.4	$3.0	$3.0
Legacy Storm Hardening Plan Initiatives	$13.6	$14.0	$14.4
Total	$200.0	$201.8	$205.9

Source: (EXH 9, P 102)

As discussed in previous issues, OPC witness Kollen testified that TECO did perform a cost/benefit analysis; however, the values utilized by the Company were flawed due to the inclusion of societal values within the calculations. (TR 966) OPC's arguments and staff's analysis on the requirements of a cost-effectiveness analysis are discussed in Issue 1A. Staff believes that TECO provided the necessary information to meet the requirements of the SPP Rule. As discussed in Issue 2A, TECO estimated the reduction in outage times and restoration costs that would result from the implementation of its proposed SPP programs. TECO also listed in its plan the program costs, including capital and operating expenses. Therefore, the estimated costs and benefits to TECO and its customers as a result of the proposed programs were presented by the Company in its SPP.

CONCLUSION

The estimated costs of TECO's SPP programs are shown in Table 5A-1. The estimated benefits, ranging from 12 percent to 55 percent of reduction in customer minutes of interruption, are discussed in Issue 2A.

Issue 6A: What is the estimated annual rate impact resulting from implementation of TECO's Storm Protection Plan during the first 3 years addressed in the plan?

Recommendation: The estimated annual rate impact, as provided by TECO, is projected to increase approximately 97 percent for the first three years of its Storm Protection Plan. In order to mitigate the rate impact to TECO's customers, staff recommends TECO's Distribution Lateral Undergrounding Program continue at the 2021 annual spending levels, approximately $79.5 million per year, beginning in 2023. (Maloy)

Position of the Parties

TECO: The following table shows the full rate impact, regardless of where rates are recovered, of the SPP on typical bills:

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2022	2.70%	2.70%	1.17%	1.08%
2023	4.13%	4.13%	1.28%	1.19%
2024	5.31%	5.31%	1.37%	1.29%

JOINT PARTIES: Since TECO improperly included certain programs and projects in its proposed SPP, TECO's customer rate impacts are not properly calculated.

WALMART: Walmart takes no position, as Walmart has not conducted this analysis.

PARTIES' ARGUMENTS

TECO

In its brief, TECO provided the Company's estimated rate impacts as required by the SPP Rule. The rate impacts reflect the total cost of TECO's SPP, despite whether costs are recovered through the SPPCRC or base rates. In response to OPC's position, TECO argued that it did not act improperly by calculating the estimated rate impacts of the plan after setting the program budgets. The Company also stated that its team was aware of potential rate impacts to customers when preparing the plan, since the 2022 SPP is essentially a continuation of the prior 2020 SPP. (TECO BR 22-24)

JOINT PARTIES

In its joint brief, OPC and FIPUG stated that TECO's rate impacts to customers were improperly calculated. The Joint Parties argued that since TECO did not calculate the specific rate impacts to customers until after the capital expenditure level for the plan was established, customer impact was not considered. The Joint Parties also argued that the customer benefits were inflated, and some programs are not affordable and thus unjustifiable. OPC and FIPUG also stated that there is no evidence that the Company considered the reasonableness of the customer impact when determining the SPP. The Joint Parties argued that with the economic situation, as well as with the fuel and purchased power cost recovery, the Commission should consider the impact on customer bills and modify TECO's SPP so that customer rate impacts are considered. (Joint Parties BR 10-13)

OPC and FIPUG also stated that the pace of the Distribution Lateral Undergrounding Program is too aggressive and represents over 60 percent of TECO's total SPP capital costs. The Joint Parties argued spending substantially less would only reduce the benefits slightly and would balance the financial impacts of storm hardening activities on customers. The Joint Parties further argued that the Distribution Overhead Feeder Hardening Program is also too aggressive and the budget should be limited to TECO's 2020 SPP level of $10 million per year. (Joint Parties BR 6-7)

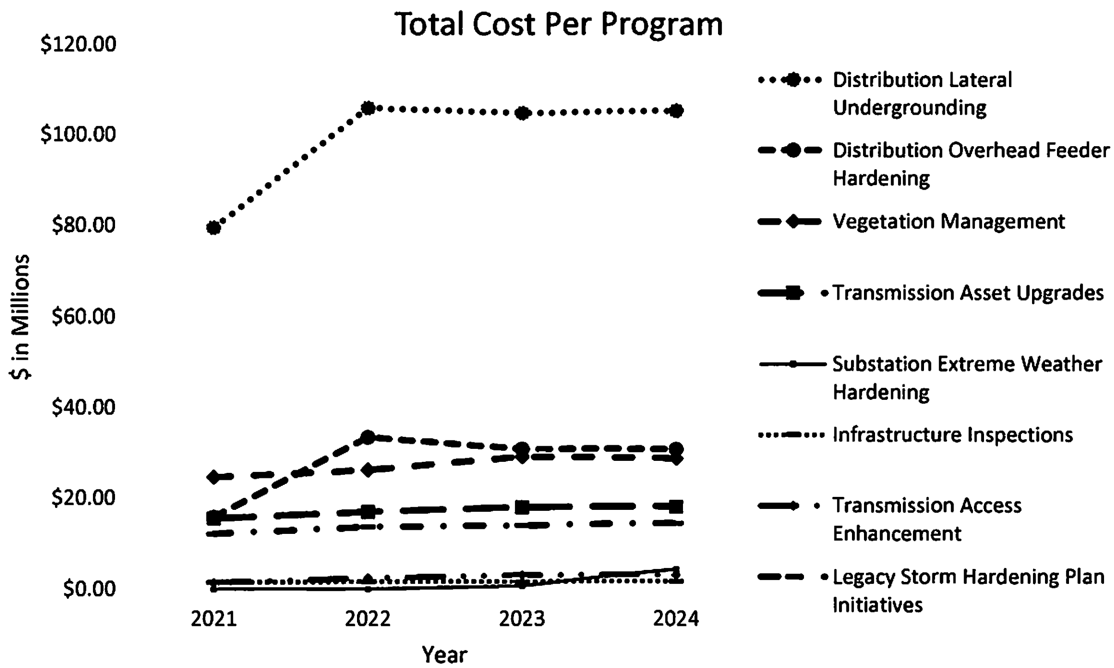
WALMART
Walmart did not take a position on this issue as it has not conducted an analysis. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(d), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 25-6.030(3)(i), F.A.C., requires the utilities to provide any description of any implementation alternatives that could mitigate the resulting rate impact. This issue will address the annual rate impacts for the first three years of the Company's SPP and deployment alternatives that would mitigate rate impacts to customers.

Figure 6A-1 is a graph of TECO's SPP estimated program costs for 2021 through 2024. As shown on the graph, TECO's Distribution Lateral Undergrounding Program is the highest cost program and has a dramatic increase in 2022, while its other programs are relatively constant.

Figure 6A-1
Total Cost Per SPP Program (2022-2031)



Source: EXH 9; EXH 37

Pursuant to Rule 25-6.030(3)(h), F.A.C., TECO provided the rate impact information for each customer type, which is shown in Table 6A-1.

Table 6A-1
SPP Estimated Rate Impact (2022-2024)

Customer Class	2022	2023	2024
Residential ($/1000 kWh)	$3.26	$4.99	$6.42
Commercial (1MW 60 percent Load Factor)	1.17%	1.28%	1.37%
Industrial (10MW 60 percent Load Factor)	1.08%	1.19%	1.29%

Source: EXH 9, P 107; EXH 79, BSP 4

OPC witness Mara compared TECO's 2020-2029 SPP to its proposed 2022-2031 SPP capital costs and determined there was an increase of $109 million in spending over the 10-year plan. (TR 726) Comparing the costs on a per customer basis, witness Mara calculated the ratio of capital spending to the number of customers had increased 7 percent. (TR 727) Witness Mara proposed a reduction of capital spending by $847 million over the 10-year period. Table 6A-2 is a summary of his adjustments. (TR 729)

Table 6A-2
Witness Mara's Recommended Program Adjustments

Program	Total 2022-2031 SPP (millions)	Proposed Reductions (millions)	Net 2022-2031 SPP (millions)	Reason for Reduction
Distribution Lateral Undergrounding	$1,070	($570)	$500	Limit impact to customers
Substation Extreme Weather (Distribution & Transmission)	$29	($29)	$0	Does not comply with 25-6.030
Distribution Overhead Feeder Hardening	$317	($217)	$100	Limit impact to customers
Transmission Access Enhancement	$31	($31)	$0	Does not comply with 25-6.030

Source: (TR 729)

Witness Mara testified that both the Substation Extreme Weather Program and Transmission Access Enhancement Program should be excluded from TECO's SPP, as neither program complied with Rule 25-6.030, F.A.C. (TR 729) The appropriateness of TECO's Substation Extreme Weather Program is addressed in Issue 4A and the appropriateness of TECO's Transmission Access Enhancement Program is addressed in Issue 10A. Because this issue focuses on deployment strategies that can mitigate rate impact, OPC's proposed cost reductions for the remaining two programs identified in Table 6A-2 are discussed below.

OPC witness Mara recommended a reduction in capital spending for the Distribution Lateral Undergrounding Program because the pace for storm hardening is not stated in the Statute, so it is left to the utilities. Witness Mara argued that TECO should limit the spending for this Program and harden the worst performing laterals first, balancing the rate impact with the benefits. (TR 741-742) Witness Mara testified that the costs of this program account for 60 percent of the total SPP budget. (TR 741) While the witness does believe that this program reduces the cost of restoration and reduces outage times caused by extreme weather, witness Mara recommended a capital budget of roughly $50 million per year, stating that by reducing the budget to $500 million over the 10-year period the benefits to customers are reduced only slightly. (TR 740-743)

In response to OPC's position to reduce the budget of the Distribution Lateral Undergrounding Program, witness Plusquellic testified that witness Mara's reductions have no reasoned basis, and the OPC witness does not identify specific projects to delay or deny. Witness Plusquellic argued that TECO was thorough and reasoned in determining the funding level of the program. Witness Plusquellic also stated that a reduction to the budget would delay the benefits that all customers would receive from avoided restoration costs and since fewer laterals would be undergrounded, delay the benefit of reduced outage times for some customers. (TR 1514)

OPC witness Mara also recommended a reduction in capital spending for the Distribution Overhead Feeder Hardening Program due to limiting the rate impact to customers. Witness Mara testified that he believed this project will help reduce damage during extreme weather events and thereby reduce restoration costs and outage times. Witness Mara recommended a capital budget of approximately $10 million per year for a total 10-year budget of $100 million. (TR 736-737)

The witness also testified that the distribution feeder sectionalizing and automation project, within the Distribution Overhead Feeder Hardening Program, does not reduce restoration costs. (TR 737-738) This project is discussed in Issue 10A.

In response to OPC, TECO witness Plusquellic argued that OPC's proposed budget cuts are arbitrary, and reducing the investment level of the program would delay benefits to the customers. (TR 1509-1510) Staff agrees with TECO that reducing the budget would postpone potential benefits to the customers, but doing so immediately provides some rate impact mitigation. Staff recommends that the Distribution Overhead Feeder Hardening Program would provide benefit to a large number of customers, for a smaller relative budget than the Distribution Lateral Undergrounding Program. For TECO's Distribution Overhead Feeder Hardening Program, staff recommends no adjustment to the program budget. Compared to the Distribution Lateral Undergrounding Program, the program budget for the Distribution Overhead Feeder Hardening Program makes up a smaller percentage of the total SPP costs and will impact a larger number of customers.

Because TECO's Distribution Lateral Undergrounding Program is such a large component of TECO's overall SPP, staff agrees with OPC that reducing the rate impact on customers is appropriate. However, staff disagrees with witness Mara's proposal because his calculation is based on the total program cost for the 10-year period. Staff recommends that making any adjustments based on a 10-year budget is not practical given that the Commission must review a utility's SPP at least every three years as well as conduct annual cost-recovery proceedings. TECO's Distribution Lateral Undergrounding Program accounts for approximately 60 percent of its total SPP budget, and staff recognizes that this program will directly affect a much smaller number of customers when compared to other types of programs such as transmission projects.

Utility facilities are designed and built to serve customers 24/7, and the basic standards of construction and maintenance account for normal weather conditions, including some contingencies such as maintenance requirements, vehicle strikes, lightning, etc. As such, the primary purpose of storm hardening is to mitigate outages due to extreme weather which would subsequently reduce restoration time and costs to all ratepayers. Any resulting improvements to day-to-day reliability are secondary to the goal of storm hardening and would only benefit the customers directly impacted by the project or activity. Since distribution lateral undergrounding projects are smaller in scale and more focused geographically, the likelihood of the project producing benefits for the general body of ratepayers is limited. Realizing that storm hardening costs may or may not produce actual financial benefits during a given time, the Commission has encouraged utilities to focus on projects that would impact the largest number of customers, such as transmission projects, and has relied upon the resulting estimated rate impact to customers as a guide to determine the reasonable level of storm hardening.

Prior to the enactment of Section 366.96, F.S., storm hardening expenditures were recovered from utility customers through base rates. When these prior storm hardening plans were approved, the Commission stated repeatedly that approval of the plan was not approval for cost recovery purposes and that the utility should consider rate impacts as it proactively implemented its plan. (See Order PSC-2019-0302-PAA) These cautionary directives are consistent with the fact that the level of storm hardening is a discretionary activity that requires close attention to the resulting rate impacts. However, Section 366.96(7), F.S., states, "after a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence." Therefore, Commission approval of a storm protection plan is now also an approval of the level of storm protection activity. Such approval also has a direct and more frequent impact on rates due to the annual cost recovery mechanism. Unlike other costs, such as fuel costs, the level of storm hardening and the associated costs are discretionary. There are no mandates as to the activity level of an SPP program that is within TECO's control. In addition, Rule 25-6.030(3)(i), F.A.C., requires the utilities to provide a description of any alternatives that could mitigate the rate impact for each of the first three years of the SPP. TECO reported that it has not identified any reasonable implementation alternatives that could mitigate the resulting rate impact. (TR 346-347)

For these reasons, staff recommends that TECO's Distribution Lateral Undergrounding Program continue at the level spent on this program in 2021, approximately $79.5 million per year, in order to mitigate the rate impact to customers.[8] Staff is not disputing that the Distribution Lateral Undergrounding Program is in the public interest; rather, staff is recommending TECO slow down the program's activity and annual spending.

CONCLUSION

The estimated annual rate impact, as provided by TECO, is projected to increase approximately 97 percent for the first three years of its Storm Protection Plan. In order to mitigate the rate impact to TECO's customers, staff recommends TECO's Distribution Lateral Undergrounding Program continue at the 2021 annual spending levels, approximately $79.5 million per year, beginning in 2023.

[8] The actual value will be determined as part of the SPPCRC proceeding.

Issue 10A: Is it in the public interest to approve, approve with modification, or deny TECO's Storm Protection Plan?

Recommendation: Staff recommends TECO's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1A. Staff recommends that TECO's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Undergrounding Program at the 2021 level; and, (2) remove the Transmission Access Enhancement Program. TECO should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff. (Maloy)

Position of the Parties

TECO: Yes, it is in the public interest to approve Tampa Electric's 2022-2031 Storm Protection Plan without modification because that Plan meets all of the requirements of, and will further all of the objectives of, Section 366.96 of the Florida Statutes and Rule 25-6.030 of the Florida Administrative Code.

JOINT PARTIES: The Commission should approve TECO's SPP with the modifications recommended by the Joint Parties. The Commission should make the adjustments as reflected in the table from page 13 of the Direct Testimony of Kevin J. Mara.

WALMART: Walmart believes the public interest would benefit if the Commission directs each utility to continue to collaborate with interested stakeholders during the interim period before their next required updated SPPs to develop ways in which customer-sited generation may be utilized as part of the SPP in order to strengthen the T&D systems and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall.

PARTIES' ARGUMENTS

TECO

TECO stated that it is in the public interest to approve its 2022-2031 SPP without modification as explained in Issues 2A through 6A of its brief. TECO argued that its SPP meets every requirement specified by the Legislature, and the Commission should consider the four factors set forth within Section 366.96(4), F.S. (TECO BR 24-25) In TECO's brief, the Company also argued that the Transmission Access Enhancement Program would allow the Company to reach their transmission rights-of-way quicker and allow for them to expedite repairs, which is critical to restoration of service. TECO stated during normal weather, when time is not critical, the Company can take a longer route through a different access point or postpone them until conditions at a given access point improve. TECO argued that witness Mara's criticism of not evaluating alternative specialized equipment is incorrect, since TECO does own and operate that type of equipment; but, in TECO's experience this equipment does not resolve all access issues. TECO also stated that the Transmission Access Enhancement Program is not replacing "aging infrastructure" as suggested by OPC, but upgrading existing access points by installing new permanent roads and bridges for improved and faster access during extreme weather events. (TECO BR 13-14)

JOINT PARTIES

In their brief, the Joint Parties argued the Transmission Access Enhancement Program should be excluded from the SPP since this Program should be part of TECO's daily operational maintenance. (Joint Parties BR 4-6)

The Joint Parties also argued that the feeder automation and sectionalizing project within the Overhead Feeder Hardening Program would not reduce outage costs, since the damage would still need to be repaired and cleaned up. Furthermore, the cost may increase since the fault isolation technology equipment may need to be restored, thus this project should be excluded from TECO's SPP. (Joint Parties BR 4-6) The Joint Parties argued the Commission should approve TECO's SPP with the modifications recommended by OPC witness Mara, and shown below in Table 10A-1. (Joint Parties BR 14)

WALMART

In its brief, Walmart stated that the Commission should carefully consider whether TECO's SPP is in the public interest. Walmart asserted that the Florida Legislature determined that there are four factors that the Commission must consider when determining whether to approve, approve with modifications, or deny TECO's SPP. These factors include the extent to which the SPP will reduce restoration costs and power outrage times, how practical a certain location selected for infrastructure is relative to TECO's service territory, the cost/benefit to customers, and the impact on customers' bills. Walmart believes that it would be in the public interest if TECO would continue to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen TECO's system and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall. (Walmart BR 2, 6)

ANALYSIS

Section 366.96(5), F.S., requires the Commission to 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 discussed in Issue 1A, staff recommends that TECO's filing satisfies the requirements of Rule 25-6.030, F.A.C., and provides the Commission with adequate information in order to satisfy its statutory requirements. TECO's SPP for the period of 2022-2031 included the following programs:

- Distribution Lateral Undergrounding
- Distribution Overhead Feeder Hardening
- Vegetation Management
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Infrastructure Inspections
- Transmission Access Enhancements
- Legacy Storm Hardening Initiatives

As discussed in prior issues, OPC witness Mara recommended modifications to four of TECO's SPP programs. The programs are: Distribution Lateral Undergrounding; Substation Extreme Weather Hardening; Distribution Overhead Feeder Hardening; and, Transmission Access Enhancements. Witness Mara also recommended eliminating the Distribution Feeder Sectionalizing and Automation Project from the Distribution Feeder Hardening Program. Witness Mara's recommendations are summarized in Table 10A-1. FIPUG took the same position and agreed with OPC. Walmart provided no witness testimony; but, argued in its brief that it would be in the public interest if TECO continued to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen TECO's system. (Walmart BR 6) Although staff agrees with continuing the collaboration between utilities and interested stakeholders, the SPP Statute does not contemplate customer-sited generation. Section 366.96(2)(b), F.S., defines a transmission and distribution storm protection plan as "a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management." Thus, on-site generation does not meet the definition as laid out in the statute. As discussed in Issue 1A, staff does not agree with witnesses Kollen and Mara's interpretation of the SPP Rule and does not recommend adjustments due to lack of compliance with the SPP Rule to the two programs listed in Table 10A-1.

Table 10A-1
Witness Mara's Recommended Program Adjustments

Program	Total 2022-2031 SPP (millions)	Proposed Reductions (millions)	Net 2022-2031 SPP (millions)	Reason for Reduction
Distribution Lateral Undergrounding	$1,070	($570)	$500	Limit impact to customers
Substation Extreme Weather (Distribution & Transmission)	$29	($29)	$0	Does not comply with 25-6.030
Distribution Overhead Feeder Hardening	$317	($217)	$100	Limit impact to customers
Transmission Access Enhancement	$31	($31)	$0	Does not comply with 25-6.030

Source: (TR 729)

OPC witness Mara's rate mitigation recommendations for the Distribution Lateral Undergrounding and Distribution Overhead Feeder Hardening Programs were discussed in Issue 6A, as well as staff's recommended adjustments. OPC witness Mara's recommendations for the Substation Extreme Weather Hardening Program were discussed in Issue 4A, as well as staff's recommended adjustments. Witness Mara's remaining recommended adjustments are discussed below. Apart from the Transmission Access Enhancement Program, the remainder of TECO's proposed programs meet the requirements of the SPP Rule.

In its proposed SPP, TECO described its Distribution Feeder Sectionalizing and Automation Projects as enhancements that involve increasing the installation of automation equipment, reclosers, trip savers, and other supporting sectionalizing infrastructure on existing distribution circuits. The devices provide many benefits, according to TECO, that will improve the performance of the overall distribution system during extreme weather events: such as allowing for the automatic transfer of load to neighboring feeders in the event of unplanned outages; allowing for the network to be re-configured automatically to minimize the number of customers experiencing prolonged outages; and reducing restoration time by isolating only those parts of the electrical system that contain faults that require assessment, investigation, follow-up and repair. (EXH 9, P 76-77)

OPC witness Mara stated that the Distribution Feeder Sectionalizing and Automation Project, a project within the Distribution Overhead Feeder Hardening Program, should be eliminated from TECO's 2022 SPP. He argued it would not reduce outage costs since damage would still need to be repaired, as well as the technology utilized needing to be restored or repaired. (TR 737-739) TECO witness Plusquellic argued that this project would allow for quicker identification and isolation of outages, which will reduce the amount of time patrolling, thus allowing for faster release of foreign crews leading to lower restoration costs. (TR 1510-1511) Staff agrees with TECO that this project will reduce the number of customers affected by an outage and allow for earlier detection of outages which leads to reduced outage times and costs.

TECO's witness Plusquellic testified that the Transmission Access Enhancement Program is an existing program that was created so that the Company could restore its transmission system quickly when outages occur. This Program first appeared in TECO's 2020 SPP which was approved by a settlement agreement.[9] One part of the program consists of access road projects that are proposed to restore access to areas impacted by extreme weather or establish new access roads. Access roads are the primary route to transmission facilities for installation, maintenance, and repair. The other part of the program consists of access bridge projects, which enhance or replace the Company's current system of bridges used to access its "off road" transmission facilities. The company identified a net total of 74 access road projects as part of this program and 21 potential bridge projects.

OPC witness Mara testified that maintaining and/or replacing access roads and bridges is not storm hardening. The witness stated that aging infrastructure programs, which do not decrease outage costs and do not reduce outage times when compared to equivalent existing system infrastructure, should go through base rates rather than the SPPCRC because they are ordinary replacements.. (TR 725-726) OPC witness Mara testified that an alternative to the Transmission Access Enhancement Program is the use of specialized equipment to access difficult terrain including track vehicles, large tire vehicles, and floating equipment. The witness stated that an electric utility has a duty to maintain its infrastructure, including roads. Replacing bridges and re-building roads are not enhancement programs, but rather, simply maintaining infrastructure at the same status quo. The witness testified that he is unsure of why TECO has not maintained its access roads and bridges and that any reduction in outage times and restoration costs should be measured against a well-maintained infrastructure of roads and bridges. The witness asserted that bringing inadequate or poor-quality roads and bridges to a well-maintained state does not reduce storm restoration costs or outage times. As such, OPC recommended excluding TECO's Transmission Access Enhancement Program from its proposed SPP. (TR 743-745)

[9] See Order No. PSC-2020-0293-AS-EI, issued August 28, 2020.

In rebuttal, TECO's witness Plusquellic testified that TECO is not replacing "like for like" bridges, the Company proposed replacing old bridges rated/sized for smaller vehicles, with higher rated and bigger bridges that can support the movement of existing larger trucks and heavy equipment. The witness stated that the installation of new bridges for additional access points and more permanent roads, along with permanent rock roads, will withstand nature for a much longer duration than the Company's current bridges and access points. (TR 1499-1500) While TECO owns some specialized equipment, such as track vehicles and large tire vehicles, the witness stated that they were not evaluated because the equipment does not resolve all access issues. Witness Plusquellic stated that all road projects included in this Program involve construction of new roads at points where a permanent road did not exist before and all bridge projects included in this Program involve construction of new or upgraded bridges. (TR 1518-1519)

Rule 25-6.030 (2)(c), F.A.C., defines transmission and distribution facilities as "all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors." Based on the FERC system of accounts, staff views this definition as inclusive of all components of a transmission or distribution project, not that each component is independently eligible for storm protection cost recovery. For example, a road may need to be repaired or relocated as part of a hardening project that converts wood poles to concrete poles. The total costs of the project, including the cost of road repair, would be included in the transmission plant reporting category and eligible for storm protection cost recovery. Staff agrees with OPC that maintaining access roads for the transmission facilities should be a regular activity and not a storm protection activity. Staff believes the Company should maintain access to its transmission facilities for activities such as vegetation management and inspections prior to hurricane season.

In summary, as discussed in Issue 6A, staff recommends that TECO's Distribution Lateral Undergrounding Program be continued as its 2021 spending level and that the Company's Transmission Access Enhancement Program be excluded from the SPP. With these two modifications, staff recommends that TECO's SPP is in the public interest. TECO should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

CONCLUSION

Staff recommends TECO's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1A. Staff recommends that TECO's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Undergrounding Program at the 2021 level; and (2) remove the Transmission Access Enhancement Program. TECO should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

Issue 11A: Should this be closed?

Recommendation: No. As discussed in Issue 10A, TECO should file an amended SPP within 30 days of the final order for administrative approval by Commission staff. Therefore, the docket shall remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively. (Trierweiler, Imig)

Position of the Parties

TECO: No position provided.

JOINT PARTIES: Not at this time.

WALMART: Yes.

PARTIES' ARGUMENTS

TECO

No post-hearing position or argument was provided in its brief.

JOINT PARTIES

No post-hearing position or argument was provided in its brief.

WALMART

No post-hearing position or argument was provided in its brief.

CONCLUSION

As discussed in Issue 10A, TECO should file an amended SPP within 30 days of the final order for administrative approval by Commission staff. Therefore, the docket shall remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively

Tampa Electric Company
Proposed 2022 – 2031 Storm Protection Plan Programs

Distribution Lateral Undergrounding
TECO's Distribution Lateral Undergrounding program is a program that strategically undergrounds existing overhead laterals. The primary factor in prioritizing laterals to be underground is based on reliability performance during extreme weather events.

Distribution Overhead Feeder Hardening
TECO's distribution system will be hardened to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events by increasing the resiliency and sectionalizing capabilities of the system.

Vegetation Management
TECO's distribution and transmission vegetation management activities are both addressed in this program. TECO's distribution tree trimming program includes circuit tree trimming activities, mid-cycle trimming activities, customer requested work, and work orders associated with circuit improvement processes. TECO's distribution system is on a four-year cycle and the transmission system is on three-year cycle.

Transmission Asset Upgrades
TECO plans to replace its remaining transmission wood poles with non-wood material. This is a continuation of TECO's existing pole replacement program, which includes replacing poles based on preventative, corrective or project-driven assessments.

Substation Extreme Weather Hardening
Hardening existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events is a new program included in TECO's SPP. No projects were planned or completed for 2021 under this program as TECO finished its studies on the substations. Nine substations are recommended for hardening; however, the projects are projected to start in 2023.

Infrastructure Inspections
TECO's distribution wood pole inspections and transmission structure inspections, and the joint use pole attachment audit are combined into one program. The distribution wood pole inspections are on an eight-year cycle program and the transmission structure inspections include a range of inspections from ground to aerial infrared patrols with a range of cycles from annual to eight years.

Transmission Access Enhancements

In order to have continuous access to its transmission facilities for restoration, TECO implemented this program in its SPP to maintain the access roads and bridges leading to its facilities. TECO did not plan or complete any projects in 2021 as the Utility continued to focus on the program's specifications, contracts, and plans. However, the utility plans to complete 25 road projects and 19 bridge projects during the 2022-2031 time frame.

Legacy Storm Hardening Initiatives

TECO's continuation of Commission Order No. PSC-06-0351-PAA-EI. Included in this program is the Geographical Information System, Post-Storm Data Collection, Outage Data-Overhead and Underground Systems, Increase Coordination with Local Governments, Collaborative Research, Disaster Preparedness and Recovery Plan, and Distribution Pole Replacements.

366.96 Storm protection plan cost recovery.—

(1) The Legislature finds that:

(a) During extreme weather conditions, high winds can cause vegetation and debris to blow into and damage electrical transmission and distribution facilities, resulting in power outages.

(b) A majority of the power outages that occur during extreme weather conditions in the state are caused by vegetation blown by the wind.

(c) It is in the state's interest 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.

(d) Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

(e) 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.

(f) All customers benefit from the reduced costs of storm restoration.

(2) As used in this section, the term:

(a) "Public utility" or "utility" has the same meaning as set forth in s. 366.02(8), except that it does not include a gas utility.

(b) "Transmission and distribution storm protection plan" or "plan" means a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management.

(c) "Transmission and distribution storm protection plan costs" means the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan.

(d) "Vegetation management" means the actions a public utility takes to prevent or curtail vegetation from interfering with public utility infrastructure. The term includes, but is not limited to, the mowing of vegetation, application of herbicides, tree trimming, and removal of trees or brush near and around electric transmission and distribution facilities.

(3) Each public utility shall file, pursuant to commission rule, a transmission and distribution storm protection plan that covers the immediate 10-year planning period. Each plan must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. The commission shall adopt rules to specify the elements that must be included in a utility's filing for review of transmission and distribution storm protection plans.

(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.

(5) No later than 180 days after a utility files a transmission and distribution storm protection plan that contains all of the elements required by commission rule, the commission shall determine whether it is in the public interest to approve, approve with modification, or deny the plan.

(6) At least every 3 years after approval of a utility's transmission and distribution storm protection plan, the utility must file for commission review an updated transmission and distribution storm protection plan that addresses each element specified by commission rule. The commission shall approve, modify, or deny each updated plan pursuant to the criteria used to review the initial plan.

(7) After a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence. The commission shall conduct an annual proceeding to determine the utility's prudently incurred transmission and distribution storm protection plan costs and allow the utility to recover such costs through a charge separate and apart from its base rates, to be referred to as the storm protection plan cost recovery clause. If the commission determines that costs were prudently incurred, those costs will not be subject to disallowance or further prudence review except for fraud, perjury, or intentional withholding of key information by the public utility.

(8) The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates and must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

(9) If a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity.

(10) Beginning December 1 of the year after the first full year of implementation of a transmission and distribution storm protection plan and annually thereafter, the commission shall submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a report on the status of utilities' storm protection activities. The report shall include, but is not limited to, identification of all storm protection activities completed or planned for completion, the actual costs and rate impacts associated with completed activities as compared to the estimated costs and rate impacts for those activities, and the estimated costs and rate impacts associated with activities planned for completion.

(11) The commission shall adopt rules to implement and administer this section and shall propose a rule for adoption as soon as practicable after the effective date of this act, but not later than October 31, 2019.

History.—s. 1, ch. 2019-158; s. 30, ch. 2022-4.

25-6.030 Storm Protection Plan.

(1) Application and Scope. Each utility as defined in Section 366.96(2)(a), F.S., must file a petition with the Commission for approval of a Transmission and Distribution Storm Protection Plan (Storm Protection Plan) that covers the utility's immediate 10-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every 3 years.

(2) For the purpose of this rule, the following definitions apply:

(a) "Storm protection program" – a category, type, or group of related storm protection projects that are undertaken to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(b) "Storm protection project" – a specific activity within a storm protection program designed for the enhancement of an identified portion or area of existing electric transmission or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) "Transmission and distribution facilities" – all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors.

(3) Contents of the Storm Protection Plan. For each Storm Protection Plan, the following information must be provided:

(a) A description of how implementation of the proposed Storm Protection Plan will 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.

(b) A description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) 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. Such description must include a general map, number of customers served within each area, and the utility's reasoning for prioritizing certain areas for enhanced performance and for designating other areas of the system as not feasible, reasonable, or practical.

(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.; and

5. A description of the criteria used to select and prioritize proposed storm protection programs.

(e) For the first three years in a utility's Storm Protection Plan, the utility must provide the following information:

1. For the first year of the plan, a description of each proposed storm protection project that includes:

a. The actual or estimated construction start and completion dates;

b. 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;

c. A cost estimate including capital and operating expenses; and

d. A description of the criteria used to select and prioritize proposed storm protection projects.

2. For the second and third years of the plan, project related information in sufficient detail, such as estimated number and costs of projects under every specific program, to allow the development of preliminary estimates of rate impacts as required by paragraph (3)(h) of this rule.

(f) For each of the first three years in a utility's Storm Protection Plan, the utility must provide a description of its proposed vegetation management activities including:

1. The projected frequency (trim cycle);

2. The projected miles of affected transmission and distribution overhead facilities;

3. The estimated annual labor and equipment costs for both utility and contractor personnel; and

4. A description of how the vegetation management activity will reduce outage times and restoration costs due to extreme weather conditions.

(g) An estimate of the annual jurisdictional revenue requirements for each year of the Storm Protection Plan.

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

(i) A description of any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan.

(j) Any other factors the utility requests the Commission to consider.

(4) By June 1, each utility must submit to the Commission Clerk an annual status report on the utility's Storm Protection Plan programs and projects. The annual status report shall include:

(a) Identification of all Storm Protection Plan programs and projects completed in the prior calendar year or planned for completion;

(b) Actual costs and rate impacts associated with completed activities under the Storm Protection Plan as compared to the estimated costs and rate impacts for those activities; and

(c) Estimated costs and rate impacts associated with programs planned for completion during the next calendar year.

Rulemaking Authority 366.96 FS. Law Implemented 366.96 FS. History–New 2-18-20.

Item 5

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 26, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Buys, King, Lewis, Ramos) TB
Office of the General Counsel (Trierweiler, Imig) AH

RE: Docket No. 20220049-EI – Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.

AGENDA: 10/04/22 – Regular Agenda – Post Hearing Decision - Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: October 8, 2022 - 180-day Statutory Deadline Per 366.96(5), Florida Statutes.

SPECIAL INSTRUCTIONS: Please place Dockets Nos. 20220048-EI, 20220049-EI, 20220050-EI, and 20220051-EI in consecutive order on the Agenda.

Table of Contents

Case 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 a plan, that contains all the elements required by Commission rule, the Commission must determine whether it is in the public interest to approve, approve with modification, or deny the plan. Section 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. Further, this section requires the Commission conduct an annual proceeding, referred to as the storm protection plan cost recovery clause (SPPCRC), to determine the utility's prudently incurred SPP costs.

IOUs were required to file their first SPPs by April 10, 2020. On March 17, 2020, Florida Public Utilities Company (FPUC) filed a Motion requesting 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 for Commission approval which covers the period of 2022-2031 and included eight programs. 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.

<u>Procedural Matter</u>
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 in this post-hearing issue that the Commission should reverse a prehearing ruling set forth in Order No. PSC-2022-0292-PCO-EI, where the Prehearing Officer granted motions to strike portions of the prefiled testimony of OPC witness Lane Kollen. In staff's 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 was denied by the full Commission. Because the evidentiary concerns relating to the testimony of witness Kollen have twice been addressed on the merits, staff believes it is appropriate to discuss OPC's "post-hearing legal issue" here only as it raises procedural concerns. For the reasons set forth below, staff believes there is no procedural error that that Commission must consider at this time.

[1] FPUC's docket was consolidate with the SPP dockets for TECO (20220048-EI), DEF (20220050-EI), and FPL (20220051-EI) for hearing purposes only.
[2] Order No. PSC-2022-0291-PHO-EI, issued August 1, 2022.

"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 in the case and to conduct cross-examination of all witnesses on the case's relevant issues both in the case in chief and in the proffered portions of the hearing. (TR 44).

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 the Commission's 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 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. (TR 824-853). 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. (TR 854-886). 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. (TR 802-808). Although the Commission ultimately decided to strike the OPC Witness testimony, OPC was provided an opportunity to make its legal argument at the administrative hearing (TR 798-810), and in its motion for reconsideration. OPC made its arguments again in its post-hearing brief.

OPC also argue that a Commission Final Order applying Rule 25-6.030, 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." (OPC BR 36) The cases cited by OPC in support on this argument all address judicial review of the constitutionality of statutes.[3] As an agency, the Commission has no jurisdiction to declare a statute unconstitutional. Moreover, following the passage of Article V, Section 21, of the Florida Constitution, the Commission's interpretation of a statute will not be relevant to a court vested with jurisdiction to consider that constitutional question.

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

There are 8 issues addressed below for the Commission to consider.[4] The Commission has jurisdiction in this matter pursuant to Section 366.96, and Chapter 120, F.S.

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[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)).

[4] FPUC's issues are 1B-6B, 10B, and 11B. Issues 7-9 are FPL only issues.

Discussion of Issues

Issue 1B: Does FPUC's Storm Protection Plan contain all of the elements required by Rule 25-6.030, Florida Administrative Code?

Recommendation: Yes. FPUC met the criteria and intent of the SPP Rule with its filing and the Commission has adequate information in order to satisfy its statutory requirements. (Trierweiler, Imig, Lewis)

Position of the Parties

FPUC: Yes.

OPC: No. Rule 25-6.030, F.A.C., establishes the necessary content of the SPP. Based on the failure to provide all the required information in SPP Rule, FPUC should be required to amend their filing and provide the necessary data for each program with opportunity for intervenors to provide review and testimony.

PARTIES' ARGUMENTS

FPUC

FPUC stated that it worked closely with Pike Engineering to develop an 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.

In sum, FPUC's chart illustrated its argument that its SPP met each of the components of the rule. (FPUC BR 4-7) FPUC argued that had a comparison of costs to cost savings been contemplated, then "cost savings" would have been used, rather than the broader term "benefits." (FPUC BR 21)

OPC

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 BR 3) OPC argued that FPUC's SPP filings are inadequate because the cost comparison did not quantify benefits pursuant to Subsections (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 BR 1, 3-5, 21) OPC witness Kollen stated 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. (TR 1029)

ANALYSIS

History

The first utility storm hardening programs were filed for Commission approval in 2007 and reviewed by the Commission 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."[5] Subsection 366.96(3), F.S., requires each IOU to file a transmission and distribution SPP for the Commission's review and directs the Commission 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.

The Commission promulgated two Rules, 25-6.030, F.A.C., Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Cost Recovery, to implement and administer Section 366.96, F.S. The full text of Section 366.96, F.S., and Rule 25-6.030, F.A.C., are included as Attachment B. This is FPUC's first SPP filing.

Issue

This issue addresses the parties' arguments concerning the filing requirements pursuant to Rule 25-6.030, F.A.C. Throughout this docket, OPC arguments have centered around 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.[6] Regardless of how information in a SPP filing is characterized, the Commission 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, staff believes that FPUC's SPP meets the requirements of Section 366.96, F.S., and 25-6.030, F.A.C.

Law

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

> 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.

[5] 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.
[6] Neither the terms "qualitative" nor "quantitative" are contained within the SPP statute or SPP Rule. Rather, these are terms that Staff and the parties use to assist with the description of the categories of information that are at issue in this docket.

The Statute further articulates that the Commission must use the public interest standard when considering a SPP. *See* § 366.96(5), stating that the Commission shall determine whether it is in the public interest to approve, modify, or deny the plan. Accordingly, Rule 25-6.030, F.A.C., requires utilities to file certain minimum information in order for the Commission to determine if it is in the public interest to approve, approve with modifications, or deny a utility's storm protection plan. In other words, Rule 25-6.030, F.A.C., is a filing requirement rule, not a standard for the Commission's decision. As such, the rule allows the utilities to have the flexibility to submit and manage their hardening plans while simultaneously requiring a utility file the information necessary for the Commission to make a determination about whether it is in the public interest to approve a plan, approve a plan with modifications, or deny a plan.

Rule 25-6.030(3), F.A.C., Storm Protection Plan, identifies the specific information to be included in each IOU's SPP.[7] Rule 25-6.030(3)(d), F.A.C., requires, in relevant part, a comparison of costs and benefits:

> 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.

Staff Analysis

Rule 25-6.030(3)(d), F.A.C., requires "...a comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in 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, the Commission lacks 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

[7] Specific elements of Rule 25-6.030, F.A.C., such as areas for prioritization and rate impacts, are discussed in more detail in Issues 2B through 6B.

analytical requirements that are not contained within the current rule, and therefore would arguably be beyond the scope of the current rule.

Staff believes that 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 the Commission consider the rate impact in order to approve a SPP. The Commission will receive all the cost numbers necessary to make a rate impact determination. Thus, Rule 25-6.030, F.A.C., should 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. [8]

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 staff believes the utility should have the option to submit what it deems to be its most accurate data analysis of costs and benefits for the Commission's consideration, staff believes that Rule 25-6.030, F.A.C., should 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

[8] 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) there are no monetized benefits to the general body of customers. 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.

projects. In other words, meeting the filing requirements of the SPP Rule allows the Commission to go forward with making a determination on approval, denial, or modification of a SPP.

In this case, staff believes 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 the Joint Parties (TR 1116; 82), 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. (TR 609; TR 619-620) 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 restoration costs associated with bringing in outside crews and services following an extreme weather event. (TR 627)

CONCLUSION

Staff recommends that FPUC met the filing requirements required by Rule 25-6.030, F.A.C., and that the Commission has adequate information necessary to make a public interest determination pursuant to Section 366.96, F.S.

Issue 2B: To what extent is FPUC's Storm Protection Plan expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability?

Recommendation: FPUC utilized historical and scientific data to support its 2022 SPP program evaluation and development. The data was used to target and prioritize system infrastructure for hardening in order to reduce restoration costs and outage times associated with extreme weather events. (Lewis)

Position of the Parties

FPUC: Implementation of FPUC's SPP will result in a significant reduction in outages, the length of outages, as well as reductions to future restoration costs from severe storms. FPUC's SPP will ultimately result in less damage in a storm event, and therefore cost savings. However, quantifying those savings depends on scope of the storm and timing.

OPC: FPUC refused to even try to quantify the costs and benefits of its programs and projects. Thus, the reduction in restoration costs and outage times and enhancement in reliability cannot be determined. Moreover, several programs and projects failed to meet the criteria to reduce restoration costs and outage times.

PARTIES' ARGUMENTS

FPUC

FPUC's 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 BR 2, 8) As argued by the Company in Issue 1B, FPUC does not believe it is realistic and reasonable to quantify FPUC's reduction in restoration costs and outage times. (FPUC BR 9-10) FPUC provided a qualitative description for each of its SPP programs. (FPUC BR 21) This description provided the issue the program is meant to address and the benefits that could be expected from the program. (FPUC BR 10) The testimony of FPUC's witness Cutshaw emphasized the Company's position that its SPP will reduce storm restoration costs based on lessons learned from Hurricane Michael.

OPC

In its brief, 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 BR 6) Based on the information provided by the Company in its SPP, the extent to which FPUC's SPP will reduce restoration costs and outage times cannot be determined. (OPC BR 8) As argued in Issue 1B, OPC believes the Company is required to quantify this information based on the SPP Rule, and that FPUC is capable of doing so despite its arguments. (OPC BR 7-8)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. As discussed in Issue 1B, 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.

As discussed in the case background, this is FPUC's first SPP filing. In the meantime, FPUC has continued to operate 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. (EXH 12 P 31)

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. For example, FPUC stated the following for several of its programs: "FPUC believes the Overhead Feeder Hardening program will achieve the desired objectives outlined in Rule 25-6.030 of 'reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.'" (OPC BR 6; TR 762) OPC argued that this statement is not adequate for the Commission to make a proper determination and the Company should have provided cost reduction estimates instead. (OPC BR 6) Therefore, FPUC's SPP does not comply with the requirements of Rule 25-6.030, F.A.C., and the Company should have been required to amend its filing with the necessary data for each program.

In rebuttal, witness Cutshaw dismissed OPC's argument that FPUC only provided vague language and also refutes OPC's argument that its SPP does not contain this particular element of the SPP Rule. In addition to the Company's SPP, witness Cutshaw also provided testimony in support of each program and explained the programs provide economic benefit in multiple ways. (FPUC BR 10; TR 1573-1590) For example, the witness explained FPUC's poles are replaced with poles that have higher loading and strength factors, which in turn, will reduce restoration times and costs associated with extreme weather events. (FPUC BR 10; TR 1579) OPC did not specifically dispute the inputs or model utilized by FPUC.

Staff believes FPUC provided the necessary information to meet the requirements of the SPP Statute and Rule related to this issue. It appears FPUC proposed programs may reduce restoration costs and outage times associated with extreme weather events and may enhance reliability.

CONCLUSION

FPUC utilized historical and scientific data to support its 2022 SPP program evaluation and development. The data was used to target and prioritize system infrastructure for hardening in order to reduce restoration costs and outage times associated with extreme weather events.

Issue 3B: To what extent does FPUC's Storm Protection Plan prioritize areas of lower reliability performance?

Recommendation: FPUC's SPP appears to prioritize areas of lower reliability performance. (Lewis)

Position of the Parties

FPUC: FPUC's 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.

OPC: FPUC did include prioritization of areas of lower reliability performance as an input in its Risk Resiliency Model, but there is no description of what weight it was given.

PARTIES' ARGUMENTS

FPUC

FPUC's 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. (FPUC BR 12-15) For these key programs, FPUC focused on prioritizing feeders with the highest risk score and statistically worse performance, while also considering other factors. (FPUC BR 16)

OPC

OPC agreed that FPUC's model used historical reliability performance of its system under extreme and non-extreme weather events and then leveraged the model's recommendations and supplemented it with other (non-disclosed) variables to identify projects for the first three years of the plan. However, there is no description of what weight the model was given for areas of lower reliability performance. Thus, OPC argued it is unclear to what extent areas of lower reliability performance were prioritized over other areas for other reasons. (OPC BR 12-13)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. (EXH 12 P 17-18) 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. (EXH 12 P 18-23) 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. (EXH 12 P 23-24)

OPC did not specifically address this issue in its testimony. Instead, its testimony reviewed the purpose of storm hardening with respect to the SPP Statute and Rule; summarized OPC's proposed reductions; reviewed specific programs contained within FPUC's SPP; and, discussed the generalized adoption of a uniformed decision methodology. (TR 992; TR 756-761)

Staff believes FPUC's SPP prioritizes areas of lower reliability based on its use of the Risk Resiliency Model and resulting criteria descriptions for each program. Thus, staff believes that FPUC demonstrated its prioritization of SPP projects in areas of lower reliability performance.

CONCLUSION

FPUC's SPP appears to prioritize areas of lower reliability performance.

Issue 4B: To what extent is FPUC's Storm Protection Plan regarding transmission and distribution infrastructure feasible, reasonable, or practical in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas?

Recommendation: With the exceptions discussed in Issue 10B, FPUC's SPP appears feasible, reasonable, and practical within the Company's service territory. (Lewis)

Position of the Parties

FPUC: The Company's SPP is feasible, reasonable, and practical for all areas and facilities that the Company'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.

OPC: Many of the programs fail the two-prong test: (1) to reduce restoration costs, and (2) to reduce outage times. Moreover, new 138 kV transmission line is not feasible, reasonable, or practical in the area proposed by FPUC.

PARTIES' ARGUMENTS

FPUC

Based on FPUC's use of the Resiliency Risk Model, the Company argued that its SPP is feasible, reasonable, and practical for all areas and facilities addressed. (FPUC BR 17) The model's inputs included data specific to FPUC's geographic location, customer population, rural areas, and flood zones. This information allowed the Company to assess the resiliency and risks for each of the unique divisions of its system and develop its comprehensive SPP to address any issues. (FPUC BR 17-18)

OPC

OPC argued that the statutory language of "feasible, reasonable, or practical" is not a test of whether the SPP is in the public interest, but rather, an assessment of the physical viability of SPP components. In its brief, OPC also argued that efforts to identify excessive spending centered on projects that did not meet the Two-Prong test of reducing outage times and reducing restoration costs and those that were not cost-effective. Additionally, OPC recommended that FPUC's proposed 138 kV transmission line should be excluded from the Company's SPP because this project is not feasible, reasonable, or practical for the proposed area. (FPUC BR 13-14)

ANALYSIS

Section 366.96(4)(b), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 area. 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. (EXH 12 P 10-11) 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. (TR 603-617) As discussed in Issue 3B, 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. (TR 606-607; FPUC BR 17)

In its brief, OPC argued that FPUC's proposed new 138 kV transmission project, which is included in FPUC's Transmission and Substation Resiliency Program, should be excluded from the SPP because this project is not feasible, reasonable, or practical in the area proposed by the Company. (OPC BR 13) OPC witness Mara provided testimony in support of this argument and reiterated that this project was not necessary or prudent, as FPUC's existing double circuit transmission line is already a hardened structure. (TR 774) This Program is discussed in greater detail in Issue 10B.

Staff recommends FPUC has met the requirements of Rule 25-6.030(3)(c), F.A.C., by providing a map of its service area, the number of customers served within each area, and the methodology of prioritizing projects within its programs. Therefore, staff believes FPUC's SPP is reasonable in certain areas of the Company's service territory including, but not limited to, flood zones, and rural areas.

CONCLUSION

With the exceptions discussed in Issue 10B, FPUC's SPP appears feasible, reasonable, and practical within the Company's service territory.

Issue 5B: What are the estimated costs and benefits to FPUC and its customers of making the improvements proposed in the Storm Protection Plan?

Recommendation: The estimated costs of FPUC's SPP programs are shown in Table 5B-1. The benefits are described in Section 3 of its proposed SPP and are discussed in Issue 2B. (Lewis)

Position of the Parties

FPUC: Over the full 10-year planning horizon, FPUC estimates that implementation of its SPP for the 2022-2031 period will cost $263.14 million, including O&M, which equates to a revenue requirement of $147,181,829.[9] All 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 will either be uninterrupted or be restored more expeditiously because of these initiatives.

OPC: The Company refused to even try to quantify the costs and benefits of its programs and projects. Thus, without even the attempt at quantification, the extent the Company's Storm Protection Plan is expected to reduce restoration costs and outage times associated with extreme weather events cannot be determined.

PARTIES' ARGUMENTS

FPUC

FPUC argued that quantifying the costs associated with a particular project is a straightforward mathematical assessment of projected costs of equipment and required resources and manpower in monetary terms. However, quantifying the benefits derived from such projects is a complex, and arguably an impossible task. Some assumptions, such as cost per mile, cannot be fully validated until projects are completed given that the price of materials and labor tend to fluctuate. In addition, the reduced amount of time without service is the same benefit from customer to customer; however, 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. (FPUC BR 9)

OPC

In its brief, 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. (OPC BR 1) 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 the Commission and stakeholders to understand the benefits of the capital investments for storm hardening relative to the "reasonableness" of the costs. (OPC BR 14-15)

[9] Hearing Exh. 89, BATES 2103.

ANALYSIS

Section 366.96(4)(c), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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, as identified and discussed in Issue 2B.

For each SPP program, FPUC provided the estimated capital costs and operating expenses for 2022 through 2024, which are summarized in Table 5B-1. The program benefits are described in Section 3 of the proposed SPP and are discussed in Issue 2B

Table 5B-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

Source: (Exhibit 12, Page 16)

OPC witness Mara argued that FPUC did not determine specific benefits in its SPP as required by the Rule and Statute. He further stated that it is impossible for any party to make a judgment on prudence without an estimate of the cost reduction for outages. (TR 761) OPC's arguments and staff's analysis on the requirements of a cost-effectiveness analysis are discussed in Issue 1B. Staff believes that FPUC provided the necessary information to meet the requirements of the SPP Rule. As discussed in Issue 2B, FPUC provided a description of the benefits that will be brought about by the programs in its proposed SPP. The Company also listed 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 Company in its SPP.

CONCLUSION

The estimated costs of FPUC's SPP programs are shown in Table 5B-1. The benefits are described in Section 3 of its proposed SPP and are discussed in Issue 2B.

Issue 6B: What is the estimated annual rate impact resulting from implementation of FPUC's Storm Protection Plan during the first 3 years addressed in the plan?

Recommendation: The estimated annual rate impact, as provided by FPUC, is projected to increase approximately 130 percent the first three years of its Storm Protection Plan. While staff is not recommending any implementation alternatives to mitigate rates, staff is recommending removal of the Future T&D Enhancements and the Transmission and Substation Resiliency Programs from FPUC's SPP because these programs do not enhance existing infrastructure. (Lewis)

Position of the Parties

FPUC: The estimated annual rate impact, inclusive of amounts recovered through base rates, which will be removed for purposes of the cost recovery proceeding in Docket No. 20220010, are:

Estimated Rate Impact per 1,000 KWH residential customer	2023[10]	2024[11]	2025
Total SPP Estimate	$6.36	$6.36	$15.21
Typical Commercial bill Increase%	5.32%	5.30%	12.72%
Typical Industrial bill Increase%	2.08%	2.07%	5.06%

OPC: The $6.60, $6.58, and $15.21 per 1,000 kWh for residential customers, 5.50%, 5,50%, and 12.72% increase for typical Commercial customers, and 2.15%, 2,20%, and 5.06% increase for typical Industrial customers first three years is too high during this period of high inflation. Alternates need to be implemented to reduce rate impacts.

PARTIES' ARGUMENTS

FPUC

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 testified that it plans to delay certain projects to mitigate customer impacts; but, those projects cannot be postponed indefinitely. Moreover, the projected costs are below the average of the other Florida IOUs when comparing 10-year investment costs in feeder and lateral hardening programs against the total system overhead miles or square miles of service territory. OPC's comparisons of costs across utilities on a per customer basis does not yield an "apples to apples" comparison. (FPUC BR 22 - 24)

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[10] Based on Hearing Exh. 89, BATES 2103.
[11] Id.

OPC

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. The SPP will 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. In addition, FPUC did not provide quantifications of the benefits from potential saving in storm damage and restoration costs; since no information was provided, there are $0 dollars in benefits from potential saving.

OPC stated that the Commission should keep in mind that the impact of the SPP programs is yet another addition to the customer bill in an environment of high inflation. Specifically, OPC pointed out that FPUC's residential customers are expected to pay for a 2022 under recovery due to natural gas price increases of roughly $83 dollars per 1,000 kWh. This is in addition to the current midcourse correction residential rate impact of $14.87. Moreover, FPUC residential customers are still paying for a Hurricane Michael surcharge of $12.80 per 1,000 kWh through 2025.

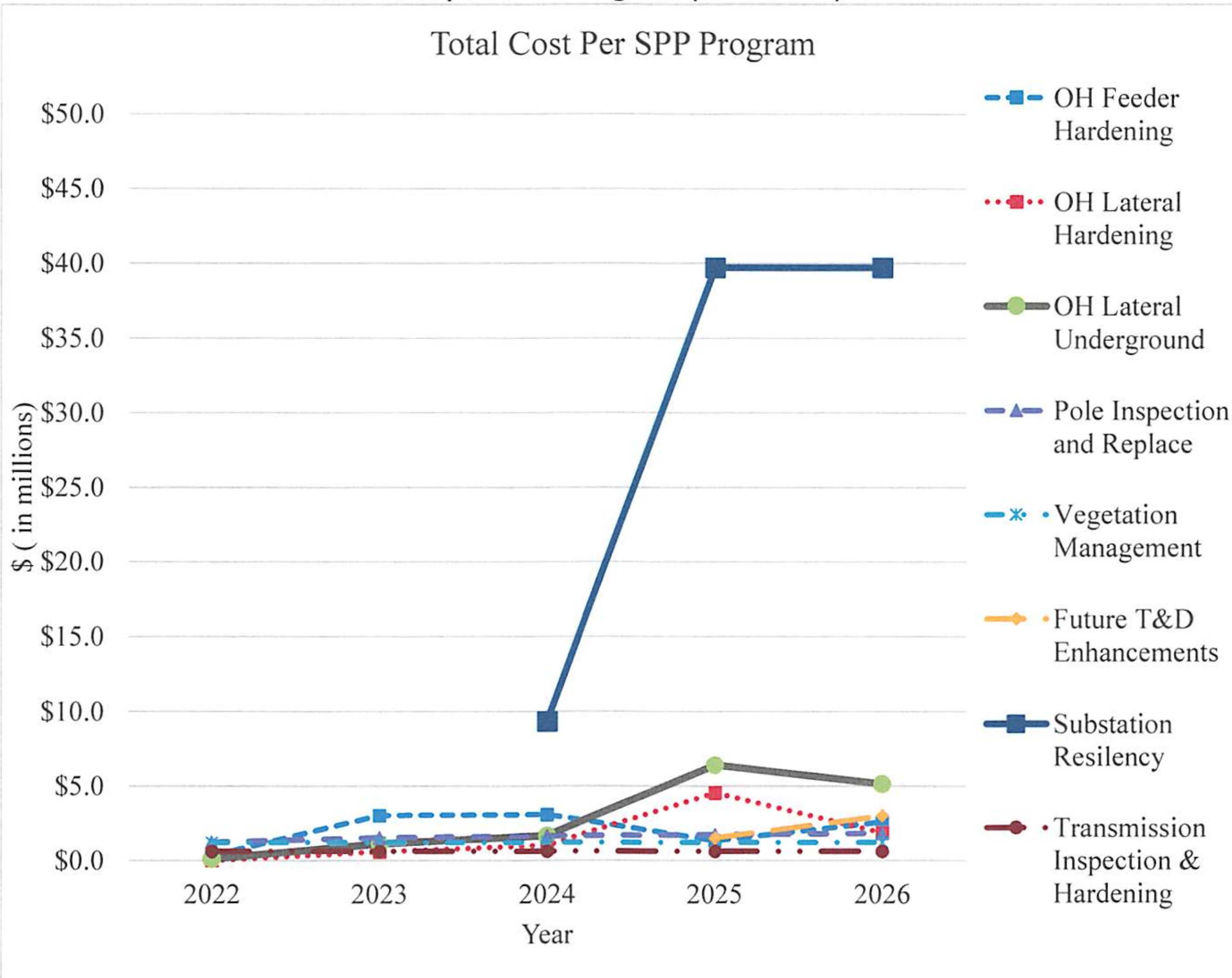
OPC provided alternatives to the proposed implementation of FPUC's SPP that would mitigate rate impacts. It recommended limitations on the expenditures of the Distribution Overhead Lateral Hardening and Undergrounding Programs and elimination of the Future T&D Enhancements Program and the Transmission & Substation Resiliency Program. These will reduce the cost per customer over the 10-years from at least $7,369 to $2,528 in capital cost investment which is still higher than most of the larger utilities in Florida. (OPC BR 18 - 22)

ANALYSIS

Section 366.96(4)(d), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. This issue will address the annual rate impacts for the first three years of the Company's SPP.

Figure 6B-1 is a graph of FPUC's estimated SPP program costs for 2022 through 2026. As shown on the graph, except for the Transmission and Substation Resiliency Program, FPUC's program cost are relatively constant.

Figure 6B-1
Total Cost per SPP Program (2022-2026)



Sources EXH 12, P 44

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 6B-1. The residential rate impact decreases slightly from 2023 to 2024 and increases by approximately 130 percent by 2025.

Table 6B-1
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%

EXH 12, P 39

OPC witness Mara proposes a reduction of capital spending by $159.8 million over the 10-year period. Below, in Table 6B-2, is a summary of his proposed adjustments. (TR 764)

Table 6B-2
Witness Mara's Recommended Program Adjustments

Program	Total 2022-2031 SPP (millions)	Proposed Reductions (millions)	Net 2023-2032 SPP (millions)	Reason for Reduction
Distribution - OH Lateral Hardening	$24.7	($12.6)	$12.1	Limit impact to Customers
Distribution – OH Lateral Undergrounding	$63.3	($31.1)	$32.2	Limit impact to Customers
Future T&D Enhancements	$30.0	($30.0)	-	Does not comply with Rule 25-6.030
Transmission/ Substation Resiliency	$86.1	($86.1)	-	Not prudent

Source: TR 764

As discussed in Issue 10B, staff is recommending that FPUC's Future T&D Enhancements and Transmission & Substation Resiliency Programs be removed from the SPP as these programs do not enhance existing infrastructure. OPC's rate mitigation recommendations for the Distribution Overhead Lateral Hardening Program and the Distribution Overhead Lateral Undergrounding Program are discussed below.

FPUC's 10-year capital budget for its Overhead Lateral Hardening Program is $24.75 million. OPC's witness Mara recommended reducing the capital budget from $24.75 million to $12.1 million for the 10-year period. He stated that his recommendation uses the same budgets proposed by FPUC for the first 3 years (2022 to 2024) and then caps the annual spending for this program to roughly $1.5 million per year for the years 2025 to 2031. (TR 769-770)

FPUC's 10-year capital budget for its Overhead Lateral Undergrounding Program is $63.35 million. Witness Mara recommended reducing the capital budget from $63.35 million to $32.5 million for the 10-year period. Like his recommendation for the Lateral Hardening Program, he uses the same budgets proposed by FPUC for the first 3 years (2022 to 2024) and then caps the annual spending for this program to roughly $4.2 million per year for the years 2025 to 2031.

According to the witness, the basis for his recommended reductions to both Programs is two-fold. First, he asserted that FPUC failed to demonstrate that the benefits to its customers outweighs the costs for hardening or undergrounding overhead laterals. While he acknowledged that in Florida hardening poles and undergrounding laterals will reduce outage costs and outage times, the extent of reductions is unknown for both Programs. Second, FPUC's overall 2022-2031 SPP has a very high cost per customer and according to witness Mara, will result in excessive rates for ratepayers who are also experiencing high inflation pressures. As such, FPUC's proposal should be scaled back. (TR 769-772)

On rebuttal, FPUC witness Cutshaw noted 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. (TR 1583) In fact, the witness stated, laterals on the FPUC system are responsible for approximately 65 percent of the CMI over the analyzed period. He argued that OPC's recommendation to arbitrarily reduce both Programs is contrary to the requirements of the SPP rule to reduce outage times associated with extreme weather events. Witness Cutshaw stated that the overhead laterals were reviewed based upon the Resiliency Risk Model within the SPP to determine which laterals meet the criteria to be included in the early stages of the upgrades and undergrounding. (TR 1584-1585) The witness testified that based on FPUC's proposed plan, assuming both the Overhead Lateral Hardening and Overhead Lateral Undergrounding are approved as submitted, it will take 30 years to accomplish the hardening. However, if the reductions recommended by OPC witness Mara occur, the completion of this work to harden the facilities could be pushed out to approximately 60 years. He continued, "[f]or those customers at the end of the line that is a long delay in achieving the reduced outage times contemplated by the Legislature, particularly given the historical impact of storms in recent years on areas of FPUC's system." (TR 1584-1586)

Staff disagrees with OPC's recommendations to reduce, by approximately half, the capital budgets for FPUC's Distribution Overhead Lateral Hardening Program and its Distribution Overhead Lateral Undergrounding Program. Witness Mara acknowledged that these Programs will reduce outage costs and outage times. His recommendations appear to be based upon his desire to mitigate rates for FPUC's customers. While rate mitigation must be considered by the Commission, there appears to be no basis for the recommended 50 percent reductions. In addition, his recommendations are based upon the total program costs for the 10-year period which is not practical given that the Commission must review a utility's SPP at least every three years as well as conduct annual cost-recovery proceedings. Moreover, the costs for these Programs, and the pace at which FPUC will move forward to implement them, appear reasonable for at least the first three years.

CONCLUSION

The estimated annual rate impact, as provided by FPUC, is projected to increase approximately 130 percent the first three years of its Storm Protection Plan. Staff is not recommending any implementation alternatives to mitigate rates. However, as discussed in Issue 10B, staff is recommending removal of the Future T&D Enhancements and the Transmission and Substation Resiliency Programs from FPUC's SPP because these programs do not enhance existing infrastructure.

Issue 10B: Is it in the public interest to approve, approve with modification, or deny FPUC's Storm Protection Plan?

Recommendation: Staff recommends FPUC's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1B. Staff recommends that FPUC's SPP, with the following modifications, is in the public interest and should be approved: (1) remove the Future T&D Enhancement Program; and (2) remove the Transmission & Substation Resiliency Program. FPUC should file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff. (Lewis)

Position of the Parties

FPUC: Yes, the Commission 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.

OPC: The SPP should be denied and refiled. Alternatively, modify the SPP to limit the 10-year capital budget for the Overhead Lateral Hardening Program and the Overhead Lateral Undergrounding Program and eliminate the 138 kV transmission line project and 69 kV line project, and the Future Transmission and Distribution Enhancements Program.

PARTIES' ARGUMENTS

FPUC

FPUC witness Cutshaw described how the installation of sectionalizing equipment with the use of Supervisory Control and Data Acquisition (SCADA) reduces the cost of service outages. Smart Grid technologies enable a utility to spend less time patrolling lines in search of damage which 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. Presently, FPUC does not have Automated Metering Infrastructure (AMI) installed on its system; therefore, the utility relies upon personnel to physically investigate the system in order to determine the location and cause of each service outage. 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 BR 11)

FPUC testified that its existing 138 kV line, serving Amelia Island, is aging putting customers on the Island at a significantly greater risk for lengthy and costly outages associated with severe weather events impacting the island. Therefore, the new proposed 138 kV line is necessary for gaining an alternative access point on FPL's system which supplies power to FPUC. The witness acknowledged that the length and location of the proposed new 138 kV transmission line is not optimal. In addition, the plan for the Island includes the hardening of an existing 69 kV line and upgrading the serving substation. 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. (FPUC BR 12)

OPC

OPC recommended that FPUC's Future T&D Enhancement Program be removed from its proposed SPP. Specifically, witness Mara indicated, this program is supposed to be done 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 details on full deployment are not yet available. Further, witness Mara testified that this type of distribution automation or smart grid will 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. Therefore, this program does not meet the requirements of the SPP Rule. (OPC BR 11-12)

OPC also recommended that FPUC's Transmission and Substation Resiliency Program be removed from its SPP. OPC argued that the 138 kV transmission line project is not a prudent investment and the 69 kV transmission line project and substation upgrade are investments to access an alternate power source for Amelia Island. These projects should not be considered as storm hardening. (OPC BR 26)

ANALYSIS

Section 366.96(5), F.S., states that the Commission 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 discussed in Issue 1B, staff recommends that FPUC's filing satisfies the requirements of Rule 25-6.030, F.A.C., and provides the Commission with adequate information in order to satisfy its statutory requirements.

As previously discussed, this is the Company'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

OPC witness Mara recommended modifications to four of FPUC's SPP programs. The programs are: Distribution - OH Lateral Hardening; Distribution - OH Lateral Undergrounding; Future T&D Enhancements; and Transmission/Substation Resiliency. Witness Mara's recommendations are summarized in Table 10B-1. (TR 764) Staff previously addressed OPC's specific recommended rate mitigation adjustments for Distribution - OH Lateral Hardening and Distribution – OH Lateral Undergrounding in Issue 6B and addresses the Future T&D Enhancements and Transmission/Substation Resiliency Programs in this issue.

Table 10B-1
Witness Mara's Recommended Program Adjustments

Program	Total 2022-2031 SPP (millions)	Proposed Reductions (millions)	Net 2023-2032 SPP (millions)	Reason for Reduction
Distribution - OH Feeder Hardening	$17.1	-	$17.1	
Distribution - OH Lateral Hardening	$24.7	($12.6)	$12.1	Limit impact to Customers
Distribution – OH Lateral Undergrounding	$63.3	($31.1)	$32.2	Limit impact to Customers
Distribution - Pole Inspection & Replace	$12.6	-	$12.6	
T & D - Vegetation Management	-	-	-	
Future T&D Enhancements	$30.0	($30.0)	-	Does not comply with Rule 25-6.030
Transmission/ Substation Resiliency	$86.1	($86.1)	-	Not prudent
Transmission - Inspection and Hardening	$7.1	-	$7.1	
SPP Program Management	$2.2	-	$2.2	

Source: TR 764

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. (EXH 12, P 14; TR 1616 – 1617) The estimated Program costs are $30 million over the 10-year interval; but expenditures do not begin until after 2024.

OPC witness Mara argued 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 will, at some time in the future, include some kind of distribution automation or smart grid technology; a SCADA will be part of this system, but since this is a "future" program, no specific costs or details on full deployment was provided. (TR 778-779) Second, witness Mara argued that that smart grid additions may reduce outage times but do not reduce outage costs. (TR 759) 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. (TR 779) Since outage costs will not be reduced, the witness asserted this Program fails to meet the criteria in Rule 25-6.030, F.A.C., and should not be included in FPUC's SPP.

FPUC witness Cutshaw refuted OPC's arguments and testified that there are many factors that drive costs during power restoration activities, both during extreme and non-extreme weather events. He noted that witness Mara agreed the devices FPUC may deploy may reduce outage times. However, witness Cutshaw noted that contrary to witness Mara's testimony, these devices also reduce outage costs. (TR 1580) These cost reductions may occur because less time is spent patrolling lines in search of damage or mobilizing and demobilizing resources between grid isolation points. Moreover, witness Cutshaw asserted that when there are thousands of outages present, as there typically are during extreme weather events, these savings quickly multiply. Additionally, witness Mara failed to account for cost savings on the customer's side resulting from eliminated or accelerated restoration times. (TR 1580)

Staff agrees with OPC witness Mara that this program is not fully developed and more importantly, 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, staff does not recommend that the underlying data gathering system is hardening of existing facilities. Therefore, staff recommends that FPUC's T&D Enhancement Program should not be characterized as storm protection pursuant to Rule 25-6.030, F.A.C.

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. (EXH 12, P 34)

FPUC witness Cutshaw explained 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 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). (EXH 12, P 34) 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. (TR 613)

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. Witness Cutshaw argued that while these projects would improve resiliency against extreme weather they would also allow FPUC to leverage the paper mill's cogeneration capacity in times of need. The WestRock Paper Mill produces electricity using steam turbines driven by boilers fed by coal and natural gas. Witness Cutshaw stated that upgrading the transmission line and interconnecting a new substation would allow the mill to be an alternate source of power to the Island in the event the Island was cut off from service from FPL. (TR 776) The estimated costs for the Transmission/Substation Resiliency Program are $88.7 million dollars over the 10-year interval, but no costs are incurred until 2024 with a proposed expenditure of $9.35 million dollars. (EXH 12, P 16, 44)

OPC witness Mara asserted the Transmission and Substation Resiliency Program should not be included in FPUC's SPP. He argued that the proposed new 138 kV transmission line is not necessary or prudent. He explains 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 witness added that research by the Florida PSC found that very few non-wood poles failed during hurricanes. Thus, he maintained, by employing the good maintenance practices described in the 2022-2031 SPP, the existing dual-circuit line would be hardened against extreme wind speeds of 120 mph with Grade B strength factors. (TR 774)

OPC witness Mara next 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. He asserted that the capacity increase for interconnection of a co-generation plant needs to 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. (TR 778) Thus, he argued, FPUC has not demonstrated that this project is necessary to reduce outage times and restoration costs and should be evaluated as a normal business operation project.

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, staff agrees 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 staff agrees that such activity may enhance a utility's transmission system, it does not strengthen existing transmission facilities. Therefore, staff recommends that a new redundant infrastructure project, such as looping substations, should not be characterized as 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, it is 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, staff recommends that the projects included in FPUC's Transmission and Substation Resiliency Program should not be characterized as storm protection activities.

In summary, staff recommends FPUC remove the Future T&D Enhancement Program and the Transmission & Substation Resiliency Program from its proposed SPP. With these two modifications, staff recommends that FPUC's proposed SPP is in the public interest. FPUC should file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff.

CONCLUSION

Staff recommends FPUC's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1B. Staff recommends that FPUC's SPP, with the following modifications, is in the public interest and should be approved: (1) remove the Future T&D Enhancement Program, and (2) remove the Transmission & Substation Resiliency Program. FPUC should file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff.

Issue 11B: Should this docket be closed?

Recommendation: No. As discussed in Issue 10B, FPUC should file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff. Therefore, the docket should remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively. (Trierweiler, Imig)

Position of the Parties

FPUC: Yes.

OPC: The Docket should remain open for FPUC to amend their filing and provide the necessary data for each program as required by Rule 25-6.030, F.A.C., with an opportunity for intervenors to provide review and testimony.

PARTIES' ARGUMENTS

FPUC

No post-hearing position or argument was provided in its brief.

OPC

No post-hearing position or argument was provided in its brief.

CONCLUSION

As discussed in Issue 10B, FPUC should file an amended SPP within 30 days of the issuance of the final order for administrative approval by Commission staff. Therefore, the docket should remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively.

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 System Enhancement
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.

Transmission System Inspection and Hardening

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.

366.96 Storm protection plan cost recovery.—

(1) The Legislature finds that:

(a) During extreme weather conditions, high winds can cause vegetation and debris to blow into and damage electrical transmission and distribution facilities, resulting in power outages.

(b) A majority of the power outages that occur during extreme weather conditions in the state are caused by vegetation blown by the wind.

(c) It is in the state's interest 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.

(d) Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

(e) 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.

(f) All customers benefit from the reduced costs of storm restoration.

(2) As used in this section, the term:

(a) "Public utility" or "utility" has the same meaning as set forth in s. 366.02(8), except that it does not include a gas utility.

(b) "Transmission and distribution storm protection plan" or "plan" means a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management.

(c) "Transmission and distribution storm protection plan costs" means the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan.

(d) "Vegetation management" means the actions a public utility takes to prevent or curtail vegetation from interfering with public utility infrastructure. The term includes, but is not limited to, the mowing of vegetation, application of herbicides, tree trimming, and removal of trees or brush near and around electric transmission and distribution facilities.

(3) Each public utility shall file, pursuant to commission rule, a transmission and distribution storm protection plan that covers the immediate 10-year planning period. Each plan must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. The commission shall adopt rules to specify the elements that must be included in a utility's filing for review of transmission and distribution storm protection plans.

(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.

(5) No later than 180 days after a utility files a transmission and distribution storm protection plan that contains all of the elements required by commission rule, the commission shall determine whether it is in the public interest to approve, approve with modification, or deny the plan.

(6) At least every 3 years after approval of a utility's transmission and distribution storm protection plan, the utility must file for commission review an updated transmission and distribution storm protection plan that addresses each element specified by commission rule. The commission shall approve, modify, or deny each updated plan pursuant to the criteria used to review the initial plan.

(7) After a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence. The commission shall conduct an annual proceeding to determine the utility's prudently incurred transmission and distribution storm protection plan costs and allow the utility to recover such costs through a charge separate and apart from its base rates, to be referred to as the storm protection plan cost recovery clause. If the commission determines that costs were prudently incurred, those costs will not be subject to disallowance or further prudence review except for fraud, perjury, or intentional withholding of key information by the public utility.

(8) The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates and must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

(9) If a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity.

(10) Beginning December 1 of the year after the first full year of implementation of a transmission and distribution storm protection plan and annually thereafter, the commission shall submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a report on the status of utilities' storm protection activities. The report shall include, but is not limited to, identification of all storm protection activities completed or planned for completion, the actual costs and rate impacts associated with completed activities as compared to the estimated costs and rate impacts for those activities, and the estimated costs and rate impacts associated with activities planned for completion.

(11) The commission shall adopt rules to implement and administer this section and shall propose a rule for adoption as soon as practicable after the effective date of this act, but not later than October 31, 2019.

History.—s. 1, ch. 2019-158; s. 30, ch. 2022-4.

25-6.030 Storm Protection Plan.

(1) Application and Scope. Each utility as defined in Section 366.96(2)(a), F.S., must file a petition with the Commission for approval of a Transmission and Distribution Storm Protection Plan (Storm Protection Plan) that covers the utility's immediate 10-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every 3 years.

(2) For the purpose of this rule, the following definitions apply:

(a) "Storm protection program" – a category, type, or group of related storm protection projects that are undertaken to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(b) "Storm protection project" – a specific activity within a storm protection program designed for the enhancement of an identified portion or area of existing electric transmission or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) "Transmission and distribution facilities" – all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors.

(3) Contents of the Storm Protection Plan. For each Storm Protection Plan, the following information must be provided:

(a) A description of how implementation of the proposed Storm Protection Plan will 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.

(b) A description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) 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. Such description must include a general map, number of customers served within each area, and the utility's reasoning for prioritizing certain areas for enhanced performance and for designating other areas of the system as not feasible, reasonable, or practical.

(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.; and

5. A description of the criteria used to select and prioritize proposed storm protection programs.

(e) For the first three years in a utility's Storm Protection Plan, the utility must provide the following information:

1. For the first year of the plan, a description of each proposed storm protection project that includes:

a. The actual or estimated construction start and completion dates;

b. 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;

c. A cost estimate including capital and operating expenses; and

d. A description of the criteria used to select and prioritize proposed storm protection projects.

2. For the second and third years of the plan, project related information in sufficient detail, such as estimated number and costs of projects under every specific program, to allow the development of preliminary estimates of rate impacts as required by paragraph (3)(h) of this rule.

(f) For each of the first three years in a utility's Storm Protection Plan, the utility must provide a description of its proposed vegetation management activities including:

1. The projected frequency (trim cycle);

2. The projected miles of affected transmission and distribution overhead facilities;

3. The estimated annual labor and equipment costs for both utility and contractor personnel; and

4. A description of how the vegetation management activity will reduce outage times and restoration costs due to extreme weather conditions.

(g) An estimate of the annual jurisdictional revenue requirements for each year of the Storm Protection Plan.

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

(i) A description of any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan.

(j) Any other factors the utility requests the Commission to consider.

(4) By June 1, each utility must submit to the Commission Clerk an annual status report on the utility's Storm Protection Plan programs and projects. The annual status report shall include:

(a) Identification of all Storm Protection Plan programs and projects completed in the prior calendar year or planned for completion;

(b) Actual costs and rate impacts associated with completed activities under the Storm Protection Plan as compared to the estimated costs and rate impacts for those activities; and

(c) Estimated costs and rate impacts associated with programs planned for completion during the next calendar year.

Rulemaking Authority 366.96 FS. Law Implemented 366.96 FS. History–New 2-18-20.

Item 6

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 26, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Buys, King, Knoblauch, Ramos) TB
Office of the General Counsel (Trierweiler, Imig) AH

RE: Docket No. 20220050-EI – Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

AGENDA: 10/04/22 – Regular Agenda – Post Hearing Decision - Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: October 8, 2022 - 180-day Statutory Deadline Per 366.96(5), Florida Statutes.

SPECIAL INSTRUCTIONS: Please place Dockets Nos. 20220048-EI, 20220049-EI, 20220050-EI, and 20220051-EI in consecutive order on the Agenda.

Table of Contents

Case 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 a plan, that contains all the elements required by Commission rule, the Commission must determine whether it is in the public interest to approve, approve with modification, or deny the plan. Section 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. Further, this section requires the Commission conduct an annual proceeding, referred to as the storm protection plan cost recovery clause (SPPCRC), to determine the utility's prudently incurred SPP costs.

Duke Energy Florida, LLC (DEF) filed its first SPP on April 10, 2020 in Docket No. 20200069-EI. The Office of Public Counsel (OPC), Walmart, Inc. (Walmart), Florida Industrial Power Users Group (FIPUG) and White Springs Agricultural Chemical, Inc. d/b/a/ PCS Phosphate (PCS) were granted intervention. This matter was set for an administrative hearing; however, prior to the hearing DEF entered into a Settlement Agreement with OPC, PCS, and Walmart.[1] An administrative hearing was held on August 10, 2020 for the Commission to hear oral argument from the parties in support of the Settlement Agreement, to admit testimony and documentary evidence into the record, and to consider the Settlement Agreement. The Commission approved the Settlement Agreement by Order No. PSC-2020-0293-AS-EI, issued August 28, 2020, in Docket No. 20200069-EI.

Key provisions of the 2020 Settlement are:

- DEF will file its updated SPP for the period 2023-2032, and that DEF will not materially expand the scope of the programs and associated expenditures it seeks to recover for the years 2020-2022 beyond those that are included in the estimates provided in specific documents, and as modified in the filing made on July 24, 2020, in the SPPCRC docket.
- DEF will base its requests for cost recovery through the SPPCRC for the years 2023, 2024 and 2025 on the SPP update to be filed in 2022.

On January 1, 2021, DEF filed a petition for limited proceeding to approve another settlement agreement which included general base rate increases (2021 Settlement Agreement). On June 4, 2021, by Order No. PSC-2021-0202-AS-EI, the Commission approved the 2021 Settlement Agreement between DEF, OPC, FIPUG, PCS Phosphate, and Nucor Steel Florida, Inc. Two scrivener's errors were corrected by an amendatory order, Order No. PSC-2021-0202A-AS-EI, issued on June 28, 2021. Paragraph 4 of the 2021 Settlement Agreement states:

[1] FIPUG took no position on the Joint Motion for Expedited Approval of a Stipulation and Settlement Agreement.

> The Parties agree that DEF has properly removed all costs associated with the Storm Protection Plan ("SPP") from the costs included in DEF's MFRs, attached hereto as Exhibit 1, as all such costs spent on approved SPP programs are properly recoverable through the SPP Cost Recovery Clause 9 "SPPCRC."

On April 11, 2022, DEF filed its proposed SPP for Commission approval which covers the period of 2023-2032 and included the same ten programs as its 2020 SPP. A description of the ten programs is provided in Attachment A. FIPUG, Nucor, OPC, PCS Phosphate, and Walmart were granted intervention in this docket. An administrative hearing was held on August 2-4, 2022.[2] Post hearing briefs were filed on September 6, 2022. OPC, FIPUG, Nucor, and PCS (Joint Parties) filed a joint brief which included a procedural matter which is addressed below.

Procedural Matter

On pages 28-37 of their post-hearing brief, the Joint Parties unilaterally inserted a "post-hearing legal issue" that was not listed in the Prehearing Order.[3] The Joint Parties argue in this post-hearing issue that the Commission should reverse a prehearing ruling, set forth in Order No. PSC-2022-0292-PCO-EI, where the Prehearing Officer granted motions to strike portions of the prefiled testimony of OPC witness Lane Kollen. In staff's 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 was denied by the full Commission. Because the evidentiary concerns relating to the testimony of witness Kollen have twice been addressed on the merits, staff believes it is appropriate to discuss the Joint Parties' "post-hearing legal issue" here only as it raises procedural concerns. For the reasons set forth below, staff believes there is no procedural error that that Commission 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 the Joint Parties, were given full opportunity to present argument on all relevant issues in the case and to conduct cross-examination of all witnesses on the case's relevant issues both in the case in chief and in the proffered portions of the hearing. (TR 44).

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 the Commission's 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 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. (TR 824-853). 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

[2] DEF's docket was consolidate with the SPP dockets for TECO (20220048-EI); FPUC (20220049-EI) and FPL (20220051-EI) for hearing purposes only.

[3] Order No. PSC-2022-0291-PHO-EI, issued August 1, 2022.

though read. (TR 854-886). 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. (TR 802-808). Although the Commission ultimately decided to strike the OPC Witness testimony, OPC was provided an opportunity to make its legal argument at the administrative hearing (TR 798-810), and in its motion for reconsideration. OPC made its arguments again in its post-hearing brief.

The Joint Parties also argue that a Commission Final Order applying Rule 25-6.030, 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." (Joint Parties BR 36) The cases cited by the Joint Parties in support on this argument all address judicial review of the constitutionality of statutes.[4] As an agency, the Commission has no jurisdiction to declare a statute unconstitutional. Moreover, following the passage of Article V, Section 21, of the Florida Constitution, the Commission's interpretation of a statute will not be relevant to a court vested with jurisdiction to consider that constitutional question.

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

There are 8 issues addressed below for the Commission to consider.[5] The Commission has jurisdiction in this matter pursuant to Section 366.96, and Chapter 120, F.S.

[4] 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)).
[5] DEF's issues are 1C-6C, 10C, and 11C. Issues 7-9 are FPL only issues.

Discussion of Issues

Issue 1C: Does DEF's Storm Protection Plan contain all of the elements required by Rule 25-6.030, Florida Administrative Code?

Recommendation: Yes, DEF appears to have met the criteria and intent of the SPP Rule with its filing and the Commission has adequate information in order to satisfy its statutory requirements. (Imig, Trierweiler, Knoblauch)

Position of the Parties

DEF: Yes, DEF's 2023-2032 Storm Protection Plan includes all of the elements required by Rule 25-6.030, Florida Administrative Code.

JOINT PARTIES: No. DEF provided verifiable program costs; however, claimed benefits information was not properly presented for determination of plan approval, modification, or rejection. Societal benefits in the form of restoration cost avoidance are highly subjective estimates of customer value of avoided outages and should not be used for plan approval determinations. DEF also improperly seeks to include fictitious "capital cost savings" in its cost-effectiveness analysis. DEF failed its burden of proving cost-effectiveness of proposed SPP programs.[6]

WALMART: No. Walmart adopts the position of OPC

PARTIES' ARGUMENTS

DEF

DEF argued its proposed 2023 SPP meets all filing requirements of Rule 25-6.030, F.A.C., and that DEF has shown by a preponderance of the evidence that its SPP is in the public interest because the SPP meets the Legislature's intended goals of reducing restoration costs and outage times to customers. (DEF BR 6) DEF stated that its proposed Plan is expected to reduce average annual storm restoration costs by over $50 million, while reducing average annual customer minutes of interruption by close to 400 million minutes. (DEF BR 6) DEF argued that all of its SPP programs reduce restoration costs and outage times and should be approved without modification. (DEF BR 17)

JOINT PARTIES

The Joint Parties argued that DEF's SPP provided an analysis of costs and benefits. However, the Joint Parties argue that DEF "superficially addressed" the key elements for program's costs and benefits. The Joint Parties argued DEF's SPP relies on highly inflated and unsubstantiated societal benefits. (Joint Parties BR 4)

WALMART

Walmart adopted the position of OPC. (Walmart BR 3)

[6] All positions on Issues 1C-6C, and 10C are subject to the agreement to allow costs shown at TR 685 of Kevin Mara's amended Direct Testimony in the table with the notation "Does not comply with 25-6.030," for the recovery periods 2023 and 2024.

ANALYSIS

<u>History</u>
The first utility storm hardening programs were filed for Commission approval in 2007 and were reviewed by the Commission 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."[7] Subsection 366.96(3), F.S., requires each IOU to file a transmission and distribution SPP for the Commission's review and directs the Commission 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.

The Commission promulgated two Rules, 25-6.030, F.A.C., Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Cost Recovery, to implement and administer Section 366.96, F.S. The full text of Section 366.96, F.S., and Rule 25-6.030, F.A.C., are provided as Attachment B. In 2020, DEF's first storm protection plan, which was primarily an extension of the Utility's existing storm hardening plan, was approved.

<u>Issue</u>
The primary issue raised by the Joint Parties is that the information that DEF provided to demonstrate its comparison of costs and benefits was flawed. The Joint Parties argued DEF's SPP included "fictitious capital costs savings" in its analysis and referred the Commission to its arguments for Issue 2 and 5 for further argument. (Joint Parties BR 4). It appears the Joint Parties' arguments in Issue 1 are about the methodology of DEF's SPP. For the reasons set forth below, Staff believes DEF provided adequate information for the Commission to evaluate DEF's SPP.

<u>Law</u>
Section 366.96(4), F.S., provides:

> 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.

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[7] 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.

The statute further articulates that the Commission must use the public interest standard when considering a SPP. *See* § 366.96(5), stating that the Commission shall determine whether it is in the public interest to approve, modify, or deny the plan. Accordingly, Rule 25-6.030, F.A.C., requires utilities to file certain minimum information in order for the Commission to determine if it is in the public interest to approve, approve with modifications, or deny a utility's storm protection plan. In other words, Rule 25-6.030, F.A.C., is a filing requirement rule, not a standard for the Commission's decision. As such, the rule allows the utilities to have the flexibility to submit and manage their hardening plans while simultaneously requiring a utility file the information necessary for the Commission to make a determination about whether it is in the public interest to approve a plan, approve a plan with modifications, or deny a plan.

Rule 25-6.030(3), F.A.C., Storm Protection Plan, identifies the specific information to be included in each IOU's SPP.[8] Rule 25-6.030(3)(d), F.A.C., requires, in relevant part, a comparison of costs and benefits:

> 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.

<u>Staff Analysis</u>
Rule 25-6.030(3)(d), F.A.C., requires "...a comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in 3(d)1." The Joint Parties argued that DEF's data was insufficient for the Commission to make a determination on outage times and reduction of costs.[9] (Joint Parties BR 4) Staff disagrees.

While the nature of cost data is objective, benefits in the context of storm hardening specifically, may require various forms description and analysis to ascertain. Staff believes that utility should have the flexibility to use a methodology that it believes most clearly demonstrates the benefits of a SPP. The Joint Parties' argument, however, does not take into account 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

[8] Specific elements of Rule 25-6.030, F.A.C., such as areas for prioritization and rate impacts, are discussed in more detail in Issues 2C through 6C.
[9] Thus, Staff's recommended denials/recommended revisions to DEF's SPP in Issues 6C and 10C are not based on any defect in filing requirements under Rule 25-6.030, F.A.C.

extreme weather conditions. Section 366.03, F.S. This means that storm hardening costs may or may not produce actual financial benefits that exceeds costs during a given time, depending on a particular utility's circumstances.[10]

This is why Section 366.96(4)(a), F.S., provides the flexibility for IOUs to submit and manage their hardening plans so long as the plans include projects that effectively "reduce restoration costs and outage times associated with extreme weather events and enhance reliability" for customers. For these reasons, staff believes that a utility should have the option to submit what it deems is its most accurate data or analysis of costs or benefits for the Commission's consideration.

In this case, DEF's SPP met the filing requirements Rule 25-6.030, F.A.C., because DEF provided adequate information to analyze the costs and benefits of its SPP. DEF provided sufficient program cost information for the Commission to make a determination concerning DEF's SPP's potential to reduce outages or restoration time, as well as to effectively evaluate the resulting rate impact from the SPP. DEF's SPP is anticipated to reduce storm restoration costs by over $50 million on average per year and reduce customer minutes of interruption by close to 400 million minutes on average per year. (DEF BR 6) Additionally, the reduction in restoration costs and outage times for each proposed program was provided in DEF's SPP. For example, DEF's Feeder Hardening Program is expected to reduce restoration costs by $15 to $18 million annually and reduce customer minutes of interruption by approximately 111 to 139 million minutes annually once the program is complete. (EXH 3, P 9) This information allows the Commission to evaluate the potential of the SPP to mitigate outages and reduce restoration costs. For these reasons, staff believes that DEF's SPP provides the Commission with adequate information necessary to make a public interest determination pursuant to Section 366.96, F.S.

CONCLUSION

Staff recommends that DEF met the filing requirements required by Rule 25-6.030, F.A.C., and that the Commission has adequate information necessary to make a public interest determination pursuant to Section 366.96, F.S.

[10] 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) there are no monetized benefits to the general body of customers. 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.

Issue 2C: To what extent is DEF's Storm Protection Plan expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability?

Recommendation: DEF utilized the Guidehouse model to support its 2023 SPP program evaluation and prioritization. The results of this model demonstrate that DEF's SPP is projected to reduce restoration costs and outage times associated with extreme weather events. (Knoblauch)

Position of the Parties

DEF: As detailed in Exhibit No. 4, after full deployment of DEF's 2023 SPP, DEF projects an average, annual reduction in outage times of approximately 399.4 million customer minutes of interruption, as well as average, annual reduction in restoration costs of approximately $56.5 million. Program-specific reductions in outage times and restoration costs are shown on Exhibit No. 3.

JOINT PARTIES: Some core proposed programs related to transmission, distribution and lateral hardening and/or undergrounding will have a better impact on reducing outage times and lowering restoration costs than will other programs. Several programs are routine maintenance and not do not qualify as storm hardening functions and thus are not SPP-eligible. Staging-related storm restoration costs will not be reduced, forcing customers to continue bearing such costs in pursuit of diminishing returns of ever faster – but cost-ineffective – storm restoration time.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

DEF

DEF argued that although it disagrees with OPC's interpretation of the SPP Rule, if the Commission were to agree with OPC, the Company's 2023 SPP should still be approved. (DEF BR 16) DEF argued its Self-Optimizing Grid (SOG) Program will reduce storm related outages, as well as restoration costs by allowing the Company the ability to direct resources to an area more efficiently. (DEF BR 17) DEF argued its Underground (UG) Flood Mitigation Program is expected to reduce restoration costs and outage times. Additionally, DEF argued that it disagrees with OPC's claim that the UG Flood Mitigation Program is merely replacement of aging infrastructure and asserted that storm hardening could include the replacement of existing infrastructure. (DEF BR 18)

For the Transmission Structure Hardening Program, DEF argued that this program provides quantifiable reductions in restoration costs and outage times, and is critical to its SPP, including each sub-program. (DEF BR 19-20) These include: (1) Tower Upgrade Sub-program – towers will be upgraded to the latest National Electrical Safety Code (NESC) and internal construction standards and not due to a design flaw; (2) Tower Cathodic Protection Sub-program – will reduce the chances of a tower failing and thus avoiding customer outages; (3) Overhead Ground Wire (OHGW) Sub-program – protecting infrastructure from extreme weather can reduce restoration costs and outage times; and (4) Gang Operated Air Break (GOAB) Switch

Automation Sub-program – will allow customer interruptions to be minimized, making restoration efforts more targeted. (DEF BR 20-22)

DEF argued its Transmission Substation Flood Mitigation Program will mitigate the risk of flood damage to vulnerable substations, which will reduce both restoration costs and outages. Further, DEF argued that its system was built to existing standards at the time of construction, and it continues to assess vulnerable areas by utilizing updated FEMA flood plains and over 200 years of storm data. (DEF BR 23) For its Transmission Loop Radially Fed Substations Program, DEF argued that the program creates a more networked, resilient system that will reduce customer outages and restoration costs. (DEF BR 23-24) DEF argued its Transmission Substation Hardening Program targets assets that are more vulnerable to failure and by speeding up restoration times, it will reduce restoration costs in the form of reduced contractor payments. (DEF BR 24-25) For its SPP, DEF argued that each of its programs contribute to reducing outage times and restoration costs, and even using OPC's description of the SPP Rule, all programs should be included in its 2023 SPP. (DEF BR 25-26)

JOINT PARTIES

The Joint Parties argued that the statute and rule require that programs reduce both storm restoration costs and outage times. (Joint Parties BR 4) DEF's plan incorporates aging infrastructure and general improvements, which may increase the grid's resiliency, but the Commission should require utilities to conform to narrower objectives as described in the SPP Statute. (Joint Parties BR 6) The Joint Parties argued that six of DEF's programs were in dispute for failing to meet the SPP Rule requirements. (Joint Parties BR 10) Those programs, excluding the Loop Radially-Fed Substation Program which does not start until 2025, were subject to the 2020 SPP Stipulation and the 2021 Stipulation. (Joint Parties BR 10-11) The 2021 Stipulation addresses program cost recovery through the SPPCRC for 2022 and 2023, and the Joint Parties concede that though not expressly discussed, year 2024 would also be encompassed. (Joint Parties BR 12)

The Joint Parties argued that OPC witness Mara testified to several examples of programs that are ineligible for inclusion in DEF's SPP. (Joint Parties BR 13) Specifically, the SOG Program is a sectionalizing program that does not reduce restoration costs or outage times. The Joint Parties argued that while DEF asserted the SOG Program does reduce outages, DEF argued the SOG Program would not reduce restoration costs. Thus, it does not meet the requirements of the SPP Statute and SPP Rule but is instead for "blue sky" reliability purposes, which should be recovered through base rates. (Joint Parties BR 13) For DEF's Transmission Structure Hardening Program, the Joint Parties argued that some of the sub-programs do not meet the SPP Statute and SPP Rule. The sub-programs and reasoning for exclusion are: (1) GOAB Switch Automation Sub-program – does not reduce restoration costs; (2)Tower Upgrade Sub-program – replacement of towers due to age or design flaws, which DEF has an obligation to replace beyond the SPP Statute; (3) Tower Cathodic Protection Sub-program – extends the life of an asset but does not reduce both restoration costs and outage times; and (4) OHGW Sub-program – part of routine maintenance and no evidence that it will reduce restoration costs and outage times. (Joint Parties BR 13-16)

The Joint Parties argued DEF's Transmission Substation Hardening Program is another example of replacing aging infrastructure, and OPC witness Mara testified that it does not reduce restoration costs or outage times. (Joint Parties BR 16) For the Transmission Loop Radial-Fed Substation Program, the Joint Parties argued that looping should be a lower priority compared to hardening transmission poles, and the program also does not reduce restoration costs. (Joint Parties BR 16-17) Further, the Transmission Loop Radial-Fed Substation Program is not currently being implemented and hence, is not covered by the 2021 Stipulation. (Joint Parties BR 17)

WALMART

Walmart adopted the position of OPC. (Walmart BR 3)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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. As discussed in Issue 1C, 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.

DEF witness Lloyd testified that a similar process used for its 2020 SPP was also used for its 2023 SPP. (TR 126) DEF started with the same programs from its 2020 SPP, and utilized a model developed by Guidehouse to support its 2023 SPP program evaluation and prioritization. (TR 125-126) The Guidehouse model applied a three-tiered modeling and analysis approach, comprised of:

- Risk Model
- Prioritization / Benefit-Cost Analysis (BCA) Model
- Decision Analysis

(EXH 4, P 22)

The inputs to the model incorporated locational risk probabilities, outage data, asset data, and detailed program definitions. This information and others were then used to model the locational impacts of extreme weather conditions and the anticipated reduction in restoration costs and outage times. (EXH 4, P 4) The estimated reductions in outage times and restoration costs were provided in DEF's SPP on a program-level basis. (EXH 3, P 9, 18, 28, 32, 41, 47, 49, 52) For the outage times, witness DEF Lloyd testified that customer minutes of interruption (CMI) were used as a proxy for duration. (TR 127). DEF estimated that once a program is complete, the reduction in CMI for each program will range between approximately 900,000 to 439 million minutes annually, depending on the program. (EXH 3, P 9, 18, 28, 32, 41, 47, 49, 52)

In its brief, the Joint Parties argued that although some of DEF's programs will have an impact on outage times and restoration costs, many of the programs are not storm hardening and do not meet the requirements of the SPP Rule. (Joint Parties BR 4) OPC's arguments and staff's analysis of the requirements of the SPP Rule are discussed in more detail in Issue 1C. OPC also argued that these programs were merely routine maintenance projects for an electric utility, and they should not be included in the Company's SPP. (Joint Parties BR 4, 6) This argument by OPC will be addressed in Issue 10C. All other intervening parties in this docket adopted the position of or agreed with OPC and, as such, no other argument was raised by an intervening party for this issue.

Staff believes that DEF provided the necessary information to meet the requirements of the SPP Statute and Rule related to this issue. Using the Guidehouse model to incorporate data specific information to its transmission and distribution facilities, the Company estimated the reduction in outage times and restoration costs that would result from the implementation of its proposed SPP programs. Based on the results of the model, DEF demonstrated that its proposed programs may reduce restoration costs and outage times associated with extreme weather events and may enhance reliability.

CONCLUSION

DEF utilized the Guidehouse model to support its 2023 SPP program evaluation and prioritization. The results of this model demonstrate that DEF's SPP is projected to reduce restoration costs and outage times associated with extreme weather events.

Issue 3C: To what extent does DEF's Storm Protection Plan prioritize areas of lower reliability performance?

Recommendation: DEF's SPP appears to prioritize areas of lower reliability performance. (Knoblauch)

Position of the Parties

DEF: The prioritization methodology for each SPP Program includes the "Probability of Damage" from extreme weather events for each major asset component. Historical reliability performance of these assets is correlated with simulated future weather exposure conditions. This technique prioritizes areas of lower reliability performance. This is more fully described in Exhibit No. 3.

JOINT PARTIES: DEF has several proposed projects that prioritize areas of lower reliability performance; however, many of these programs and projects either do not qualify as permissible SPP programs or projects and/or are not economically justifiable.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

DEF

DEF did not provide a specific argument for Issue 3C in its brief.

JOINT PARTIES

The Joint Parties stated that they did not have a specific concern with DEF's geographic prioritization efforts, and this issue did not factor into the objections raised by the Joint Parties regarding the spending of the SPP. (Joint Parties BR 17)

WALMART

Walmart adopted the position of OPC. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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)1.d, F.A.C., requires a description of the criteria used to select and prioritize proposed SPP projects be provided.

DEF Witness Lloyd testified that a model was used for the Company's program evaluation and prioritization as was used with DEF's prior SPP. (TR 126) The model developed by Guidehouse and used by DEF applied a three-tiered modeling and analysis approach. (EXH 4, P 22)

- Risk Model
- Prioritization / Benefit-Cost Analysis (BCA) Model

- Decision Analysis

For the risk model and prioritization, a range of information at each location was utilized including asset data, historic outage data, risk data, and National Oceanic and Atmospheric Administration (NOAA) weather station data. Using this information, the Guidehouse model estimated the probabilistic failures before and after the storm hardening programs were implemented. (EXH 4, P 26)

The BCA model uses outputs from the risk model and other information to analyze the benefits and costs for each combination of program and location. (EXH 4, P 23) The BCA results were used for prioritization and for the deployment plan of the programs. (EXH 4, P 30) Based on the BCA results, a decision analysis was performed which was a high-level prioritization of projects. However, this high-level prioritization did not account for constraints like work crew availability, site-specific engineering considerations, and other prioritization factors. (EXH 4, P 23) Therefore, utilizing the results of the model, as well as taking into account factors such as multiple projects in the same area, critical customers, operational knowledge, and resource availability, DEF's subject matter experts were able to optimize the deployment plan. (EXH 3, P 9; EXH 3, P 41)

In its brief, the Joint Parties argued that DEF's geographic prioritization did not factor into its objections regarding the SPP spending. (Joint Parties BR 17) OPC witness Mara testified that with unchecked spending on SPP programs, an excessive burden will be placed on the rate payers. Therefore, a higher priority should be placed on equipment that is most vulnerable to extreme storms, such as feeders, laterals, and poles, which provides greater benefit in the early stages of implementation. (TR 686) Witness Mara argued this same point for DEF's transmission system, stating that if the Company put "a higher priority on strengthening the radial taps, the proposed looped transmission lines are not necessary to achieve storm hardening." (TR 711)

In rebuttal, DEF witness Lloyd testified that DEF first prioritized projects in the most vulnerable areas. (TR 1341) Nevertheless, customers who are served by circuits that are less vulnerable can still be impacted by extreme weather events. Witness Lloyd asserted that these types of customers "should have the opportunity for their circuits to be hardened even if the benefits to cost ratio is lower than higher prioritized projects." (TR 1342) Additionally, witness Lloyd testified that the appropriate funding level, which includes the acceptable level of customer bill impact, was an explicit limitation on a program scope. (TR 1340) The analysis of the rate impact and program limitation will be further discussed in Issue 6C.

Staff agrees with the concept presented by witness Mara of targeting the most vulnerable equipment that impacts the greatest number of customers. Laterals typically affect a small number of customers, unlike transmission that can impact thousands. That being said, staff does believe DEF's SPP prioritizes areas of lower reliability performance. DEF described the method and criteria it used to select and prioritize the proposed SPP projects while utilizing its three-tiered modeling and analysis approach. In addition to the results of the Guidehouse model, DEF also relied on its subject matter experts for further analysis and prioritization of the projects. As discussed above, the Joint Parties did not dispute that DEF's proposed projects prioritized areas of lower reliability. Instead, OPC disagreed with inclusion of several of DEF's programs and projects due to cost or qualification as a SPP program. These items are discussed further in

Issues 6C and 10C. Thus, staff believes that DEF demonstrated its prioritization of SPP projects in areas of lower reliability performance.

CONCLUSION

DEF's SPP appears to prioritize areas of lower reliability performance.

Issue 4C: To what extent is DEF's Storm Protection Plan regarding transmission and distribution infrastructure feasible, reasonable, or practical in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas?

Recommendation: With the exceptions discussed in Issues 6C and 10C, DEF's SPP appears feasible, reasonable, and practical within the Company's service territory. (Knoblauch)

Position of the Parties

DEF: DEF's SPP is feasible, reasonable, and practical throughout the Company's service territory. The model used to produce DEF's SPP, detailed in Exhibit No. 3 and Exhibit No. 4, considered the geographic location and characteristics of each asset as part of the analysis of the feasibility and reasonableness of implementing the various SPP Programs at each given location.

JOINT PARTIES: A number of programs in flood zones that DEF has proposed for SPP inclusion would, absent the 2021 Stipulation, be more appropriately addressed in a base rate case since they do not harden the system from extreme storm events. Many of these programs fail the Two-Prong test.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

DEF

DEF did not provide a specific argument for Issue 4C in its brief

JOINT PARTIES

The Joint Parties argued that the focus of their objections related to the lack of compliance of DEF's 2023 SPP with the SPP Statute and SPP Rule. The Joint Parties argued that the specific language "feasible, reasonable, or practical" is not a statutory test for determining prudence or public interest of a plan but relates to the "physical viability of plan components." (Joint Parties BR 18)

WALMART

Walmart adopted the position of OPC. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(b), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 SPP, DEF provided a map of its service territory, which included the number of customers served within each area. (EXH 5) Witness Lloyd testified that the Company did not determine any areas of its service territory in which it would not be feasible, reasonable, or practical to execute SPP projects. (TR 125) Further, witness Lloyd stated that DEF utilized a model to estimate the reduction in storm damage and outage duration for potential project locations. The model could then prioritize work by looking at the probability of damage to specific assets and the consequences of that damage, such as the number and/or type of customers served by a particular asset. The model allowed DEF to prioritize the projects over the life of a program, putting the highest benefit work first. Additionally, the outcome from the model was then evaluated by DEF subject matter experts for further analysis and prioritization. (TR 127)

As mentioned above, the Joint Parties argued that the language "feasible, reasonable, or practical" relates to the physical viability of a plan and is not used for determining prudence or public interest. (Joint Parties BR 18) OPC witness Mara testified that DEF's Underground Flood Mitigation Program appeared to be the replacement of aged assets, rather than flood mitigation. (TR 699) Witness Mara stated that it is more appropriate for the replacement costs of aged assets to be recovered through base rates as to prevent double counting of a unit. (TR 699) Another program that witness Mara identified as problematic was the Substation Flood Mitigation Program. Witness Mara testified that flood maps were issued in 1973; therefore, substations constructed after 1973 should have been designed to account for potential flood waters. (TR 708) Additionally, in instances where a transformer is de-energized due to flooding, the load from that substation could likely be switched to an adjacent substation that is not flooded. In such a case, the Substation Flood Mitigation Program would not reduce outage times or restoration costs. Witness Mara stated that DEF had "not had any outages due to flooding of its substations in recent years." (TR 709)

Absent a provision in DEF's 2021 Settlement Agreement,[11] witness Mara stated that he would recommend excluding the Underground Flood Mitigation Program from the Company's SPP, and would recommend including the Substation Flood Mitigation Program on a limited basis. (TR 700-701, TR 709-710) More specifically, for the Substation Flood Mitigation Program, witness Mara recommended excluding any substation where there is an alternate feed to the substation or for any substation that has not had a history of flooding or where flooding does not present a threat. (TR 709-710) However, witness Mara acknowledged that by excluding these costs, it would likely eliminate the entire 10-year budget for the Substation Flood Mitigation Program. (TR 710) Despite witness Mara's objections, the 2021 Settlement Agreement includes a provision that the costs incurred within DEF's SPP are properly recovered through the

[11] Order No. PSC-2021-0202A-AS-EI, issued June 28, 2021, in Docket Nos. 20190110-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Michael and approval of second implementation stipulation, by Duke Energy Florida, LLC,* 20190222-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Dorian and Tropical Storm Nestor, by Duke Energy Florida, LLC,* 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*

SPPCRC for cost recovery years 2023-2024, and these costs were removed from base rates. (TR 685, 1345) For this reason, witness Mara testified that his recommendations should not be considered for the rate recovery years 2023-2024 where they conflict with the provisions of the settlement agreement. (TR 685)

In his rebuttal testimony, DEF witness Lloyd testified that the focus of the Underground Flood Mitigation Program is to target existing underground distribution facilities in areas that are prone to storm surge during extreme weather events. While the program could include the replacement of aging equipment, that is not the objective of the program. (TR 1350) The Underground Flood Mitigation Program instead is replacing existing conventional switchgears with submersible switchgears, which are designed to withstand potential storm surges and flood waters. (TR 1351) Minimizing asset damage caused by storm surge will result in reduced customer outages and, according to DEF's SPP, expedite restoration after the storm surge has receded. (EXH 3, P 32)

In rebuttal to witness Mara's testimony regarding the Substation Flood Mitigation Program, witness Howe testified that all DEF substations were built to the existing standards in the year that they were installed. Additionally, the program targets substations at the highest risk of flooding using the most current 100-Year Federal Emergency Management Agency (FEMA) flood plain, which is reviewed and updated on a continuous basis. (TR 1276) Therefore, a substation built with an approved design at the time of construction could be "reclassified" in the future where the design is no longer sufficient for that location. OPC witness Howe testified that the model utilized for the Substation Flood Mitigation Program uses historical data to evaluate substations in the flood plain, along with further analytics to determine prudency and cost-effective measures for mitigation. Regarding witness Mara's assertions on substations without a history of flooding, witness Howe testified that witness Mara only examined three-years of flood data, which is not sufficient to prudently plan for the long-term functionality and service of a substation. (TR 1277)

Staff believes DEF has met the requirements of Rule 25-6.030(3)(c), F.A.C., by providing a map of its service area, the number of customers served within each area, and the methodology of prioritizing projects within its programs. While staff agrees with witness Mara that the replacement of aged assets does not always equate to storm hardening, witness Lloyd indicated that the new assets for the Underground Flood Mitigation Program are designed to withstand potential storm surges and flood waters. The implementation of the new assets, which are better equipped to withstand extreme weather events, will mitigate outages and reduce restoration time. For the Substation Flood Mitigation Programs, witness Mara did not present any specific outage or performance data for substations with alternate feeds. He stated that these substations could "likely" be switched to an adjacent substation not experiencing flood conditions; however, witness Mara did not identify any specific substations where this had occurred or could occur in the future. Given the variability of extreme weather events, it is not clear that a scenario as described by witness Mara of an available, unaffected, adjacent substation is reasonable to assume given the limited information.

Additionally, based on witness Howe's testimony, witness Mara only examined a limited amount of flood history data for DEF. Regarding rural customers, witness Lloyd testified at the hearing that when considering projects in low density areas, it is "necessary that those rural customers still get an opportunity to have hardened assets." (TR 1355-1356) While witness Mara presented testimony on the Underground and Substation Flood Mitigation Programs, his recommendations are superseded by the 2021 Settlement Agreement, which the witness did not dispute. Staff recognizes that the 2021 Settlement Agreement includes a provision that these program costs are properly recovered through the SPPCRC; however, staff believes these programs also meet the requirements of the SPP Rule. In view of the information presented in DEF's SPP and witness testimony, specifically on the Underground and Substation Flood Mitigation Programs, staff believes DEF's SPP is reasonable in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas.

CONCLUSION

With the exceptions discussed in Issues 6C and 10C, DEF's SPP appears feasible, reasonable, and practical within the Company's service territory.

Issue 5C: What are the estimated costs and benefits to DEF and its customers of making the improvements proposed in the Storm Protection Plan?

Recommendation: The estimated costs of DEF's SPP programs are shown in Table 5C-1. The estimated benefits, characterized by the reduction in CMI, are discussed in Issue 2C. (Knoblauch)

Position of the Parties

DEF: The estimated benefits are provided in DEF's position on Issue 2C, and the estimated costs are shown on Exhibit No. 3, page 56.

JOINT PARTIES: DEF's SPP costs are accepted only for qualification purposes, but no reliable, objective benefits are reasonably and accurately quantified in terms of dollars. None of the DEF programs present benefits that exceed the costs when the cost/benefit analyses are corrected. Programs not economically justified are not prudent, and their costs would be imprudent and unreasonable. These programs should not be allowed in the SPP, subject to the 2021 Stipulation, where applicable.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

DEF

DEF argued that based on OPC's assertions, none of the utilities' proposed SPP Programs had benefits that outweighed the costs or were cost-effective. DEF argued that it had provided a benefit/cost analysis, though OPC took issue with the Company's utilization of the Interruption Cost Estimator (ICE) to assign a value to the avoided CMI. OPC witness Kollen had testified that quantifying a societal value of customer interruptions is subjective; however, DEF argued that OPC had insisted that a quantification of the estimated benefits was needed. (DEF BR 15) DEF argued that it did perform a quantification of the benefits, as OPC argued was required by the SPP Rule, and showed its SPP's benefits exceeded the costs. (DEF BR 16)

JOINT PARTIES

The Joint Parties argued DEF's estimated program benefits were largely assessed based on societal benefits that were converted to dollar amounts using the ICE model. (Joint Parties BR 18-19) The Joint Parties argued that DEF was unable to explain how the ICE model values were determined or if the values were applicable to the Company's service area. Further, the importance of avoided power outages for each individual residential customer will vary drastically depending on the customer's specific circumstances. (Joint Parties BR 19) The Joint Parties argued the ICE quantification provided in DEF's rebuttal testimony were spread across all programs, giving the impression that the programs are cost-effective. (Joint Parties BR 20) Once the estimated storm restoration cost savings are removed, the remaining numerical benefits are made up entirely of ICE-generated societal benefit values, meaning the ICE calculated values give the illusion that the programs are cost-effective. (Joint Parties BR 20-21) The Joint Parties argued that DEF witness Lloyd acknowledged that he could not explain how the ICE values were determined, but that they were conservative estimates. DEF utilized a contractor, Guidehouse, for modeling and the determination of societal benefits. (Joint Parties BR 21) The Joint Parties argued that there was a "circular nature of the input and verification process" and the ICE model was used to provide the appearance of cost-effective programs. (Joint Parties BR 22) Unless the outage avoidance ICE values are incorporated into the cost/benefit comparison, none of DEF's programs are cost-effective. (Joint Parties BR 23)

WALMART

Walmart adopted the position of OPC. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(c), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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, as identified and discussed in Issue 2C.

For each SPP program, DEF listed the estimated capital costs and operating expenses, which are summarized in Table 5C-1. The Company compared these costs with the estimated benefits that could be achieved from the completion of its programs. The benefits included the reduction in outage times (CMI reduction), as discussed in Issue 2C. (EXH 3, P 9, 18, 28, 32, 41, 47, 49, 52)

Table 5C-1
DEF's 2023-2025 SPP Program Costs

Program	2023 (millions)	2024 (millions)	2025 (millions)
Distribution Feeder Hardening	$163.3	$147.0	$171.5
Distribution Lateral Hardening	$208.4	$243.0	$275.6
Distribution Self-Optimizing Grid	$77.3	$136.7	$136.7
Distribution Underground Flood Mitigation	$1.0	$1.5	$1.5
Transmission Structure Hardening	$142.5	$153.6	$167.7
Transmission Substation Flood Mitigation	$3.8	$3.8	$3.8
Transmission Loop Radially Fed Substations	-	-	$10.3
Transmission Substation Hardening	$9.5	$11.5	$14.0
Distribution Vegetation Management	$47.1	$48.5	$49.9
Transmission Vegetation Management	$21.8	$24.9	$23.2
Total	$674.7	$770.5	$854.2

Source: (EXH 25, P 1)

In its brief, the Joint Parties argued that DEF did determine quantitative benefits in its SPP; however, they were not reliable or objective. (Joint Parties BR 18-20) Additionally, OPC stated that from the cost/benefit analysis presented by DEF, the incremental costs of the SPP programs have costs that exceed the benefits. In such instances, the programs and projects are not economically justified or prudent and should be excluded from the plan. OPC's arguments and staff's analysis on the requirements of a cost-effectiveness analysis are discussed in Issue 1C. Staff believes that DEF provided the necessary information to meet the requirements of the SPP

Rule. As discussed in Issue 2C, DEF estimated the reduction in outage times and restoration costs that could result from the implementation of its proposed SPP programs. The Company also listed in its plan the program costs, including capital and operating expenses. Therefore, the estimated costs and benefits to DEF and its customers as a result of the proposed programs were presented by the Company in its SPP.

CONCLUSION

The estimated costs of DEF's SPP programs are shown in Table 5C-1. The estimated benefits, characterized by the reduction in CMI, are discussed in Issue 2C.

Issue 6C: What is the estimated annual rate impact resulting from implementation of DEF's Storm Protection Plan during the first 3 years addressed in the plan?

Recommendation: The estimated annual rate impact, as provided by DEF, is projected to increase approximately 108 percent the first three years of its Storm Protection Plan. In order to mitigate the rate impact to DEF's customers, staff recommends DEF's Distribution Lateral Hardening Program continue at the 2022 annual spending levels, approximately $187.3 million per year, beginning in 2023. (Knoblauch)

Position of the Parties

DEF:

Estimated SPP Rate Impacts Residential $/1,000 kWh	2023	2024	2025
(1) Estimated SPP Rate Impact	$4.21	$6.52	$8.75
(2) Typical Commercial % Increase from prior year Bill	1.0%-1.2%	1.4%-1.6%	1.3%-1.5%
(3) Typical Industrial % Increase from prior year Bill	0.8%-1.2%	1.2%-1.7%	1.1%-1.6%

Estimates the first three years of the SPP Residential Rate factor.
Commercial & Industrial % increase incorporates base rate increases set forth in DEF's 2021 Settlement, approved in Order No. PSC-2021-0202A-AS-EI.

JOINT PARTIES: The rate impacts are estimated in the proposed Updated Plan. To the extent that they included inappropriate costs or exclude cost savings they are overstated. The Commission should consider these impacts and associated revenue requirements in the context of coming rate increases and adopt the Joint Parties' recommendations.

WALMART: Walmart takes no position, as Walmart has not conducted this analysis.

PARTIES' ARGUMENTS

DEF

DEF argued that it disagreed with OPC's position regarding the spending levels between the 2020 SPP and 2023 SPP. While OPC argued that there was a large increase in spending from the Company's 2020 SPP to its 2023 SPP, DEF asserted that this was not accurate as the plans cannot be compared. (DEF BR 26-27) DEF argued that there were fairly low levels of capital investment in the 2020 Plan because it was still in development and was not fully funded or implemented until year 2022. Moreover, if a capital spending comparison were to be made between the common years for the 2020 SPP and the 2023 SPP, the spending actually decreases. (DEF BR 27) Although the Company recognizes the current economic climate, DEF argued that decreasing the 2023 SPP investment level by an arbitrarily amount would also reduce or delay the benefits realized from the plan. (DEF BR 28) Further, the SPP Statute states that it is in the state's interest to strengthen utility infrastructure. DEF argued the residential rates impact related to the 2023 SPP would be roughly one percent per year, which is similar for the commercial and industrial customers. (DEF BR 29) Given the risk of extreme weather events to Florida customers, DEF argued the benefits of its SPP should not be delayed. (DEF BR 29-30)

JOINT PARTIES

The Joint Parties argued the revenue requirements for the 2023 SPP increase significantly from year to year, which is further compounded when taking into account the base rate increases from the 2021 DEF rate case settlement. (Joint Parties BR 24-25) The Joint Parties argued that DEF supplied its modeling contractor, Guidehouse, with "directional targets" for spending plan options, but the final proposed SPP only considered its own financial objectives rather than customer impacts. (Joint Parties BR 25) Considering the lack of cost-effectiveness and statutory compliance of DEF's programs, the Joint Parties argued the 2023 SPP budget should be held at the 2020 spending levels. (Joint Parties BR 26)

WALMART

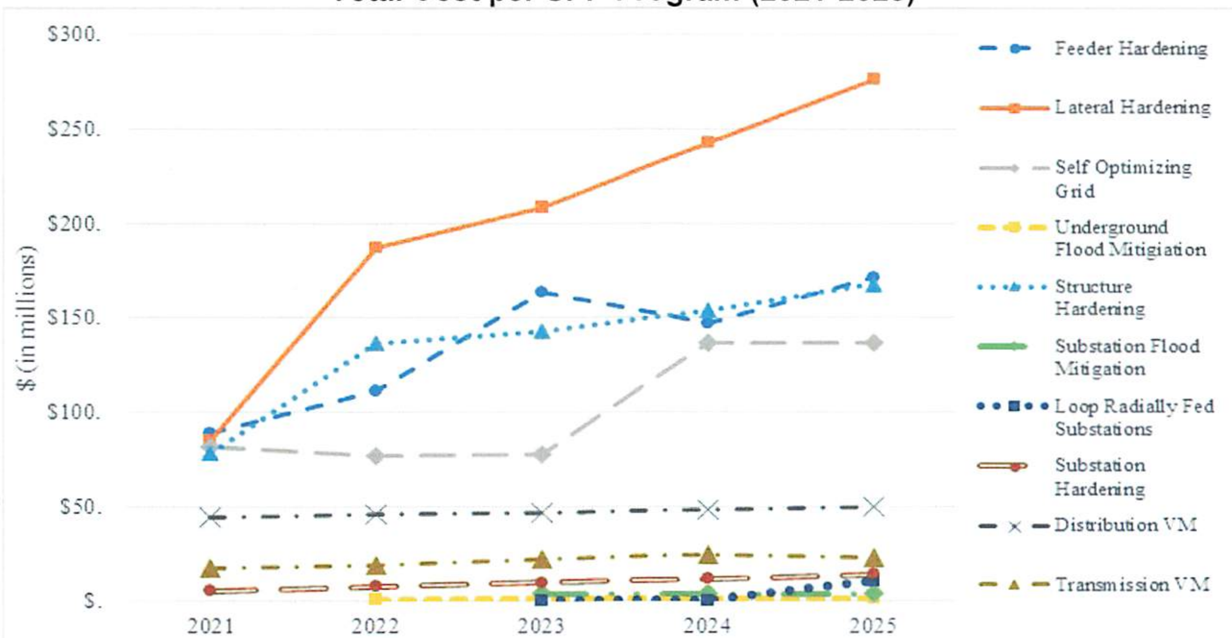
Walmart did not take a position on this issue as it has not conducted an analysis. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(d), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 25-6.030(3)(i), F.A.C., requires the utilities to provide a description of any implementation alternatives that could mitigate the resulting rate impact. This issue will address the annual rate impacts for the first three years of the Company's SPP and deployment alternatives that would mitigate rate impacts to customers.

Figure 6C-1 is a graph of DEF's SPP estimated program costs for 2021 through 2025. As shown on the graph, DEF's Distribution Lateral Hardening Program is the highest cost program and is moving forward at an accelerated pace while its other programs are relatively constant.

Figure 6C-1
Total Cost per SPP Program (2021-2025)



Source: EXH 3, EXH 26

DEF provided the estimated rate impacts for each type of customers, which is shown in Table 6C-1. As the shown in the table, the residential rate impact increases approximately 55 percent from 2023 to 2024 and 108 percent from 2023 to 2025.

Table 6C-1
SPP Estimated Rate Impacts (2023-2025)

Customer Class	2023	2024	2025
Residential ($/1,000 kWh)	$4.21	$6.52	$8.75
Typical Commercial Percent Increase from Prior Year Bill*	1.0%-1.2%	1.4%-1.6%	1.3%-1.5%
Typical Industrial Percent Increase from Prior Year Bill*	0.8%-1.2%	1.2%-1.7%	1.1%-1.6%

*Commercial & Industrial percent increase incorporates base rate increases set forth in DEF's 2021 Settlement, approved in Order No. PSC-2021-0202A-AS-EI.
Source: (EXH 3, P 56)

OPC witness Mara compared DEF's 2020-2029 SPP to its current 2023-2032 SPP capital costs and determined there was an increase of more than $682 million in spending over the 10-year plan. (TR 683) Comparing the costs on a per customer basis, witness Mara calculated the ratio of capital spending to the number of customers had increased more than 10 percent. (TR 684) Witness Mara stated that "the only limit to the magnitude of the SPP budgets was the limitation of resources in terms of engineers and construction personnel realistically available to complete the annual goals of the program." (TR 728) In other words, rather than considering the rate impact to customers, the only limit on spending for DEF's SPP was based on resource availability. As a result, witness Mara proposed a reduction in capital spending of $2.0 billion. Table 6C-1 is a summary of witness Mara's adjustments.

Table 6C-2
Witness Mara's Recommended Program Adjustments

Program	Total 2023-2032 SPP (millions)	Reductions Proposed by Mara (millions)	Net 2023-2032 SPP (millions)	Reason for Reduction
Feeder Hardening	$2,027	($500)	$1,527	Limit impact to customers
Lateral Hardening	$2,931	($700)	$2,231	Limit impact to customers
Self-Optimizing Grid	$340	($340)	$0	Does not comply with SPP Rule
Underground Flood Mitigation	$15	($15)	$0	Does not comply with SPP Rule
Structure Hardening	$1,603	($200)	$1,403	Does not comply with SPP Rule
Substation Flood Mitigation	$38	($38)	$0	Does not comply with SPP Rule
Loop Radially Fed Substations	$82	($82)	$0	Does not comply with SPP Rule
Substation Hardening	$133	($133)	$0	Does not comply with SPP Rule

Source: (TR 685)

However, witness Mara testified that his recommended adjustments and elimination of six programs in their entirety were superseded by a stipulation approved by the Commission in Order No. PSC-2021-0202A-AS-EI. According to the OPC witnesses, the programs or subprograms which witness Mara recommended for exclusion from DEF's SPP for not complying with the SPP Rule, conflict with the provisions of the 2021 Settlement Agreement. As discussed in Issue 1C, staff does not agree with witnesses Kollen and Mara's interpretation of the SPP Rule and does not recommend adjustments due to lack of compliance with the SPP Rule to the six programs.

For the Feeder Hardening Program, witness Mara testified that the program budget for 2023-2032 is $1.8 billion compared to $1.5 billion in DEF's 2020 SPP. (TR 691) Witness Mara recommended keeping the Feeder Hardening Program at the same level as the 2020-2029 SPP at $1.5 billion or essentially capping the annual spending at $150 million per year. In addition, witness Mara recommended eliminating the costs related to clearance encroachments from the program. (TR 691-692) The witness asserted that DEF has a duty to maintain the appropriate distance from the buildings and other structures; therefore, it is DEF's sole responsibility for correcting encroachment problems. (TR 691)

For the Lateral Hardening Program, witness Mara testified that the program budget for 2023-2032 is $2.9 billion compared to $2.2 billion in DEF's 2020-2029 SPP. Witness Mara recommended reducing the budget for the Lateral Undergrounding and the Lateral Overhead Hardening sub-programs, with no change to the pole inspection and pole replacement budget. The 10-year costs for the Undergrounding and Overhead Hardening sub-programs totals $2.5 billion, which witness Mara recommended reducing to approximately $1.8 billion. (TR 694) This would cap the annual spending for this program to approximately $180 million per year. (TR

695) However, his calculation is based on the total program cost for the 10-year period. Staff recommends that making any adjustments based on a 10-year budget is not practical given that the Commission must review a utility's SPP at least every three years as well as conduct annual cost-recovery proceedings.

On rebuttal, DEF witness Lloyd testified that DEF's 2020 SPP and 2023 SPP should not be compared since 2020 and 2021 were transitional years as the Company worked to finish other projects and to ramp up engineering and construction. (TR 1346) As an example, work for the Feeder Hardening Program did not start until 2021, resulting in an appearance of an increase in cost from DEF's 2020 SPP. However, the costs for the 2023 SPP reaches a steady state and are actually a continuation of DEF previously approved plan. (TR 1346-1347) Addressing the clearance encroachments, witness Lloyd testified that the Company requires proper clearances for new pole locations, sizes, and guying, which cannot be met with existing overhead structures in the public right of way. DEF is also required to maintain clearance to other existing public and privately-owned underground facilities. Witness Lloyd stated that "newly installed facilities should remain open to truck access for maintenance purposes and should be in easements or adjacent to roadways as outlined in Rule 25-6.0341 (Location of the Utility's Electric Distribution Facilities)." (TR1347)

Utility facilities are designed and built to serve customers 24/7 and the basic standards of construction and maintenance account for normal weather conditions including some contingencies such as maintenance requirements, vehicle strikes, lightning, etc. As such, the primary purpose of storm hardening is to mitigate outages due to extreme weather which would subsequently reduce restoration time and costs to all ratepayers. Any resulting improvements to day to day reliability are secondary to the goal of storm hardening and would only benefit the customers directly impacted by the project or activity. Since lateral hardening projects are smaller in scale and more focused geographically, the likelihood of the project producing benefits for the general body of ratepayers is limited. Realizing that storm hardening costs may or may not produce actual financial benefits during a given time, the Commission has encouraged utilities to focus on projects that would impact the largest numbers of customers, such as transmission projects, and has relied upon the resulting estimated rate impact to customers as a guide to determine the reasonable level of storm hardening.

Prior to the enactment of Section 366.96, F.S., storm hardening expenditures were recovered from utility customers through base rates. When these prior storm hardening plans were approved, the Commission stated repeatedly that approval of the plan was not approval for cost recovery purposes and that the utility should consider rate impacts as it proactively implemented its plan. (See Order PSC-2019-0312-PAA-EI) These cautionary directives are consistent with the fact that the level of storm hardening is a discretionary activity that requires close attention to the resulting rate impacts. However, Section 366.96(7), F.S., states "[a]fter a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence." Therefore, Commission approval of a storm protection plan is now also an approval of the level of storm protection activity. Such approval also has a direct and more frequent impact on rates due to the annual cost recovery mechanism. Unlike other costs, such as fuel costs, the level of storm hardening and the associated costs are discretionary. There are no mandates as to the activity level of an SPP program which is within DEF's control.

In addition, Rule 25-6.030(3)(i), F.A.C., requires the utilities to provide a description of any alternatives that could mitigate the rate impact for each of the first three years of the SPP. DEF reported that it has not identified any reasonable implementation alternatives that could mitigate the resulting rate impact. (TR 129) However, DEF's Distribution Lateral Hardening Program would directly affect a much smaller number of customers when compared to other types of programs, such as transmission projects, and accounts for the majority of the projected increase in SPP costs. Therefore, staff agrees with OPC that reducing the rate impact on customers is appropriate at this time. For these reasons, staff recommends that DEF's Distribution Lateral Hardening Program continue at the level spent on this Program in 2022, approximately $187.3 million per year, in order to mitigate the rate impact to customers.[12] Staff is not disputing that the Distribution Lateral Hardening Program is in the public interest; rather, staff is recommending to slow down the program's activity and annual spending.

For DEF's Feeder Hardening Program, staff recommends no adjustment to the Program budget. Compared to the Lateral Hardening Program, the Program budget for the Feeder Hardening Program makes up a smaller percentage of the total SPP costs and will impact a larger number of customers. Specific to the clearance encroachments concerns identified by witness Mara, staff is inclined to agree with witness Lloyd that encroachment issues may occur when installing new hardened poles and it is appropriate to address these issues within this program.

CONCLUSION

The estimated annual rate impact, as provided by DEF, is projected to increase approximately 108 percent the first three years of its Storm Protection Plan. In order to mitigate the rate impact to DEF's customers, staff recommends DEF's Distribution Lateral Hardening Program continue at the 2022 annual spending levels, approximately $187.3 million per year.

[12] The actual value will be determined as part of the SPPCRC proceeding.

Issue 10C: Is it in the public interest to approve, approve with modification, or deny DEF's Storm Protection Plan?

Recommendation: Staff recommends DEF's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1C. Staff recommends that DEF's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Hardening Program at the 2022 level; and, (2) remove the Transmission Loop Radially Fed Substation Program. DEF should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff. (Knoblauch)

Position of the Parties

DEF: DEF's 2023 SPP is in the public interest and should be approved without modification. DEF demonstrated by a preponderance of the evidence that its 2023 SPP is estimated to provide the outage reduction and restoration cost reductions the Legislature has determined to be in the public interest, and does so in a cost-effective manner.

JOINT PARTIES: No, the DEF SPP 2023 should not be approved without modification. The programs are not cost-effective, compliant or prudent to undertake. Except for the programs/projects that are subject to the, the plan should not be approved as filed. Subject to 2021 Stipulation for 2023 and 2024, the adjustments recommended by Kevin J. Mara at TR 685 are required.

WALMART: Walmart believes the public interest would benefit if the Commission directs each utility to continue to collaborate with interested stakeholders during the interim period before their next required updated SPPs to develop ways in which customer-sited generation may be utilized as part of the SPP in order to strengthen the T&D systems and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall.

PARTIES' ARGUMENTS

DEF

DEF argued its 2023 SPP, as required by the SPP Statute and Rule, balances the costs to customers along with the resulting benefits. DEF argued that all of its SPP programs would reduce restoration costs and outages, improve reliability, and are cost-effective. Therefore, DEF argued that the Commission should approve its 2023 SPP without modification as it complies with the requirements of the SPP Rule and is in the public interest as outlined by the SPP Statute. (DEF BR 30)

JOINT PARTIES

As laid out in Issues 2C and 5C, the Joint Parties argued the DEF's proposed SPP programs are not cost-effective and do not reduce both restoration costs and outage times. Nevertheless, the Commission should allow the inclusion of the Distribution Feeder Hardening and Distribution Lateral Hardening Programs at the reduced spending levels outlined by OPC witness Mara. The six programs discussed in Issue 2C should be included for the years 2023 and 2024, but for 2025 and beyond, the programs should be excluded from DEF's SPP. The Distribution and

Transmission Vegetation Management Programs should remain in DEF's SPP as proposed. (Joint Parties BR 27)

WALMART

Walmart argued it would be in the public interest if DEF would continue to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen DEF's system. (Walmart BR 6)

ANALYSIS

Section 366.96(5), F.S., states that the Commission 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 discussed in Issue 1C, staff recommends that DEF's filing satisfies the requirements of Rule 25-6.030, F.A.C., and provides the Commission with adequate information in order to satisfy its statutory requirements.

As described by DEF witness Lloyd, the Company's proposed SPP covers the period of 2023-2032, and uses the same analysis methodology and programs that were included in its previous SPP for the period of 2020-2029. (TR 122) DEF's SPP includes the following 10 programs:

- Distribution Feeder Hardening
- Distribution Lateral Hardening
- Distribution Self-Optimizing Grid
- Distribution Underground Flood Mitigation
- Transmission Structure Hardening
- Transmission Substation Flood Mitigation
- Transmission Loop Radially Fed Substations
- Transmission Substation Hardening
- Distribution Vegetation Management
- Transmission Vegetation Management

As discussed in prior issues, OPC witness Mara recommended modifications to all of DEF's SPP programs, except for the vegetation management programs. Witness Mara's recommendations are summarized in Table 10C-1. FIPUG, PCS, and NUCOR took the same position and agreed with OPC. Walmart provided no witness testimony but argued in its brief that it would be in the public interest if DEF continued to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen DEF's system. (Walmart BR 6) Although staff agrees with continuing the collaboration between utilities and interested stakeholders, the SPP Statute does not contemplate customer-sited generation. Section 366.96(2)(b), F.S., defines a transmission and distribution storm protection plan as "a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management." Thus, on-site generation does not meet the definition as laid out in the statute. As discussed in Issue 1C, staff does not agree with witnesses Kollen and Mara's interpretation of the SPP Rule and does not recommend adjustments due to lack of compliance with the SPP Rule to the six programs listed in Table 10C-1.

Table 10C-1
Witness Mara's Recommended Program Adjustments

Program	Total 2023-2032 SPP (millions)	Reductions Proposed by Mara (millions)	Net 2023-2032 SPP (millions)	Reason for Reduction
Feeder Hardening	$2,027	($500)	$1,527	Limit impact to customers
Lateral Hardening	$2,931	($700)	$2,231	Limit impact to customers
Self-Optimizing Grid	$340	($340)	$0	Does not comply with SPP Rule
Underground Flood Mitigation	$15	($15)	$0	Does not comply with SPP Rule
Structure Hardening	$1,603	($200)	$1,403	Does not comply with SPP Rule
Substation Flood Mitigation	$38	($38)	$0	Does not comply with SPP Rule
Loop Radially Fed Substations	$82	($82)	$0	Does not comply with SPP Rule
Substation Hardening	$133	($133)	$0	Does not comply with SPP Rule

Source: (TR 685)

Witness Mara's rate mitigation recommendations for the Feeder and Lateral Hardening Programs were discussed in detail in Issue 6C, as well as staff's recommended adjustments. Further, as stated previously in Issue 6C, witness Mara acknowledges that his recommended adjustments to the remaining six programs are superseded by a stipulation approved by the Commission in Order No. PSC-2021-0202A-AS-EI. The stipulation allows for the costs of the six programs to be included in the SPPCRC for recovery in the years 2023-2024. With the exception of the Loop Radially Fed Substations Program that is discussed below, the remainder of the programs meet the requirements of the SPP Rule, are a continuation of DEF's 2020 SPP, and are built upon the foundation established in DEF's Storm Hardening Plans. (TR 125, 211)

Staff does have concerns regarding the Transmission Loop Radially Fed Substations (LRFS) Program, which is scheduled to start in 2025. Since the Program has not yet begun, DEF was not required to provide project-level detail since none of the projects will fall within the first year (2023) of the plan per the SPP Rule. The information provided for the scope of the Transmission LRFS Program was it would address approximately 17 sites over 20 years, the estimated 10-year cost would be approximately $82 million, and a description listing the types of assets that would be targeted. (EXH 3, P 49) While staff believes DEF met the requirements of the SPP Rule, there is limited, particularly project-level detail for the Transmission LRFS Program at this time.

Moreover, staff does not believe the Transmission LRFS Program meets the objective of storm protection or hardening. 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. Looping substations is a common utility practice to ensure reliable service. 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) The Transmission LRFS Program involves the construction of new redundant infrastructure, rather than the enhancement or hardening of existing facilities. While staff agrees that such activity may enhance a utility's transmission system, it does not strengthen existing transmission facilities. Therefore, staff recommends that a new redundant infrastructure project, such as looping substations, should not be characterized as storm protection pursuant to Rule 25-6.030(1)(a), F.A.C. Witness Mara testified to the concept of limiting programs, stating that "unchecked spending on SPP programs will result in an excessive burden on the rate payers." (TR 685-686) As previously discussed, customer rate impact is a critical component of encouraging storm protection activities.

In summary, as discussed in Issue 6C, staff recommends DEF's Lateral Hardening Program be continued at its 2022 spending level, and the Transmission LRFS Program be excluded from DEF's 2023 SPP. The Transmission LRFS Program is not planned to begin until 2025; therefore it is not in conflict with the stipulation approved by the Commission which addresses cost recovery for years 2023 and 2024. With these two modifications, staff recommends that DEF's SPP is in the public interest. DEF should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

CONCLUSION

Staff recommends DEF's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1C. Staff recommends that DEF's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Hardening Program at the 2022 level; and (2) remove the Transmission Loop Radially Fed Substation Program. DEF should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

Issue 11C: Should this docket be closed?

Recommendation: No. As discussed in Issue 10C, DEF should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff. Therefore, the docket should remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively. (Trierweiler, Imig)

Position of the Parties

DEF: Yes, after the Commission enters its final order, this docket should be closed.

JOINT PARTIES: The Docket should remain open for DEF to amend their filing consistent with the modifications the commission orders. OPC has raised a legal issue regarding the Order striking Mr. Kollen's testimony. The legal issue requires resolution before the docket is closed. In connection with the legal issue, both parties have made evidentiary proffers which must be considered if OPC prevails on the legal issue.

WALMART: Yes.

PARTIES' ARGUMENTS

DEF

No post-hearing position or argument was provided in its brief.

JOINT PARTIES

No post-hearing position or argument was provided in its brief.

WALMART

No post-hearing position or argument was provided in its brief.

CONCLUSION

As discussed in Issue 10C, DEF should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff. Therefore, the docket should remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively.

Duke Energy Florida, LLC
Proposed 2023-2032 Storm Protection Plan Programs

Distribution Feeder Hardening

By incorporating pole inspection and replacement activities, existing feeder circuits can be strengthened to better withstand extreme weather events. This includes strengthening or replacing structures, updating basic insulation levels and conductors to current standards, relocating difficult to access facilities, relocating or undergrounding facilities to address clearance encroachments, and replacing oil filled equipment as appropriate. All new structures will meet the NESC 250C extreme wind load standard.

Distribution Lateral Hardening

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

Distribution Self-Optimizing Grid

This program utilizes automated switching which allows most circuits to be restored from alternate sources. In addition, the program provides segmentation such that the distribution circuits have much smaller line segments, thus reducing the number of customers that are affected by outages.

Distribution Underground Flood Mitigation

Underground facilities that are prone to storm surge will be converted to submersible lines and equipment. In some cases, the pad mounted equipment is placed on elevated structures, which raises the equipment two to four feet above grade, to mitigate potential flood impacts.

Distribution Vegetation Management

The program consists of routine maintenance trimming, hazard tree removal, herbicide applications, vine removal, customer requested work, and right-of-way brush mowing. DEF trims its feeders on a three-year cycle and trims its laterals on a five-year cycle.

Transmission Structure Hardening

This program includes wood to non-wood upgrades, tower upgrades, adding cathodic protection, automating gang operated air break switches, overhead groundwire upgrades, and structure inspections.

Transmission Substation Flood Mitigation

This program builds in protection for substations most vulnerable to flood damage using flood plain and storm surge data. It includes a systematic review and prioritization of substations at risk of flooding to determine the proper mitigation solution, which may include elevating or modifying equipment, or relocating substations altogether. New assets could include control houses, relays, or total station rebuilds to increase elevation, etc.

Transmission Loop Radially-Fed Substations

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

Transmission Substation Hardening

The replacement of electro-mechanical relays with electronic relays is designed to support rapid restoration. Electronic relays are equipped with communication capabilities and microprocessor technology, which enables a quicker recovery from events. Relay upgrades will be matched with breaker replacements when feasible.

Transmission Vegetation Management

DEF trims its transmission system on a three to six-year cycle in order to minimize vegetation related interruptions and ensures adequate conductor-to-vegetation clearances. The program consists of danger tree identification and mitigation, reactive work, herbicide, mowing, and hand cutting brush management.

366.96 Storm protection plan cost recovery.—

(1) The Legislature finds that:

(a) During extreme weather conditions, high winds can cause vegetation and debris to blow into and damage electrical transmission and distribution facilities, resulting in power outages.

(b) A majority of the power outages that occur during extreme weather conditions in the state are caused by vegetation blown by the wind.

(c) It is in the state's interest 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.

(d) Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

(e) 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.

(f) All customers benefit from the reduced costs of storm restoration.

(2) As used in this section, the term:

(a) "Public utility" or "utility" has the same meaning as set forth in s. 366.02(8), except that it does not include a gas utility.

(b) "Transmission and distribution storm protection plan" or "plan" means a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management.

(c) "Transmission and distribution storm protection plan costs" means the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan.

(d) "Vegetation management" means the actions a public utility takes to prevent or curtail vegetation from interfering with public utility infrastructure. The term includes, but is not limited to, the mowing of vegetation, application of herbicides, tree trimming, and removal of trees or brush near and around electric transmission and distribution facilities.

(3) Each public utility shall file, pursuant to commission rule, a transmission and distribution storm protection plan that covers the immediate 10-year planning period. Each plan must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. The commission shall adopt rules to specify the elements that must be included in a utility's filing for review of transmission and distribution storm protection plans.

(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.

(5) No later than 180 days after a utility files a transmission and distribution storm protection plan that contains all of the elements required by commission rule, the commission shall determine whether it is in the public interest to approve, approve with modification, or deny the plan.

(6) At least every 3 years after approval of a utility's transmission and distribution storm protection plan, the utility must file for commission review an updated transmission and distribution storm protection plan that addresses each element specified by commission rule. The commission shall approve, modify, or deny each updated plan pursuant to the criteria used to review the initial plan.

(7) After a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence. The commission shall conduct an annual proceeding to determine the utility's prudently incurred transmission and distribution storm protection plan costs and allow the utility to recover such costs through a charge separate and apart from its base rates, to be referred to as the storm protection plan cost recovery clause. If the commission determines that costs were prudently incurred, those costs will not be subject to disallowance or further prudence review except for fraud, perjury, or intentional withholding of key information by the public utility.

(8) The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates and must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

(9) If a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity.

(10) Beginning December 1 of the year after the first full year of implementation of a transmission and distribution storm protection plan and annually thereafter, the commission shall submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a report on the status of utilities' storm protection activities. The report shall include, but is not limited to, identification of all storm protection activities completed or planned for completion, the actual costs and rate impacts associated with completed activities as compared to the estimated costs and rate impacts for those activities, and the estimated costs and rate impacts associated with activities planned for completion.

(11) The commission shall adopt rules to implement and administer this section and shall propose a rule for adoption as soon as practicable after the effective date of this act, but not later than October 31, 2019.

History.—s. 1, ch. 2019-158; s. 30, ch. 2022-4.

25-6.030 Storm Protection Plan.

(1) Application and Scope. Each utility as defined in Section 366.96(2)(a), F.S., must file a petition with the Commission for approval of a Transmission and Distribution Storm Protection Plan (Storm Protection Plan) that covers the utility's immediate 10-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every 3 years.

(2) For the purpose of this rule, the following definitions apply:

(a) "Storm protection program" – a category, type, or group of related storm protection projects that are undertaken to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(b) "Storm protection project" – a specific activity within a storm protection program designed for the enhancement of an identified portion or area of existing electric transmission or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) "Transmission and distribution facilities" – all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors.

(3) Contents of the Storm Protection Plan. For each Storm Protection Plan, the following information must be provided:

(a) A description of how implementation of the proposed Storm Protection Plan will 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.

(b) A description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) 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. Such description must include a general map, number of customers served within each area, and the utility's reasoning for prioritizing certain areas for enhanced performance and for designating other areas of the system as not feasible, reasonable, or practical.

(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.; and

5. A description of the criteria used to select and prioritize proposed storm protection programs.

(e) For the first three years in a utility's Storm Protection Plan, the utility must provide the following information:

1. For the first year of the plan, a description of each proposed storm protection project that includes:

a. The actual or estimated construction start and completion dates;

b. 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;

c. A cost estimate including capital and operating expenses; and

d. A description of the criteria used to select and prioritize proposed storm protection projects.

2. For the second and third years of the plan, project related information in sufficient detail, such as estimated number and costs of projects under every specific program, to allow the development of preliminary estimates of rate impacts as required by paragraph (3)(h) of this rule.

(f) For each of the first three years in a utility's Storm Protection Plan, the utility must provide a description of its proposed vegetation management activities including:

1. The projected frequency (trim cycle);

2. The projected miles of affected transmission and distribution overhead facilities;

3. The estimated annual labor and equipment costs for both utility and contractor personnel; and

4. A description of how the vegetation management activity will reduce outage times and restoration costs due to extreme weather conditions.

(g) An estimate of the annual jurisdictional revenue requirements for each year of the Storm Protection Plan.

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

(i) A description of any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan.

(j) Any other factors the utility requests the Commission to consider.

(4) By June 1, each utility must submit to the Commission Clerk an annual status report on the utility's Storm Protection Plan programs and projects. The annual status report shall include:

(a) Identification of all Storm Protection Plan programs and projects completed in the prior calendar year or planned for completion;

(b) Actual costs and rate impacts associated with completed activities under the Storm Protection Plan as compared to the estimated costs and rate impacts for those activities; and

(c) Estimated costs and rate impacts associated with programs planned for completion during the next calendar year.

Rulemaking Authority 366.96 FS. Law Implemented 366.96 FS. History–New 2-18-20.

Item 7

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 26, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Buys, King, Ramos) TB
Office of the General Counsel (Trierweiler, Imig) AH

RE: Docket No. 20220051-EI – Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.

AGENDA: 10/04/22 – Regular Agenda – Post Hearing Decision - Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: October 8, 2022 – 180-day Statutory Deadline Per 366.96(5), Florida Statutes.

SPECIAL INSTRUCTIONS: Please place Dockets Nos. 20220048-EI, 20220049-EI, 20220050-EI, and 20220051-EI in consecutive order on the Agenda.

Table of Contents

Case 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 a plan containing all the elements required by Commission rule, the Commission must determine whether it is in the public interest to approve, approve with modification, or deny the plan. Section 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. Further, this section requires the Commission conduct an annual proceeding, referred to as the storm protection plan cost recovery clause (SPPCRC), to determine the utility's prudently incurred SPP costs.

Florida Power & Light Company (FPL) and Gulf Power Company (Gulf) filed their first SPPs on April 10, 2020, in Dockets Nos. 20200070-EI (Gulf) and 20200071-EI (FPL).[1] The Office of Public Counsel (OPC), Walmart, Inc. (Walmart), and Florida Industrial Power Users Group (FIPUG) were granted intervention in both dockets. These matters were set for an administrative hearing; however, prior to the hearing FPL/Gulf entered into a Settlement Agreement with OPC and Walmart.[2] An administrative hearing was held on August 10, 2020 for the Commission to hear oral argument from the parties in support of the Settlement Agreement, to admit testimony and documentary evidence into the record, and to consider the Settlement Agreement. The Commission approved the Settlement Agreement by Order No. PSC-2020-0293-AS-EI, issued August 28, 2020, in Docket Nos. 20200070-EI and 20200071-EI.

Key provisions of the 2020 Settlement are:

- Approval of the Gulf and FPL Settlement Agreement does not include or imply a determination of prudence for any particular project under a given program approved under the settlement. OPC retains the right to challenge the prudence or reasonableness of any projects or costs for any project submitted through the SPPCRC docket for programs approved under the settlement.
- FPL and Gulf will not seek recovery of any SPP program operation and maintenance (O&M) expenses incurred in 2020 or 2021 through the SPPCRC. FPL and Gulf will address the recovery of future SPP program O&M expenses in their next base rate cases, including whether such O&M expenses are to be recovered through base rates or through the SPPCRC.

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[1] Gulf was merged with FPL in 2021, however, the utilities remained separate ratemaking entities. As such, the utilities separately administered their SPP programs and projects during 2021. In 2022, the utilities were consolidated, with FPL being the surviving entity.
[2] FIPUG took no position on the Joint Motion for Expedited Approval of a Stipulation and Settlement Agreement.

On April 11, 2022, FPL filed its proposed SPP for Commission approval which covers the period of 2023-2032 and included eleven programs.[3] The majority of these programs are a continuation of both FPL's and Gulf's 2020 SPPs and are described in Attachment A. FIPUG, OPC, Southern Alliance for Clean Energy (SACE), and Walmart were granted intervention in this docket. An administrative hearing was held on August 2-4, 2022.[4] Post hearing briefs were filed on September 6, 2022. OPC and FIPUG (Joint Parties) filed a joint brief which included a procedural matter which is addressed below.

Procedural Matter

On pages 17-23 of their post-hearing brief, the Joint Parties unilaterally inserted a "post-hearing legal issue" that was not listed in the Prehearing Order.[5] The Joint Parties argue in this post-hearing issue that the Commission should reverse a prehearing ruling, set forth in Order No. PSC-2022-0292-PCO-EI, where the Prehearing Officer granted motions to strike portions of the prefiled testimony of OPC witness Lane Kollen. In staff's opinion, this legal argument does not raise a new substantive issue not previously ruled upon. 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 was denied by the full Commission. Because the evidentiary concerns relating to the testimony of witness Kollen have twice been addressed on the merits, staff believes it is appropriate to discuss the Joint Parties' "post-hearing legal issue" here only as it raises procedural concerns. For the reasons set forth below, staff believes there is no procedural error that that Commission 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 the Joint Parties, were given full opportunity to present argument on all relevant issues in the case and to conduct cross-examination of all witnesses on the case's relevant issues both in the case in chief and in the proffered portions of the hearing. (TR 44).

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 the Commission's 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 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. (TR 824-853). 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. (TR 854-886). 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

[3] On July 11, 2022, FPL filed a notice withdrawing its proposed Distribution and Transmission Winterization Programs. As such, its revised proposed SPP included nine programs rather than eleven.

[4] FPL's docket was consolidated with the SPP dockets for TECO (20220048-EI), FPUC (20220049-EI), and DEF (20220050-EI) for hearing purposes only.

[5] Order No. PSC-2022-0291-PHO-EI, issued August 1, 2022.

testimony that had been stricken. Counsel for OPC also made legal arguments about the rule interpretation at that time. (TR 802-808). Although the Commission ultimately decided to strike the OPC witness testimony, OPC was provided an opportunity to make its legal argument at the administrative hearing (TR 798-810), and in its motion for reconsideration. OPC made its arguments again in its post-hearing brief.

The Joint Parties also argue that a Commission Final Order applying Rule 25-6.030, 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." (Joint Parties BR 23) The cases cited by the Joint Parties in support on this argument all address judicial review of the constitutionality of statutes.[6] As an agency, the Commission has no jurisdiction to declare a statute unconstitutional. Moreover, following the passage of Article V, Section 21, of the Florida Constitution, the Commission's interpretation of a statute will not be relevant to a court vested with jurisdiction to consider that constitutional question.

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

There are 9 issues addressed below for the Commission to consider.[7] The Commission has jurisdiction in this matter pursuant to Section 366.96, and Chapter 120, F.S.

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[6] 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)).

[7] FPL's issues are 1D-6D; Issues 7 and 8, which were withdrawn prior to the hearing; Issue 9; Issue 10D and 11D.

Discussion of Issues

Issue 1D: Does FPL's Storm Protection Plan contain all of the elements required by Rule 25-6.030, Florida Administrative Code?

Recommendation: Yes, FPL appears to have met the criteria and intent of the SPP Rule with its filing and the Commission has adequate information in order to satisfy its statutory requirements. (Trierweiler, Imig, P. Buys)

Position of the Parties

FPL: Yes. FPL's 2023 SPP includes all of the information expressly required by Rule 25-6.030(3), F.A.C., and Section 366.96, F.S., which can be used and compared by the Commission to determine if the 2023 SPP is in the public interest. There is nothing in Rule 25-6.030(3), F.A.C., that (i) requires the SPP benefits to be projected, quantified, or monetized, or (ii) requires a formulaic comparison of the SPP costs and benefits as suggested by Intervenors. (*FPL witness Jarro*)

JOINT PARTIES: No. The Company failed to provide the requisite benefit estimates in a form by which comparisons required by the SPP Rule can be meaningfully made; this failure precludes an accurate determination of whether the continuation and expansion of existing programs and implementation of new programs are reasonable. Additionally, the data FPL provided regarding past storm performance is not applicable to the new program regarding Transmission Access.

SACE: FPL's proposed Storm Protection Plan does not contain the necessary elements required by Rule 25-6.030, F.A.C. The FPL Storm Protection Plan does not provide the resulting reduction in restoration costs of its programs, reduction in outage times, or a comparison of costs and dollar benefits. Therefore, the Storm Protection Plan, as filed, cannot be approved. See the argument below.

WALMART: No. Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

FPL

In support of its position, FPL argued that its SPP tracks the language of and provides information consistent with the express requirements of Rule 25-6.030, F.A.C. (FPL BR 9) Additionally, FPL argued that there is nothing in the SPP Statute or Rule that requires SPP benefits to be projected, quantified, or monetized. (FPL BR 10) FPL argued that the SPP Rule expressly provides that the SPP must include a description of the benefits of the SPP programs. (FPL BR 11) FPL argued that storm hardening is not a simple cost-effective proposition and the qualitative component, which is outage times, of the SPP Rule cannot be ignored. (FPL BR 13) FPL also argued that the monetary value individual customers or communities place on reduced outage times cannot be accurately or uniformly estimated, and that such analyses are dependent on highly speculative assumptions regarding the frequency and impacts of future extreme weather events and a very wide range of subjective economic assumptions. (FPL BR 14) FPL argued there is no accurate way to truly provide a forward-looking view of the estimated benefits of the SPP programs for the entire 2023-2032 SPP period. (FPL BR 14)

Finally, FPL argued that there is nothing in the SPP Statute or Rule that requires a quantitative comparison of estimated costs and benefits of SPP Programs. (FPL BR 17) FPL argued that nothing in the SPP Statute or Rule requires a cost-effectiveness test or threshold for the SPP programs or projects. (FPL BR 17)

JOINT PARTIES

The Joint Parties argued that the SPP Rule requires a comparison of a cost estimate including capital and operating expense against an estimate of the resulting reduction in outage times and restoration costs expected to be gained from the SPP programs. (Joint Parties BR 3) The Joint Parties argued that the plain text of the SPP Rule requires a comparison of costs and benefits. A meaningful comparison for purposes of the SPP Rule that serves the purpose of the statute regarding customer rates requires a substantive comparison of like factors, i.e., quantification in terms of dollars. (Joint Parties BR 4) Finally, the Joint Parties argued that the best way for the Commission to conduct the evaluation required by the statute is for the utility to present forward-looking data and analyses in its SPP. (Joint Parties BR 5)

SACE

SACE argued that the SPP Rule 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, and that the description must include an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions. (SACE BR 4-5) SACE argued that the word "cost" has a clear and definite meaning, the amount paid for something; therefore, restoration "costs" required in the SPP Rule should be provided in a dollar amount. (SACE BR 5) Finally, SACE argued that FPL's SPP fails to meet the requirements of the SPP Rule because FPL did not provide quantitative benefits for its proposed programs. (SACE BR 6)

WALMART

Walmart argued that FPL witness Jarro admitted that FPL did not provide quantified estimates of benefits but instead provided a qualitative description of what the benefits would be. (Walmart BR 3)

ANALYSIS

<u>History</u>

The first utility storm hardening programs were filed for Commission approval in 2007 and were reviewed by the Commission 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."[8] Subsection 366.96(3), F.S., requires each IOU

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[8] 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 facilitates, 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.

to file a transmission and distribution SPP for the Commission's review and directs the Commission 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.

The Commission promulgated two Rules, 25-6.030, F.A.C., Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Cost Recovery, to implement and administer Section 366.96, F.S. The full text of Section 366.96 and Rule 25-6.030, F.A.C., are provided as Attachment B. In 2020, FPL's first storm protection plan, which was primarily an extension of the utility's existing storm hardening plans, was approved.

Issue

Throughout this docket, the Joint Parties made arguments about whether SPP filings contained descriptive or narrative information, i.e., "qualitative" information or whether the filings contained information with numeric, dollar amounts i.e., "quantitative" information[9] to identify SPP benefits. As such, the primary issue raised by the Joint Parties is whether Rule 25-6.030, F.A.C. requires information to be filed in a qualitative or quantitative format. Regardless of how information in a SPP filing is characterized, the Commission 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, staff believes that FPL's SPP meets the requirements of Section 366.96, F.S., and 25-6.030, F.A.C.

Law

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

> 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 Statute further articulates that the Commission must use the public interest standard when considering a SPP. *See* § 366.96(5), stating that the Commission shall determine whether it is in the public interest to approve, modify, or deny the plan. Accordingly, Rule 25-6.030, F.A.C., requires utilities to file certain minimum information in order for the Commission to determine if it is in the public interest to approve, approve with modifications, or deny a utility's storm

[9] Neither the terms "qualitative" nor "quantitative" are contained within the SPP statute or SPP Rule. Rather, these are terms that Staff and the parties use to assist with the description of the categories of information that are at issue in this docket.

protection plan. In other words, Rule 25-6.030, F.A.C., is a filing requirement rule, not a standard for the Commission's decision. As such, the rule allows the utilities to have the flexibility to submit and manage their hardening plans while simultaneously requiring a utility file the information necessary for the Commission to make a determination about whether it is in the public interest to approve a plan, approve a plan with modifications, or deny a plan.

Rule 25-6.030(3), F.A.C., Storm Protection Plan, identifies the specific information to be included in each IOU's SPP.[10] Rule 25-6.030(3)(d), F.A.C., requires, in relevant part, a comparison of costs and benefits:

> 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.

<u>Staff Analysis</u>
Rule 25-6.030(3)(d), F.A.C., requires "...a comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in 3(d)1." The crux of the Joint Parties' 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. The Joint Parties and SACE argued that if no traditional cost-effectiveness evaluation or "quantitative" cost-benefit analysis is contained in the utility's SPP filings, the Commission lacks the information necessary to make a determination that a SPP can be approved in the public interest. In making this argument, however, the Joint Parties make 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 the Joint Parties, 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 the Joint Parties, 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.

Staff believes that 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

[10] Specific elements of Rule 25-6.030, F.A.C., such as areas for prioritization and rate impacts, are discussed in more detail in Issues 2D through 6D.

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 the Commission consider the rate impact in order to approve a SPP. The Commission will receive all the cost numbers necessary to make a rate impact determination. Thus, Rule 25-6.030, F.A.C., should be interpreted to allow for both quantitative and qualitative information in the SPPs.

Second, the Joint Parties' 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 that exceed costs during a given time, depending on a particular utility's circumstances, and qualitative information may provide additional information of the benefits of a SPP. [11]

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. Also, quantitative or qualitative information can provide the Commission with adequate information to consider the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan, as required by section 366.96(4)(c), F.S.

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 the Commission to go forward with making a determination on approval, denial, or modification of a SPP.

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

[11] 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) there are no monetized benefits to the general body of customers. 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.

- 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 including an estimate of the resulting reduction in outage times and restoration costs

FPL provided data as to the costs and benefits associated with its SPP programs and projects. (TR 1116; 82) The qualitative information that FPL provided was historical data that demonstrates how past storm hardening measures have reduced restoration costs and outage times. (FPL BR 16) For example, FPL's analysis of Hurricanes Irma and Matthew indicated the construction man-hours (CMH), days to restore and storm restoration costs would have been significantly greater without its storm hardening programs. Restoration for Hurricane Matthew would have been extended by two additional days (50 percent) and costs increased by $105 million (36 percent) without hardening. Similarly for Hurricane Irma, FPL estimated that restoration would have been extended by four days (40 percent) and costs increased by $496 million (40 percent) without hardening. (FPL BR 21)

CONCLUSION

Staff recommends that FPL met the filing requirements required by Rule 25-6.030, F.A.C., and that the Commission has adequate information necessary to make a public interest determination pursuant to Section 366.96, F.S.

Issue 2D: To what extent is FPL's Storm Protection Plan expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability?

Recommendation: FPL utilized historical data to support its 2023 SPP program evaluation and prioritization. The historical data demonstrates that FPL's SPP may reduce restoration costs and outage times associated with extreme weather events. (P. Buys)

Position of the Parties

FPL: FPL has demonstrated in Sections II, IV, and Appendix A of Revised Exhibit MJ-1 that each of its SPP programs have and will continue to provide increased T&D infrastructure resiliency, reduced outage times, and reduced restoration costs when FPL's system is impacted by extreme weather conditions. (*FPL witness Jarro*)

JOINT PARTIES: Some of FPL's proposed programs will have a greater impact on reducing outages times and lowering restoration costs than others. FPL asserted its Transmission Pole replacements already resulted in no pole failures from Hurricanes Matthew or Irma. There is no evidence that creating new roads and bridges as suggested in the Transmission Access Program will reduce restoration costs or improve outage times.

SACE: FPL did not provide the necessary information required by Rule 25-6.030, F.A.C., for the resulting reduction in restoration costs and outage times for its proposed programs. As such, one cannot make a determination to what extent and by how much the proposed programs will reduce restoration costs and outage times. Therefore, the FPL Storm Protection Plan, as filed, cannot be approved. See the argument below.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

FPL

In support of its position, FPL argued that the estimate of cumulative reductions in restoration costs and outage times will be directly affected by how frequently FPL's service area is impacted by extreme weather events. FPL did not provide projected reductions in restoration costs and outage times due to the many highly variable and subjective factors associated with storms and because there is no Industry/Commission-accepted method to do so. Instead, FPL relied on its actual and real-world experience with recent extreme weather events. Using data from Hurricanes Irma and Matthew, FPL demonstrated that its storm hardening programs work and will continue to provide customers with both reductions in restoration costs and outage times associated with extreme weather events. (FPL BR 19-20)

In addition, FPL stated that its 2023 SPP is largely a continuation of the programs included in its current 2020 SPP, and a majority of the programs have been in place since 2007. These programs have already demonstrated that they have provided and will continue to provide increased infrastructure resiliency, reduced restoration times, and reduced restoration costs. (FPL BR 20-21)

FPL's analysis of Hurricanes Irma and Matthew indicated the CMH, days to restore, and storm restoration costs would have been significantly greater without its storm hardening programs. For example, restoration for Hurricane Matthew would have been extended by two days (50 percent) and costs increased by $105 million (36 percent) without hardening. Similarly for Hurricane Irma, FPL estimated that restoration would have been extended by four days (40 percent) and costs increased by $496 million (40 percent) without hardening. Further, FPL pointed out that its underground laterals performed 6.6 times, or 85 percent better, during Hurricane Irma than its overhead laterals. (FPL BR 21)

FPL calculated the 40-year net present value (NPV) of savings associated with storm hardening if similar storms to Hurricanes Matthew and Irma occurred every three and five years to demonstrate the significant savings attributable to storm hardening. These calculations are contained within Appendix A of FPL's SPP. (FPL BR 21; EXH 2)

FPL argued that while no electric system can be made to completely withstand the impacts of extreme weather, its SPP programs are appropriate and necessary to meet the requirements of the SPP Statute and Rule. In addition, FPL argued that the SPP programs will collectively provide increased resiliency and faster restoration to its infrastructure. (FPL BR 21-22)

JOINT PARTIES

The Joint Parties argued that Rule 25-6.030(3)(d), F.A.C., contains a "Two-Prong" test, requiring each program to accomplish both a reduction in outage times and restoration costs in order to be eligible for inclusion in the SPP. (Joint Parties BR 6) As part of its argument, the Joint Parties voiced concern that the utility included general infrastructure work as part of its SPP, which instead should be recovered through base rates as part of normal routine maintenance. The Joint Parties believe that a strict application of the "Two-Prong" test and a reasonable cost-effectiveness standard will ensure implementation of programs that meet the needs of Floridians in an affordable manner. (Joint Parties BR 7)

Further, the Joint Parties argued that FPL did not provide proper data estimating reductions in restoration costs and outage times in order to comply with the requirements of the SPP Rule. Instead, FPL provided historical data, which the Joint Parties argued is inadequate, especially for FPL's new Transmission Access Enhancement program, since the data predates this new program. (Joint Parties BR 8-9)

SACE

SACE argued that FPL's SPP did not meet the requirements of Rule 25-6.030(3)(d)1., F.A.C., because the Company did not provide any estimate of the resulting reduction in outage times or restoration costs due to extreme weather conditions. In addition, SACE argued that FPL did not provide a consistent and measurable metric for a comparison of costs and benefits of its proposed programs. SACE stated that FPL merely provided amorphous narratives as the benefits of the programs and did not provide an estimate of the resulting reduction in outage times or an estimate of restoration costs for any of its proposed programs. (SACE BR 6)

SACE stated that the scope of the cost of the plan is being determined in this docket, which will be shouldered by Florida's customers. SACE further argued that the matter before the Commission is not whether storm hardening is in the public interest, because that is not disputed, but rather, whether FPL complied with the provisions of the Commission's rule. SACE argued that the answer is no and that this answer places the Commission in a difficult position of not having facts in the record to support a public interest determination. (SACE BR 10)

WALMART
Walmart adopted the position of OPC on this issue. (Walmart BR 3)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission shall consider the extent to which the storm protection plan is expected to reduce restoration costs and outages times associated with extreme weather events, and enhance reliability, including whether the plan prioritizes areas of lower reliability performance. 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.

FPL provided an analysis of Hurricanes Matthew and Irma to demonstrate that the existing SPP programs have increased infrastructure resiliency, reduced restoration time, and reduced restoration costs. Table 2D-1 shows how the restoration costs and times for Hurricanes Matthew and Irma would have differed without hardening.

Table 2D-1
FPL Impacts of Hurricanes Matthew/Irma without any Storm Hardening

	Hurricane Matthew	Hurricane Irma
Additional Construction Man-Hours	93,000 (36%)	483,000 (40%)
Additional Restoration time (days)	2 (50%)	4 (40%)
Additional Restoration Costs (Millions)	$105 (36%)	$496 (40%)

Source: EXH 2, P 9

FPL also conducted a 40-year NPV analysis of savings which indicated the savings achieved from storm hardening if a storm similar to Hurricane Matthew and Hurricane Irma occurred once every year three years and once every five years. FPL's analysis is shown in Table 2D-2. (EXH 2, P 9-10)

Table 2D-2
FPL's 40-year NPV Analysis

Storm	40-Year NPV Savings Every 3 Years (2017$)	40-Year NPV Savings Every 5 Years (2017$)
Matthew	$653 million	$406 million
Irma	$3,082 million	$1,915 million

Source: EXH 2, P 9-10; FPL BR 21

OPC argued that although some of FPL's proposed SPP programs will indeed have a greater impact on reducing outage times and lowering restoration costs than others, FPL's SPP did not meet the requirements set forth in the SPP Rule. (Joint Parties BR 5) SACE also argued that FPL's SPP did not meet these same SPP Rule requirements. (SACE BR 4-8) The parties' arguments and staff's analysis on the requirements of the SPP Rule are addressed in Issue 1D. Additionally, OPC believes that several of the programs are not unique to extreme weather storm hardening and/or are incremental to base rate recoverable costs in the normal cost of business. Therefore, those programs should not be included in FPL's SPP. (Joint Parties BR 7-9) More specifically, OPC witness Mara testified that both the Substation Storm Surge/Flood Mitigation Program and Transmission Access Enhancement Program should be excluded from FPL's SPP, as neither program complied with Rule 25-30.030, F.A.C., as these programs do not reduce outage times. (TR 660; TR 645; TR 649-650) The parties' arguments, as well as staff's recommendation regarding FPL's Substation Storm Surge/Flood Mitigation Program and Transmission Access Enhancement Program are addressed in Issues 4D and 9, respectively.

Staff believes that FPL provided the necessary information to meet the requirements of the SPP Statute and Rule related to this issue. Using historical data, the Company estimated the reduction in outage times and restoration costs that would result from the implementation of its proposed SPP programs. Based on the historical data, FPL demonstrated that its proposed programs may reduce restoration costs and outage times associated with extreme weather.

CONCLUSION

FPL utilized historical data to support its 2023 SPP program evaluation and prioritization. The historical data demonstrates that FPL's proposed SPP may reduce restoration costs and outage times associated with extreme weather events.

Issue 3D: To what extent does FPL's Storm Protection Plan prioritize areas of lower reliability performance?

Recommendation: FPL's SPP appears to prioritize areas of lower reliability performance. (P. Buys)

Position of the Parties

FPL: FPL's 2023 SPP prioritizes areas of lower reliability performance. FPL has selected, prioritized, and deployed all of its historical storm hardening programs in a deliberate and effective manner over the past sixteen years, and FPL is employing this same approach for its 2023 SPP programs. (*FPL witness Jarro*)

JOINT PARTIES: FPL has several proposed projects that prioritize areas of lower reliability performance, including Feeder Hardening, Lateral Hardening, and Transmission Hardening. Substation Storm Surge and Transmission Access do not qualify as permissible SPP programs or projects and/or are not economically justifiable; therefore, they must be excluded.

SACE: No position.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

FPL

FPL argued that while all of its SPP programs are system-wide initiatives, annual activities and projects are prioritized and selected based on factors that include: last vegetation maintenance date; historic service reliability performance during extreme weather conditions; and efficient use of resources. Beginning in 2025, FPL proposed to add a new Management Region selection approach to its Distribution Lateral Hardening Program to target areas of highest risk of hurricane impacts, highest concentration of customers, and areas that would require significant travel times for out-of-state crews during extreme weather restoration events. FPL stated that no parties opposed or challenged its proposed prioritization and selection methodologies. (FPL BR 22-23)

JOINT PARTIES

The Joint Parties reiterated and incorporated their arguments regarding the proposed Substation Storm Surge/Flood Mitigation and Transmission Access Enhancement programs. (Joint Parties BR 10)

SACE

SACE did not take a position on this issue. (SACE BR 3)

WALMART

Walmart adopted the position of OPC on this issue. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(a), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 to be provided.

In Section III of its SPP, FPL provided a description of its overall service area and transmission and distribution facilities. (EXH 2, P 12-13) FPL's SPP programs are system-wide initiatives; however, the annual activities are prioritized based on last inspection dates, last vegetation management dates, reliability performance, and efficient resource utilization. For each of its SPP programs, FPL included the specific criteria and factors used to select and prioritize projects. This information was included in Section IV as part of the SPP program descriptions. (EXH 2, P 13) For example, as part of its project level detail, FPL indicated if the feeder, lateral, or transmission structure to be hardened experienced outages during Hurricanes Irma, Matthew, and Michael, then these factors were considered for the prioritization selection of its projects. (EXH 2, Appendix E)

OPC acknowledged that FPL's SPP has several proposed projects that prioritize areas of lower reliability performance, such as the Distribution Feeder Hardening Program, Distribution Lateral Hardening Program, and Transmission Hardening Program. (Joint Parties BR 10) However, OPC argued the Substation Storm Surge/Flood Mitigation Program and the Transmission Access Enhancement Program do not qualify as permissible SPP program or projects and/or are not economically justifiable. (Joint Parties BR 10) In support of this position, OPC witnesses Mara and Kollen testified that these two programs do not comply with the SPP Rule and would result in an excessive burden on rate payers. (TR 645-646; TR 846) However, this issue addresses the extent to which FPL's SPP prioritizes areas of lower reliability performance. Therefore, OPC's arguments regarding the Company's Substation Storm Surge/Flood Mitigation Program and Transmission Enhancement Access Program are discussed in Issues 4D and 9, respectively. OPC did not specifically dispute the extent to which FPL's SPP prioritized areas of lower reliability performance.

Staff recommends FPL's SPP prioritizes areas of lower reliability performance. FPL described the method and criteria it used to select and prioritize the proposed SPP projects. As identified above, OPC did not dispute that FPL's proposed projects prioritized areas of lower reliability. Instead, OPC disagreed with inclusion of several of FPL's programs and projects due to cost or qualification as a SPP program which is addressed in other issues. Thus, staff recommends that FPL demonstrated its prioritization of SPP projects in areas of lower reliability performance.

CONCLUSION

FPL's SPP appears to prioritize areas of lower reliability performance.

Issue 4D: To what extent is FPL's Storm Protection Plan regarding transmission and distribution infrastructure feasible, reasonable, or practical in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas?

Recommendation: With the exceptions discussed in Issues 6D, 9, and 10D, FPL's SPP appears feasible, reasonable, and practical within the Company's service territory. (P. Buys)

Position of the Parties

FPL: FPL has not identified any areas where its SPP programs would not be feasible, reasonable, or practical. (*FPL witness Jarro*)

JOINT PARTIES: A large number of programs that FPL has proposed as SPP programs in flood zones are more appropriately addressed in a base rate case, since it has not been demonstrated that these programs or projects will harden the system from extreme storm events. Additionally, many programs do not reduce BOTH restoration costs and outage times.

SACE: No position.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

FPL

In its brief, FPL stated that it has not identified any areas where its SPP programs would not be feasible, reasonable, or practical. (FPL BR 23)

FPL argued that OPC's recommendations regarding the Substation Storm Surge/Flood Mitigation Program are inconsistent. FPL further argued that OPC witness Mara recommended that only substations with alternate feeds or no history of flooding should be excluded for this Program. However, witness Mara does not identify any specific substation that would be excluded by his proposal, nor does he explain the elimination of the entire budget for this program. This is the same SPP program in FPL's 2020 SPP, and was projected to be completed by 2022. However, due to field conditions and permitting delays, FPL was unable to complete the Program. FPL is only proposing to continue the Program to address the remaining four substations originally identified in its 2020 SPP. FPL argued that it is not adding new or additional substations to the Substation Storm Surge/Flood Mitigation Program. In addition, all four of the remaining substations to be completed under this Program have experienced floods or storm surge in the past. FPL pointed out that no Intervenors disputed that the Substation Storm Surge/Flood Mitigation Program will reduce restoration costs and outage times associated with the need to de-energize and repair substations impacted by storm surge and/or floods. FPL argued that the Intervenors' recommended adjustments overlook that the mitigation measures of this Program will not only reduce outages but will reduce restoration costs. (FPL BR 25-26)

JOINT PARTIES

In their joint brief, OPC and FIPUG reiterated and incorporated by reference their arguments made in Issue 2D. In addition, the Joint Parties stated they focused their evaluation and resulting objections on the lack of strict compliance with the SPP Rule and Statute. They argued that their efforts to identify excessive spending centered on projects that did not meet the Two-Prong test of reducing outage times and reducing restoration costs and those projects that were not cost-effective. The Joint Parties stated that "feasible, reasonable, or practical" is a test of the physical viability of the plan components and is not a statutory test for whether the plan is in the public interest nor does it exclude the consideration of prudence. In addition, the Joint Parties argued that the Commission should reduce the budgets for the Distribution Lateral Hardening Program and the Substation Surge/Flood Mitigation Program, and deny the Transmission Access Enhancement Program as recommended by witness Mara. (Joint Parties BR 10-11)

SACE

SACE did not take a position on this issue. (SACE BR 3)

WALMART

Walmart adopted the position of OPC on this issue. (Walmart BR 4)

ANALYSIS

Section 366.96(4)(b), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 SPP, FPL provided a map of its service territory, which included the number of customers served within each area. (EXH 2, Appendix B) FPL also provided descriptions of its service territory in Section III of its SPP. (EXH 2, P 12-13) FPL has not identified any areas of its service area where its SPP programs would not be feasible, reasonable, or practical. This includes the former Gulf service areas. (EXH 2, P 13)

In their brief, the Joint Parties argued that FPL's SPP programs that target issues in flood zones are more appropriately addressed in a base rate case since it has not been demonstrated that these programs or projects will harden the system. (Joint Parties BR 10) OPC raised issues concerning FPL's Transmission Access Enhancement Program, which are addressed in Issue 9.

Witness Mara testified that the Substation Storm Surge/Flood Mitigation program does not reduce outage times and should be excluded from FPL's SPP because raising a substation does not reduce outage times. In addition, he testified that if a transformer had to be de-energized for flooding, the load from that substation could be switched to an adjacent substation that is not flooded. Witness Mara recommends excluding any substation where there are alternate feeds to allow the substation to be de-energized due to flooding and excluding any substation that has not had a history of flooding. (TR 649-650)

FPL witness Jarro testified that FPL has not added new or additional substations to the Substation Surge/Flood Mitigation program. These were the original substations listed in its 2020 SPP. The Program was originally scheduled to be completed by 2022. However, there were permitting delays and field conditions that delayed the projects. Witness Jarro testified that de-energizing one substation due to flooding does not mean the adjacent substation can support the load from the other substation. He further testified that witness Mara's recommendation is not practical because the four remaining substations have a history of flooding. Witness Jarro opined that the Substation Program will reduce outages and restoration costs associated with the need to repair the flooded substation. (TR 1127-1128)

Staff recommends FPL has met the requirements of Rule 25-6.030(3)(c), F.A.C., by providing a map of its service area, the number of customers served within each area, and the methodology of prioritizing projects within its programs. Staff disagrees with witness Mara regarding the Substation Storm Surge/Flood Mitigation program because FPL is raising the equipment above the projected flood level and constructing flood protection walls. Witness Jarro testified that the four remaining substations require this mitigation, and that FPL has not added new or additional substations from what was included in FPL's 2020 SPP. (TR 1127) In view of the information presented in FPL's SPP and witness testimony, specifically on the Substation Storm Surge/Flood Mitigation program, staff believes FPL's SPP is reasonable in certain areas of the Company's service territory, including, but not limited to, flood zones and rural areas.

CONCLUSION

With the exceptions discussed in Issues 6D, 9, and 10D, FPL's SPP appears feasible, reasonable, and practical within the Company's service territory.

Issue 5D: What are the estimated costs and benefits to FPL and its customers of making the improvements proposed in the Storm Protection Plan?

Recommendation: The estimated costs of FPL's SPP programs are shown in Table 5D-1. The estimated benefits, characterized by the reduction in CMH and outage times, are discussed in Issue 2D. (P. Buys)

Position of the Parties

FPL: The estimated costs for each SPP program are provided in Section IV and Appendix C of Revised Exhibit MJ-1. Consistent with historical results, FPL expects that the programs included in the 2023 SPP will result in a reduction of restoration costs and outage times associated with extreme weather events. A description the benefits of FPL's 2023 SPP is provided in Section II, Section IV, and Appendix A of Revised Exhibit MJ-1. (*FPL witness Jarro*)

JOINT PARTIES: The Company failed to quantify the dollar benefits of any of its programs and failed to use comparisons of benefits to costs to identify beneficial programs, select and rank those projects, or determine the magnitude of those projects.

SACE: FPL did not provide the necessary cost and dollar benefit data to the Commission required by Rule 25-6.030, F.A.C. As such, one cannot determine, or compare, the estimated costs and dollar benefits of the Storm Protection Plan programs and projects. Therefore, the FPL Storm Protection Plan, as filed, cannot be approved.

WALMART: Walmart adopts the position of OPC.

PARTIES' ARGUMENTS

FPL

FPL argued that based on the results of actual historical events, each of its 2023 SPP programs will continue to provide increased infrastructure resiliency, reduced outage times, and reduced restoration costs when the system is impacted by an extreme weather event, as further explained in Issue 2D. FPL stated that the Intervenors argued that the terms "estimated benefits" and "estimate of the resulting reduction in outage times and restoration costs" in the SPP Statute and Rule required a projection of quantified and monetized benefits for the 10-year SPP period. FPL disagreed as discussed in Issue 1D. (FPL BR 23-24)

FPL explained that the estimated costs for each of the SPP programs are included in its SPP. FPL evaluated the total customer rate impacts for the overall budget as a whole, which is the same process FPL utilized in developing its O&M and capital expenditures budgets. FPL pointed out that the only costs challenged by the Intervenors are for the Substation Storm Surge/Flood Mitigation Program and the Distribution Lateral Hardening Program. (FPL BR 24) In its brief, FPL refuted the Intervenors' recommended adjustments for these two specific SPP Programs, as well as any staff adjustments to the Distribution Feeder/Lateral Hardening Programs.

JOINT PARTIES

The Joint Parties argued that FPL not only failed to estimate benefits of its proposed programs going forward, but also testified that it is not appropriate to conduct an estimate of benefits as FPL did. The Joint Parties opined that this is contrary to the SPP Rule's requirements. The Joint Parties restated and incorporated their arguments made in Issue 1D. (Joint Parties BR 11)

The Joint Parties further argued that the Legislature intended to create and require the use of a mechanism designed to serve the public interest, which includes consideration of customers' rates. They argued that it would be disingenuous for the utilities to avoid any evaluation of the reasonableness of the proposed programs, or cost and benefit comparisons, as required by the SPP Rule, by allowing utilities to unilaterally decide if, when, and how they should produce benefit estimates in terms which can be compared to the cost estimates or rate impacts, meaning dollars. The Joint Parties argued that FPL failed to provide meaningful or quantifiable information regarding the expected costs and benefits of its SPP programs. In addition, the Joint Parties opined that the record shows the costs far outweigh the benefits. (Joint Parties BR 11-12)

SACE

SACE argued that FPL's SPP did not meet the requirements of Rule 25-6.030(3)(d)1., F.A.C., because the Company did not provide any estimate of the resulting reduction in outage times or restoration costs due to extreme weather conditions. In addition, SACE argued that FPL did not provide a consistent and measurable metric for a comparison of cost and benefits of its proposed programs and merely provided amorphous narratives as the benefits of the programs. (SACE BR 6)

SACE stated that the scope of the cost of the plan being determined in this docket will be shouldered by Florida customers. SACE further argued that the matter before the Commission is not whether storm hardening is in the public interest, because that is not disputed, but rather, whether FPL complied with all the provisions of the Commission's rule. SACE argued that answer is no, and that this answer places the Commission in a difficult position of not having facts in the record to support a public interest determination. (SACE BR 10)

WALMART

Walmart adopted the position of OPC on this issue. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(c), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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, as identified and discussed in Issue 2D.

For each SPP program, FPL listed the estimated capital costs and operating expenses, which are summarized in Table 5D-1. The Company compared these costs with the estimated benefits that could be achieved from the completion of its programs. The benefits included the reduction in outage times, as discussed in Issue 2D. (EXH 2, P 13-59, Appendix C)

Table 5D-1
FPL's 2023-2025 SPP Program Costs

Program	2023 (millions)	2024 (millions)	2025 (millions)
Distribution Inspection	$62.7	$64.3	$65.9
Transmission Inspection	$75.9	$62.9	$60.4
Distribution Feeder Hardening	$689.0	$687.0	$544.3
Distribution Lateral Hardening	$523.1	$628.6	$758.4
Transmission Hardening	$55.6	$54.5	$54.5
Distribution Vegetation Management	$73.0	$72.8	$71.9
Transmission Vegetation Management	$11.8	$12.5	$12.6
Substation Storm Surge/ Flood Mitigation	$8.0	$8.0	-
Transmission Access Enhancement	$0.8	$2.8	$15.8
Total	$1,499.9	$1,593.4	$1,583.8

Source: EXH 2, Appendix C

In their brief, the Joint Parties argued that FPL failed to: quantify the dollar benefits of any of the SPP programs, use comparisons of benefits to costs to identify beneficial programs and projects, select and rank those projects, or determine the magnitude of those projects. (Joint Parties BR 11) As argued in Issues 1D and 2D, OPC witness Mara asserted that without an estimate of the cost reduction for outages, it is impossible to make a judgement on prudence, and the monetized values of the reductions during extreme weather events are necessary and should be provided. (TR 642-643) OPC witness Kollen testified that specific decision criteria should be applied to proposed SPP programs and should include justification in the form of a benefit/cost analysis in addition to the qualitative assessments of whether the programs and projects will reduce restoration costs and outage times. (TR 835) In addition, witness Kollen testified that FPL could use its Storm Damage Model to quantify the costs to give a dollar benefit amount. (TR 845)

FPL witness Jarro testified that storm hardening is not a simple cost-effective proposition. He further argued that OPC's belief that outage times should be monetized ignores the very real and simple fact that the monetary value individual customers or communities place on reduced outage times cannot be accurately or uniformly estimated. (TR 1111) Witness Jarro refuted that there is nothing in either the SPP Statute or SPP Rule that prescribes that the benefits of SPP programs must be quantified or monetized. Rather, the SPP rule expressly provides that the SPP must include a "description" of benefits of the SPP programs. (TR 1116) Witness Jarro argued that FPL's Storm Damage Model could not be used to monetize restoration costs and outage times because FPL will not know which specific projects will be completed each year or where they will be located for the entire ten year period of the SPP. He explained that the scope and location of the storm hardening projects used in the Storm Damage Model for each year of the SPP will have a significant impact on the results of the analysis. (TR 1118) Witness Jarro argued that forward-looking estimates would contain inaccurate data as to hurricane tracking, impacts to FPL's infrastructure, and potential system improvement. (TR 74-76)

Staff believes that FPL provided the necessary information to meet the requirements of the SPP Rule. As discussed in Issue 2D, FPL estimated the reduction in outage times and restoration costs that would result from the implementation its proposed SPP programs. The Company also listed in its plan the program costs, including capital and operating expenses. Therefore, the estimated costs and benefits to FPL and its customers as a result of the proposed programs were presented by the Company in its SPP.

CONCLUSION

The estimated costs of FPL's SPP programs are shown in Table 5D-1. The estimated benefits, characterized by the reduction in construction man-hours and outage times, are discussed in Issue 2D.

Issue 6D: What is the estimated annual rate impact resulting from implementation of FPL's Storm Protection Plan during the first 3 years addressed in the plan?

Recommendation: The estimated annual rate impact, as provided by FPL, is projected to increase approximately 65 percent the first three years of its Storm Protection Plan. In order to mitigate the rate impact to FPL's customers, staff recommends FPL's Distribution Lateral Hardening Program continue at the 2022 annual spending levels, approximately $368.2 million per year, starting in 2023. (P. Buys)

Position of the Parties

FPL:

Customer Class	**2023**	**2024**	**2025**
Residential (RS-1) ($/kWh)	$0.00431	$0.00604	$0.00771
Commercial (GSD-1) ($/kW)	$0.73	$1.03	$1.33
Industrial (GSLDT-3) ($/kW)	$0.10	$0.14	$0.17

The estimated rate impacts are based on the total estimated costs of the 2023 SPP programs, which could vary by as much as 10 percent to 15 percent, and does not distinguish which costs would be recovered in the SPPCRC and base rates. (*FPL witness Jarro*)

JOINT PARTIES: Since FPL improperly included certain programs in its proposed SPP, FPL's customer rate impacts are not properly calculated.

SACE: No position.

WALMART: Walmart takes no position, as Walmart has not conducted this analysis.

PARTIES' ARGUMENTS

FPL

In its brief, FPL stated that it provided an estimated rate impact per Rule 25-6.030(3)(h), F.A.C., based upon its estimated annual revenue requirements, which was required by Rule 25-6.030(3)(g), F.A.C. FPL stated that the estimated revenue requirements and rate impacts for the SPP could vary by as much as 10 to 15 percent and included the total program costs, no matter if the costs are in base rates or recovered through the SPPCRC. FPL cautioned that the estimated revenue requirements and rate impacts are not intended to be used to set rates, but are part of what the Commission can consider in order to determine whether it is in the public interest to approve, approve with modification, or deny FPL's 2023 SPP. (FPL BR 33-34)

In addition, no Intervenor opposed the Distribution Lateral Hardening Program or otherwise suggested that it will not reduce restoration costs and customer outage times associated with extreme weather events. FPL pointed out that OPC witness Mara suggested that FPL needs to do more so lateral hardening and undergrounding, and their associated benefits, are spread to more customers and communities. Despite this, the Intervenors recommended that the annual budget for this Program be capped at $606 million per year, which will result in a total ten-year budget reduction of approximately $3.4 billion. FPL argued that the Intervenors overlook the fact that this Program was deployed as a limited pilot and FPL is seeking to deploy this Program as a full-scale permanent SPP program. FPL argued that ramping up the Program will provide the benefits of undergrounding and hardening laterals throughout its system, including the former Gulf service area. Further, FPL argued that the Distribution Lateral Hardening Program is a critical step necessary to harden its transmission and distribution system, since FPL has nearly finished its transmission hardening and feeder hardening programs. This Program will bring the benefits for storm hardening to the individual customers, including both reduced outage times and aesthetics. (FPL BR 27-29)

FPL argued that reducing the number of projects per year for the Distribution Feeder Hardening Program and Distribution Lateral Hardening Program, as staff explored during discovery, would delay the SPP benefits to a significant number of customers with only very little incremental impact on rates. FPL opined that the ramp up in the number of laterals to be completed each year under the Distribution Lateral Hardening Program is due to the inclusion of the former Gulf service area, the significant number of laterals that remain to be hardened throughout FPL's service area, the strong local support and interest in the program, and the addition of the unopposed Management Region selection approach. FPL further argued that reducing the number of projects, per staff's example, would add ten years to complete the Program and would impact 1.0 million customers by exposing them to extended outages after extreme weather events. (FPL BR 30-32)

JOINT PARTIES

In their joint brief, OPC and FIPUG stated that FPL rejected the concept of cost-effectiveness or any sort of analysis of costs versus benefits and did not include either of these concepts in its SPP. Moreover, the Joint Parties argued that there is a lack of evidence in the record of the cost-effectiveness of the programs in dispute so their reasonableness cannot be assessed for the purpose of inclusion in FPL's SPP. The Joint Parties believe the estimated rate impact was not calculated properly due to the fact that the programs in dispute were included in the rate impact calculation. As such, The Joint Parties argued that certain programs should have been excluded from FPL's SPP; and therefore, excluded from the estimated rate impacts (Joint Parties BR 12-13)

SACE

SACE did not take a position on this issue. (SACE BR 3)

WALMART

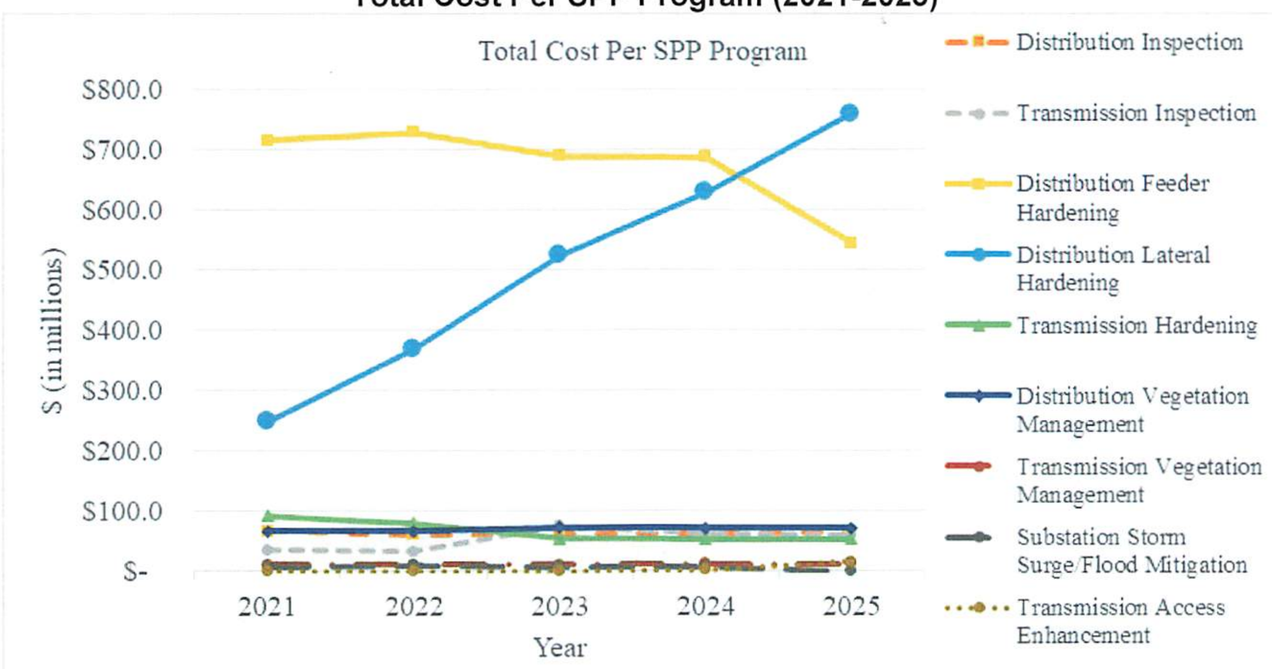
Walmart did not take a position on this issue as it has not conducted an analysis. (Walmart BR 5)

ANALYSIS

Section 366.96(4)(d), F.S., states that when reviewing a utility's transmission and distribution storm protection plan, the Commission 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 25-6.030(3)(i), F.A.C., requires the utilities to provide a description of any implementation alternatives that could mitigate the resulting rate impact. This issue will address the annual rate impacts for the first three years of the Company's SPP and deployment alternatives that would mitigate rate impacts to customers.

Figure 6D-1 is a graph of FPL's actual (2021), and estimated (2022-2025), SPP program costs. As shown on the graph, FPL's Distribution Lateral Hardening Program is moving forward at an accelerated pace while its other programs are relatively constant.

Figure 6D-1
Total Cost Per SPP Program (2021-2025)



Sources: EXH2, EXH55

Pursuant to Rule 25-6.030(3)(h), F.A.C., FPL provided the rate impact information for each customer type, which is shown in Table 6D-1. The residential rate impact increases 40 percent from 2023 to 2024 and up to 65 percent by 2025.

Table 6D-1
SPP Estimated Rate Impact (2023-2025)

Customer Class	2023	2024	2025
Residential (RS-1) ($/kWh)	$0.00431	$0.00604	$0.0071
Commercial (GSD-1) ($/kW)	$0.73	$1.03	$1.33
Industrial (GSLDT-3) ($/kW)	$0.10	$0.14	$0.174

Source: EXH 2, P 62

OPC witness Mara compared FPL's capital costs from the current 2020-2029 SPP to its proposed 2023-2032 SPP capital costs and determined there was a projected increase of $3.5 billion in spending over the 10-year plan. (TR 643) Comparing the costs on a per customer basis, witness Mara calculated the ratio of capital spending to the number of customers had increased 34 percent. (TR 644) Witness Mara proposed a reduction of capital spending by $3.6 billion over the 10-year period. Below is a summary of his adjustments: (TR 645)

- Substation Storm Surge/Flood Mitigation Program - $16 million reduction because this program does not comply with the SPP Rule.
- Transmission Access Enhancement Program - $116 million reduction from the $116 million total program capital cost because this program does not comply with the SPP Rule.
- Distribution Lateral Hardening Program - $3,389 million reduction from the $9,391 million total program cost to limit rate impact to customers.

(TR 645)

FPL's Substation Storm Surge/Flood Mitigation Program is addressed in Issue 4D and FPL's new Transmission Access Enhancement Program is addressed in Issue 9. OPC's rate mitigation recommendation for the Distribution Lateral Hardening Program is discussed below.

Witness Mara recommended a reduction in capital spending for the Distribution Lateral Hardening Program because FPL failed to demonstrate any cost reductions from outages or rate relief to customers due to this program. To support his proposed reduction in capital spending for this program, witness Mara testified that the costs of this program account for 67 percent of the total SPP budget. (TR 663) He argued that this program is a significant investment for a small portion of FPL's system and should be scaled back, since the benefit value of this program is unknown. (TR 664-666) In addition, witness Mara calculated that the investment of this program per customer would range from $8,158 to $16,379. (TR 664) As a result, witness Mara recommended the program should be separated into two projects, one for overhead laterals and one for undergrounding laterals to help with tracking costs and reviewing projects. He also recommended a capital budget reduction of approximately $3.4 billion. The budget would remain the same for 2023 and 2024, and spending would be capped for 2025 through 2032 at $606 million per year, to relieve some of the rate impacts on customers. (TR 665-666) However, his calculation is based on the total program cost for the 10-year period. Staff recommends that making any adjustments based on a 10-year budget is not practical, given that the Commission must review a utility's SPP at least every three years as well as conduct annual cost-recovery proceedings.

In rebuttal testimony, FPL witness Jarro argued that the majority of FPL's existing SPP programs have been in place since 2007 and storm hardening is not a simple cost-effective proposition as argued by OPC. (TR 1108; TR 1111) In addition, he testified that OPC's testimony on this point is contradictory. They argued SPP programs should be cost-justified before they can be approved, but then recommended that the Commission reject only one of the nine programs in FPL's 2023 SPP. Witness Jarro further explained that stated differently, OPC does not dispute that it would be reasonable for the Commission to allow FPL to implement the eight programs included in FPL's 2023 SPP without further cost-justification. (TR 1111; TR 1117-1118)

In response to OPC's position, witness Jarro testified that a reduction to the budget would reduce the number of laterals to be completed each year and delay when customers will receive the direct benefits of the program. (TR 1129) Witness Jarro explained that the Lateral Program was a pilot and FPL is ramping up the program in order to provide the benefits of underground lateral hardening throughout its system. (TR 1134) In rebuttal, he further argued that although all customers indirectly benefit from overhead hardening and undergrounding laterals, through reduction in restoration costs, the direct benefits for customers include both reduced outage times and aesthetics. (TR 1135) He also testified that there does not need to be separate overhead and underground lateral SPP programs. Witness Jarro disagreed with OPC's recommendation to separate this program out into two components, since the underground and overhead components of the program are symbiotic and the work will be part of the same overall lateral project. Witness Jarro explained that each lateral on the feeder to be hardened will be evaluated to determine if overhead hardening or undergrounding would be beneficial depending on field conditions and limitations at that time. (TR 1129-1130)

Utility facilities are designed and built to serve customers 24/7 and the basic standards of construction and maintenance account for normal weather conditions including some contingencies such as maintenance requirements, vehicle strikes, lightning, etc. As such, the primary purpose of storm hardening is to mitigate outages due to extreme weather which would subsequently reduce restoration time and costs to all ratepayers. Any resulting improvements to day-to-day reliability are secondary to the goal of storm hardening and would only benefit the customers directly impacted by the project or activity. Since lateral hardening projects are smaller in scale and more focused geographically, the likelihood of the project producing benefits for the general body of ratepayers is limited. Realizing that storm hardening costs may or may not produce actual financial benefits during a given time, the Commission has encouraged utilities to focus on projects that would impact the largest numbers of customers, such as transmission projects, and has relied upon the resulting estimated rate impact to customers as a guide to determine the reasonable level of storm hardening.

Prior to the enactment of Section 366.96, F.S., storm hardening expenditures were recovered from utility customers through base rates. When these prior storm hardening plans were approved, the Commission stated repeatedly that approval of the plan was not approval for cost recovery purposes and that the utility should consider rate impacts as it proactively implemented its plan. (See Order PSC-2019-0301-PAA) These cautionary directives are consistent with the fact that the level of storm hardening is a discretionary activity which requires close attention to the resulting rate impacts. However, Section 366.96(7), F.S., states, "[a]fter a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence." Therefore, Commission approval of a storm protection plan is now also an approval of the level of storm protection activity. Such approval also has a direct and more frequent impact on rates due to the annual cost recovery mechanism. Unlike other costs, such as fuel costs, the level of storm hardening and the associated costs are discretionary. There are no mandates as to the activity level of an SPP program which is within FPL's control. In addition, Rule 25-6.030(3)(i), F.A.C., requires the utilities to provide a description of any alternatives that could mitigate the rate impact for each of the first three years of the SPP. FPL reported that it has not identified any reasonable implementation alternatives that could mitigate the resulting rate impact. (EXH 2, P62) However, FPL's Distribution Lateral Hardening Program will directly affect a much smaller number of customers when compared to other types of programs, such as transmission projects, and accounts for the majority of the projected increase in SPP costs. Therefore, staff agrees with OPC that reducing the rate impact on customers is appropriate at this time. For these reasons, staff recommends that FPL's Distribution Lateral Hardening Program continue at the level spent on this program in 2022, approximately $368.2 million per year, in order to mitigate the rate impact to customers.[12] Staff is not disputing that the Distribution Lateral Hardening program is in the public interest; rather, staff is recommending FPL slow down the program's activity and annual spending.

CONCLUSION

The estimated annual rate impact, as provided by FPL, is projected to increase approximately 65 percent the first three years of its Storm Protection Plan. In order to mitigate the rate impact to FPL's customers, staff recommends FPL's Distribution Lateral Hardening Program continue at the 2022 annual spending levels, approximately $368.2 million per year.

[12] The actual value will be determined as part of the SPPCRC proceeding.

Issues 7 & 8: Withdrawn.

Issue 9: Should the Commission approve, approve with modification, or deny FPL's new Transmission Access Enhancement Program?

Recommendation: FPL's new Transmission Access Enhancement Program should be denied and excluded from its 2023 SPP. (P. Buys)

Position of the Parties

FPL: The Commission should approve FPL's new Transmission Access Enhancement Program without modification. The Transmission Access Enhancement Program will allow FPL and its contractors to quickly access transmission facilities in areas that become inaccessible due to severe flooding or saturated soils after an extreme weather event, which would result in a reduction of outage times for tens of thousands to hundreds of thousands of customers following an extreme weather event. (*FPL witness Jarro*)

JOINT PARTIES: The Commission should not approve FPL's Transmission Access Enhancement Program ("TEAP").

SACE: No position.

WALMART: Walmart takes no position, as Walmart has not conducted this analysis.

PARTIES' ARGUMENTS

FPL

In its brief, FPL stated that its new Transmission Access Enhancement Program was modeled after a similar program approved by the Commission in a settlement that OPC was party to. FPL further stated that in parts of its service area, some transmission facilities are located in low-lying areas, areas prone to severe flooding, or areas with saturated soils. These areas become inaccessible for repair and restoration following an extreme weather event. Specialized equipment can be used to access these areas after an extreme weather event; however, sometimes the equipment has limited availability during storm events and is typically available at a higher cost than traditional equipment. FPL stated that the purpose of the new Transmission Access Enhancement Program is to target and address such areas so FPL and its contractors can quickly restore transmission outages. (FPL BR 34-35)

FPL argued that the Intervenors ignore the scope and purpose of the new program by arguing that maintenance of bridges, roads, and culverts to access transmission facilities are ordinary base rate activities. FPL argued that it is not proposing to simply maintain roads, bridges, and culverts to access transmission facilities for day-to-day maintenance and vegetation management activities. Rather, the purpose of the new program is to ensure that FPL has access to its transmission access facilities following an extreme weather event. (FPL BR 35)

In addition, FPL rebuts the Intervenors' allegations that it did not demonstrate that the Transmission Access Enhancement Program would reduce restoration costs and outage times and argued that the Intervenors misinterpreted Rule 25-6.030, F.A.C., as requiring SPP benefits to be projected, quantified, and monetized. FPL opined that a transmission-related outage can result in an outage affecting tens of thousands to hundreds of thousands of customers. FPL assured that the Transmission Access Enhancement Program will allow FPL and its contractors access to the transmission facilities in order to address and restore the transmission outages, which will shorten the associated restoration costs and restoration times. FPL believes the Transmission Access Enhancement Program is consistent with the definition of a "storm protection project" from Rule 25-6.030(2)(b), F.A.C., which is defined as "a specific activity within a storm protection program designed for enhancement of an identified portion or area of existing electric or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability." (FPL BR 35-36)

JOINT PARTIES

In their joint brief, OPC and FIPUG stated that the record shows that the Transmission Access Enhancement Program is not necessary for FPL to harden its transmission system against extreme weather events. The Joint Parties pointed out that FPL has already replaced 99 percent of its transmission structures and the existing roads and bridges were sufficient to achieve the work needed. In addition, the Joint Parties stated that FPL's transmission system is designed with adequate redundancy and complies with NERC standards regarding redundancy. (Joint Parties BR 13)

The Joint Parties argued that maintaining or replacing a company's infrastructure, including bridges and transmission right-of-ways, is part of FPL's basic responsibilities in the normal course of business. They further opined that such maintenance does not harden the system or reduce outages. The Joint Parties argued that recovery for basic maintenance should be addressed in a rate case and should not be allowed to be recovered through SPP recovery. In addition, they argued that FPL's description of benefits for the Transmission Access Enhancement Program is vague and does not satisfy the SPP Rule. The Joint Parties believe the benefits description is inadequate to justify taking hundreds of millions of dollars from ratepayers who are already dealing with inflation pressures and pandemic-related economic challenges. (Joint Parties BR 13-14)

SACE

SACE did not take a position on this issue. (SACE BR 3)

WALMART

Walmart did not take a position on the issue as it has not conducted an analysis. (Walmart BR 5)

ANALYSIS

FPL's Transmission Access Enhancement Program is a new program included in the Utility's 2023 SPP. This program focuses on enhancing access roads, bridges, and culverts at targeted transmission facilities to ensure FPL and its contractors have reasonable access for repair and restoration activities after an extreme weather event. (TR 54-57; TR 69; EXH 2, P 58) FPL witness Jarro testified that there are transmission facilities located in low-lying areas that are not readily accessible due to severe flooding or saturated soil during extreme weather events. (TR 56) FPL argued that the program will reduce the need for specialized equipment and will also reduce restoration time and costs associated with extreme weather conditions for specific hard to access transmission facilities and equipment. (TR 56; EXH 2, P 59) The enhancement projects are scheduled to begin in 2023 in Clay, Flagler, Brevard, Palm Beach, Broward, Homestead, and Columbia Counties. (EXH 60, BSP 129-132; EXH 2, Appendix E, P 20) The total estimated program costs are $117.4 million for 2023-2032. The estimated annual average program cost is $6.5 million per year for the first three years.

The Joint Parties opposed FPL's Transmission Access Enhancement Program and argued that it should be denied. (TR 660) OPC witness Mara testified that:

- The activities within this Program are to maintain infrastructure with the status quo rather than enhance it. (TR 640)
- Enhancements to an electric utility system, such as the replacement of a bridge, do not meet the criteria set forth in Rule 25-6.030, F.A.C., because outages would not be reduced. (TR 660)
- As an alternative, purchasing and maintaining specialized equipment to access difficult terrain including track vehicles, large tire vehicles, and floating equipment may be more cost-effective than expending $115.8 million in capital cost for maintenance of roads and bridges. (TR 659)

Witness Mara testified that adding a culvert or bridge can increase access; however, if the right-of-way is flooded, it would not matter if there is a bridge or culvert and this capital investment would not result in enhanced access. Additionally, witness Mara argued that the utility has a responsibility to maintain its infrastructure; and therefore, replacing a bridge that needs to be replaced is a normal course of business, and does not qualify as a storm protection project. To support his argument, witness Mara explains that 99 percent of FPL's transmission structures, in the former FPL service area, are now hardened with steel or concrete poles. Therefore, it is unclear as to why FPL did not previously see a need to maintain its access roads in the ordinary course of business to gain access to these poles while hardening. He also argued that any reduction in outage times or restoration costs should be measured against a well-maintained infrastructure. Witness Mara understands that specialized equipment has limited availability during storm events; however, purchasing the vehicles instead of renting or building bridges may be more cost-effective. (TR 658-659)

In his rebuttal testimony, FPL witness Jarro refuted OPC's claims and testified:

- This Program is to ensure access to specific transmission facilities in low-lying areas following an extreme weather event, not to simply maintain FPL's infrastructure as an ordinary base rate activity. (TR 1136)
- The Program will reduce the need and associated costs for specialized equipment and will help expedite restoration activities and thereby reduce customer outage times. The witness notes that a transmission-related outage can affect tens of thousands of customers and may cause a cascading event that could result in loss of service for hundreds of thousands of customers. (TR 1137)

- OPC witness Mara acknowledged that these low-lying areas may not be accessible following an extreme weather event without specialized equipment and vehicles. In addition, specialized equipment and vehicles may have limited availability during and immediately following storm events. (TR 1137)

Witness Jarro also argued that the intent of the Program's enhancements is not for accessibility for day-to-day maintenance during drier times of the year; but rather, for access when it is flooding or the soil is saturated due to extreme weather. He also testified that witness Mara appears to overlook that the Commission's SPP Rule defines a storm protection project to include enhancement of transmission and distribution areas and not just the transmission and distribution facilities themselves. (TR 1136-1138)

Witness Jarro opined that even if the specialized equipment was readily available for purchase, FPL would need a large fleet of specialized equipment because of the size of FPL's service area and miles of transmission lines. Further, purchasing a large fleet of specialty vehicles would require ongoing specialized maintenance and specialized contractors that are trained and familiar with operating and maintaining the specialized equipment. (TR 1138-1139) When asked about the cost for large tire vehicles to perform restoration work, FPL responded that it has not been able to identify the vehicles to perform the jobs; however, FPL did provide the cost of renting certain types of vehicles that would be capable for performing the job. The hourly rates, which include the cost of trailer for transport, range from $140 to $200 per hour. FPL also indicated that it did not perform any studies or analysis comparing the costs and/or benefits of building bridges and access roads rather than purchasing additional equipment necessary to access these areas. (EXH 60, BSP 129-132)

Rule 25-6.030 (2)(c), F.A.C., defines transmission and distribution facilities as "all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors." Based on the FERC system of accounts, staff views this definition as inclusive of all components of a transmission or distribution project, not that each component is independently eligible for storm protection cost recovery. For example, a road may need to be repaired or relocated as part of a hardening project that converts wood poles to concrete poles. The total costs of the project, including the cost of road repair, would be included in the transmission plant reporting category and eligible for storm protection cost recovery. Therefore, staff agrees with OPC witness Mara that improvements to roads and bridges should be undertaken as part of the overall hardening project for a given transmission line segment. In addition, staff agrees with OPC that maintaining access roads for the transmission facilities should be a regular activity and not a storm protection activity. As discussed above, FPL did not provide actual data supporting its position that obtaining or renting specialized equipment is difficult or more costly than its proposed program. Even though FPL explained in discovery that some of its transmission systems were constructed without access roads, the Company should still maintain access for activities, such as vegetation management and inspections, prior to hurricane season. (EXH 60, BSP 131) As such, staff recommends FPL's Transmission Access Enhancement Program be denied and excluded from its 2023 SPP.

CONCLUSION

FPL's new Transmission Access Enhancement Program should be denied and excluded from its 2023 SPP.

Issue 10D: Is it in the public interest to approve, approve with modification, or deny FPL's Storm Protection Plan?

Recommendation: Staff recommends FPL's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1D. Staff recommends that FPL's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Hardening Program at the 2022 level; (2) remove the new Transmission Access Enhancement Program; and, (3) remove the transmission looping initiative from the Transmission Hardening Program. FPL should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff. (P. Buys)

Position of the Parties

FPL: Yes. FPL's Revised 2023 SPP meets the objectives of Section 366.96, F.S., satisfies the requirements of Rule 25-6.030, F.A.C., is in the public interest, and should be approved without modification. The programs included in the Revised 2023 SPP will collectively provide increased resiliency and faster restoration to the electric infrastructure that FPL's 5.7 million customers and Florida's economy rely on for their electricity needs. (*FPL witness Jarro*)

JOINT PARTIES: It is not in the public interest to approve FPL's Storm Protection Plan without making the modifications recommended by the Office of Public Counsel. The Commission should make the adjustments reflected in the table below from page 13 of the Direct Testimony of Kevin J. Mara.

SACE: FPL did not provide the necessary information required by Rule 25-6.030, F.A.C., for the Commission to render a public interest determination. Due to the Company's non-compliance with certain provisions of Rule 25-6.030, F.A.C., the FPL Storm Protection Plan, as filed, cannot be approved to be in the public interest. See the argument below.

WALMART: Walmart believes the public interest would benefit if the Commission directs each utility to continue to collaborate with interested stakeholders during the interim period before their next required updated SPPs to develop ways in which customer-sited generation may be utilized as part of the SPP in order to strengthen the T&D systems and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall.

PARTIES' ARGUMENTS

FPL

FPL stated that its 2023 SPP is in the public interest and should be approved for all the reasons more fully explained in Issues 1D through 9 of its brief. (FPL BR 37)

JOINT PARTIES

OPC and FIPUG recommended modification to FPL's SPP, which are listed below in Table 10D-1. The Joint Parties further recommended that in determining the costs to be recovered through the SPPCRC, Construction Work In Progress (CWIP) should be excluded from both the return on rate base and depreciation expenses, and instead allow a deferred return on CWIP until it is converted to plant in service or prudently abandoned. However, as an alternative, the Joint

Parties recommended a return on CWIP could be deferred either as an allowance for funds used during construction (AFUDC) or as a miscellaneous deferred debit. (Joint Parties BR 15)

The Joint Parties argued that the determination of whether a project meets the public interest standard requires the presentation of facts and analysis. The Joint Parties opined that the public interest is served by decisions that consider affordability and reasonableness. (Joint Parties BR 15-16) Further, they stated that the SPP Statute requires estimates of customer rate impacts and the SPP Rule requires a comparison of expected costs and benefits. In addition, the Joint Parties argued that whether the comparison required in the SPP Rule is made by a cost/benefits analysis or some other determinant of cost-effectiveness, there must be rational guidelines in the application of the SPP Statute. (Joint Parties BR 16)

The Joint Parties further argued that the costs customers must pay will quickly spiral out of control if there are no rational guidelines. The Joint Parties recommended that the Commission should exercise caution as recovery from the SPPCRC will add another cost onto the customer's bill, over and above base rates. They stated that customer bills are already subject to increasing natural gas prices and base rate increases, not to mention the general economic pressures due to increasing costs of everything, including food and household necessities. The Joint Parties argued that consideration of the public interest must take into account not only the need for storm hardening, but also the level at which it is cost-effective and affordable for ratepayers. They state that based on the information provided by FPL, the costs of FPL's SPP outweigh the benefits and the SPP should be modified as recommended to satisfy the public interest standard and qualify for approval. (Joint Parties BR 16-17)

SACE

SACE argued that FPL's SPP did not meet the requirements of Rule 25-6.030(3)(d)1., F.A.C., because the Company did not provide any estimate of the resulting reduction in outage times or restoration costs due to extreme weather conditions. In addition, SACE argued that FPL did not provide a consistent and measurable metric for a comparison of cost and benefits of its proposed programs. SACE stated that FPL merely provided amorphous narratives as the benefits of the programs and did not provide an estimate of the resulting reduction in outage times or an estimate of restoration costs for any of its proposed programs. (SACE BR 6)

SACE stated that the scope of the cost of the plan being determined in this docket will be shouldered by Florida customers. SACE further argues that the matter before the Commission is not whether storm hardening is in the public interest, because that is not disputed, but rather whether FPL complied with all the provisions of the Commission's rule. SACE argued that answer is no and that this answer places the Commission in a difficult position of not having facts in the record to support a public interest determination. (SACE BR 10)

WALMART

Walmart argued it would be in the public interest if FPL will continue to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen FPL's system. (Walmart BR 2)

ANALYSIS

Section 366.96(5), F.S., requires the Commission to 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 discussed in Issue 1D, staff recommends that FPL's filing satisfies the requirements of Rule 25-6.030, F.A.C., and provides the Commission with adequate information in order to satisfy its statutory requirements.

As described by FPL witness Jarro, the Company's proposed SPP covers the period of 2023-2032, and uses the same analysis methodology and programs that were included in its previous SPP for the period of 2020-2029. FPL's proposed SPP originally included 11 programs. However, on July 11, 2022, FPL filed a notice withdrawing its proposed Distribution and Transmission Winterization Programs. As such, its revised proposed SPP included nine programs rather than eleven. Of these nine programs, eight programs are a continuation from FPL's previous SPP and there is one proposed new program, Transmission Access Enhancement. (TR 53-54) FPL's SPP included the following nine programs:

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

As discussed in prior issues, OPC witness Mara recommended modifications to three of FPL's SPP programs; Distribution Lateral Hardening, Substation Storm Storm/Flood Mitigation, and the Transmission Access Enhancement. Witness Mara's recommendations are summarized in Table 10D-1. Staff previously addressed OPC's specific recommended adjustments in the following issues: Issue 4D (Substation Storm Surge/Flood Mitigation), Issue 6D (Distribution Lateral Hardening), and Issue 9 (Transmission Access Enhancement). FIPUG and SACE took the same position and agreed with OPC. Walmart provided no witness testimony, but argued in its brief that it would be in the public interest if FPL continued to collaborate with Walmart and other interested stakeholders to develop ways in which customer-sited generation may be utilized to strengthen FPL's system. (Walmart BR 2) Although staff agrees with continuing the collaboration between utilities and interested stakeholders, the SPP Statute does not contemplate customer-sited generation. Section 366.96(2)(b), F.S., defines a transmission and distribution storm protection plan as "a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management." Thus, on-site generation does not meet the definition as laid out in the statute.

Table 10D-1
OPC Witness Mara's Recommended Program Adjustments

Program	Total 2023-2032 SPP (millions)	Proposed Reductions (millions)	Net 2023-2032 SPP (millions)	Reason for Reduction
Distribution Inspection	$629	-	$629	
Transmission Inspection	$657	-	$657	
Distribution Feeder Hardening	$2,437	-	$2,437	
Distribution Lateral Hardening	$9,389	($3,389)	$6,000	Limit impact to customers
Transmission Hardening	$499	-	$499	
Distribution Vegetation Management	$28	-	$28	
Transmission Vegetation Management	-	-	-	
Substation Storm Surge/Flood Mitigation	$16	($16)	-	Does not comply with SPP Rule
Transmission Access Enhancement	$116	($116)	-	Does not comply with SPP Rule

Source: (TR 645)

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 part of FPL's Transmission Hardening Program, FPL seeks to continue an initiative from Gulf's 2020 SPP. This initiative would add additional transmission lines into radially fed substations and additional transformers in single bank transmission substations. (EX 2, P 37) Looping substations is a common utility practice to ensure reliable service and staff does not believe the initiative meets the objective of storm protection or hardening. 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) The looping initiative involves the construction of new redundant infrastructure, rather than the enhancement or hardening of existing facilities. While staff agrees that such activity may enhance a utility's transmission system, it does not strengthen existing transmission facilities. Therefore, staff recommends that a new redundant infrastructure project, such as looping substations, should not be characterized as storm protection pursuant to Rule 25-6.030, F.A.C.

In summary, as discussed in Issue 6D, staff recommends that FPL's Distribution Lateral Hardening Program be continued at its 2022 spending level, and that the Company's new Transmission Access Enhancement Program as well as the transmission looping initiative within the Transmission Hardening Program, be excluded from the SPP. With these three modifications, staff recommends that FPL's SPP is in the public interest. FPL should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

CONCLUSION

Staff recommends FPL's SPP meets the requirements of Rule 25-6.030, F.A.C., as discussed in Issue 1D. Staff recommends that FPL's SPP, with the following modifications, is in the public interest and should be approved: (1) continue the level of spending for the Distribution Lateral Hardening Program at the 2022 level; (2) remove the new Transmission Access Enhancement Program; and (3) remove the transmission looping initiative from the Transmission Hardening Program. FPL should file an amended SPP within 30 days of issuance of the final order for administrative approval by Commission staff.

Issue 11D: Should this docket be closed?

Recommendation: No. As discussed in Issue 10D, FPL should file an amended SPP within 30 days of the final order for administrative approval by Commission staff. Therefore, the docket shall remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively. (Trierweiler, Imig)

Position of the Parties

FPL: Yes. This docket should be closed upon the issuance of an appropriate order approving FPL's Revised 2023 SPP without modification.

JOINT PARTIES: No. Joint Parties raised a legal issue regarding the Order striking Mr. Kollen's testimony. The legal issue requires resolution before the docket is closed. In connection with the legal issue, both parties have made evidentiary proffers which must be considered if Joint Parties prevail on the legal issue.

SACE: No Position

WALMART: Yes.

PARTIES' ARGUMENTS

FPL
No post-hearing argument was provided in its brief.

JOINT PARTIES
No post-hearing argument was provided in its brief.

SACE
No post-hearing position or argument was provided in its brief.

WALMART
No post-hearing argument was provided in its brief.

CONCLUSION

As discussed in Issue 10D, FPL should file an amended SPP within 30 days of the final order for administrative approval by Commission staff. Therefore, the docket shall remain open for staff's verification that the amended SPP has been filed and complies with the Commission's order. Once these actions are complete, this docket should be closed administratively.

Florida Power & Light Company
Proposed 2023-2032 Storm Protection Plan Programs

Distribution Inspection
Inspections are conducted on an eight-year pole inspection cycle using methods such as visual and sound and bore. Replacement poles are based on the National Electrical Safety Code's Grade B construction standard.

Transmission Inspection
The program includes visual inspection each year of FPL's transmission structures and substations. Climbing and bucket truck inspections on wood structures are on a six-year cycle and steel and concrete structures are on a ten-year cycle.

Distribution Feeder Hardening
Feeders are hardened as a result of FPL's Priority Feeder Initiative which is a reliability program that targets feeders experiencing the highest number of interruptions and/or customers interrupted. This includes FPL's initiative of design and construction practices to meet the NESC extreme wind loading (EWL) criteria.

Distribution Lateral Hardening
FPL originally started this Program as a pilot program in 2018 and has continued the Program as part of its SPP. This Program targets certain overhead laterals, which were impacted by recent storms and have a history of vegetation-related outages and other reliability issues, for conversion from overhead to underground. FPL has also established and incorporated protocols for determining when a lateral may be overhead hardened as opposed to being placed underground.

Transmission Hardening
This Program replaces all wood transmission structures with steel or concrete structures. This Program also removes critical single points of failure from the transmission and/or substation systems and adds additional transmission lines into radially fed substations and additional transformers in single bank transmission substations to improve resiliency during extreme weather conditions.

Distribution Vegetation Management
This Program includes a three-year trim cycle for feeders, mid-year targeted trim maintenance cycle for certain feeders, six-year trim cycle for laterals, and continued customer education through FPL's Right Tree, Right Place initiative.

Transmission Vegetation Management

This Program includes inspecting the rights-of-way of transmission infrastructure, documenting vegetation inspection results and findings, and prescribing and executing a work plan. The North American Electric Reliability Corporation's (NERC) vegetation management standards/requirements serve as the basis for FPL's transmission vegetation management program, which requires annual inspection requirements, executing 100 percent of a utility's annual vegetation work plan, and prevent any encroachment into established minimum vegetation clearance distances.

Substation Storm Surge/Flood Mitigation

Damage to substations that are susceptible to storm surge and flooding during extreme weather events can be eliminated by raising the equipment at certain substations above flood level and constructing flood protection walls around other substations. FPL has identified certain substations located in areas throughout its service area that are susceptible to storm surge or flooding during extreme weather events.

Transmission Access Enhancement

In parts of FPL's service area, transmission facilities are located in areas that are not readily accessible for repair/restoration following an extreme weather event, such as low-lying areas, areas prone to severe flooding, or areas with saturated soils. The Program will focus on developing access roads, bridges, and culverts at targeted transmission facilities to ensure they are accessible after an extreme weather event.

366.96 Storm protection plan cost recovery.—

(1) The Legislature finds that:

(a) During extreme weather conditions, high winds can cause vegetation and debris to blow into and damage electrical transmission and distribution facilities, resulting in power outages.

(b) A majority of the power outages that occur during extreme weather conditions in the state are caused by vegetation blown by the wind.

(c) It is in the state's interest 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.

(d) Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

(e) 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.

(f) All customers benefit from the reduced costs of storm restoration.

(2) As used in this section, the term:

(a) "Public utility" or "utility" has the same meaning as set forth in s. 366.02(8), except that it does not include a gas utility.

(b) "Transmission and distribution storm protection plan" or "plan" means a plan for the overhead hardening and increased resilience of electric transmission and distribution facilities, undergrounding of electric distribution facilities, and vegetation management.

(c) "Transmission and distribution storm protection plan costs" means the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan.

(d) "Vegetation management" means the actions a public utility takes to prevent or curtail vegetation from interfering with public utility infrastructure. The term includes, but is not limited to, the mowing of vegetation, application of herbicides, tree trimming, and removal of trees or brush near and around electric transmission and distribution facilities.

(3) Each public utility shall file, pursuant to commission rule, a transmission and distribution storm protection plan that covers the immediate 10-year planning period. Each plan must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. The commission shall adopt rules to specify the elements that must be included in a utility's filing for review of transmission and distribution storm protection plans.

(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.

(5) No later than 180 days after a utility files a transmission and distribution storm protection plan that contains all of the elements required by commission rule, the commission shall determine whether it is in the public interest to approve, approve with modification, or deny the plan.

(6) At least every 3 years after approval of a utility's transmission and distribution storm protection plan, the utility must file for commission review an updated transmission and distribution storm protection plan that addresses each element specified by commission rule. The commission shall approve, modify, or deny each updated plan pursuant to the criteria used to review the initial plan.

(7) After a utility's transmission and distribution storm protection plan has been approved, proceeding with actions to implement the plan shall not constitute or be evidence of imprudence. The commission shall conduct an annual proceeding to determine the utility's prudently incurred transmission and distribution storm protection plan costs and allow the utility to recover such costs through a charge separate and apart from its base rates, to be referred to as the storm protection plan cost recovery clause. If the commission determines that costs were prudently incurred, those costs will not be subject to disallowance or further prudence review except for fraud, perjury, or intentional withholding of key information by the public utility.

(8) The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates and must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

(9) If a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity.

(10) Beginning December 1 of the year after the first full year of implementation of a transmission and distribution storm protection plan and annually thereafter, the commission shall submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a report on the status of utilities' storm protection activities. The report shall include, but is not limited to, identification of all storm protection activities completed or planned for completion, the actual costs and rate impacts associated with completed activities as compared to the estimated costs and rate impacts for those activities, and the estimated costs and rate impacts associated with activities planned for completion.

(11) The commission shall adopt rules to implement and administer this section and shall propose a rule for adoption as soon as practicable after the effective date of this act, but not later than October 31, 2019.

History.—s. 1, ch. 2019-158; s. 30, ch. 2022-4.

25-6.030 Storm Protection Plan.

(1) Application and Scope. Each utility as defined in Section 366.96(2)(a), F.S., must file a petition with the Commission for approval of a Transmission and Distribution Storm Protection Plan (Storm Protection Plan) that covers the utility's immediate 10-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every 3 years.

(2) For the purpose of this rule, the following definitions apply:

(a) "Storm protection program" – a category, type, or group of related storm protection projects that are undertaken to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(b) "Storm protection project" – a specific activity within a storm protection program designed for the enhancement of an identified portion or area of existing electric transmission or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) "Transmission and distribution facilities" – all utility owned poles and fixtures, towers and fixtures, overhead conductors and devices, substations and related facilities, land and land rights, roads and trails, underground conduits, and underground conductors.

(3) Contents of the Storm Protection Plan. For each Storm Protection Plan, the following information must be provided:

(a) A description of how implementation of the proposed Storm Protection Plan will 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.

(b) A description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability.

(c) 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. Such description must include a general map, number of customers served within each area, and the utility's reasoning for prioritizing certain areas for enhanced performance and for designating other areas of the system as not feasible, reasonable, or practical.

(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.; and

5. A description of the criteria used to select and prioritize proposed storm protection programs.

(e) For the first three years in a utility's Storm Protection Plan, the utility must provide the following information:

1. For the first year of the plan, a description of each proposed storm protection project that includes:

a. The actual or estimated construction start and completion dates;

b. 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;

c. A cost estimate including capital and operating expenses; and

d. A description of the criteria used to select and prioritize proposed storm protection projects.

2. For the second and third years of the plan, project related information in sufficient detail, such as estimated number and costs of projects under every specific program, to allow the development of preliminary estimates of rate impacts as required by paragraph (3)(h) of this rule.

(f) For each of the first three years in a utility's Storm Protection Plan, the utility must provide a description of its proposed vegetation management activities including:

1. The projected frequency (trim cycle);

2. The projected miles of affected transmission and distribution overhead facilities;

3. The estimated annual labor and equipment costs for both utility and contractor personnel; and

4. A description of how the vegetation management activity will reduce outage times and restoration costs due to extreme weather conditions.

(g) An estimate of the annual jurisdictional revenue requirements for each year of the Storm Protection Plan.

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

(i) A description of any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan.

(j) Any other factors the utility requests the Commission to consider.

(4) By June 1, each utility must submit to the Commission Clerk an annual status report on the utility's Storm Protection Plan programs and projects. The annual status report shall include:

(a) Identification of all Storm Protection Plan programs and projects completed in the prior calendar year or planned for completion;

(b) Actual costs and rate impacts associated with completed activities under the Storm Protection Plan as compared to the estimated costs and rate impacts for those activities; and

(c) Estimated costs and rate impacts associated with programs planned for completion during the next calendar year.

Rulemaking Authority 366.96 FS. Law Implemented 366.96 FS. History–New 2-18-20.

Item 8

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Docket No. 20220019-WU

FROM: Adam J. Teitzman, Commission Clerk, Office of Commission Clerk AJT

RE: Rescheduled Commission Conference Item

Staff's memorandum assigned DN 04877-2022 was filed on July 21, 2022, for the August 2, 2022 Commission Conference. As the vote sheet reflects, this item was deferred. This item has been placed on the October 4, 2022 Commission Conference Agenda.

/ajt

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: July 21, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Maloy, Ramos) TB
Division of Accounting and Finance (Thurmond, Sewards) ALM
Division of Economics (Bruce, Hudson) JGH
Office of the General Counsel (J. Crawford) JSC

RE: Docket No. 20220019-WU – Application for transfer of water facilities of Neighborhood Utilities, Inc. and water Certificate No. 430-W to CSWR-Florida Utility Operating Company, LLC, in Duval County.

AGENDA: 08/02/22 – Regular Agenda – Proposed Agency Action for Issues 2, 3, and 4 - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Neighborhood Utilities, Inc. (Neighborhood, Utility, or Seller) is a Class C water utility providing service to approximately 439 residential and 4 general service customers in Duval County. The Utility is located in the St. Johns River Water Management District (SJRWMD) in the Water Resource Caution Area. Wastewater service is provided by septic tanks. In its 2021 Annual Report, the Utility reported operating revenues of $183,323 and a net operating loss of $18,732.

The Florida Public Service Commission (Commission) granted an original water certificate to Neighborhood in 1984.[1] The Commission approved an amendment in 2011.[2] The rates for the Utility were last set by the Commission in 2016.[3]

On January 14, 2022, CSWR-Florida Utility Operating Company, LLC (CSWR-Neighborhood or Buyer) filed an application with the Commission for the transfer of Certificate No. 430-W from Neighborhood to CSWR-Neighborhood in Duval County. The sale will close after the Commission has voted to approve the transfer. In its application, the Buyer has requested a positive acquisition adjustment, which is discussed in Issue 3.

Intervention by the Office of Public Counsel (OPC) was acknowledged on March 3, 2022. OPC and staff have issued a number of discovery and data requests to CSWR-Neighborhood in this docket.

This recommendation addresses the transfer of the water system and Certificate No. 430-W, the appropriate net book value of the water system for transfer purposes, and the request for an acquisition adjustment. The Commission has jurisdiction pursuant to Sections 367.071 and 367.081, Florida Statutes (F.S.).

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[1]Order No. 13723, issued September 28, 1984, in Docket No. 19840063-WU, *In re: Application of Neighborhood Utilities, Inc., for a certificate to operate a water utility in Duval County.*
[2]Order No. PSC-11-0135-FOF-WU, issued February 28, 2011, in Docket No. 20090441-WU, *In re: Application for amendment of Certificate No. 430-W to add territory in Duval County by Neighborhood Utilities, Inc.*
[3]Order No. PSC-16-0537-PAA-WU, issued November 23, 2016, in Docket No. 20150181-WU, *In re: Application for staff-assisted rate case in Duval County by Neighborhood Utilities, Inc.*

Discussion of Issues

Issue 1: Should the transfer of Certificate No. 430-W in Duval County from Neighborhood Utilities, Inc. to CSWR-Florida Utility Operating Company, LLC be approved?

Recommendation: Yes. The transfer of the water system and Certificate No. 430-W is in the public interest and should be approved effective the date that the sale becomes final. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The Buyer should submit the executed and recorded deed for continued access to the land upon which its facilities are located and copies of its permit transfer applications to the Commission within 90 days of the Order approving the transfer, which is final agency action. If the sale is not finalized within 90 days of the resultant Order, the Buyer should file a status update in the docket file. The Utility's existing rates, late payment charge, service availability charges, non-sufficient funds charges, and initial customer deposits as shown on Schedule No. 2, should remain in effect, until a change is authorized by this Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475(1), Florida Administrative Code, (F.A.C.). The Seller is current with respect to annual reports and regulatory assessment fees (RAFs) through December 31, 2021, and the Buyer should be responsible for filing annual reports and paying RAFs for all future years. (Maloy, Thurmond, Bruce)

Staff Analysis: On January 14, 2022, CSWR-Neighborhood filed an application for the transfer of Certificate No. 430-W from Neighborhood to CSWR-Neighborhood in Duval County. The application complies with Section 367.071, F.S., and Commission rules concerning applications for transfer of certificates. The sale to CSWR-Neighborhood will become final after Commission approval of the transfer, pursuant to Section 367.071(1), F.S.

Noticing, Territory, and Land Ownership

CSWR-Neighborhood provided notice of the application pursuant to Section 367.071, F.S., and Rule 25-30.030, F.A.C. No objections to the transfer were filed, and the time for doing so has expired. The application contains a description of the service territory, which is appended to this recommendation as Attachment A. In its response to staff's September 8, 2021 deficiency letter, CSWR-Neighborhood provided an unrecorded warranty deed as evidence that the buyer will have long-term use of the land upon which the treatment facilities are located pursuant to Rule 25-30.037(2)(s), F.A.C. CSWR-Neighborhood should submit the executed and recorded deed to the Commission within 90 days of the Order approving the transfer.

Purchase Agreement and Financing

Pursuant to Rule 25-30.037(2)(g), (h), and (i), F.A.C., the application contains a statement regarding financing and a copy of the purchase agreement, which includes the purchase price, terms of payment, and a list of the assets purchased. There are no guaranteed revenue contracts, or customer advances of Neighborhood that must be disposed of with regard to the transfer. CSWR-Neighborhood will review all leases and developer agreements and will assume or renegotiate those agreements on a case-by-case basis prior to closing. Any customer deposits will be refunded to customers by the Seller prior to the closing. According to the purchase and sale agreement, the total purchase price for the assets is $460,000. According to the Buyer, the closing has not yet taken place and is dependent on Commission approval of the transfer, pursuant to Section 367.071(1), F.S.

Facility Description and Compliance

The Utility's water treatment plant is rated at 360,000 gallons per day (gpd). Raw water is drawn from a single well, with an emergency water source of JEA Major Grid at a capacity of 360,000 gpd. The raw water is treated by hypochlorination. The water is stored in a 2,000 gallon hydropneumatic tank and two ground tanks, with a capacity of 15,000 gallons and 25,000 gallons, before distribution.

Staff reviewed the Utility's most recent Florida Department of Environmental Protection (DEP) inspection reports. In 2019, the Utility was issued a warning letter for its on-site generator not functioning, which failed in 2017 during a power outage from Hurricane Irma. The DEP conducted an inspection of the water treatment facility on July 1, 2020, and it was found to be in violation of the DEP's rules and regulations. The July 1, 2020 Sanitary Survey addressed a leaking service pump and well pump, bio growth in the casing of the well pump, as well as the non-functional on-site generator. Thereafter, the DEP issued a Consent Order on April 1, 2022. The Consent Order addressed the same violations as the Utility's most recent sanitary survey. The Utility addressed the violations set forth in the Consent Order and the actions required by the DEP have been completed. Furthermore, the Utility is currently passing all DEP secondary water standards. [4]

CSWR-Neighborhood provided copies of the Utility's current permits from the DEP and SJRWMD pursuant to Rule 25-30.037(2)(r)(1), F.A.C. The Buyer should provide copies of its permit transfer applications, reflecting the change in ownership, to the Commission within 90 days of the Order approving the transfer. In the Buyer's application, CSWR-Neighborhood provided its assessment of Neighborhood's water system, and lists several improvements and repairs it recommends be made to the system. The Buyer's suggested repairs and improvements, which do not appear to be required by a governmental authority, are discussed further in Issue 3.

Technical and Financial Ability

Pursuant to Rule 25-30.037(2)(l) and (m), F.A.C., the application contains statements describing the technical and financial ability of the Buyer to provide service to the proposed service area. As referenced in the transfer application, the Buyer will fulfill the commitments, obligations, and representation of the Seller with regards to Utility matters. CSWR-Neighborhood's application states that it owns and operates more than 257 water/wastewater systems in Missouri, Arkansas, Kentucky, Louisiana, Texas, Mississippi, North Carolina, Arizona, and Tennessee that service approximately 70,000 water and 110,000 wastewater customers. The Buyer plans to use qualified and licensed contractors to provide routine operation and maintenance of the systems, as well as to handle billing and customer service. Staff reviewed the financial statements of CSWR-Neighborhood and believes the Buyer has documented adequate resources to support the Utility's water operations. Based on the above, staff recommends that the Buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

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[4]Document No. 01594-2022.

Rates, Charges, and Initial Customer Deposits

The Utility's rates, charges, and initial customer deposits were last approved in a 2016 staff-assisted rate case.[5] Since the Utility's last rate case, the rates were decreased to remove an expired rate case expense amortization.[6] Rule 25-9.044(1), F.A.C., provides that in the case of a change of ownership or control of a Utility, the rates, classifications, and regulations of the former owner must continue unless authorized to change by this Commission. In addition, the Utility has miscellaneous service charges. The late payment charge of $4.30 is appropriate. However, the remaining miscellaneous service charges do not conform to Rule 25-30.460, F.A.C., and are discussed in Issue 4. Therefore, staff recommends that the Utility's existing rates, late payment charge, service availability charges, non-sufficient funds charges, and initial customer deposits as shown on Schedule No. 2, should remain in effect, until a change is authorized by this Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475(1), F.A.C.

Regulatory Assessment Fees and Annual Report

Staff has verified that the Utility is current on the filing of annual reports and RAFs through December 31, 2021. The Buyer should be responsible for filing the Utility's annual reports and paying RAFs for all future years.

Conclusion

Based on the foregoing, staff recommends the transfer of the water system and Certificate No. 430-W is in the public interest and should be approved effective the date that the sale becomes final. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The Buyer should submit the executed and recorded deed for continued access to the land upon which its facilities are located and copies of its permit transfer applications to the Commission within 90 days of the Order approving the transfer, which is final agency action. If the sale is not finalized within 90 days of the transfer Order, the Buyer should file a status update in the docket file. The Utility's existing rates, late payment charge, service availability charges, non-sufficient funds charges, and initial customer deposits as shown on Schedule No. 2, should remain in effect, until a change is authorized by this Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475(1), F.A.C. The Seller is current with respect to annual reports and RAFs through December 31, 2021, and the Buyer should be responsible for filing annual reports and paying RAFs for all future years.

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[5]Order No. PSC-16-0537-PAA-WU, issued November 23, 2016, in Docket No. 20150181-WU, *In re: Application for staff assisted rate case by Neighborhood Utilities, Inc.*

[6]Id.

Issue 2: What is the appropriate net book value for CSWR-Florida Utility Operating Company, LLC's water system for transfer purposes?

Recommendation: For transfer purposes, the net book value (NBV) of the water system is $60,063 as of January 31, 2022. Within 90 days of the date of the consummating order, CSWR-Neighborhood should be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in the Utility's 2022 Annual Report when filed. (Thurmond)

Staff Analysis: Rate base was last established on November 23, 2016, by Order No. PSC-2016-0537-PAA-WU.[7] The purpose of establishing NBV for transfers is to determine whether an acquisition adjustment should be approved. CSWR-Neighborhood's request for a positive acquisition adjustment is addressed in Issue 3. The NBV does not include normal ratemaking adjustments for used and useful plant or working capital. The Utility's NBV has been updated to reflect balances as of January 31, 2022.[8] Staff's recommended NBV, as described below, is shown on Schedule No. 1.

Utility Plant in Service (UPIS)

According to the Utility's general ledger, the total UPIS balance was $672,155 as of December 31, 2021. Staff auditors compiled the plant additions and retirements to UPIS from June 30, 2015, to January 31, 2022, and traced supporting documentation. As a result, staff recommends an increase to UPIS of $1,299 as of January 31, 2022. Accordingly, staff recommends a total UPIS balance of $673,454 as of January 31, 2022.

Land

The Utility's general ledger reflected a land balance of $1,000 as of June 30, 2015. There have been no additions to land since June 30, 2015. Therefore, staff recommends no adjustments to its land balance.

Accumulated Depreciation

According to the Utility's general ledger, the total accumulated depreciation balance was $540,622 as of December 31, 2021. Staff auditors recalculated depreciation accruals for all water accounts since the last rate case through January 31, 2022, using audited UPIS balances and the depreciation rates established by Rule 25-30.140, F.A.C. As a result, staff recommends that the accumulated depreciation balance be increased by $21,745 as of January 31, 2022. Accordingly, staff recommends a total accumulated depreciation balance of $562,367 as of January 31, 2022.

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[7]Order No. PSC-16-0537-PAA-WU, issued November 23, 2016, in Docket No. 20150181-WU, *In re: Application for staff-assisted rate case in Duval County by Neighborhood Utilities, Inc.*

[8]Net book value is calculated through the date of the closing. According to the Utility's application, the closing will not occur until after the transaction receives Commission approval. Therefore, staff is relying on the most current information provided to staff auditors at the time of the filing.

Contributions-in-Aid-of-Construction (CIAC) and Accumulated Amortization of CIAC

According to the Utility's general ledger, the CIAC balance and accumulated amortization of CIAC were $76,431 and $0, respectively, as of December 31, 2021. Staff auditors traced CIAC and accumulated amortization of CIAC balances from June 30, 2015, to January 31, 2022, using supporting documentation. As a result, staff recommends that the CIAC balance be increased by $193,145 as of January 31, 2022. Staff also recommends that the accumulated amortization of CIAC balance be increased by $217,552 as of January 31, 2022. Accordingly, staff recommends total CIAC and Accumulated Amortization of CIAC balances of $269,576 and $217,552, respectively, as of January 31, 2022.

Net Book Value

The Utility's general ledger reflected a NBV of $56,102 as of December 31, 2021. Based on the adjustments described above, staff recommends a NBV of $60,063 as of January 31, 2022. Staff's recommended NBV and the National Association of Regulatory Utility Commissioners, Uniform System of Accounts (NARUC USOA) balances for UPIS and accumulated depreciation are shown on Schedule No. 1 as of January 31, 2022. As addressed in Issue 3, a positive acquisition adjustment should not be recognized for ratemaking purposes.

Conclusion

Based on the above, staff recommends a NBV of $60,063 as of January 31, 2022, for transfer purposes. Within 90 days of the date of the consummating order, the Buyer should be required to notify the Commission in writing, that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in the Utility's 2022 Annual Report when filed.

Issue 3: Should a positive acquisition adjustment be recognized for ratemaking purposes?

Recommendation: No. Pursuant to Rule 25-30.0371, F.A.C., a positive acquisition adjustment should not be granted as the Buyer failed to demonstrate extraordinary circumstances. (Thurmond, Maloy)

Staff Analysis: In its filing, the applicant requested a positive acquisition adjustment be included in the calculation of the Utility's rate base. An acquisition adjustment results when the purchase price differs from the NBV of the assets at the time of acquisition. Pursuant to Rule 25-30.0371, F.A.C., a positive acquisition adjustment results when the purchase price is greater than the NBV and a negative acquisition adjustment results when the purchase price is less than the NBV. A positive acquisition adjustment, if approved, increases rate base.

According to the purchase agreement, the Buyer will purchase the Utility for $460,000. As discussed in Issue 2, staff is recommending a NBV of $60,063. This would result in a positive acquisition adjustment of $399,937.

Any entity that believes a full or partial positive acquisition adjustment should be made has the burden to prove the existence of extraordinary circumstances. Rule 25-30.0371(2), F.A.C., states:

> In determining whether extraordinary circumstances have been demonstrated, the Commission shall consider evidence provided to the Commission such as anticipated improvements in quality of service, anticipated improvements in compliance with regulatory mandates, anticipated rate reductions or rate stability over a long-term period, anticipated cost efficiencies, and whether the purchase was made as part of an arms-length transaction.

If a purchase price above depreciated original cost is used to determine rate base, without the requirement for extraordinary circumstances, it could encourage utilities to "swap assets" and inappropriately increase costs to customers.

Deferral

In discovery, CSWR-Neighborhood stated that it intends to ask for deferral of a decision regarding the requested acquisition adjustment. In its application, the Buyer laid out factors such as improvements to quality of service, cost efficiencies, and rate stability. These are discussed below and staff recommends that these factors do not constitute extraordinary circumstances. In response to discovery, the Buyer agreed that after rate base is set, if a company provides support in a separate and subsequent case that there are utility assets that were not previously recorded, then the company can prospectively recover the unrecorded amount of that investment. Therefore, if the Buyer finds assets were incorrectly recorded on the Seller's balance sheet, the Buyer can support those costs and recover them in a future rate case which is Commission practice and not considered extraordinary circumstances.

In the past, the Commission has approved positive acquisition adjustments for three separate natural gas utilities: the acquisition of Florida City Gas by AGL Resources, Inc., the acquisition of Florida Public Utilities Company (FPUC) by the Florida Division of Chesapeake Utilities

Corporation, and the acquisition of Indiantown Gas Company by FPUC.[9] In all three cases, the buyers provided detailed information estimating net savings to customers that could be achieved should the transfer and acquisition adjustment be approved. In addition, all three utilities acknowledged that if the estimated cost savings did not materialize or were less than represented, that some or all of the granted positive acquisition adjustments could be removed prospectively. In contrast, CSWR-Neighborhood stated that such estimates cannot be given at this time and thus requested the decision regarding the acquisition adjustment be deferred until it has the information to estimate net cost savings to customers. Staff believes the cases noted above demonstrate that a buyer that has undertaken the appropriate level of due diligence has the ability and responsibility to provide estimated net cost savings to customers at the time of transfer.

Pursuant to Commission practice, the buyer has the burden to prove extraordinary circumstances at the time of transfer. Staff believes in the instant case the Buyer has failed to provide proof of extraordinary circumstances. Further, the Buyer had multiple opportunities to provide pertinent information needed to determine if a positive acquisition adjustment is appropriate. As such, staff recommends the Commission deny the request to defer a decision on the positive acquisition adjustment.

Finally, it is long-standing Commission practice to address the disposition of any positive or negative acquisition adjustment at the time of transfer. Pursuant to Section 120.68(7)(e)3., F.S., when agencies change their established policies, practices and procedures, they must give an explanation for the deviation. Staff does not believe the facts in this case warrant such a deviation. As such, staff believes the deferral of a positive acquisition adjustment decision in this docket would result in an unnecessary deviation from Commission practice.

Improvements in Quality of Service and Compliance with Regulatory Mandates

In its application, CSWR-Neighborhood listed six business practices that it believes will improve the quality of service to its customers: (1) provision of 24-hour emergency service phone numbers; (2) on-call emergency service personnel who are required to respond to emergency service calls within prescribed time limits; (3) a computerized maintenance management system; (4) access to resources not usually available to comparably sized systems and the ability to supplement local personnel with resources owned by the parent and sister companies; (5) online bill payment options; and (6) an updated website for customer communication, bulletins, procedures, etc.

Staff reviewed the complaints filed with the Commission for the five-year period prior to the application, January 2017 to March 2022. For the five-year period, the Commission recorded a total of two customer complaints pertaining to billing. Additionally, in its application, CSWR-Neighborhood indicated that the Utility has not received any customer complaints pertaining to

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[9]Order No. PSC-07-0913-PAA-GU, issued November 13, 2007, in Docket No. 20060657-GU, *In re: Petition for approval or acquisition adjustment and recognition of regulatory asset to reflect purchase of Florida City Gas by AGL Resources, Inc.;* Order No. PSC-12-0010-PAA-GU, issued January 3, 2012, in Docket No. 20110133-GU, *In re: Petition for approval of acquisition adjustment and recovery of regulatory assets, and request for the consolidation of regulatory filings and records of Florida Public Utilities Company and Florida Divisions of Chesapeake Utilities Corporation;* Order No. PSC-14-0015-PAA-GU, issued January 6, 2014, in Docket No. 20120311-GU, *In re: Petition for approval of positive acquisition adjustment to reflect the acquisition of Indiantown Gas Company by Florida Public Utilities Company.*

secondary water standards during the past five years. As discussed in Issue 1, staff also reviewed the Utility's most recent DEP inspection reports. While the Utility was issued a Consent Order on April 1, 2022, the Utility has addressed the violations and completed DEP's requirements set forth in the Consent Order.

Based on the Commission's complaint data and the DEP's reports, it does not appear that the Utility currently has issues with respect to quality of service and regulatory compliance such that they would warrant extraordinary efforts to remedy. For this reason, staff does not believe CSWR-Neighborhood has demonstrated extraordinary circumstances for its requested positive acquisition adjustment. Instead, staff believes that the proposed anticipated improvements in quality of service and compliance with regulatory mandates demonstrates CSWR-Neighborhood's intention to responsibly execute its obligations as a utility owner. While staff does not believe the Utility's anticipated improvements justify its requested positive acquisition adjustment, these improvements may be considered for prudency and cost recovery in a future rate proceeding.

Anticipated Cost Efficiencies and Rates

In its application, the Buyer stated that based on its size, the anticipated consolidation of many small systems under one financial and managerial entity would result in operational cost efficiencies particularly in the areas of:

- PSC and environmental regulatory reporting
- Managerial and operational oversight
- Utility asset planning
- Engineering planning
- Ongoing utility maintenance
- Utility record keeping
- Customer service responsiveness
- Improved access to capital necessary to repair and upgrade Neighborhood's systems to ensure compliance with all health and environmental requirements and ensure service to customers remains safe and reliable

In response to discovery, the Buyer provided an estimated annual reduction of operation and maintenance (O&M) expense of approximately $20,000. However, with a requested acquisition adjustment of $399,937, the requested amount is approximately six and one-half times greater than the system's current NBV of $60,063. Even if the Buyer was able to achieve these savings in O&M expense, the inclusion of the requested acquisition adjustment in rate base and the inclusion of the annual amortization expense in the net operating income calculation, would result in an increased revenue requirement. By operation of math, the overall impact would be a net increase to customer rates.

The Buyer also stated that CSWR-Neighborhood would bring long-term rate stability to the Utility, should the transfer be approved. Staff agrees that economies of scale and potential consolidation of several systems in Florida, as proposed by CSWR-Neighborhood, could bring some amount of long-term rate stability. However, absent specific and detailed support for these assertions, the Buyer has failed to meet its burden of demonstrating extraordinary circumstances. Moreover, Neighborhood has exhibited rate stability. The Utility has had only two staff-assisted rate cases, seven price indices, and one pass-through increase since it was granted its water certificate in 1984.

Staff's recommendation is consistent with the Commission's decision in Order No. PSC-2020-0458-PAA-WS.[10] In that docket, the buyer identified estimates of anticipated cost efficiencies, including a reduction in O&M expense and a reduction of cost of capital that would result from the transfer. Additionally, the buyer cited several improvements it made to the water treatment plant and wastewater lift station since acquisition to improve the quality of service and compliance with regulatory mandates. While the Commission acknowledged that the buyer accomplished cost savings, it did not believe the actions performed demonstrated extraordinary circumstances that would justify approval of a positive acquisition adjustment.

Staff's recommendation is also consistent with the Commission's decisions for CSWR-Florida Utility Operating Company, LLC's request for a positive acquisition adjustment in Order Nos. PSC-2022-0116-PAA-SU, PSC-2022-0120-PAA-WU, and PSC-2022-0115-PAA-WS.[11] In those cases, it was determined that CSWR-Florida Utility Operating Company, LLC failed to provide sufficient evidence of extraordinary circumstances and was denied a positive acquisition adjustment in all three cases. In those cases, CSWR-Florida Utility Operating Company, LLC also requested a deferral of the decision regarding the positive acquisition adjustments which was denied by the Commission. Staff finds the facts of this case similar to the three cases discussed above.

Conclusion

Pursuant to Rule 25-30.0371, F.A.C., staff recommends a positive acquisition adjustment not be granted as the Buyer did not demonstrate extraordinary circumstances. Staff believes the Buyer's anticipated improvements in quality of service and compliance with regulatory mandates do not illustrate extraordinary circumstances and instead demonstrates CSWR-Neighborhood's intentions to responsibly provide utility service.

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[10]Order No. PSC-2020-0458-PAA-WS, issued November, 23, 2020, in Docket No. 20190170-WS, *In re: Application for transfer of facilities and Certificate Nos. 259-W and 199-S in Broward County from Royal Utility Company to Royal Waterworks, Inc.*

[11]Order No. PSC-2022-0116-PAA-SU, issued March 17, 2022, in Docket No. 20210133-SU, *In re: Application for transfer of facilities of North Peninsula Utilities Corporation and wastewater Certificate No. 249-S to CSWR-Florida Utility Operating Company, LLC, in Volusia County.* ; Order No. PSC-2022-0120-PAA-WU, issued March 18, 2022, in Docket No. 20220095-WU, *In re: Application for transfer of water facilities of Sunshine Utilities of Central Florida, Inc. and water Certificate No. 363-W to CSWR-Florida Utility Operating Company, LLC, in Marion County*; Order No. PSC-2022-0115-PAA-WS, issued March 15, 2022, in Docket No. 20210093-WS, *Application for transfer of water and wastewater systems of Aquarina Utilities, Inc., water Certificate No. 517-W, and wastewater Certificate No. 450-S to CSWR-Florida Utility Operating Company, LLC, in Brevard County.*

Issue 4: Should CSWR-Florida Utility Operating Company, LLC's miscellaneous service charges be revised to conform to amended Rule 25-30.460, F.A.C.?

Recommendation: Yes. The miscellaneous service charges should be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of initial connection and normal reconnection charges. CSWR-Neighborhood should be required to file a proposed customer notice to reflect the Commission-approved charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved charges should not be implemented until staff has approved the proposed customer notice and the notice has been received by customers. CSWR-Neighborhood should provide proof of the date notice was given within 10 days of the date of the notice. CSWR-Neighborhood should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding. (Bruce)

Staff Analysis: Effective June 24, 2021, Rule 25-30.460, F.A.C., was amended to remove initial connection and normal reconnection charges.[12] The definitions for initial connection charges and normal reconnection charges were subsumed in the definition of the premises visit charge. The Utility's miscellaneous service charges consist of initial connection and normal reconnection charges. The normal reconnection charge is more than the premises visit charge. Since the premises visit entails a broader range of tasks, staff believes the premises visit charge should reflect the amount of the normal reconnection charge of $34 for normal hours and $38 for after hours. Therefore, staff recommends that the initial connection and normal reconnection charges be removed, the premises visit charge should be revised to $34 for normal hours and $38 for after hours, and the definition for the premises visit charge be updated to comply with amended Rule 25-30.460, F.A.C. The Utility's existing and staff's recommended miscellaneous service charges are shown below in Tables 4-1 and 4-2.

Table 4-1
Utility Existing Miscellaneous Service Charges

	Normal Hours	After Hours
Initial Connection Charge	$19.00	$21.00
Normal Reconnection Charge	$34.00	$38.00
Violation Reconnection Charge	$30.00	$32.00
Premises Visit Charge (in lieu of disconnection)	$19.00	$21.00

Table 4-2
Staff Recommended Miscellaneous Service Charges

	Normal Hours	After Hours
Violation Reconnection Charge	$30.00	$32.00
Premises Visit Charge	$34.00	$38.00

[12]Order No. PSC-2021-0201-FOF-WS, issued June 4, 2020, in Docket No. 20200240-WS, *In re: Proposed amendment of Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges.*

Conclusion

Based on the above, staff recommends the miscellaneous service charges be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of initial connection and normal reconnection charges. CSWR-Neighborhood should be required to file a proposed customer notice to reflect the Commission-approved charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved charges should not be implemented until staff has approved the proposed customer notice and the notice has been received by customers. CSWR-Neighborhood should provide proof of the date notice was given within 10 days of the date of the notice. CSWR-Neighborhood should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 5: Should this docket be closed?

Recommendation: Yes. If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the order, a consummating order should be issued and the docket should be closed administratively upon Commission staff's verification that the revised tariff sheets have been filed, the Buyer has notified the Commission in writing that it has adjusted its books in accordance with the Commission's decision, proof that appropriate noticing has been done pursuant to Rule 25-30.4345, F.A.C., and the Buyer has submitted the executed and recorded warranty deed and that the Buyer has submitted a copy of its application for permit transfer to the DEP within 90 days of the Commission's Order approving the transfer. (J. Crawford)

Staff Analysis: If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the order, a consummating order should be issued and the docket should be closed administratively upon Commission staff's verification that the revised tariff sheets have been filed, the Buyer has notified the Commission in writing that it has adjusted its books in accordance with the Commission's decision, proof that appropriate noticing has been done pursuant to Rule 25-30.4345, F.A.C., and the Buyer has submitted the executed and recorded warranty deed and that the Buyer has submitted a copy of its application for permit transfer to the DEP within 90 days of the Commission's Order approving the transfer.

DESCRIPTION OF TERRITORY SERVED

Please refer to description of territory served as filed in Docket Number 840063-WU. Order Number 13723, Issued 9/28/84, Certificate Number 430-W.

In Township 2 South, Range 25 East:

Section 31

The South ½ of said Section 31
LESS
the West 660 feet of said Section 31, and the Southeast 1/4 of the Southwest 1/4 of said Section 31, and the South 165 feet of the Southeast 1/4 of the Southeast 1/4 of said Section 31, and the North 300 feet of the South 756 feet of the East 437 feet of the Southeast 1/4 of the Southeast 1/4 of said Section 31, and the East 40 feet of the South 1/2 of said Section 31.

Docket No. 090441-WU; Order No. PSC-11-0135-FOF-WU, Issued 2/28/11:

NEIGHBORHOOD UTILITIES, INC.
DESCRIPTION OF WATER TERRITORY TO BE ADDED
DUVAL COUNTY

In Township 2 South, Range 25 East:

Section 31

Area name: NU-1. A portion of Tracts 13 and 14, Block 3, in Section 31 as shown on the plat of Jacksonville Heights, as recorded in Plat Book 5, Page 93 of the current public records of Duval County, Florida, more particularly described as follows:

Commence at the Southwest corner of said Section 31; thence N 89° 42' 31" E along the south line of said Section 31, a distance of 1,224.03 feet to the Southwest corner of Tract 13, Block 3, Jacksonville Heights to the Point of Beginning; thence continue along said south line of Section 31, N 89° 42' 30" E a distance of 663.36 feet; thence N 00° 50' 36" E a distance of 664.62 feet; thence S 89° 46' 36" W a distance of 664.95 feet: thence S 00° 47' 27" W a distance of 665.40 feet to the Point of Beginning. Containing 10.14 acres.

In Township 2 South, Range 25 East and in Township 3 South, Range 25 East:

Area name: NU-2. A portion of Tracts 1 through 6, inclusive, Tracts 10 through 14, Block 3, and Tracts 5 through 8, inclusive Tracts 9, 11, and 12, Block 4, in Section 31, Township 2 South, Range 25 East, together with a portion of Tracts 6 and 7, Block 2, in Section 6, Township 3 South, Range 25 East as shown on the plat of Jacksonville Heights, as recorded in Plat Book 5, Page 93 of the current public records of Duval County, Florida, more particularly described as follows:

(Continued on Sheet No. 3.2)

(Continued from Sheet No. 3.1)

Commence at the Southwest corner of said Section 31; thence N 89° 42' 31" E along the south line of said Section 31, a distance of 664.35 feet to the Southwest corner of Tract 11, Block 3, Jacksonville Heights, to the Point of Beginning; thence N 00° 44' 25 E a distance of 166.54 feet; thence S 89° 43' 33" W a distance of 614.49 feet; thence S 00° 39' 57" W a distance of 327.10 feet; thence N 89° 42' 31" E a distance of 248.32 feet; thence S 00° 38' 40" W a distance of 173.91 feet; thence N 89° 17' 13" E a distance of 364.98 feet; thence S 00° 39' 10" W a distance of 516.95 feet; thence N 84° 58' 30" E a distance of 172.65 feet; thence N 00° 40' 1O" E a distance of 222.00 feet; thence N 84° 58' 30" E a distance of 160.00 feet; thence N 00° 41' 18" E a distance of 599.1O feet; thence S 89° 42' 31" W a distance of 330.34 feet to the Point of Beginning. Containing 11.61 acres.

NEIGHBORHOOD UTILITIES, INC.
DESCRIPTION OF WATER TERRITORY TO BE DELETED
DUVAL COUNTY

In Township 2 South, Range 25 East:

Section 31

Area name: JEA-1. A portion of Tracts 11 and 12, Block 3, in Section 31, as shown on the plat of Jacksonville Heights, as recorded in Plat Book 5, Page 93 of the current public records of Duval County, Florida, more particularly described as follows:

Commence at the Southwest corner of said Section 31; thence N 89° 42' 31" E along the south line of said Section 31, a distance of 1,224.03 feet to the Southwest corner of Tract 13, Block 3, Jacksonville Heights, thence N 00° 47' 27" E along the west line of said Tract 13 a distance of 861.76 feet to the Point of Beginning; thence N 55° 09' 07" W a distance of 66.88 feet; thence N 89° 18' 56" W a distance of 219.61 feet; thence N 00° 46' 00" E a distance of 65.71 feet; thence N 89° 15' 41" W a distance of 110.00 feet; thence N 00° 43' 08" E a distance of 275.01 feet; thence N 89° 50' 42" E a distance of 155.39 feet; thence N 00° 01' 1O" E a distance of 135.00 feet; thence N 89° 50' 42" E a distance of 230.97 feet; thence S 00° 47' 27" W a distance of 519.05 feet to the Point of Beginning. Containing 3.61 acres.

Area name: JEA-2. A portion of Tracts 9, 11, and 12, plus all of Tract 10, Block 4, in Section 31, as shown on the plat of Jacksonville Heights, as recorded in Plat Book 5, Page 93 of the current public records of Duval County, Florida, more particularly described as follows:

Commence at the Southwest corner of said Section 31; thence N 89° 42' 31" E along the south line of said Section 31, a distance of 2,657.56 feet to the Southwest corner of Tract 11, Block 4, Jacksonville Heights, to the Point of Beginning; thence N 00° 53' 47" E a distance of 1327.69 feet; thence S 44° 38' 49" E a distance of 1,856.48 feet; thence S 89° 42' 31" W a distance of 1,325.40 feet to the Point of Beginning. Containing 20.19 acres.

FLORIDA PUBLIC SERVICE COMMISSION
authorizes
Neighborhood Utilities, Inc.
pursuant to
Certificate Number 430-W

to provide water service in Duval County in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Orders of this Commission in the territory described by the Orders of this Commission. This authorization shall remain in force and effect until superseded, suspended, canceled or revoked by Order of this Commission.

Order Number	Date Issued	Docket Number	Filing Type
13723	09/28/84	840063-WU	Original Certificate
PSC-11-0135-FOF-WU	02/28/11	090441-WU	Amendment
*		20220019-WU	Transfer

***Order Number and date to be provided at time of issuance.**

CSWR-Florida Utility Operating Company, LLC
Neighborhood Utilities, Inc.

Schedule of Net Book Value as of January 31, 2022

Description	Balance Per Utility 12/31/21	Adjustments		Staff 1/31/22
Utility Plant in Service	$672,155	$1,299	A	$673,454
Land & Land Rights	1,000	-		1,000
Accumulated Depreciation	(540,622)	(21,745)	B	(562,367)
CIAC	(76,431)	(193,145)	C	(269,576)
Amortization of CIAC	0	217,552	D	217,552
Total	$56,102	$3,961		$60,063

CSWR-Florida Utility Operating Company, LLC
Neighborhood Utilities, Inc.

Explanation of Adjustments to Net Book Value as of January 31, 2022

Explanation	Amount
A. UPIS To reflect the appropriate balance.	$1,299
B. Accumulated Depreciation To reflect the appropriate balance.	(21,745)
C. CIAC To reflect the appropriate balance.	(193,145)
D. Accumulated Amortization of CIAC To reflect the appropriate balance.	217,552
Total Adjustments to Net Book Value as of January 31, 2022	($3,961)

CSWR-Florida Utility Operating Company, LLC
Neighborhood Utilities, Inc.

Schedule of Staff's Recommended Account Balances as of January 31, 2022

Account No.	Description	UPIS	Accumulated Depreciation
304	Structures & Improvements	$14,967	($13,179)
305	Collecting & Impounding Reservoirs	90,940	(81,390)
307	Wells and Springs	45,388	(45,388)
309	Supply Mains	2,708	(557)
311	Pumping Equipment	58,328	(57,907)
320	Water Treatment Equipment	33,508	(31,588)
330	Distribution Reservoirs & Standpipes	30,830	(13,655)
331	Transmission and Distribution Mains	248,307	(202,216)
333	Services	64,444	(40,761)
334	Meters and Meter Installations	32,587	(32,587)
335	Hydrants	35,812	(34,961)
339	Other Plant Misc. Equipment	13,921	(7,018)
340	Office Furniture and Equipment	1,714	(1,158)
	Total	$673,454	$562,367

CSWR-Florida Utility Operating Company, LLC
Neighborhood Utilities, Inc.
Monthly Water Rates

Residential and General Service	
Base Facility Charge by Meter Size	
5/8" x 3/4"	$8.44
3/4"	$12.66
1"	$21.09
1 1/2"	$42.19
2"	$67.50
3"	$134.99
4"	$210.93
6"	$421.86
Charge per 1,000 gallons - Residential	
0 – 5,000 gallons	$4.34
5,001 – 10,000 gallons	$5.34
Over 10,000 gallons	$8.00
Charge per 1,000 gallons – General Service	$4.81

Initial Customer Deposits

Meter Size	Residential	General Service
5/8" x 3/4"	$58.00	2x the average estimated monthly bill
All over 5/8" x 3/4"	2x the average estimated monthly bill	2x the average estimated monthly bill

Miscellaneous Service Charges

Late Payment Charge	$4.30
NSF Charges	Pursuant to Section 68.065, F.S.

Service Availability Charges

Meter Installation Charge	
5/8" x 3/4"	$206.00
All other meter sizes	Actual Cost
Plant Capacity Charge	
Residential-per ERC (350 GPD)	$420.00
All others per gallon	$1.20

Item 9

FILED 9/22/2022
DOCUMENT NO. 07569-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Lewis, Ramos) TB
Division of Accounting and Finance (Sewards) ALM
Division of Economics (Bethea) JGH
Office of the General Counsel (Sandy) JSC

RE: Docket No. 20220085-WS – Application for transfer of water and wastewater facilities of River Grove Utilities, Inc., water Certificate No. 674-W, and wastewater Certificate No. 575-S to Cobblestone II RVG LLC; and amendment of water Certificate No. 674-W, and wastewater certificate 575-S, in Brevard County.

Docket No. 20220090-WS – Application for quick-take amendment of Certificate Nos. 674-W and 575-S, to delete territory in Brevard County by Cobblestone II RVG LLC, a Delaware limited liability company d/b/a River Grove Utility.

AGENDA: 10/04/22 – Regular Agenda – In Proposed Agency Action for Issues 2 and 3 - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners (20220085-WS and 20220090-WS)

PREHEARING OFFICER: Graham (20220085-WS)
Administrative (20220090-WS)

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

River Grove Utilities, Inc. (RGU or Seller) is a Class C water and wastewater utility providing service to approximately 179 residential customers in Brevard County. RGU is located in the St. Johns River Management District. According to RGU's 2021 Annual Report, the Utility had gross revenues of $166,257 and a net operating loss of $2,365. The Florida Public Service Commission (Commission) granted an original certificate to RGU in 2019.[1] On April 22, 2022, Cobblestone II RVG LLC, (Cobblestone or Buyer) filed an application for the transfer of Certificate Nos. 674-W and 575-S from RGU to Cobblestone (Docket No. 20220085-WS).

On May 5, 2022, Cobblestone filed a separate application for a quick-take amendment of Certificate Nos. 674-W and 575-S, to delete part of the service territory (Docket No. 20220085-WS). The property being deleted contains two single-family residences with additional undeveloped acreage. These residences are not receiving water or wastewater services from the Utility. This property is owned by the seller of RGU and he does not object to this deletion of the service territory.

This recommendation addresses, the transfer of Certificate Nos. 674-W and 575-S, the appropriate net book value of the system for transfer purposes, the need for an acquisition adjustment (Docket No. 20220085-WS), and the request for a service territory deletion (Docket No. 20220090-WS). The Commission has jurisdiction pursuant to Sections 367.045, 367.071, and 367.081, Florida Statutes (F.S).

[1] Order No. PSC-2020-0059-PAA-WS, issued February 24, 2020, in Docket No. 20190147-WS, *In re: Application for certificates to provide water and wastewater service in Brevard County by River Grove Utilities, Inc.*

Discussion of Issues

Issue 1: Should the transfer of Certificate Nos. 674-W and 575-S from River Grove Utilities, Inc., to Cobblestone II RVG LLC, be approved?

Recommendation: Yes. The transfer of Certificate Nos. 674-W and 575-S is in the public interest and should be approved effective the date of the Commission's vote. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The existing rates and charges shown on Schedule No. 2 should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariffs reflecting the transfer should be effective for services rendered or connections made on or after the stamped approval date on the tariffs pursuant to Rule 25-30.475, Florida Administrative Code (F.A.C.). The Seller is current with respect to annual reports and Regulatory Assessment Fees (RAFs) through December 31, 2021. The Buyer should be responsible for filing the Utility's annual reports and paying RAFs after April 21, 2022, and all future years. (Lewis, Sewards, Bethea)

Staff Analysis: On April 22, 2022, the Buyer filed an application for the transfer of Certificate Nos. 674-W and 575-S from RGU to Cobblestone. The application is in compliance with Section 367.071, F.S., and the Commission rules concerning applications for transfer of certificates. The sale to the Buyer occurred on April 21, 2022, contingent upon the Commission's approval, pursuant to Section 367.071(1), F.S.

Noticing, Territory, and Land Ownership

Cobblestone provided notice of the application pursuant to Section 367.071, F.S., and Rule 25-30.030, F.A.C. No objections to the transfer were filed, and the time for doing so has expired. The application contains a description of the service territory, which is appended to this recommendation as Attachment A.[2] The Buyer provided a copy of the warranty deed executed on April 15, 2022, as evidence that the Utility has rights to long-term use of the land upon which the treatment facilities are located pursuant Rule 25-30.30.037(2)(s), F.A.C.

Purchase Agreement and Financing

Pursuant to Rule 25-30.037(2)(g), (h), and (i), F.A.C., the application contains a statement regarding financing and a copy of the Purchase Agreement, which includes the purchase price, terms of payment, and a list of the assets purchased. There are no customer deposits, guaranteed revenue contracts, developer agreements, customer advances, leases, or debt of River Grove that must be disposed of with regard to the transfer. According to the Purchase Agreement, the total purchase price for the mobile home community, as well as the water and wastewater assets is $19,000,000. In response to staff's data request, the Buyer stated the specific purchase price of the water and wastewater assets should be set equal to the depreciated original cost as established by this Commission. As discussed later, staff has calculated a net book value of $159,093 for water and $2,250 for wastewater. Therefore, staff recommends a purchase price of $161,343 ($159,093 + $2,250) for the water and wastewater assets should be recognized
.

[2] Attachment A represents the proposed service territory to be served, including the deleted territory discussed in Issue 4.

Facility Description and Compliance

In March 2019, RGU interconnected its water distribution system with Brevard County's Barefoot Bay and now purchases bulk water service from Barefoot Bay. RGU's wastewater treatment plant (WWTP) has the permitted capacity of 0.030 million gallons per day and consists of flow equalization, influent screening, aeration, secondary clarification, chlorination, and aerobic digestion of biosolids. Based on the Utility's application and staff's investigation, the systems appear to be in satisfactory condition and compliant with the Florida Department of Environmental Protection standards.

Financial and Technical Ability

Pursuant to Rule 25-30.037(2)(l), and (m), F.A.C., the Buyer provided statements describing its financial and technical ability to provide water and wastewater service. As referenced in the transfer application, the Buyer will fulfill the commitments, obligations, and representation of the Seller with regards to utility matters. Staff reviewed the financial statements of the parent company, Cobblestone MHC Fund II LP, and believes the Buyer has documented adequate resources to support the Utility's operations.

In its application, the Buyer indicated that it has no experience in the water or wastewater industry; however, it will rely on one of its related parties which operates a wastewater system serving one of its other mobile home communities in Florida. Additionally, the Seller contracted its WWTP operations to US Water Services Corporation and the Buyer indicated that it intends to keep this contract in place. Based on the above, staff recommends that the Buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

Rates, Charges, and Customer Deposits

The Utility's rates, charges, and initial customer deposits were last approved in its 2019 application for original certificates to provide water and wastewater.[3] Rule 25-9.044(1), F.A.C., provides that, in the case of a change of ownership or control of a Utility, the rates, classifications, and regulations of the former owner must continue unless authorized to change by this Commission. In regard to the Utility's miscellaneous service charges, the late payment charge of $7.50 is appropriate. However, the remaining miscellaneous service charges do not conform to Rule 25-30.460, F.A.C., and are discussed in Issue 3. Therefore, staff recommends that the Utility's existing rates, late payment charge, service availability charges, non-sufficient funds charges, and initial customer deposits as shown Schedule No. 2, should remain in effect, until authorized to change by this Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C.

[3] Order No. PSC-2020-0059-PAA-WS, issued February 24, 2020, in Docket No. 20190147-WS, *In re: Application for certificates to provide water and wastewater service in Brevard County by River Grove Utilities, Inc.*

Regulatory Assessment Fees (RAFs) and Annual Reports

Staff has verified that the Seller is current on the filing of annual reports and RAFs through December 31, 2021. The Buyer should be responsible for filing the Utility's annual reports and paying RAFs after April 21, 2022, and all future years.

Conclusion

Based on the foregoing, staff recommends the transfer of Certificate Nos. 674-W and 575-S is in the public interest and should be approved effective the date of the Commission's vote. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The existing rates and charges shown on Schedule No. 2 should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariffs reflecting the transfer should be effective for services rendered or connections made on or after the stamped approval date on the tariffs pursuant to Rule 25-30.475, F.A.C. The Utility is current with respect to annual reports and RAFs through December 31, 2021. The Buyer should be responsible for filing the Utility's annual reports and paying RAFs after April 21, 2022, and all future years.

Issue 2: What is the appropriate net book value (NBV) for the River Grove water and wastewater systems for transfer purposes, and should an acquisition adjustment be approved?

Recommendation: The appropriate NBV of the water and wastewater systems for transfer purposes are $159,093 and $2,250, respectively, as of April 1, 2022. No acquisition adjustment is necessary as the purchase price is equal to the NBV. Within 90 days of the date of the final order, the Utility should be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in Cobblestone's 2022 Annual Report when filed. (Sewards)

Staff Analysis: Rate base has never been established for the Utility. The purpose of establishing NBV for transfers is to determine whether an acquisition adjustment should be approved. The NBV does not include normal ratemaking adjustments for used and useful plant or working capital. The Utility's NBV has been updated to reflect balances as of April 1, 2022. Staff's recommended NBV is shown on Schedule No. 1.

Utility Plant in Service (UPIS)

The Utility's general ledger reflects UPIS balances of $661,426 for water and $8,100 for wastewater as of April 1, 2022. Staff does not have any adjustments to the Utility's UPIS balances. Therefore, staff recommends UPIS balances of $661,426 for water and $8,100 for wastewater as of April 1, 2022.

Land

The Utility's general ledger reflects land balances of $2,250 for water and $2,250 for wastewater as of April 1, 2022. Staff does not have any adjustments to the Utility's land balances. Therefore, staff recommends land balances of $2,250 for water and $2,250 for wastewater as of April 1, 2022.

Accumulated Depreciation

The Utility's general ledger reflects accumulated depreciation balances of $73,163 for water and $8,100 for wastewater as of April 1, 2022. Staff does not have any adjustments to the Utility's accumulated depreciation balances. Therefore, staff recommends accumulated depreciation balances of $73,163 for water and $8,100 for wastewater as of April 1, 2022.

Contributions-in-Aid-of-Construction (CIAC) and Accumulated Amortization of CIAC

The Utility's general ledger reflects CIAC balances of $476,202 for water and $0 for wastewater as of April 1, 2022. The Utility's general ledger also reflects accumulated amortization of CIAC balances of $44,782 for water and $0 for wastewater as of April 1, 2022. Staff does not have any adjustments to the Utility's CIAC or Accumulated Amortization of CIAC balances. Therefore, staff recommends CIAC balances of $476,202 for water and $0 for wastewater, and accumulated amortization of CIAC balances of $44,782 for water and $0 for wastewater, as of April 1, 2022.

Net Book Value

The Utility's general ledger reflects NBV of $159,093 for water and $2,250 for wastewater as of April 1, 2022. Staff does not recommend any adjustments. As such, staff recommends NBV of $159,093 for water and $2,250 for wastewater. Staff's recommended NBV and the National

Association of Regulatory Utility Commissioners, Uniform System of Accounts (NARUC USOA) balances for UPIS and accumulated depreciation are shown on Schedule No. 1, as of April 1, 2022.

Acquisition Adjustment

An acquisition adjustment results when the purchase price differs from the NBV of the assets at the time of the acquisition. The Utility and its assets were purchased for $161,343. As stated above, staff recommends the appropriate NBV total to be $161,343. Pursuant to Rule 25-30.0371, F.A.C., a positive acquisition adjustment may be appropriate when the purchase price is greater than the NBV, and a negative acquisition adjustment may be appropriate when the purchase price is less than NBV. As the purchase price is equal to the NBV, staff recommends that no acquisition adjustment is warranted.

Conclusion

Based on the above, staff recommends that the NBV of the water and wastewater systems for transfer purposes is $159,093 and $2,250, respectively, as of April 1, 2022. No acquisition adjustment should be included in rate base. Within 90 days of the date of the final order, the buyer should be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in the Utility's 2022 Annual Report when filed.

Issue 3: Should Cobblestone's miscellaneous service charges be revised to conform to amended Rule 25-30.460, F.A.C.?

Recommendation: Yes. Staff recommends the miscellaneous service charges be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of initial connection and normal reconnection charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. Cobblestone should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding. (Bethea)

Staff Analysis: Effective June 24, 2021, Rule 25-30.460, F.A.C., was amended to remove initial connection and normal reconnection charges.4 The definitions for initial connection charges and normal reconnection charges were subsumed in the definition of the premises visit charge. It was envisioned that the utility tariffs would be reviewed by staff on a prospective basis to ensure conformance with the amended rule. The Utility's miscellaneous service charges consist of initial connection and normal reconnection charges. Therefore, staff recommends that the initial connection and normal reconnection charges be removed and the definition for the premises visit charge be updated to comply with amended Rule 25-30.460, F.A.C. The Utility's proposed and staff's recommended miscellaneous service charges are shown below in Tables 3-1 and 3-2.

Table 3-1
Utility Proposed Miscellaneous Service Charges

	Normal Hours
Initial Connection Charge	$30.00
Normal Reconnection Charge	$30.00
Violation Reconnection Charge	$30.00
Premises Visit Charge (in lieu of disconnection)	$30.00

Table 3-2
Staff Recommended Miscellaneous Service Charges

	Normal Hours
Violation Reconnection Charge	$30.00
Premises Visit Charge	$30.00

[4]Order No. PSC-2021-0201-FOF-WS, issued June 4, 2020, in Docket No. 20200240-WS, *In re: Proposed amendment of Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges.*

Conclusion

Based on the above, the miscellaneous service charges should be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of initial connection and normal reconnection charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. Cobblestone should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 4: Should the Commission approve Cobblestone's application for amendment of Certificate Nos. 674-W and 575-S to delete territory from its certificated service area in Brevard County?

Recommendation: Yes. The Commission should approve the application filed by Cobblestone to delete a portion of its service territory, as reflected in Attachment A. The resultant Order should serve as Cobblestone's amended certificates and should be retained by the Utility. (Lewis)

Staff Analysis: On May 5, 2022, Cobblestone applied for an amendment to delete a portion of its certificated service territory. In its application, Cobblestone provided a legal description of the territory proposed to be deleted in the format prescribed in Rule 25-30.029, F.A.C., along with a complete legal description of the remaining territory. Cobblestone also provided a detailed system map with the territory proposed to be deleted and retained plotted thereon.

In addition to their application, Cobblestone filed a notice with the Commission Clerk on June 14, 2022.[5] As set forth in the application and notice, the area to be deleted is undeveloped acreage with two single-family homes that are not served by the Utility. The property is owned by the Seller of RGU, who does not object to this deletion. No objections to the application have been received and the time for filing such has expired. The Utility's application is compliant with the filing requirements set forth in Rule 25-30.036(4), F.A.C.

Conclusion

Based on the above, staff recommends that it is in the public interest to approve the application filed by Cobblestone to amend its water and wastewater certificates to delete territory with the resulting territory as shown in Attachment A. The resultant Order should serve as Cobblestone's amended certificates and should be retained by the Utility.

[5] Document No. 03882-2022, filed in Docket No. 20220085-WS and Document No. 03881-2022, filed in Docket No. 20220090-WS.

Issue 5: Should this docket be closed?

Recommendation: Yes. If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the Order, a Consummating Order should be issued and the docket should be closed administratively upon Commission staff's verification that within 90 days of the date of the final order, the buyer has notified Commission staff in writing that it has adjusted its books in accordance with the Commission's Order approving the transfer. (Sandy)

Staff Analysis: If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the Order, a Consummating Order should be issued and the docket should be closed administratively upon Commission staff's verification that within 90 days of the date of the final order, the buyer has notified Commission staff in writing that it has adjusted its books in accordance with the Commission's Order approving the transfer.

RIVER GROVE UTILITIES, INC. SERVICE AREA - TO BE DELETED

A PORTION OF SECTION 14, TOWNSHIP 30 SOUTH, RANGE 38 EAST OF THE PUBLIC RECORDS OF FLAGLER COUNTY, FLORIDA AND BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:

FOR A POINT OF BEGINNING, COMMENCE AT THE SOUTHWEST CORNER OF SAID SECTION 14; THENCE NORTH 00 DEGREES 15 MINUTES 51 SECONDS EAST, ALONG THE WEST LINE OF SECTION 14, A DISTANCE OF 3974.89 FEET; THENCE SOUTH 89°32'41" EAST, DEPARTING FROM SAID WEST LINE OF SECTION 14, A DISTANCE OF 659.98 FEET; THENCE SOUTH 00°13'15 WEST, A DISTANCE OF 649.93 FEET; THENCE SOUTH 89 DEGREES 31 MINUTES 52 SECONDS EAST, A DISTANCE OF 659.54 FEET; THENCE SOUTH 00 DEGREES 15 MINUTES 51 SECONDS WEST, A DISTANCE OF 3324.96 FEET TO A POINT LYING ON THE SOUTH LINE OF THE AFOREMENTIONED SECTION 14; THENCE NORTH 89 DEGREES 32 MINUTES 41 SECONDS WEST, ALONG SAID SOUTH LINE OF SAID SECTION 14, A DISTANCE OF 1320.01 FEET TO THE SOUTHWEST CORNER OF SAID SECTION 14 AND THE POINT OF BEGINNING.

RIVER GROVE UTILITIES, INC. SERVICE AREA – AFTER DELETION

A PORTION OF SECTION 14, TOWNSHIP 30 SOUTH, RANGE 38 EAST OF THE PUBLIC RECORDS OF FLAGLER COUNTY, FLORIDA AND BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:

FOR A POINT OF BEGINNING, COMMENCE AT THE INTERSECTION OF THE SOUTH LINE OF THE NORTH 786.51 FEET OF GOVERNMENT LOTS 2 AND 5, IN SECTION 14, TOWNSHIP 30 SOUTH, RANGE 38 EAST, BREVARD COUNTY, FLORIDA AND THE WESTERLY RIGHT OF WAY LINE OF U.S. HIGHWAY NO. 1, SAID POINT ALSO LYING ON A CURVE, SAID CURVE BEING CONCAVE NORTHEASTERLY, HAVING A RADIUS OF 8672.41 FEET; THENCE SOUTHEASTERLY ALONG SAID ARC AND ALONG SAID WESTERLY RIGHT OF WAY LINE, AN ARC DISTANCE OF 243.82 FEET, SAID ARC BEING SUBTENDED BY A CHORD BEARING AND DISTANCE OF SOUTH 23 DEGREES 51 MINUTES 29 SECONDS EAST, 243.81 FEET TO THE POINT OF TANGENCY OF SAID CURVE; THENCE SOUTH 24 DEGREES 39 MINUTES 48 SECONDS EAST, ALONG SAID WESTERLY RIGHT OF WAY LINE, A DISTANCE OF 186.37 FEET TO THE SOUTH LINE OF THE NORTH 293.76 FEET OF THE SOUTH 448.49 FEET OF GOVERNMENT LOTS 2 AND 5, SECTION 14, TOWNSHIP 30 SOUTH, RANGE 38 EAST, BREVARD COUNTY, FLORIDA; THENCE NORTH 89 DEGREES 33 MINUTES 24 SECONDS WEST, DEPARTING FROM SAID WESTERLY RIGHT OF WAY LINE AND ALONG SAID SOUTH LINE, A DISTANCE OF 1562.71 FEET TO A POINT LYING ON THE WESTERLY RIGHT OF WAY LINE OF FLORIDA EAST COAST RAILROAD; THENCE SOUTH 02 DEGREES 10 MINUTES 00 SECONDS EAST, ALONG SAID WESTERLY RIGHT OF WAY LINE OF FLORIDA EAST COAST RAILROAD, A DISTANCE OF 155.05 FEET; THENCE NORTH 89 DEGREES 10 MINUTES 00 SECONDS WEST, DEPARTING FROM WESTERLY RIGHT OF WAY LINE OF FLORIDA EAST COAST RAILROAD, A DISTANCE OF 685.05 FEET; THENCE NORTH 00 DEGREES 15 MINUTES 51 SECONDS EAST, A DISTANCE OF 1167.47 FEET; THENCE NORTH 89 DEGREES 32 MINUTES 41 SECONDS WEST. A DISTANCE OF 301.95 FEET; THENCE NORTH 09 DEGREES 14 MINUTES 29 SECONDS WEST, A DISTANCE OF 170.00 FEET; THENCE SOUTH 89 DEGREES 32 MINUTES 41 SECONDS EAST, A DISTANCE OF 330.00 FEET; THENCE SOUTH 00 DEGREES 17 MINUTES 14 SECONDS WEST, A DISTANCE OF 115.09 FEET; THENCE SOUTH 89 DEGREES 32 MINUTES 49 SECONDS EAST, A DISTANCE OF 586.35 FEET TO A POINT LYING ON THE AFOREMENTIONED WEST RIGHT OF WAY LINE OF FLORIDA EAST COAST RAILROAD, SAID POINT ALSO ON A CURVE, SAID CURVE BEING CONCAVE SOUTHWESTERLY, HAVING A RADIUS OF 5679.65 FEET; THENCE SOUTHEASTERLY ALONG SAID WEST RIGHT OF WAY LINE AND ALONG THE ARC OF SAID CURVE, AN ARC DISTANCE OF 681.65 FEET, SAID ARC BEING SUBTENDED BY A CHORD BEARING AND DISTANCE OF SOUTH 06 DEGREES 04 MINUTES 54 SECONDS EAST, 681.25 FEET TO A POINT ON SAID CURVE; THENCE SOUTH 89 DEGREES 29 MINUTES 18 SECONDS EAST, DEPARTING FROM SAID WEST RIGHT OF WAY LINE OF FLORIDA EAST COAST RAILROAD, A DISTANCE OF 1401.39 FEET TO THE POINT OF BEGINNING.

FLORIDA PUBLIC COMMISSION

Authorizes

Cobblestone II RVG LLC

Pursuant to

Certificate Number 674-W

To provide water services in Brevard County in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Order of this Commission in the territory described by the Orders of the Commission. The authorization shall remain in the force and effect until superseded, suspended, concealed or revoked by Order of the Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-2020-0059-PAA-WS	02/24/2020	20190147-WS	Original Certificate
*	*	20220085-WS	Transfer
*	*	20220090-WS	Territory Amendment

FLORIDA PUBLIC COMMISSION

Authorizes

Cobblestone II RVG LLC

Pursuant to

Certificate Number 575-S

To provide wastewater services in Brevard County in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Order of this Commission in the territory described by the Orders of the Commission. The authorization shall remain in the force and effect until superseded, suspended, concealed or revoked by Order of the Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-2020-0059-PAA-WS	02/24/2020	20190147-WS	Original Certificate
*	*	20220085-WS	Transfer
*	*	20220090-WS	Territory Amendment

Cobblestone II RVG LLC
Water System

Schedule of Net Book Value as of April 1, 2022

Description	Balance Per Utility	Adjustments	Staff
Utility Plant in Service	$661,426	$0	$661,426
Land & Land Rights	2,250	0	2,250
Accumulated Depreciation	(73,163)	0	(73,163)
CIAC	(476,202)	0	(476,202)
Amortization of CIAC	44,782	0	44,782
Total	$159,093	$0	$159,093

Wastewater System

Schedule of Net Book Value as of April 1, 2022

Description	Balance Per Utility	Adjustments	Staff
Utility Plant in Service	$8,100	$0	$8,100
Land & Land Rights	2,250	0	2,250
Accumulated Depreciation	(8,100)	0	(8,100)
CIAC	0	0	0
Amortization of CIAC	0	0	0
Total	$2,250	$0	$2,250

Cobblestone II RVG LLC

Water System
Schedule of Staff Recommended Account Balances as of April 1, 2022

Account No.	Description	UPIS	Accumulated Depreciation
303	Land and Land Rights	$2,250	-
310	Power Generation Equipment	4,000	4,000
320	Water Treatment Equipment	8,100	8,100
331	Transmission and Distribution Mains	287,909	22,730
333	Services	303,598	26,023
334	Meter and Meter Install.	51,308	9,054
340	Office Furniture & Equip.	6,511	3,256
		$663,676	$73,163

Wastewater System
Schedule of Staff Recommended Account Balances as of April 1, 2022

Account No.	Description	UPIS	Accumulated Depreciation
353	Land and Land Rights	$2,250	-
380	Treatment and Disposal Equipment	8,100	8,100
		$10,350	$8,100

Cobblestone II RVG, LLC.
Monthly Water Rates

Residential and General Service	
All Meter Sizes	$34.92
Charge Per 1,000 gallons	$7.15

Initial Customer Deposits

Meter Sizes	**Residential**	**General Service**
5/8” x 3/4”	$175.00	2x Average Estimated Bill
All Other Meter Sizes	2x Average Estimated Bill	2x Average Estimated Bill

Service Availability Charges
Meter Installation Charge

5/8" x 3/4"	$353.00
All Other Meter Sizes	Actual Cost

Cobblestone II RVG, LLC.
Monthly Wastewater Rates

Residential and General Service

All Meter Sizes	$24.66
Charge Per 1,000 gallons	$3.36

Initial Customer Deposits

Meter Sizes	Residential	General Service
5/8" x 3/4"	$99.00	2x Average Estimated Bill
All Other Meter Sizes	2x Average Estimated Bill	2x Average Estimated Bill

Item 10

FILED 9/22/2022
DOCUMENT NO. 07584-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Economics (Forrest, Draper) JGH
Division of Accounting and Finance (Gatlin, Norris) ALM
Division of Engineering (Ellis, Phillips) TB
Office of the General Counsel (Stiller, Crawford) JSC

RE: Docket No. 20220148-EI – Petition to implement 2023 generation base rate adjustment provisions in 2021 agreement, by Tampa Electric Company.

AGENDA: 10/04/22 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 10/25/22 (60-Day Suspension Date)

SPECIAL INSTRUCTIONS: None

Case Background

On August 26, 2022, Tampa Electric Company (TECO or Company) filed a petition to implement the 2023 Generation Base Rate Adjustment (GBRA) provisions in its 2021 rate case Stipulation and Settlement Agreement (settlement agreement). The Commission previously approved the settlement agreement in Order No. PSC-2021-0423-S-EI (settlement order).[1] The GBRA provisions of the settlement agreement provide for an increase in base rates to reflect the 2023 GBRA amount of $89,754,622, effective with the first billing cycle of January 2023. In this petition, TECO proposed to increase the GBRA amount to $91,011,994, to reflect the increased return on equity (ROE) allowed by a trigger provision of the 2021 settlement agreement and

[1] Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

approved by the Commission on August 16, 2022, in Docket No. 20220122-EI.[2] The Commission has jurisdiction over this matter pursuant to Section 366.076, Florida Statutes (F.S.).

[2] Order No. PSC-2022-0322-FOF-EI, issued September 12, 2022, in Docket No. 20220122-EI, *In re: Petition for limited proceeding rate increase to implement return on equity provisions in 2021 agreement, by Tampa Electric Company.*

Discussion of Issues

Issue 1: Should the Commission approve the updated GBRA amount of $91,011,994?

Recommendation: Yes, the updated 2023 GBRA amount of $91,011,994 should be approved. (Gatlin, Norris)

Staff Analysis: As discussed in the Case Background, subparagraphs 4(a) and (b) of the 2021 settlement agreement provide that TECO's base rates will increase by $89,754,622 effective with the first billing cycle in January 2023.[3] The calculation of this GBRA amount was based on the authorized return on equity (ROE) mid-point of 9.95 percent as specified in subparagraph 2(a). However, subparagraph 4(d) states that if the Company's authorized ROE mid-point changes by operation of subparagraph 2(b) prior to the effective date of the rate adjustment specified in subparagraph 4(b), the calculation of the 2023 GBRA amount shall be updated to reflect the new authorized ROE.

As memorialized in Order No. PSC-2022-0322-FOF-EI, the Commission approved TECO's petition to implement the ROE trigger provisions of subparagraph 2(b) of the 2021 settlement agreement following an evidentiary hearing on August 16, 2022.[4] As a result, the Company's authorized ROE midpoint was increased by 25 basis points from 9.95 percent to 10.20 percent, effective as of July 1, 2022, for all regulatory purposes. In its petition to implement the 2023 GBRA, TECO provided a calculation updating the GBRA amount to $91,011,994 to reflect the Company's 10.20 percent authorized ROE mid-point. Staff reviewed the Company's calculation and recommends the updated amount be approved.

[3] Order No. PSC-2021-0423-S-EI
[4] Order No. PSC-2022-0322-FOF-EI

Issue 2: Should the Commission approve TECO's revised tariffs to implement the GBRA increase effective January 2023?

Recommendation: Yes, the Commission should approve TECO's revised tariffs to implement the GBRA increase effective with the first billing cycle of January 2023 as approved in the settlement order. (Forrest, Draper)

Staff Analysis: TECO's petition includes the proposed tariff sheets, the allocation of the revenue increase to the various rate classes and calculations showing the revenue from the sale of electricity by rate schedule under current and proposed rates. A residential customer who uses 1,000 kilowatt-hours (kWh) per month will see an increase of $6.76 on the base rate portion of their monthly bill as a result of the GBRA increase.

Subparagraph 4(e) of the settlement agreement, which addresses the GBRA increase and was approved by Order No. PSC-2021-0423-S-EI, states:

> … the GBRAs shall be reflected on customer bills by allocating each GBRA revenue requirement to rate classes as shown in Exhibit K and demand and energy base rate charges shall be increased on an equal percentage basis (to the extent practicable) within each class to recover the allocated revenue requirement increase for each class, and shall be calculated based upon the billing determinants used in the company's then-most-current-ECCR filing with the Commission for the twelve months following the effective date of any respective GBRA. For GSD, GSLDPR, and GSLDSU rate classes, the increase will be recovered exclusively based on demand charges.

TECO's most current Energy Conservation Cost Recovery Clause (ECCR) filing in Docket No. 20220002-EI was filed on August 5, 2022.[5] Staff has confirmed that the billing determinants used in calculating the proposed GBRA base rate charges are consistent with the billing determinants in TECO's most recent ECCR filing, and in compliance with the language of the settlement agreement.

Staff has also reviewed TECO's proposed 2023 GBRA tariff sheets and supporting documentation. The calculations are accurate and reflect the language of the approved settlement agreement. The Commission should approve TECO's tariff rate changes to implement the updated GBRA increase of $91,011,994, due to the ROE trigger provision in the settlement agreement. Pursuant to the settlement order, the rate changes should become effective with the first billing cycle of January 2023. TECO should notify its customers of the approved new rates, by way of bill notification, in the December 2022 billing cycle.

[5] Document No. 05237-2022, filed August 5, 2022, in Docket No. 20220002-EI, *In re: Energy Conservation Cost Recovery Clause.*

Issue 3: Should this docket be closed?

Recommendation: If Issues 1 and 2 are approved and a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Stiller)

Staff Analysis: If Issues 1 and 2 are approved and a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 1 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-FIRST REVISED SHEET NO. 6.030
CANCELS THIRTIETH REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

RATES:

Basic Service Charge:
$ 0.71 per day.

Energy and Demand Charge:

First 1,000 kWh	6.492 ¢ per kWh
All additional kWh	7.617 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

Continued to Sheet No. 6.031

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-SECOND REVISED SHEET NO. 6.050
CANCELS THIRTY-FIRST REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

RATES:

Basic Service Charge:

Metered accounts	$0.75 per day
Un-metered accounts	$0.63 per day

Energy and Demand Charge:
7.642 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.171 ¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-FIRST REVISED SHEET NO. 6.080
CANCELS THIRTIETH REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

STANDARD

Basic Service Charge:

Secondary Metering Voltage	$ 1.08 per day
Primary Metering Voltage	$ 5.98 per day
Subtrans. Metering Voltage	$17.48 per day

Demand Charge:
$14.13 per kW of billing demand

Energy Charge:
0.736 ¢ per kWh

OPTIONAL

Basic Service Charge:

Secondary Metering Voltage	$ 1.08 per day
Primary Metering Voltage	$ 5.98 per day
Subtrans. Metering Voltage	$17.48 per day

Demand Charge:
$0.00 per kW of billing demand

Energy Charge:
7.115 ¢ per kWh

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWELFTH REVISED SHEET NO. 6.140
CANCELS ELEVENTH REVISED SHEET NO. 6.140

GENERAL SERVICE - LARGE DEMAND PRIMARY

SCHEDULE: GSLDPR

AVAILABLE: Entire Service Area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge:	$ 19.52 per day
Demand Charge:	$ 11.83 per kW of billing demand
Energy Charge:	1.042¢ per kWh

Continued to Sheet No. 6.145

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.160
CANCELS FIRST REVISED SHEET NO. 6.160

GENERAL SERVICE - LARGE DEMAND SUBTRANSMISSION

SCHEDULE: GSLDSU

AVAILABLE: Entire Service Area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $ 83.90 a day

Demand Charge: $ 9.24 per kW of billing demand

Energy Charge: 1.151¢ per kWh

Continued to Sheet No. 6.165

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-SEVENTH REVISED SHEET NO. 6.290
CANCELS THIRTY-SIXTH REVISED SHEET NO. 6.290

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

RATES:
Basic Service Charge: $0.75 per day

Energy and Demand Charge: 7.642 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

MISCELLANEOUS: A Temporary Service Charge of $320.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 7 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-FIRST REVISED SHEET NO. 6.320
CANCELS THIRTIETH REVISED SHEET NO. 6.320

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

RATES:

Basic Service Charge:
$0.75 per day

Energy and Demand Charge:
11.972¢ per kWh during peak hours
6.154¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-SECOND REVISED SHEET NO. 6.330
CANCELS THIRTY-FIRST REVISED SHEET NO.6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Basic Service Charge:

Secondary Metering Voltage	$ 1.08 per day
Primary Metering Voltage	$ 5.98 per day
Subtransmission Metering Voltage	$17.48 per day

Demand Charge:
$4.53 per kW of billing demand, plus
$9.24 per kW of peak billing demand

Energy Charge:
1.193¢ per kWh during peak hours
0.571¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWELFTH REVISED SHEET NO. 6.370
CANCELS ELEVENTH REVISED SHEET NO. 6.370

**TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
PRIMARY
(OPTIONAL)**

SCHEDULE: GSLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $19.52 a day

Demand Charge:
$3.76 per kW of billing demand, plus
$8.04 per kW of peak billing demand

Energy Charge:
1.584¢ per kWh during peak hours
0.847¢ per kWh during off-peak hours

Continued to Sheet No. 6.375

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

EIGHTH REVISED SHEET NO. 6.400
CANCELS SEVENTH REVISED SHEET NO. 6.400

TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
SUBTRANSMISSION
(OPTIONAL)

SCHEDULE: GSLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $83.90 a day

Demand Charge:
$2.94 per kW of billing demand, plus
$6.28 per kW of peak billing demand

Energy Charge:
1.386¢ per kWh during peak hours
1.078¢ per kWh during off-peak hours

Continued to Sheet No. 6.405

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SEVENTEENTH REVISED SHEET NO. 6.565
CANCELS SIXTEENTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

RATES:

Basic Service Charge: $0.71per day

Energy and Demand Charges: 6.846¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTEENTH REVISED SHEET NO. 6.600
CANCELS EIGHTEENTH REVISED SHEET NO. 6.600

STANDBY AND SUPPLEMENTAL SERVICE
DEMAND

SCHEDULE: SBD

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.91
Primary Metering Voltage	$ 6.80
Subtransmission Metering Voltage	$18.31

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$ 1.74 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$ 1.69 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$ 0.67 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.857 ¢ per Standby kWh

Continued to Sheet No. 6.601

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 13 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-SECOND REVISED SHEET NO. 6.601
CANCELS TWENTY-FIRST REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 14.13 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
0.736¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SIXTEENTH REVISED SHEET NO. 6.605
CANCELS FIFTEENTH REVISED SHEET NO. 6.605

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL DEMAND SERVICE
(OPTIONAL)

SCHEDULE: SBDT

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.91
Primary Metering Voltage	$ 6.80
Subtransmission Metering Voltage	$ 18.31

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$1.74 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$1.69 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.67 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.857¢ per Standby kWh

Continued to Sheet No. 6.606

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 15 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTEENTH REVISED SHEET NO. 6.606
CANCELS EIGHTEENTH REVISED SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

\$4.53	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
\$9.24	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.193¢	per Supplemental kWh during peak hours
0.571¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 16 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.610
CANCELS NINTH REVISED SHEET NO. 6.610

STANDBY- LARGE - DEMAND
PRIMARY

SCHEDULE: SBLDPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Basic Service Charge: $20.35 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$1.33 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$1.42 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$0.56 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.615

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 17 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.615
CANCELS FIRST REVISED SHEET NO. 6.615

Continued from Sheet No. 6.610

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 11.83 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.042¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:
Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during a 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.620

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.630
CANCELS FIRST REVISED SHEET NO. 6.630

STANDBY-LARGE DEMAND
SUBTRANSMISSION

SCHEDULE: SBLDSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $84.73 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$0.86 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$1.11 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.44 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.635

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 19 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.635
CANCELS FIRST REVISED SHEET NO. 6.635

Continued from Sheet No. 6.630

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:

$ 9.24 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:

1.151¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units:

Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.640

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.650
CANCELS FIRST REVISED SHEET NO. 6.650

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
PRIMARY
(OPTIONAL)

SCHEDULE: SBLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $20.35 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$1.33 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$1.42 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.56 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.857¢ per Standby kWh

Continued to Sheet No. 6.655

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.655
CANCELS FIRST REVISED SHEET NO. 6.655

Continued from Sheet No. 6.650

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$ 3.76	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$ 8.04	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.584¢	per Supplemental kWh during peak hours
0.847¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.660

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.670
CANCELS FIRST REVISED SHEET NO. 6.670

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
SUBTRANSMISSION
(OPTIONAL)

SCHEDULE: SBLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take service from the utility. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $ 84.73 per day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 0.86 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.11 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.44 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.675

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.675
CANCELS FIRST REVISED SHEET NO. 6.675

Continued from Sheet No. 6.670

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$2.94	per kW/Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$6.28	per kW/Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.386¢	per Supplemental kWh during peak hours
1.078¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units:

Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.680

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTEENTH REVISED SHEET NO. 6.805
CANCELS FOURTEENTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	4.45	2.48	0.64	0.32
802	862	Cobra/Nema[1]	6,300	70	29	14	4.52	2.11	0.93	0.45
803	863	Cobra/Nema[1]	9,500	100	44	22	5.12	2.33	1.41	0.70
804	864	Cobra[1]	16,000	150	66	33	5.89	2.02	2.11	1.05
805	865	Cobra[1]	28,500	250	105	52	6.87	2.60	3.35	1.66
806	866	Cobra[1]	50,000	400	163	81	7.18	2.99	5.21	2.59
468	454	Flood[1]	28,500	250	105	52	7.57	2.60	3.35	1.66
478	484	Flood[1]	50,000	400	163	81	8.06	3.00	5.21	2.59
809	869	Mongoose[1]	50,000	400	163	81	9.17	3.02	5.21	2.59
509	508	Post Top (PT)[1]	4,000	50	20	10	4.34	2.48	0.64	0.32
570	530	Classic PT[1]	9,500	100	44	22	16.72	1.89	1.41	0.70
810	870	Coach PT[1]	6,300	70	29	14	6.65	2.11	0.93	0.45
572	532	Colonial PT[1]	9,500	100	44	22	12.82	1.89	1.41	0.70
573	533	Salem PT[1]	9,500	100	44	22	12.74	1.89	1.41	0.70
550	534	Shoebox[1]	9,500	100	44	22	11.30	1.89	1.41	0.70
566	536	Shoebox[1]	28,500	250	105	52	12.26	3.18	3.35	1.66
552	538	Shoebox[1]	50,000	400	163	81	10.39	2.44	5.21	2.59

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 3.195¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTEENTH REVISED SHEET NO. 6.806
CANCELS TWELFTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra[1]	29,700	350	138	69	10.62	4.99	4.41	2.20
520	522	Cobra[1]	32,000	400	159	79	8.50	4.01	5.08	2.52
705	725	Flood[1]	29,700	350	138	69	12.06	5.04	4.41	2.20
556	541	Flood[1]	32,000	400	159	79	11.80	4.02	5.08	2.52
558	578	Flood[1]	107,800	1,000	383	191	14.81	8.17	12.24	6.10
701	721	General PT[1]	12,000	150	67	34	14.95	3.92	2.14	1.09
574	548	General PT[1]	14,400	175	74	37	15.37	3.73	2.36	1.18
700	720	Salem PT[1]	12,000	150	67	34	13.16	3.92	2.14	1.09
575	568	Salem PT[1]	14,400	175	74	37	13.23	3.74	2.36	1.18
702	722	Shoebox[1]	12,000	150	67	34	10.18	3.92	2.14	1.09
564	549	Shoebox[1]	12,800	175	74	37	11.22	3.70	2.36	1.18
703	723	Shoebox[1]	29,700	350	138	69	13.47	4.93	4.41	2.20
554	540	Shoebox[1]	32,000	400	159	79	14.13	3.97	5.08	2.52
576	577	Shoebox[1]	107,800	1,000	383	191	23.28	8.17	12.24	6.10

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 3.195¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT FIVE
PAGE 26 OF 31

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.808
CANCELS THIRTEENTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:
(1) Closed to new business

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(4)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(2)	Lamp Wattage(3)	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway(1)	5,155	56	20	10	10.81	1.74	0.64	0.32
820	840	Roadway (1)	7,577	103	36	18	16.27	1.19	1.15	0.58
821	841	Roadway(1)	8,300	106	37	19	16.27	1.20	1.18	0.61
829	849	Roadway(1)	15,285	157	55	27	16.21	2.26	1.76	0.86
822	842	Roadway(1)	15,300	196	69	34	20.56	1.26	2.20	1.09
823	843	Roadway(1)	14,831	206	72	36	23.70	1.38	2.30	1.15
835	855	Post Top(1)	5,176	60	21	11	23.31	2.28	0.67	0.35
824	844	Post Top(1)	3,974	67	24	12	27.47	1.54	0.77	0.38
825	845	Post Top(1)	6,030	99	35	17	28.93	1.56	1.12	0.54
836	856	Post Top(1)	7,360	100	35	18	23.55	2.28	1.12	0.58
830	850	Area-Lighter(1)	14,100	152	53	27	20.95	2.51	1.69	0.86
826	846	Area-Lighter(1)	13,620	202	71	35	26.95	1.41	2.27	1.12
827	847	Area-Lighter(1)	21,197	309	108	54	29.07	1.55	3.45	1.73
831	851	Flood(1)	22,122	238	83	42	22.43	3.45	2.65	1.34
832	852	Flood(1)	32,087	359	126	63	27.02	4.10	4.03	2.01
833	853	Mongoose(1)	24,140	245	86	43	20.75	3.04	2.75	1.37
834	854	Mongoose(1)	32,093	328	115	57	23.01	3.60	3.67	1.82

(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 3.195¢ per kWh for each fixture.

Continued to Sheet No. 6.809

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

77

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.809
CANCELS EIGHTH REVISED SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[3]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[1]	Lamp Wattage[2]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	7.57	1.74	0.29	0.16
914	901	Roadway	5,392	47	16	8	7.49	1.74	0.51	0.26
921	902	Roadway/Area	8,500	88	31	15	11.59	1.74	0.99	0.48
926	982	Roadway	12,414	105	37	18	10.64	1.19	1.18	0.58
932	903	Roadway/Area	15,742	133	47	23	20.01	1.38	1.50	0.73
935	904	Area-Lighter	16,113	143	50	25	14.91	1.41	1.60	0.80
937	905	Roadway	16,251	145	51	26	11.34	2.26	1.63	0.83
941	983	Roadway	22,233	182	64	32	14.45	2.51	2.04	1.02
945	906	Area-Lighter	29,533	247	86	43	20.79	2.51	2.75	1.37
947	984	Area-Lighter	33,600	330	116	58	26.07	1.55	3.71	1.85
951	985	Flood	23,067	199	70	35	16.19	3.45	2.24	1.12
953	986	Flood	33,113	255	89	45	27.24	4.10	2.84	1.44
956	987	Mongoose	23,563	225	79	39	17.42	3.04	2.52	1.25
958	907	Mongoose	34,937	333	117	58	21.79	3.60	3.74	1.85
965	991	Granville Post Top (PT)	3,024	26	9	4	8.30	2.28	0.29	0.13
967	988	Granville PT	4,990	39	14	7	18.14	2.28	0.45	0.22
968	989	Granville PT Enh[4]	4,476	39	14	7	21.67	2.28	0.45	0.22
971	992	Salem PT	5,240	55	19	9	14.78	1.54	0.61	0.29
972	993	Granville PT	7,076	60	21	10	19.84	2.28	0.67	0.32
973	994	Granville PT Enh[4]	6,347	60	21	10	23.30	2.28	0.67	0.32
975	990	Salem PT	7,188	76	27	13	19.19	1.54	0.86	0.42

[1] Average
[2] Average wattage. Actual wattage may vary by up to +/- 10 %.
[3] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 3.195¢ per kWh for each fixture.
[4] Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.810
CANCELS SIXTH REVISED SHEET NO. 6.810

Continued from Sheet No. 6.809

Pole/Wire and Pole/Wire Maintenance Charges:

Rate Code	Style	Description	Wire Feed	Charge Per Unit ($) Pole/Wire	Charge Per Unit ($) Maintenance
425	Wood (Inaccessible)[(1)]	30 ft	OH	7.68	0.17
626	Wood	30 ft	OH	3.79	0.17
627	Wood	35 ft	OH	4.49	0.17
597	Wood	40/45 ft	OH	9.59	0.31
637	Standard	35 ft, Concrete	OH	8.03	0.17
594	Standard	40/45 ft, Concrete	OH	15.37	0.31
599	Standard	16 ft, DB Concrete	UG	22.16	0.14
595	Standard	25/30 ft, DB Concrete	UG	30.42	0.14
588	Standard	35 ft, DB Concrete	UG	31.89	0.34
607	Standard (70 - 100 W or up to 100 ft span)[(1)]	35 ft, DB Concrete	UG	16.31	0.34
612	Standard (150 W or 100 -150 ft span)[(1)]	35 ft, DB Concrete	UG	21.85	0.34
614	Standard (250 -400W or above 150 ft span)[(1)]	35 ft, DB Concrete	UG	32.98	0.34
596	Standard	40/45 ft, DB Concrete	UG	37.16	0.14
523	Round	23 ft, DB Concrete	UG	29.86	0.14
591	Tall Waterford	35 ft, DB Concrete	UG	41.12	0.14
592	Victorian	PT, DB Concrete	UG	35.31	0.14
593	Winston	PT, DB Aluminum	UG	19.86	1.10
583	Waterford	PT, DB Concrete	UG	29.85	0.14
422	Aluminum[(1)]	10 ft, DB Aluminum	UG	12.22	1.30
616	Aluminum	27 ft, DB Aluminum	UG	40.58	0.34
615	Aluminum	28 ft, DB Aluminum	UG	17.43	0.34
622	Aluminum	37 ft, DB Aluminum	UG	55.56	0.34
623	Waterside	38 ft, DB Aluminum	UG	47.83	3.85
584	Aluminum[(1)]	PT, DB Aluminum	UG	22.92	1.10
581	Capitol[(1)]	PT, DB Aluminum	UG	34.99	1.10
586	Charleston	PT, DB Aluminum	UG	26.69	1.10
585	Charleston Banner	PT, DB Aluminum	UG	34.93	1.10
590	Charleston HD	PT, DB Aluminum	UG	30.20	1.10
580	Heritage[(1)]	PT, DB Aluminum	UG	25.29	1.10
587	Riviera[(1)]	PT, DB Aluminum	UG	26.70	1.10
589	Steel[(1)]	30 ft, AB Steel	UG	50.02	1.68
624	Fiber[(1)]	PT, DB Fiber	UG	10.63	1.30
582	Winston [(1)]	PT, DB Fiber	UG	19.33	1.10
525	Franklin Composite	PT, DB Composite	UG	31.86	1.10
641	Existing Pole		UG	6.80	0.34

[(1)] Closed to new business

Continued from Sheet No. 6.815

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.815
CANCELS THIRTEENTH REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$8.23	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.66	$0.06

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023

FRANCHISE FEE: See Sheet No. 6.023

PAYMENT OF BILLS: See Sheet No. 6.023

STORM PROTECTION PLAN RECOVERY PLAN: See Sheet Nos. 6.021 and 6.023

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 3.195¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020. 6.021, 6.022 and 6.023.

Continued to Sheet No. 6.820

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.830
CANCELS SIXTH SHEET NO. 6.830

CUSTOMER SPECIFIED LIGHTING SERVICE

SCHEDULE: LS-2

AVAILABLE: Entire service area

APPLICABLE:

Customer Specified Lighting Service is applicable to any customer for the sole purpose of lighting roadways or other outdoor areas. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party. At the Company's option, a deposit amount of up to a two (2) month's average bill may be required at anytime.

CHARACTER OF SERVICE:

Service is provided during the hours of darkness normally on a dusk-to-dawn basis. At the Company's option and at the customer's request, the company may permit a timer to control a lighting system provided under this rate schedule that is not used for dedicated street or highway lighting. The Company shall install and maintain the timer at the customer's expense. The Company shall program the timer to the customer's specifications as long as such service does not exceed 2,100 hours each year. Access to the timer is restricted to company personnel.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgment of the Company, location of the proposed lights are, and will continue to be, feasible and accessible to Company personnel and equipment for both construction and maintenance and such installation is not appropriate as a public offering under LS-1.

TERM OF SERVICE:

Service under this rate schedule shall, at the option of the company, be for an initial term of twenty (20) years beginning on the date one or more of the lighting equipment is installed, energized, and ready for use and shall continue after the initial term for successive one-year terms until terminated by either party upon providing ninety (90) days prior written notice. Any customer transferring service to the LS-2 rate schedule from the LS-1 rate schedule shall continue the remaining primary initial term from LS-1 agreement.

SPECIAL CONDITIONS:

On lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 3.195¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020, 6.021, 6.022 and 6.023

Continued to Sheet No. 6.835

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.835
CANCELS SIXTH SHEET NO. 6.835

Continued from Sheet No. 6.830

MONTHLY RATE: The monthly charge shall be calculated by applying the monthly rate of 0.93% to the In-Place Value of the customer specific lighting facilities identified in the Outdoor Lighting Agreement entered into between the customer and the Company for service under this schedule.

The In-Place Value may change over time as new lights are added to the service provided under this Rate Schedule to a customer taking service, the monthly rate shall be applied to the In-Place Value in effect that billing month. The In-Place Value of any transferred LS-1 service shall be defined by the value of the lighting Equipment or its LED equivalent based on the average cost of a current installation. The in-Place Value of any new LS-2 service shall be defined by the value of the lighting equipment when it was first put in service.

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

Payment may be made in a lump sum at the time the agreement is entered into, or at the customer's option these non-standard costs may be included in the In-Place Value to which the monthly rate will be applied.

MINIMUM CHARGE: The monthly charge.

ENERGY CHARGE: For monthly energy served under this rate schedule, 3.195¢ per kWh.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 1 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTIETH~~ THIRTY-FIRST REVISED SHEET NO. 6.030
CANCELS ~~TWENTY-NINTH~~THIRTIETH REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

RATES:

Basic Service Charge:
$ 0.71 per day.

Energy and Demand Charge:

First 1,000 kWh	~~5.816~~6.492 ¢ per kWh
All additional kWh	~~6.824~~7.617 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

Continued to Sheet No. 6.031

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~THIRTY-FIRST~~THIRTY-SECOND REVISED SHEET NO. 6.050
CANCELS ~~THIRTIETH~~ THIRTY-FIRST REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

RATES:

Basic Service Charge:

Metered accounts	$0.75 per day
Un-metered accounts	$0.63 per day

Energy and Demand Charge:

~~6.688~~7.642 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.171 ¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~THIRTIETH~~ THIRTY-FIRST REVISED SHEET NO. 6.080
CANCELS ~~TWENTY-NINTH~~THIRTIETH REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

STANDARD		OPTIONAL	
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ 1.08 per day	Secondary Metering Voltage	$ 1.08 per day
Primary Metering Voltage	$ 5.98 per day	Primary Metering Voltage	$ 5.98 per day
Subtrans. Metering Voltage	$17.48 per day	Subtrans. Metering Voltage	$17.48 per day
Demand Charge:		Demand Charge:	
$~~13.86~~14.13 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		Energy Charge:	
0.736 ¢ per kWh		7.115 ¢ per kWh	

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.140
CANCELS ~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.140

GENERAL SERVICE - LARGE DEMAND PRIMARY

SCHEDULE: GSLDPR

AVAILABLE: Entire Service Area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge:	$ 19.52 per day
Demand Charge:	$ 11.~~59~~ 83 per kW of billing demand
Energy Charge:	1.042¢ per kWh

Continued to Sheet No. 6.145

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.160
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.160

GENERAL SERVICE - LARGE DEMAND SUBTRANSMISSION

SCHEDULE: GSLDSU

AVAILABLE: Entire Service Area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge:	$ 83.90 a day
Demand Charge:	$ 9.~~06~~ 24 per kW of billing demand
Energy Charge:	1.151¢ per kWh

Continued to Sheet No. 6.165

ISSUED BY: A. D. Collins, President DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 6 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~THIRTY-SIXTH~~THIRTY-SEVENTH REVISED SHEET NO. 6.290
CANCELS ~~THIRTY-FIFTH~~THIRTY-SIXTH REVISED SHEET NO. 6.290

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

RATES:
Basic Service Charge: $0.75 per day

Energy and Demand Charge: ~~6.688~~7.642 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

MISCELLANEOUS: A Temporary Service Charge of $320.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 7 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTIETH~~ THIRTY-FIRST REVISED SHEET NO. 6.320
CANCELS ~~TWENTY-NINTH~~THIRTIETH REVISED SHEET NO. 6.320

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

RATES:

Basic Service Charge:
$0.75 per day

Energy and Demand Charge:
~~10.478~~11.972¢ per kWh during peak hours
~~5.386~~6.154¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

90

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 8 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTY-FIRST~~THIRTY-SECOND REVISED SHEET NO. 6.330
CANCELS ~~THIRTIETH~~ THIRTY-FIRST REVISED SHEET NO.6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Basic Service Charge:

Secondary Metering Voltage	$ 1.08 per day
Primary Metering Voltage	$ 5.98 per day
Subtransmission Metering Voltage	$17.48 per day

Demand Charge:
$4.~~44~~ 53 per kW of billing demand, plus
$9.~~06~~ 24 per kW of peak billing demand

Energy Charge:
1.193¢ per kWh during peak hours
0.571¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: A. D. Collins, President DATE EFFECTIVE:

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.370
CANCELS ~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.370

TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
PRIMARY
(OPTIONAL)

SCHEDULE: GSLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $19.52 a day

Demand Charge:
$3.~~68~~ 76 per kW of billing demand, plus
$~~7.88~~ 8.04 per kW of peak billing demand

Energy Charge:
1.584¢ per kWh during peak hours
0.847¢ per kWh during off-peak hours

Continued to Sheet No. 6.375

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.400
CANCELS ~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.400

TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
SUBTRANSMISSION
(OPTIONAL)

SCHEDULE: GSLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $83.90 a day

Demand Charge:
$2.~~88~~ 94 per kW of billing demand, plus
$6.~~15~~ 28 per kW of peak billing demand

Energy Charge:
1.386¢ per kWh during peak hours
1.078¢ per kWh during off-peak hours

Continued to Sheet No. 6.405

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

93

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SIXTEENTH~~ SEVENTEENTH REVISED SHEET NO. 6.565
CANCELS ~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

RATES:
Basic Service Charge: $0.71per day

Energy and Demand Charges: 6.~~133~~846¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

94

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 12 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~EIGHTEENTH~~ NINTEENTH REVISED SHEET NO. 6.600
CANCELS ~~SEVENTEENTH~~ EIGHTEENTH REVISED
SHEET NO. 6.600

STANDBY AND SUPPLEMENTAL SERVICE
DEMAND

SCHEDULE: SBD

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.91
Primary Metering Voltage	$ 6.80
Subtransmission Metering Voltage	$18.31

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$	1.~~74~~74	per kW/Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:

$	1.~~66~~69	per kW/Month of Standby Demand (Power Supply Reservation Charge) or
$	0.~~66~~67	per kW/Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Energy Charge:

0.857 ¢	per Standby kWh

Continued to Sheet No. 6.601

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 13 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~TWENTY-FIRST~~ TWENTY-SECOND REVISED SHEET NO. 6.601
CANCELS ~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ ~~13.86~~14.13 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
0.736¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units:

Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 14 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.605
CANCELS ~~FOURTEENTH~~ FIFTEENTH REVISED SHEET NO. 6.605

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL DEMAND SERVICE
(OPTIONAL)

SCHEDULE: SBDT

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.91
Primary Metering Voltage	$ 6.80
Subtransmission Metering Voltage	$ 18.31

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$1.~~71~~74 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$1.~~66~~ 69 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$0.~~66~~67 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.606

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 15 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~EIGHTEENTH~~ NINTEENTH REVISED SHEET NO. 6.606
CANCELS ~~SEVENTEENTH~~ EIGHTEENTH REVISED
SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$4.~~44~~53	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$9.~~06~~24	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.193¢	per Supplemental kWh during peak hours
0.571¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~NINTH~~ TENTH REVISED SHEET NO. 6.610
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 6.610

STANDBY- LARGE - DEMAND
PRIMARY

SCHEDULE: SBLDPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Basic Service Charge: $20.35 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$1.~~30~~ 33 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$1.~~39~~ 42 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$0.~~55~~ 56 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.615

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.615
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.615

Continued from Sheet No. 6.610

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 11.~~59~~83 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.042¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during a 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.620

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 18 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.630
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.630

STANDBY-LARGE DEMAND
SUBTRANSMISSION

SCHEDULE: SBLDSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $84.73 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$0.~~84~~86 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$1.~~09~~11 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.~~43~~44 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.857¢ per Standby kWh

Continued to Sheet No. 6.635

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.635
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.635

Continued from Sheet No. 6.630

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 9.~~06~~24 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.151¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.640

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.650
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.650

**TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
PRIMARY
(OPTIONAL)**

SCHEDULE: SBLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $20.35 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$1.~~30~~33 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$1.~~39~~42 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.~~55~~56 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.857¢ per Standby kWh

Continued to Sheet No. 6.655

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

103

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 21 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.655
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.655

Continued from Sheet No. 6.650

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$ 3.~~68~~76	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$ ~~7.88~~8.04	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.584¢	per Supplemental kWh during peak hours
0.847¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.660

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

104

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 22 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.670
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.670

**TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
SUBTRANSMISSION
(OPTIONAL)**

SCHEDULE: SBLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take service from the utility. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $ 84.73 per day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$ 0.~~84~~86 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$ 1.~~09~~11 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$ 0.~~43~~44 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.857¢ per Standby kWh

Continued to Sheet No. 6.675

ISSUED BY: A. D. Collins, President DATE EFFECTIVE:

105

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 23 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FIRST~~ SECOND REVISED SHEET NO. 6.675
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.675

Continued from Sheet No. 6.670

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$2.~~88~~94	per kW/Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$6.~~15~~28	per kW/Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.386¢	per Supplemental kWh during peak hours
1.078¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.680

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 24 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~FOURTEENTH~~ FIFTEENTH REVISED SHEET NO. 6.805
CANCELS ~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	4.45 ~~4.06~~	2.48	0.64 ~~0.57~~	0.32 ~~0.29~~
802	862	Cobra/Nema[1]	6,300	70	29	14	4.52 ~~4.14~~	2.11	0.93 ~~0.83~~	0.45 ~~0.40~~
803	863	Cobra/Nema[1]	9,500	100	44	22	5.12 ~~4.60~~	2.33	1.41 ~~1.26~~	0.70 ~~0.63~~
804	864	Cobra[1]	16,000	150	66	33	5.89 ~~5.40~~	2.02	2.11 ~~1.90~~	1.05 ~~0.95~~
805	865	Cobra[1]	28,500	250	105	52	6.87 ~~6.20~~	2.60	3.35 ~~3.02~~	1.66 ~~1.49~~
806	866	Cobra[1]	50,000	400	163	81	7.18 ~~6.58~~	2.99	5.21 ~~4.68~~	2.59 ~~2.33~~
468	454	Flood[1]	28,500	250	105	52	7.57 ~~6.94~~	2.60	3.35 ~~3.02~~	1.66 ~~1.49~~
478	484	Flood[1]	50,000	400	163	81	8.06 ~~7.39~~	3.00	5.21 ~~4.68~~	2.59 ~~2.33~~
809	869	Mongoose[1]	50,000	400	163	81	9.17 ~~8.40~~	3.02	5.21 ~~4.68~~	2.59 ~~2.33~~
509	508	Post Top (PT)[1]	4,000	50	20	10	4.34 ~~3.96~~	2.48	0.64 ~~0.57~~	0.32 ~~0.29~~
570	530	Classic PT[1]	9,500	100	44	22	16.72 ~~15.32~~	1.89	1.41 ~~1.26~~	0.70 ~~0.63~~
810	870	Coach PT[1]	6,300	70	29	14	6.65 ~~6.00~~	2.11	0.93 ~~0.83~~	0.45 ~~0.40~~
572	532	Colonial PT[1]	9,500	100	44	22	12.82 ~~11.75~~	1.89	1.41 ~~1.26~~	0.70 ~~0.63~~
573	533	Salem PT[1]	9,500	100	44	22	12.74 ~~11.67~~	1.89	1.41 ~~1.26~~	0.70 ~~0.63~~
550	534	Shoebox[1]	9,500	100	44	22	11.30 ~~10.35~~	1.89	1.41 ~~1.26~~	0.70 ~~0.63~~
566	536	Shoebox[1]	28,500	250	105	52	12.26 ~~11.23~~	3.18	3.35 ~~3.02~~	1.66 ~~1.49~~
552	538	Shoebox[1]	50,000	400	163	81	10.39 ~~9.52~~	2.44	5.21 ~~4.68~~	2.59 ~~2.33~~

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.874~~ 3.195¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 25 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.806
CANCELS ~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code		Description	Lamp Size				Charges per Unit ($)			
					kWh				Base Energy(4)	
Dusk to Dawn	Timed Svc.		Initial Lumens(2)	Lamp Wattage(3)	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra(1)	29,700	350	138	69	10.62~~9.73~~	4.99	4.41~~3.97~~	2.20~~1.98~~
520	522	Cobra(1)	32,000	400	159	79	8.50~~7.79~~	4.01	5.08~~4.57~~	2.52~~2.27~~
705	725	Flood(1)	29,700	350	138	69	12.06~~11.05~~	5.04	4.41~~3.97~~	2.20~~1.98~~
556	541	Flood(1)	32,000	400	159	79	11.80~~10.81~~	4.02	5.08~~4.57~~	2.52~~2.27~~
558	578	Flood(1)	107,800	1,000	383	191	14.81~~13.57~~	8.17	12.24~~11.01~~	6.10~~5.49~~
701	721	General PT(1)	12,000	150	67	34	14.95~~13.70~~	3.92	2.14~~1.93~~	1.09~~0.98~~
574	548	General PT(1)	14,400	175	74	37	15.37~~14.03~~	3.73	2.36~~2.13~~	1.18~~1.06~~
700	720	Salem PT(1)	12,000	150	67	34	13.16~~12.06~~	3.92	2.14~~1.93~~	1.09~~0.98~~
575	568	Salem PT(1)	14,400	175	74	37	13.23~~12.12~~	3.74	2.36~~2.13~~	1.18~~1.06~~
702	722	Shoebox(1)	12,000	150	67	34	10.18~~9.33~~	3.92	2.14~~1.93~~	1.09~~0.98~~
564	549	Shoebox(1)	12,800	175	74	37	11.22~~10.28~~	3.70	2.36~~2.13~~	1.18~~1.06~~
703	723	Shoebox(1)	29,700	350	138	69	13.47~~12.34~~	4.93	4.41~~3.97~~	2.20~~1.98~~
554	540	Shoebox(1)	32,000	400	159	79	14.13~~13.05~~	3.97	5.08~~4.57~~	2.52~~2.27~~
576	577	Shoebox(1)	107,800	1,000	383	191	23.28~~21.33~~	8.17	12.24~~11.01~~	6.10~~5.49~~

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.874~~3.195¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. ___________
EXHIBIT SIX
PAGE 26 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.808
CANCELS ~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:
(1) Closed to new business

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(4)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(2)	Lamp Wattage(3)	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway(1)	5,155	56	20	10	10.81 ~~9.90~~	1.74	0.64 ~~0.57~~	0.32 ~~0.29~~
820	840	Roadway (1)	7,577	103	36	18	16.27 ~~14.01~~	1.19	1.15 ~~1.03~~	0.58 ~~0.52~~
821	841	Roadway(1)	8,300	106	37	19	16.27 ~~14.91~~	1.20	1.18 ~~1.06~~	0.61 ~~0.55~~
829	849	Roadway(1)	15,285	157	55	27	16.21 ~~14.85~~	2.26	1.76 ~~1.58~~	0.86 ~~0.78~~
822	842	Roadway(1)	15,300	196	69	34	20.56 ~~18.84~~	1.26	2.20 ~~1.98~~	1.09 ~~0.98~~
823	843	Roadway(1)	14,831	206	72	36	23.70 ~~21.71~~	1.38	2.30 ~~2.07~~	1.15 ~~1.03~~
835	855	Post Top(1)	5,176	60	21	11	23.31 ~~21.36~~	2.28	0.67 ~~0.60~~	0.35 ~~0.32~~
824	844	Post Top(1)	3,974	67	24	12	27.47 ~~25.42~~	1.54	0.77 ~~0.69~~	0.38 ~~0.34~~
825	845	Post Top(1)	6,030	99	35	17	28.93 ~~26.51~~	1.56	1.12 ~~1.01~~	0.54 ~~0.49~~
836	856	Post Top(1)	7,360	100	35	18	23.55 ~~21.58~~	2.28	1.12 ~~1.01~~	0.58 ~~0.52~~
830	850	Area-Lighter(1)	14,100	152	53	27	20.95 ~~19.19~~	2.51	1.69 ~~1.52~~	0.86 ~~0.78~~
826	846	Area-Lighter(1)	13,620	202	71	35	26.95 ~~24.60~~	1.41	2.27 ~~2.04~~	1.12 ~~1.01~~
827	847	Area-Lighter(1)	21,197	309	108	54	29.07 ~~26.62~~	1.55	3.45 ~~3.10~~	1.73 ~~1.55~~
831	851	Flood(1)	22,122	238	83	42	22.43 ~~20.56~~	3.45	2.65 ~~2.39~~	1.34 ~~1.21~~
832	852	Flood(1)	32,087	359	126	63	27.02 ~~24.76~~	4.10	4.03 ~~3.62~~	2.01 ~~1.81~~
833	853	Mongoose(1)	24,140	245	86	43	20.75 ~~19.01~~	3.04	2.75 ~~2.47~~	1.37 ~~1.24~~
834	854	Mongoose(1)	32,093	328	115	57	23.01 ~~21.08~~	3.60	3.67 ~~3.31~~	1.82 ~~1.64~~

(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.874~~3.185¢ per kWh for each fixture.

Continued to Sheet No. 6.809

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

109

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 27 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.809
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh(1)				Base Energy(3)	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens(1)	Lamp Wattage(2)	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	7.57~~6~~ ~~94~~	1.74	0.29~~0~~ ~~.26~~	0.16~~0~~ ~~.14~~
914	901	Roadway	5,392	47	16	8	7.49~~6~~ ~~86~~	1.74	0.51~~0~~ ~~.46~~	0.26~~0~~ ~~.23~~
921	902	Roadway/Area	8,500	88	31	15	11.59~~1~~ ~~0.62~~	1.74	0.99~~0~~ ~~.89~~	0.48~~0~~ ~~.43~~
926	982	Roadway	12,414	105	37	18	10.64~~0~~ ~~.75~~	1.19	1.18~~1~~ ~~.08~~	0.58~~0~~ ~~.52~~
932	903	Roadway/Area	15,742	133	47	23	20.01~~1~~ ~~9.33~~	1.38	1.50~~1~~ ~~.35~~	0.73~~0~~ ~~.66~~
935	904	Area-Lighter	16,113	143	50	25	14.91~~1~~ ~~3.66~~	1.41	1.60~~1~~ ~~.44~~	0.80~~0~~ ~~.72~~
937	905	Roadway	16,251	145	51	26	11.34~~1~~ ~~0.30~~	2.26	1.63~~1~~ ~~.47~~	0.83~~0~~ ~~.75~~
941	983	Roadway	22,233	182	64	32	14.45~~1~~ ~~3.24~~	2.51	2.04~~1~~ ~~.84~~	1.02~~0~~ ~~.92~~
945	906	Area-Lighter	29,533	247	86	43	20.79~~1~~ ~~9.05~~	2.51	2.75~~2~~ ~~.47~~	1.37~~1~~ ~~.24~~
947	984	Area-Lighter	33,600	330	116	58	26.07~~3~~ ~~3.80~~	1.55	3.71~~3~~ ~~.33~~	1.85~~1~~ ~~.67~~
951	985	Flood	23,067	199	70	35	16.19~~1~~ ~~4.83~~	3.45	2.24~~2~~ ~~.01~~	1.12~~1~~ ~~.01~~
953	986	Flood	33,113	255	89	45	27.24~~2~~ ~~4.96~~	4.10	2.84~~2~~ ~~.56~~	1.44~~1~~ ~~.29~~
956	987	Mongoose	23,563	225	79	39	17.42~~1~~ ~~5.06~~	3.04	2.52~~2~~ ~~.27~~	1.25~~1~~ ~~.12~~
958	907	Mongoose	34,937	333	117	58	21.79~~1~~ ~~9.06~~	3.60	3.74~~3~~ ~~.36~~	1.85~~1~~ ~~.67~~
965	991	Granville Post Top (PT)	3,024	26	9	4	8.30~~7~~ ~~.60~~	2.28	0.29~~0~~ ~~.26~~	0.13~~0~~ ~~.11~~
967	988	Granville PT	4,990	39	14	7	18.14~~1~~ ~~6.62~~	2.28	0.45~~0~~ ~~.40~~	0.22~~0~~ ~~.20~~
968	989	Granville PT Enh(4)	4,476	39	14	7	21.67~~1~~ ~~0.85~~	2.28	0.45~~0~~ ~~.40~~	0.22~~0~~ ~~.20~~
971	992	Salem PT	5,240	55	19	9	14.78~~1~~ ~~2.54~~	1.54	0.61~~0~~ ~~.55~~	0.29~~0~~ ~~.26~~
972	993	Granville PT	7,076	60	21	10	19.84~~1~~ ~~8.18~~	2.28	0.67~~0~~ ~~.60~~	0.32~~0~~ ~~.29~~
973	994	Granville PT Enh(4)	6,347	60	21	10	23.30~~2~~ ~~1.35~~	2.28	0.67~~0~~ ~~.60~~	0.32~~0~~ ~~.29~~
975	990	Salem PT	7,188	76	27	13	19.19~~1~~ ~~7.58~~	1.54	0.86~~0~~ ~~.78~~	0.42~~0~~ ~~.37~~

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

110

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 28 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.809
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.809

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.874~~3.195¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: A. D. Collins, President DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 29 OF 32

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.810
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 6.810

Continued from Sheet No. 6.809

Pole/Wire and Pole/Wire Maintenance Charges:

Rate Code	Style	Description	Wire Feed	Charge Per Unit ($) Pole/Wire	Charge Per Unit ($) Maintenance
425	Wood (Inaccessible)[(1)]	30 ft	OH	7.68 ~~7.04~~	0.17
626	Wood	30 ft	OH	3.79 ~~3.47~~	0.17
627	Wood	35 ft	OH	4.49 ~~4.11~~	0.17
597	Wood	40/45 ft	OH	8.59 ~~8.70~~	0.31
637	Standard	35 ft, Concrete	OH	8.03 ~~7.36~~	0.17
594	Standard	40/45 ft, Concrete	OH	15.37 ~~14.08~~	0.31
599	Standard	16 ft, DB Concrete	UG	22.16 ~~20.30~~	0.14
595	Standard	25/30 ft, DB Concrete	UG	30.42 ~~27.87~~	0.14
588	Standard	35 ft, DB Concrete	UG	31.89 ~~29.22~~	0.34
607	Standard (70 - 100 W or up to 100 ft span)[(1)]	35 ft, DB Concrete	UG	16.31 ~~14.04~~	0.34
612	Standard (150 W or 100 -150 ft span)[(1)]	35 ft, DB Concrete	UG	21.85 ~~20.02~~	0.34
614	Standard (250 -400W or above 150 ft span)[(1)]	35 ft, DB Concrete	UG	32.88 ~~30.22~~	0.34
596	Standard	40/45 ft, DB Concrete	UG	37.18 ~~34.05~~	0.14
523	Round	23 ft, DB Concrete	UG	29.86 ~~27.36~~	0.14
591	Tall Waterford	35 ft, DB Concrete	UG	41.12 ~~37.67~~	0.14
592	Victorian	PT, DB Concrete	UG	35.31 ~~32.35~~	0.14
593	Winston	PT, DB Aluminum	UG	19.86 ~~18.20~~	1.10
583	Waterford	PT, DB Concrete	UG	29.85 ~~27.35~~	0.14
422	Aluminum[(1)]	10 ft, DB Aluminum	UG	12.22 ~~11.20~~	1.30
616	Aluminum	27 ft, DB Aluminum	UG	40.58 ~~37.18~~	0.34
615	Aluminum	28 ft, DB Aluminum	UG	17.43 ~~15.97~~	0.34
622	Aluminum	37 ft, DB Aluminum	UG	55.58 ~~50.90~~	0.34
623	Waterside	38 ft, DB Aluminum	UG	47.83 ~~43.82~~	3.85
584	Aluminum[(1)]	PT, DB Aluminum	UG	22.92 ~~21.00~~	1.10
581	Capitol[(1)]	PT, DB Aluminum	UG	34.99 ~~32.06~~	1.10
586	Charleston	PT, DB Aluminum	UG	26.69 ~~24.45~~	1.10
585	Charleston Banner	PT, DB Aluminum	UG	34.93 ~~32.00~~	1.10
590	Charleston HD	PT, DB Aluminum	UG	30.20 ~~27.67~~	1.10
580	Heritage[(1)]	PT, DB Aluminum	UG	25.28 ~~23.17~~	1.10
587	Riviera[(1)]	PT, DB Aluminum	UG	26.70 ~~24.46~~	1.10
589	Steel[(1)]	30 ft, AB Steel	UG	50.02 ~~45.83~~	1.68
624	Fiber[(1)]	PT, DB Fiber	UG	10.63 ~~9.74~~	1.30
582	Winston [(1)]	PT, DB Fiber	UG	19.33 ~~17.71~~	1.10
525	Franklin Composite	PT, DB Composite	UG	31.86 ~~29.19~~	1.10
641	Existing Pole		UG	6.80 ~~6.23~~	0.34

[(1)] Closed to new business

Continued from Sheet No. 6.815

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE: ~~July 25, 2022~~

112

TAMPA ELECTRIC COMPANY
DOCKET NO. ___________
EXHIBIT SIX
PAGE 30 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.815
CANCELS ~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$~~7.54~~8.23	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.~~27~~66	$0.06

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023

FRANCHISE FEE: See Sheet No. 6.023

PAYMENT OF BILLS: See Sheet No. 6.023

STORM PROTECTION PLAN RECOVERY PLAN: See Sheet Nos. 6.021 and 6.023

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be ~~2.874~~3.195¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020. 6.021, 6.022 and 6.023.

Continued to Sheet No. 6.820

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

113

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 31 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.830
CANCELS ~~FIFTH~~ SIXTH SHEET NO. 6.830

CUSTOMER SPECIFIED LIGHTING SERVICE

SCHEDULE: LS-2

AVAILABLE: Entire service area

APPLICABLE:

Customer Specified Lighting Service is applicable to any customer for the sole purpose of lighting roadways or other outdoor areas. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party. At the Company's option, a deposit amount of up to a two (2) month's average bill may be required at anytime.

CHARACTER OF SERVICE:

Service is provided during the hours of darkness normally on a dusk-to-dawn basis. At the Company's option and at the customer's request, the company may permit a timer to control a lighting system provided under this rate schedule that is not used for dedicated street or highway lighting. The Company shall install and maintain the timer at the customer's expense. The Company shall program the timer to the customer's specifications as long as such service does not exceed 2,100 hours each year. Access to the timer is restricted to company personnel.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgment of the Company, location of the proposed lights are, and will continue to be, feasible and accessible to Company personnel and equipment for both construction and maintenance and such installation is not appropriate as a public offering under LS-1.

TERM OF SERVICE:

Service under this rate schedule shall, at the option of the company, be for an initial term of twenty (20) years beginning on the date one or more of the lighting equipment is installed, energized, and ready for use and shall continue after the initial term for successive one-year terms until terminated by either party upon providing ninety (90) days prior written notice. Any customer transferring service to the LS-2 rate schedule from the LS-1 rate schedule shall continue the remaining primary initial term from LS-1 agreement.

SPECIAL CONDITIONS:

On lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be ~~2.874~~3.195¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020, 6.021, 6.022 and 6.023

Continued to Sheet No. 6.835

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY
DOCKET NO. __________
EXHIBIT SIX
PAGE 32 OF 32

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.835
CANCELS ~~FIFTH~~ SIXTH SHEET NO. 6.835

Continued from Sheet No. 6.830

MONTHLY RATE: The monthly charge shall be calculated by applying the monthly rate of 0.93% to the In-Place Value of the customer specific lighting facilities identified in the Outdoor Lighting Agreement entered into between the customer and the Company for service under this schedule.

The In-Place Value may change over time as new lights are added to the service provided under this Rate Schedule to a customer taking service, the monthly rate shall be applied to the In-Place Value in effect that billing month. The In-Place Value of any transferred LS-1 service shall be defined by the value of the lighting Equipment or its LED equivalent based on the average cost of a current installation. The in-Place Value of any new LS-2 service shall be defined by the value of the lighting equipment when it was first put in service.

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

Payment may be made in a lump sum at the time the agreement is entered into, or at the customer's option these non-standard costs may be included in the In-Place Value to which the monthly rate will be applied.

MINIMUM CHARGE: The monthly charge.

ENERGY CHARGE: For monthly energy served under this rate schedule, ~~2.874~~3.195¢ per kWh.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

115

Item 11

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Economics (Guffey) JGH
Office of the General Counsel (Brownless) JSC

RE: Docket No. 20220123-GU – Petition for approval of transportation service agreement to reflect expansion of St. Cloud by Florida Public Utilities Company and Peninsula Pipeline Company, Inc.

AGENDA: 10/04/22 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On July 6, 2022, Peninsula Pipeline Company, Inc. (Peninsula) filed a petition seeking approval of a firm transportation service agreement (Agreement) between Peninsula and Florida Public Utilities Company (FPUC), collectively the parties. The purpose of the Agreement is to expand and reinforce the St. Cloud gas distribution system in Osceola County. On July 7, 2022, Peninsula filed an amended petition correcting the title of the petition. Peninsula operates as an intrastate natural gas transmission company as defined by Section 368.103(4), Florida Statutes

(F.S.).[1] FPUC is a local distribution company (LDC) subject to the regulatory jurisdiction of the Commission pursuant to Chapter 366, F.S.

By Order No. PSC-07-1012-TRF-GP,[2] Peninsula received approval of an intrastate gas pipeline tariff that allows it to construct and operate intrastate pipeline facilities and to actively pursue agreements with natural gas customers. Peninsula provides gas transportation service only; it does not engage in the sale of natural gas. Pursuant to Order No. PSC-07-1012-TRF-GP, Peninsula is allowed to enter into certain gas transmission agreements without prior Commission approval.[3] However, Peninsula is requesting Commission approval of this proposed Agreement as it does not fit any of the criteria enumerated in the tariff for which Commission approval would not be required.[4] The parties are subsidiaries of Chesapeake Utility Corporation (Chesapeake), a Delaware corporation authorized to conduct business in Florida, and agreements between affiliated companies must be approved by the Commission pursuant to Section 368.105, F.S., and Order No. PSC-07-1012-TRF-GP.

Pursuant to the proposed Agreement and project map (Attachments A and B to this recommendation), Peninsula will construct, own, and operate a new natural gas pipeline, a new district regulator, and an additional interconnect with Florida Gas Transmission Company's (FGT) system. Additionally, pursuant to the proposed Agreement, FPUC will construct a pipeline which will interconnect to Peninsula. The proposed project will enable FPUC to serve the Twin Lakes community and potential future gas customers in Osceola County. During the evaluation of the amended petition, staff issued a data request to the parties for which responses were received on August 5, 2022. The Commission has jurisdiction over this matter pursuant to Sections 366.05(1), 366.06, and 368.105, F.S.

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[1] Order No. PSC-06-0023-DS-GP, issued January 9, 2006, in Docket No. 050584-GP, *In re: Petition for declaratory statement by Peninsula Pipeline Company, Inc. concerning recognition as a natural gas transmission company under Section 368.101, F.S., et seq.*
[2] Order No. PSC-07-1012-TRF-GP, issued December 21, 2007, in Docket No. 070570-GP, *In re: Petition for approval of natural gas transmission pipeline tariff by Peninsula Pipeline Company, Inc.*
[3] Peninsula Pipeline Company, Inc., Intrastate Pipeline Tariff, Original Vol. 1, Original Sheet No. 11, Section 3.
[4] Peninsula Pipeline Company, Inc., Intrastate Pipeline Tariff, Original Vol. 1, Original Sheet No. 12, Section 4.

Discussion of Issues

Issue 1: Should the Commission approve the proposed firm transportation Agreement dated June 20, 2022 between FPUC and Peninsula?

Recommendation: Yes, the Commission should approve the proposed firm transportation Agreement dated June 20, 2022 between FPUC and Peninsula. The proposed Agreement is reasonable and meets the requirements of Section 368.105, F.S. Furthermore, the proposed Agreement benefits FPUC's current and potential future customers by having an additional source of gas for the growing areas in Osceola County. (Guffey)

Staff Analysis: Proposed Transportation Service Agreement

FPUC provides natural gas service to residential, commercial, and industrial customers in Osceola County, and receives deliveries of natural gas to serve these customers over interstate transmission pipelines owned by Florida Gas Transmission (FGT).

The parties have entered into the proposed firm transportation Agreement to enable FPUC to reinforce its St. Cloud distribution system and meet increased natural gas demand in Osceola County. The proposed Agreement has the added benefit of providing FPUC with an additional source of gas (via the Peninsula intrastate pipeline) and enhancing an existing interconnection with the FGT pipeline.

The proposed Agreement specifies an initial term of 20 years and thereafter shall be extended on a year-to-year basis, unless either party gives no less than 90 days of written notification of termination. If either party desires to negotiate modifications to the rates or terms of this Agreement, they may do so no less than 120 days prior to expiration of the current active term. The proposed St. Cloud expansion project is discussed below and the project map is Attachment B to this recommendation.

Proposed St. Cloud Expansion Project

Attachment B shows the proposed St. Cloud gas distribution expansion project. As shown by the blue line, starting at an existing city gate interconnection with FGT on Missouri Avenue in Osceola County, Peninsula will construct 23,232 feet (4.4 miles) of 4-inch steel pipeline traveling south along Missouri Avenue, west along Fertic Road, then south along Canoe Creek Road up to the Nolte Road intersection.

From the Canoe Creek Road and Nolte Road intersection, Peninsula will continue the steel pipeline east along Nolte Road and conclude at the district regulator station at the intersection of Nolte Road and Hickory Tree Road, also shown by the blue line.

Finally, indicated by a red line, from the Nolte Road and Hickory Tree Road intersection, FPUC will construct 1,320 feet of 6-inch medium-density polyethylene plastic pipeline along Hickory Tree Road providing a connection to an existing gas main. The parties assert that the selected route of the St. Cloud expansion project provides the largest benefit to the area, to FPUC, and its customers.

Anticipated System benefits

The parties assert that the proposed project will enable FPUC to serve the Twin Lakes community, a large residential development projected to have 1,400 dwelling units when fully built out. Other commercial customers, along Peninsula's portion of the project, are expected to be served as well. The petition also states that FPUC will be positioned to serve other developments to be built in and around St. Cloud in Osceola County. The parties assert that construction of the pipeline is necessary because the existing infrastructure is not adequate to serve the Twin Lakes community when it is expected to be fully built out by 2029.[5] Additionally, FPUC is currently negotiating with the developer of Center Lake Ranch, which at built out is expected to have a total of 2,054 dwelling units (in two development phases) and some commercial development.[6] The parties assert that the proposed project will reinforce FPUC's St. Cloud distribution system with an additional source of interstate gas with the potential to provide natural gas service to future customers in Osceola County.

In response to staff's data request, the parties stated that FPUC did not obtain formal Request for Proposals (RFP) responses from other entities. FPUC explained that in previous discussions and requests with FGT for other projects, FGT has declined to bid on projects related to construction, owning, and operating laterals such as the proposed expansion project in this petition, which are not a focus of FGT's expansion activities.

Negotiated Monthly Reservation Payments to Peninsula

The parties assert that the negotiated monthly reservation charge contained in the proposed agreement is consistent with market rates, because the rates are substantially the same as rates set forth in similar agreements as required by Section 368.105(3)(b), F.S. The parties assert that Peninsula will recover the pipeline and district regulator construction costs through the monthly reservation charge to FPUC as shown in Exhibit A to the proposed Agreement. The monthly reservation charge is designed to recover costs such as, but not limited to, engineering, permitting, materials, and installation costs associated with pipeline and related facilities, ongoing maintenance including Pipeline and Hazardous Materials Safety Administration (PHMSA) compliance, safety requirements, property taxes, gas control, and Peninsula's return on investment.

FPUC is proposing to recover its payments to Peninsula through Purchased Gas Adjustment (PGA) and swing service rider mechanisms. The PGA allows FPUC to periodically adjust the price of natural gas supplied to its customers to reflect the actual cost of gas purchased and delivered on behalf of the customers. The swing service rider allows FPUC to recover intrastate capacity costs from their transportation customers and is a cents per therm charge that is included in the monthly customer gas bill of transportation customers. While FPUC will incur costs associated with this service expansion, new load added to the system will help spread the costs over a larger customer base.

Conclusion

Based on the petition and the parties' responses to staff's data request, staff believes that the proposed Agreement is reasonable and meets requirements of Section 368.105, F.S. Furthermore,

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[5] Response No. 3 in Staff's First Data Request, Document No. 05281-2022.
[6] Response No. 11 in Staff's First Data Request, Document No. 05281-2022

the proposed Agreement benefits FPUC's current and potential future customers by having an additional source of gas for the growing areas in Osceola County. Staff therefore recommends approval of the proposed Agreement between Peninsula and FPUC dated June 20, 2022.

Issue 2: Should this docket be closed?

Recommendation: Yes. If no protest is filed by a person whose substantial interest are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order. (Brownless)

Staff Analysis: If no protest is filed by a person whose substantial interest are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order.

PENINSULA PIPELINE COMPANY, INC.
FIRM TRANSPORTATION SERVICE AGREEMENT

THIS AGREEMENT entered into this 20th day of June, 2022, by and between Peninsula Pipeline Company, Inc., a corporation of the State of Delaware (herein called "Company"), and Florida Public Utilities Corporation, a corporation of the State of Florida (herein called "Shipper").

WITNESSETH

WHEREAS, Shipper desires to obtain Firm Transportation Service ("FTS") from Company; and

WHEREAS, Company desires to provide Firm Transportation Service to Shipper in accordance with the terms hereof; and

WHEREAS, Company intends to construct an intrastate pipeline on behalf of Shipper, the origin of which will be a modified gate station with Florida Gas Transmission and the terminus of which will be the end of the existing Florida Public Utilities distribution system, allowing for Shipper's distribution meter to be placed into service near the intersection of Nolte Road and Hickory Tree Road (the "Pipeline").

NOW THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the sufficiency of which is hereby acknowledged, Company and Shipper do covenant and agree as follows:

ARTICLE I
DEFINITION

Unless otherwise defined in this Agreement, all definitions for terms used herein have the same meaning as provided in Company's Tariff.

"In-Service Date" means the date that PPC has commenced commercial operations of the Pipeline and that construction has been completed and that the Pipeline has been inspected and tested as required by applicable law.

"Targeted In-Service Date" means the approximately 6 months after construction has begun or a date mutually agreed to by the Parties.

ARTICLE II
QUANTITY & UNAUTHORIZED USE

2.1 The Maximum Daily Transportation Quantity ("MDTQ") and the Maximum Hourly Transportation Percentage ("MHTP") shall be set forth on Exhibit A attached hereto. The applicable MDTQ shall be the largest daily quantity of Gas, expressed in Dekatherms, which Company is obligated to transport on a firm basis and make available for delivery for the account of Shipper under this Agreement on any one Gas Day.

2.2 If, on any Day, Shipper utilizes transportation quantities, as measured at the Point(s) of Delivery, in excess of the established MDTQ, as shown on Exhibit A, such unauthorized use of transportation quantities (per Dekatherm) shall be billed at a rate of 2.0 times the rate to be charged for each Dekatherm of the MDTQ as set forth on Exhibit A of this Agreement.

ARTICLE III
FIRM TRANSPORTATION SERVICE RESERVATION CHARGE

3.1 The Monthly Reservation Charge for Firm Transportation Service provided under this Agreement shall be as set forth on Exhibit A of this Agreement and shall be charged to Shipper beginning on the In-Service Date, and shall thereafter be assessed in accordance with the terms and conditions set forth herein.

3.2 The parties agree to execute and administratively file with the Commission an affidavit, in the form provided in Company's Tariff to comply with the provisions of the Natural Gas Transmission Pipeline Intrastate Regulatory Act.

3.3 If, at any time after the Execution Date (as herein defined) and throughout the term of this Agreement, the Company is required by any Governmental Authority (as that term is defined in Section 9.10) asserting jurisdiction over this Agreement and the transportation of Gas hereunder, to incur additional tax charges (including, without limitation, income taxes and property taxes) with regard to the service provided by Company under this Agreement, then Shipper's Monthly Reservation Charge shall be adjusted and Exhibit A updated accordingly, and the new Monthly Reservation Charge shall be implemented immediately upon the effective date of such action. If Shipper does not agree to the adjusted Monthly Reservation Charge, Company shall no longer be required to continue to provide the service contemplated in this Agreement should an action of a Governmental Authority result in a situation where Company otherwise would be required to provide transportation service at rates that are not just and reasonable, and in such event the Company shall have the right to terminate this Agreement pursuant to the conditions set forth in Section D of the Rules and Regulations of Company's Tariff.

3.4 If, at any time after the Execution Date (as herein defined) and throughout the term of this Agreement, the Company is required by any Governmental Authority (as that term is defined in Section 9.10) asserting jurisdiction over this Agreement and the transportation of Gas hereunder, to incur additional capital expenditures with regard to the service provided by Company under this Agreement, other than any capital expenditures required to provide transportation services to any other customer on the pipeline system serving Shipper's facility, but including, without limitation, mandated relocations of Company's pipeline facilities serving Shipper's facility and costs to comply with any changes in pipeline safety regulations, then Shipper's Monthly Reservation Charge shall be adjusted and Exhibit A updated accordingly, and the new Monthly Reservation Charge shall be implemented immediately upon the effective date of such action. If Shipper does not agree to the adjusted Monthly Reservation Charge, Company shall no longer be required to continue to provide the service contemplated in this Agreement should an action of a Governmental Authority result in a situation where Company otherwise would be required to provide transportation service at rates that are not just and reasonable, and in such event the Company shall have the right to terminate this Agreement pursuant to the conditions set forth in Section D of the Rules and Regulations of Company's Tariff.

ARTICLE IV
TERM AND TERMINATION

4.1 Subject to all other provisions, conditions, and limitations hereof, this Agreement shall be effective upon its date of execution by both parties (the "Execution Date") and shall continue in full force for an initial period of twenty (20) years from the In-Service Date ("Initial Term"). Thereafter, the Agreement shall be extended on a year to year basis (each a "Renewed Term" and, all Renewed Terms together with the Initial Term, the "Current Term"), unless either party gives written notice of termination to the other party, not less than (90) days prior to the expiration of the Current Term. This Agreement may only be terminated earlier in accordance with the provisions of this Agreement and the parties' respective rights under applicable law.

4.2 No less than 120 days before expiration of the Current Term, either party may request the opportunity to negotiate a modification of the rates or terms of this Agreement to be effective with the subsequent Renewed Term. Neither Party is obligated to, but may, agree to any mutually acceptable modification to the Agreement for the subsequent Renewed Term. In the event the parties reach agreement for a modification to the Agreement for the subsequent Renewed Term, such agreed upon modification ("Agreement Modification") shall be set forth in writing and signed by both parties prior to the expiration of the Current Term.

4.3 Any portion of this Agreement necessary to resolve monthly balancing and operational controls under this Agreement, pursuant to the Rules and Regulations of Company's Tariff, shall survive the other parts of this Agreement until such time as such monthly balancing and operational controls have been resolved.

4.4 In the event Shipper fails to pay for the service provided under this Agreement or otherwise fails to meet Company's standards for creditworthiness set forth in Section C of the Rules and Regulations of the Company's Tariff or otherwise violates the Rules and Regulations of Company's Tariff, or defaults on this Agreement, Company shall have the right to terminate this Agreement pursuant to the conditions set forth in Section D of the Rules and Regulations of Company's Tariff.

PENINSULA PIPELINE COMPANY, INC.
FIRM TRANSPORTATION SERVICE AGREEMENT

ARTICLE V

COMPANY'S TARIFF PROVISIONS

5.1 Company's Tariff approved by the Commission, including any amendments thereto approved by the Commission during the term of this Agreement ("Company's Tariff"), is hereby incorporated into this Agreement and made a part hereof for all purposes. In the event of any conflict between Company's Tariff and the specific provisions of this Agreement, the latter shall prevail, in the absence of a Commission Order to the contrary.

ARTICLE VI

REGULATORY AUTHORIZATIONS AND APPROVALS

6.1 Company's obligation to provide service is conditioned upon receipt and acceptance of any necessary regulatory authorization to provide Firm Transportation Service for Shipper in accordance with the Rules and Regulations of Company's Tariff.

ARTICLE VII

DELIVERY POINT(S) AND POINT(S) OF DELIVERY

7.1 The Delivery Point(s) for all Gas delivered for the account of Shipper into Company's pipeline system under this Agreement, shall be as set forth on Exhibit A attached hereto.

7.2 The Point(s) of Delivery shall be as set forth on Exhibit A attached hereto.

7.3 Shipper shall cause Transporter to deliver to Company at the Delivery Point(s) on the Transporter's system, the quantities of Gas to be transported by Company hereunder. Company shall have no obligation for transportation of Shipper's Gas prior to receipt of such Gas from the Transporter at the Delivery Point(s), nor shall Company have any obligation to obtain capacity on Transporter for Shipper or on Shipper's behalf. The Company shall deliver such quantities of Gas received from the Transporter at the Delivery Point(s) for Shipper's account to Company's Point(s) of Delivery identified on Exhibit A.

ARTICLE VIII

SCHEDULING AND BALANCING

8.1 Shipper shall be responsible for nominating quantities of Gas to be delivered by the Transporter to the Delivery Point(s) and delivered by Company to the Point(s) of Delivery. Shipper shall promptly provide notice to Company of all such nominations. Imbalances between quantities (i) scheduled at the Delivery Point(s) and the Point(s) of Delivery, and (ii) actually delivered by the Transporter and/or Company hereunder, shall be resolved in accordance with the applicable provisions of Company's Tariff, as such provisions, and any amendments to such provisions, are approved by the Commission.

8.2 The parties hereto recognize the desirability of maintaining a uniform rate of flow of Gas to Shipper's facilities over each Gas Day throughout each Gas Month. Therefore, Company agrees to receive from the Transporter for Shipper's account at the Delivery Point(s) and deliver to the Point(s) of Delivery up to the MDTQ as described in Exhibit A, subject to any restrictions imposed by the Transporter and to the provisions of Article IX of this Agreement, and Shipper agrees to use reasonable efforts to regulate its deliveries from Company's pipeline system at a daily rate of flow not to exceed the applicable MDTQ for the Gas Month in question, subject to any additional restrictions imposed by the Transporter or by Company pursuant to Company's Tariff.

ARTICLE IX
MISCELLANEOUS PROVISIONS

9.1 Notices and Other Communications. Any notice, request, demand, statement, or payment provided for in this Agreement, unless otherwise specified, shall be sent to the parties hereto at the following addresses:

Company: Peninsula Pipeline Company, Inc.
500 Energy Lane, Suite 200
Dover, Delaware 19901
Attention: Contracts

Shipper: Florida Public Utilities Company
208 Wildlight Avenue
Yulee, Florida 32097
Attention: Contracts

9.2 Headings. All article headings, section headings and subheadings in this Agreement are inserted only for the convenience of the parties in identification of the provisions hereof and shall not affect any construction or interpretation of this Agreement.

9.3 Entire Agreement. This Agreement, including the Exhibit attached hereto, sets forth the full and complete understanding of the parties as of the Execution Date, and it supersedes any and all prior negotiations, agreements and understandings with respect to the subject matter hereof. No party shall be bound by any other obligations, conditions, or representations with respect to the subject matter of this Agreement.

9.4 Amendments. Neither this Agreement nor any of the terms hereof may be terminated, amended, supplemented, waived or modified except by an instrument in writing signed by the party against which enforcement of the termination, amendment, supplement, waiver or modification shall be sought. A change in (a) the place to which notices pursuant to this Agreement must be sent or (b) the individual designated as the Contact Person pursuant to Section 9.1 shall not be deemed nor require an amendment of this Agreement provided such change is communicated in accordance with Section 9.1 of this Agreement. Further, the parties expressly acknowledge that the limitations on amendments to this Agreement set forth in this section shall not apply to or otherwise limit the effectiveness of amendments that are or may be necessary to comply with the requirements of, or are otherwise approved by, the Commission or its successor agency or authority.

9.5 Severability. If any provision of this Agreement becomes or is declared by a court of competent jurisdiction to be illegal, unenforceable or void, this Agreement shall continue in full force and effect without said provision; provided, however, that if such severability materially changes the economic benefits of this Agreement to either party, the parties shall negotiate in good faith an equitable adjustment in the provisions of this Agreement.

9.6 Waiver. No waiver of any of the provisions of this Agreement shall be deemed to be, nor shall it constitute, a waiver of any other provision whether similar or not. No single waiver shall constitute a continuing waiver, unless otherwise specifically identified as such in writing. No waiver shall be binding unless executed in writing by the party making the waiver.

9.7 Attorneys' Fees and Costs. In the event of any litigation between the parties arising out of or relating to this Agreement, the prevailing party shall be entitled to recover all costs incurred and reasonable attorneys' fees, including attorneys' fees in all investigations, trials, bankruptcies, and appeals.

9.8 Independent Parties. Company and Shipper shall perform hereunder as independent parties. Neither Company nor Shipper is in any way or for any purpose, by virtue of this Agreement, a partner, joint venture, agent, employer or employee of the other. Nothing in this Agreement shall be for the benefit of any third person for any purpose, including, without limitation, the establishing of any type of duty, standard of care or liability with respect to any third person.

9.9 Assignment and Transfer. No assignment of this Agreement by either party may be made without the prior written approval of the other party (which approval shall not be unreasonably withheld) and unless the assigning or transferring party's assignee or transferee shall expressly assume, in writing, the duties and obligations under this Agreement of the assigning or transferring party. Upon such assignment or transfer, as well as assumption of the duties and obligations, the assigning or transferring party shall furnish or cause to be furnished to the other party a true and correct copy of such assignment or transfer and the assumption of duties and obligations.

9.10 Governmental Authorizations; Compliance with Law. This Agreement shall be subject to all valid applicable state, local and federal laws, orders, directives, rules and regulations of any governmental body, agency or official having jurisdiction over this Agreement and the transportation of Gas hereunder. Company and Shipper shall comply at all times with all applicable federal, state, municipal, and other laws, ordinances and regulations. Company and/or Shipper will furnish any information or execute any documents required by any duly constituted federal or state regulatory authority in connection with the performance of this Agreement. Each party shall proceed with diligence to file any necessary applications with any governmental authorities for any authorizations necessary to carry out its obligations under this Agreement. In the event this Agreement or any provisions herein shall be found contrary to or in conflict with any applicable law, order, directive, rule or regulation, the latter shall be deemed to control, but nothing in this Agreement shall prevent either party from contesting the validity of any such law, order, directive, rule, or regulation, nor shall anything in this Agreement be construed to require either party to waive its respective rights to assert the lack of jurisdiction of any governmental agency other than the Commission, over this Agreement or any part thereof. In the event of such contestation, and unless otherwise prohibited from doing so under this Section 9.10, Company shall continue to transport and Shipper shall continue to take Gas pursuant to the terms of this Agreement. In the event any law, order, directive, rule, or regulation shall prevent either party from performing hereunder, then neither party shall have any obligation to the other during the period that performance under the Agreement is precluded. If, however, any Governmental Authority's modification to this Agreement or any other order issued, action taken, interpretation rendered, or rule implemented, will have a material adverse effect on the rights and obligations of the parties, including, but not limited to, the relative economic position of, and risks to, the parties as reflected in this Agreement, then, subject to the provisions of Sections 3.3 and 3.4 of this Agreement, the parties shall use reasonable efforts to agree upon replacement terms that are consistent with the relevant order or directive, and that maintain the relative economic position of, and risks to, the parties as reflected in this Agreement as of the Execution Date. As used herein, "Governmental Authority" shall mean any United States federal, state, local, municipal or other government; any governmental, regulatory or administrative agency, court, commission or other authority lawfully exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power; and any court or governmental tribunal.

(i) If any Governmental Authority asserting jurisdiction over the pipeline facility contemplated in this Agreement, issues an order, ruling, decision or regulation not covered by Section 3.3 or 3.4 of this Agreement (including denial of necessary permits or amendments to existing permits) related to the operation, maintenance, location, or safety and integrity compliance, including any new or revised enforceable regulatory classification of the pipeline facility, as applicable, which is not reasonably foreseeable as of the Execution Date and which results in a materially adverse effect on either party's rights and benefits under this Agreement, each party shall use commercially reasonable efforts and shall cooperate with the other party to pursue all necessary permits, approvals and authorizations, if any, of such applicable Governmental Authority, and to amend the terms and conditions of this Agreement, in each case as may be reasonably required in order that provision of firm transportation service under this Agreement shall continue; provided that neither party shall be required to take any action pursuant to this Section which is reasonably likely to have a materially adverse effect on such party's rights and benefits under this Agreement.

(ii) If the Parties are unable or unwilling to reach agreement pursuant to this Section 9.10, Company shall have the right to terminate this Agreement, without any further obligations to Shipper, upon one hundred twenty (120) days prior written notice to Shipper.

9.11 Applicable Law and Venue. This Agreement and any dispute arising hereunder shall be governed by and interpreted in accordance with the laws of the State of Florida. The venue for any action, at law or in equity, commenced by either party against the other and arising out of or in connection with this Agreement shall be in a court of the State of Florida having jurisdiction.

9.12 Counterparts. This Agreement may be executed in counterparts, all of which taken together shall constitute one and the same instrument and each of which shall be deemed an original instrument as against any party who has signed it.

PENINSULA PIPELINE COMPANY, INC.
FIRM TRANSPORTATION SERVICE AGREEMENT

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their duly authorized officers or representatives.

COMPANY	SHIPPER
Peninsula Pipeline Company, Inc.	Florida Public Utilities Company
By: Bill Hancock	By: Jeff Sylvester
Bill Hancock	Jeff S. Sylvester
Title: Assistant Vice President	Title: Senior Vice President & COO
Date: June 20, 2022	Date: 6/20/2022

(To be attested by the corporate secretary if not signed by an officer of the company)

By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

EXHIBIT A TO

FIRM TRANSPORTATION SERVICE AGREEMENT

BETWEEN

PENINSULA PIPELINE COMPANY, INC.

AND

FLORIDA PUBLIC UTILITIES COMPANY

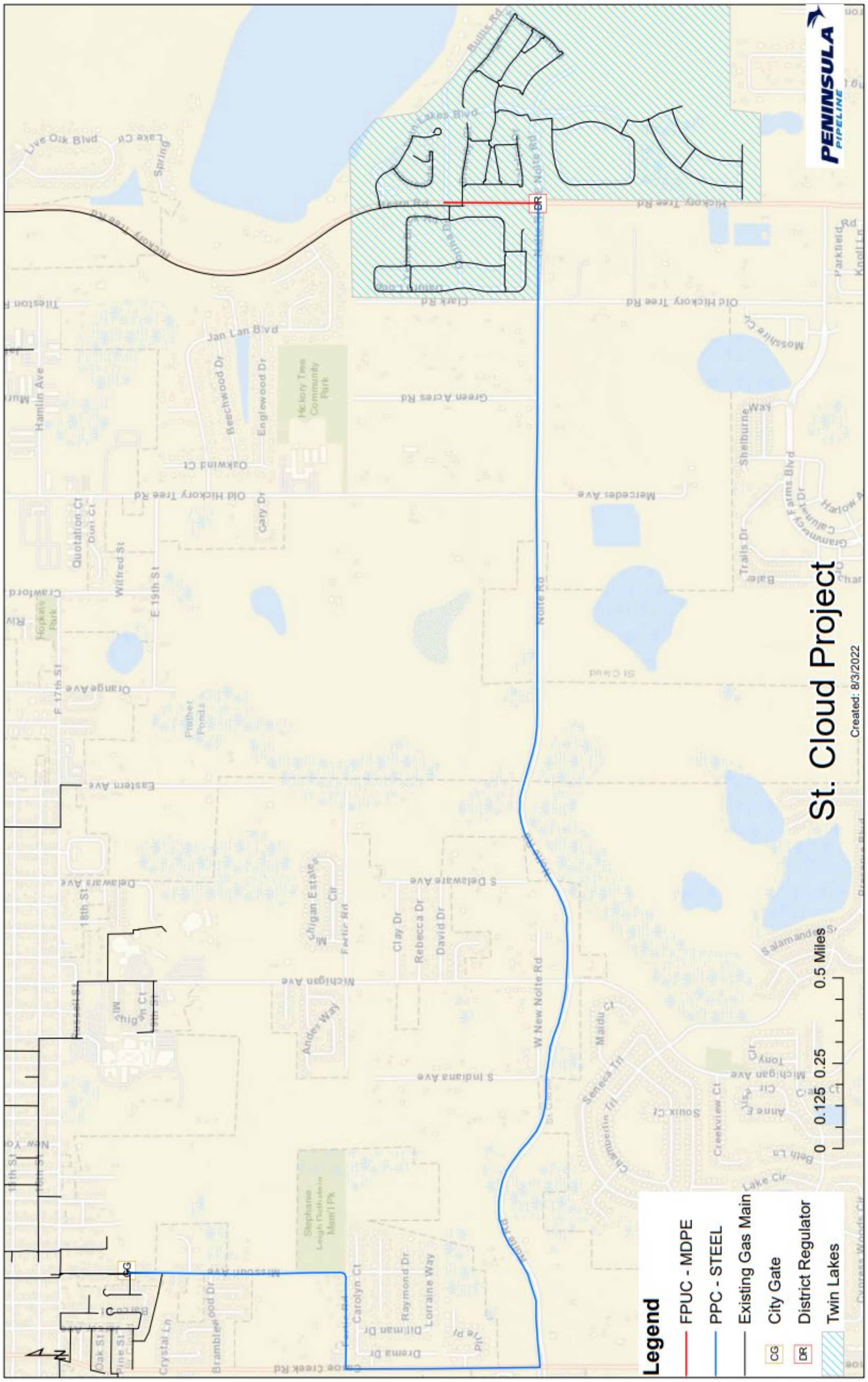
June 20, 2022

Description of Transporter Delivery Point(s)	Description of Point(s) of Delivery	MDTQ, in Dekatherms, excluding Fuel Retention
St Cloud Gate Station interconnecting with Florida Gas Transmission Pipeline	At or near the intersection of Hickory Tree Road and Nolte Road	[redacted] Dt/Day

Total MDTQ (Dekatherms): [redacted] Dt/Day

MHTP: 4.17%

Monthly Reservation Charge: $[redacted] ([redacted]/Dekatherm). This charge is subject to adjustment pursuant to the terms of this Agreement.


PENINSULA PIPELINE
St. Cloud Project
Created: 8/3/2022
Legend
FPUC - MDPE
PPC - STEEL
Existing Gas Main
CG City Gate
DR District Regulator
Twin Lakes
0 0.125 0.25 0.5 Miles

Item 12

FILED 9/22/2022
DOCUMENT NO. 07573-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Economics (Ward, Draper) JGH
Office of the General Counsel (Dose) JSC

RE: Docket No. 20220151-WU – Petition by Southwest Ocala Utility, Inc. to establish base facility charges for additional meter sizes.

AGENDA: 10/04/22 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 10/09/22 (60-Day Suspension Date)

SPECIAL INSTRUCTIONS: None

Case Background

Southwest Ocala Utility, Inc. (Southwest Ocala or utility) is a Class C utility providing water service to approximately 539 residential, 10 general service, and two private fire protection customers located in Marion County.[1] Southwest Ocala's current rates were approved by the Commission in 2015 in a transfer of the utility from County-Wide Utility Co., Inc. to Southwest Ocala.[2]

On August 10, 2022, Southwest Ocala filed a request to add additional base facility charges (BFC) to its tariff for larger meter sizes for general service customers. On September 9, 2022, the utility filed a corrected tariff sheet No. 13.1. Currently, the utility only has Commission-

[1] Number of customers as reported in 2021 Annual Report ending December 31, 2021.
[2] Order No. PSC-2017-0311-FOF-WU, issued August 7, 2017, in Docket No. 20150012-WU, *In re: Application for transfer of Certificate No. 390-W from County Wide Utility Co., Inc. to Southwest Ocala Utility, Inc. in Marion County.*

approved general service BFCs up to a 6-inch meter. This recommendation addresses the utility's request to add the additional BFCs for larger meter sizes to the general service tariff and adjustments to the BFCs in the private fire protection tariff. The Commission has jurisdiction pursuant to Section 367.091, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the utility's proposed tariffs containing the BFCs for additional meter sizes for the general service and private fire protection classes be approved?

Recommendation: Yes, the utility's proposed tariffs containing the BFCs for additional meter sizes for the general service and revised and additional BFCs for the private fire protection classes conform to the American Water Works Association's meter equivalent factors and should be approved. Southwest Ocala's Fourth Revised Sheet No. 12.0 and Fourth Revised Sheet No. 13.1 should be approved as filed. The approved tariffs should be effective on the date of the Commission vote. Since no current customers are affected by the proposed tariff revisions, no customer notices are required. (Ward)

Staff Analysis: The utility explained that it is anticipating the possible addition of some larger meter size multifamily residential or general service customers. Currently, Southwest Ocala's general service tariff only has BFCs for meter sizes up to 6 inches. The utility's proposed BFCs for the additional meter sizes are calculated by using the utility's existing BFC of $11.50 for the 5/8 inch x 3/4 inch size meter as a foundation, and then applying the American Water Works Association's (AWWA's) meter equivalent factor. The AWWA meter equivalent factors are contained in Rule 25-30.055, Florida Administrative Code (F.A.C.). Southwest Ocala's existing BFCs and the BFCs for the three proposed additional general service meters based on the AWWA meter equivalents are shown in Table 1-1.

Table 1-1
Current and Proposed General Service BFC Charges

Meter Size	AWWA Meter Factor	BFC
5/8" X 3/4"	1	$11.50
3/4"	1.5	$17.25
1"	2.5	$28.75
1-1/2"	5	$57.50
2"	8	$92.00
3"	16	$184.00
4"	25	$287.50
6"	50	$575.00
8"	90	$1035.00
10"	145	$1667.50
12"	215	$2472.50

Source: Utility's filing

The utility also proposed one additional meter size (12 inches) for the private fire protection tariff and adjusted the existing fire protection BFCs for the 8-inch and 10-inch meter sizes in order to comply with the AWWA equivalent factors contained in Rule 25-30.055, F.A.C. Pursuant to Rule 25-30.465, F.A.C., the BFCs for private fire protection are 1/12th the amount of the equivalent sized general service BFCs. Southwest Ocala's current and proposed BFCs for the private fire protection tariff are shown in Table 1-2.

Table 1-2
Current and Proposed Fire Protection BFC Charges

Meter Size	Current BFC	Proposed BFC
4"	$23.96	$23.96
6"	$47.92	$47.92
8"	$76.67	$86.25
10"	$110.21	$138.96
12"	-	$206.04

Source: Utility's filing

Conclusion

The utility's proposed tariffs containing the BFCs for additional meter sizes for the general service and revised and additional BFCs for the private fire protection classes conform to the American Water Works Association's meter equivalent factors and should be approved. Southwest Ocala's Fourth Revised Sheet No. 12.0 and Fourth Revised Sheet No. 13.1 should be approved as filed. The approved rates should be effective on the date of the Commission vote. Since no current customers are affected by the proposed tariff revisions, no customer notices are required.

Issue 2: Should this docket be closed?

Recommendation: Yes. If Issue 1 is approved, the tariff sheets should become effective on the date of the Commission vote. If a protest is filed within 21 days of the issuance of the Order, the tariff should remain in effect with the revenues held subject to refund pending resolution of the protest, and the docket should remain open. If no timely protest is filed, the docket should be closed upon the issuance of a Consummating Order. (Dose)

Staff Analysis: If Issue 1 is approved, the tariff sheets should become effective on the date of the Commission vote. If a protest is filed within 21 days of the issuance of the Order, the tariff should remain in effect with the revenues held subject to refund pending resolution of the protest, and the docket should remain open. If no timely protest is filed, the docket should be closed upon the issuance of a Consummating Order.

Item 13

FILED 9/22/2022
DOCUMENT NO. 07645-2022
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 22, 2022

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (M. Watts, Ramos) TB
Division of Accounting and Finance (Bennett, Sewards) ALM
Division of Economics (Bethea, Hudson) JGH
Office of the General Counsel (Stiller, J. Crawford) JSC

RE: Docket No. 20200185-WS – Application for certificates to provide water and wastewater service in Lake and Sumter Counties, by Gibson Place Utility Company, LLC.

AGENDA: 10/04/22 – Regular Agenda – Proposed Agency Action - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Clark

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On July 22, 2020, Gibson Place Utility Company, LLC (GPU, Gibson, or Utility) filed its application for original water and wastewater certificates in Sumter County. The area is in the Southwest Florida Water Management District (SWFWMD) and is not in a water use caution area.

Concurrent with its application for original water and wastewater certificates, the Utility also filed a petition for a temporary waiver of Rules 25-30.033(1)(p) and (q), Florida Administrative Code (F.A.C.), in order to bifurcate the certification and rate setting aspects of the case. The Florida Public Service Commission (Commission) granted Certificate Nos. 677-W and 577-S to

GPU to provide water and wastewater service in Sumter County, and granted its request for temporary rule waiver.[1] In the Order granting the waiver, the Commission required GPU to file a status update every six months from the date of the Order as to: (1) the status of the Utility's permitting with the Florida Department of Environmental Protection (DEP) and the SWFWMD, and (2) the anticipated date of the commencement of the Utility's operations.

On July 27, 2021, GPU filed an application for an amendment of its service territory to delete a portion of the territory that would be developed at a different pace than the remaining territory. This request for territory deletion was granted.[2] The territory that was deleted will serve two separate areas, one consisting of high-density commercial customers, and the other consisting of some commercial customers with mostly multi-family residential units. The remaining territory, to be served by GPU, will consist of single family age-restricted housing units. On April 25, 2022, Middleton Utility Company, LLC (Middleton) filed an application for original water and wastewater certificates to serve the territory deleted from GPU.[3] Middleton and GPU have the same parent company, Holding Company of The Villages, Inc. Staff's recommendation regarding Middleton's application is scheduled to be presented at the November 1, 2022 Agenda Conference.

GPU filed the required status reports on May 24, 2021, November 10, 2021, February 17, 2022, and March 29, 2022. On April 19, 2022, GPU filed the supporting financial information required to establish rates and charges. This recommendation addresses the initial rates and charges for the Utility's water and wastewater services. The Commission has jurisdiction pursuant to Sections 367.031, 367.045, 367.081, 367.091 and 120.452, Florida Statutes (F.S.).

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[1] Order No. PSC-17-0059-PAA-WS, issued February 24, 2017, in Docket No. 20160220-WS, *In re: Application for original water and wastewater certificates in Sumter County, by South Sumter Utility Company, LLC.*

[2] Order No. PSC-2022-0049-FOF-WS, issued January 31, 2022, in Docket No. 20210125-WS, *In re: Application for amendment of Certificate Nos. 677-W and 577-S to delete territory in Lake and Sumter Counties, by Gibson Place Utility Company, LLC.*

[3] Docket No. 20220088-WS, *In re: Application for certificates to provide water and wastewater service and approval of initial rates and charges in Sumter County, by Middleton Utility Company, LLC.*

Discussion of Issues

Issue 1: What are the appropriate water and wastewater rates and return on investment for Gibson Place Utility Company, LLC?

Recommendation: Staff's recommended water and wastewater rates, shown on Schedule Nos. 4-A and 4-B, are reasonable and should be approved. The approved rates should be effective for services rendered or connections made on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved rates until authorized to change them by the Commission in a subsequent proceeding. A return on equity (ROE) of 7.84 percent with a range of plus or minus 100 basis points should also be approved. (Bennett, Bethea, Hudson)

Staff Analysis:

Projected Rate Base

Consistent with Commission practice in applications for original certificates, rate base is identified only as a tool to aid in setting initial rates and is not intended to formally establish rate base. Based on GPU's growth projections, the Utility anticipates operating at 80 percent of its design capacity in 2026. The Utility's proposed water and wastewater rate base calculations, as well as staff adjustments, are described below.

The Utility proposed plant in service balances of $47,755,289 for water and $111,533,582 for wastewater. Staff does not have any adjustments to GPU's proposed balances. Therefore, staff recommends a plant in service balance of $47,755,289 for water and $111,533,582 for wastewater.

The Utility proposed land balances of $151,008 for water and $1,617,500 for wastewater. Staff does not have any adjustments to GPU's proposed balances. Therefore, staff recommends a land balance of $151,008 for water and $1,617,500 for wastewater.

GPU proposed an accumulated depreciation balance of $3,438,665 for water and $12,114,001 for wastewater. Based on staff's calculations, accumulated depreciation for water should be reduced by $1,773 to account for a rounding error. Staff does not have any adjustments for wastewater. As such, staff recommends an accumulated depreciation balance of $3,436,892 for water and $12,114,001 for wastewater.

In its filing, GPU proposed contributions in aid of construction (CIAC) balances of $20,167,016 for water and $45,442,029 for wastewater. As discussed further below, staff has recommended an adjustment to the plant capacity charges, as well as an updated meter installation charge that was not included in GPU's proposed CIAC calculation. As a result, staff recommends an adjustment to increase CIAC by $3,854,889 for water and decrease CIAC by $4,047,133 for wastewater. Based on these adjustments, staff recommends CIAC balances of $24,021,905 for water and $41,394,896 for wastewater.

The Utility proposed an accumulated amortization of CIAC balance of $1,027,813 for water and $3,285,601 for wastewater. As discussed further below, staff has recommended an adjustment to the plant capacity charges, as well as an updated meter installation charge that was not included in GPU's proposed CIAC calculation. Additionally, using the depreciation rates pursuant to Rule 25-30.140, F.A.C., staff has adjusted accumulated amortization of CIAC to reflect the use of the proper accounts in determining amortization rates for the plant capacity and main extension charges. As a result, staff recommends adjustments to increase accumulated amortization by $1,249,711 for water, and $2,093,101 for wastewater. Based on the adjustments above, staff recommends accumulated amortization of CIAC balances of $2,277,524 for water and $5,378,702 for wastewater.

GPU proposed a working capital allowance of $120,158 for water and $259,389 for wastewater based on the one-eighth of the estimated operation and maintenance (O&M) expenses for each system. The Commission has previously allowed this methodology in original certificate cases as the O&M expenses are just an estimate.[4] Staff does not have any adjustments to the Utility's proposed working capital allowance. Therefore, staff recommends a working capital allowance of $120,158 for water and $259,389 for wastewater.

In total, the Utility proposed a rate base of $25,448,587 for water and $59,140,042 for wastewater. Based on the adjustments discussed above, staff recommends that the rate base be decreased by $2,603,405 for water and increased by $6,140,234 for wastewater. As such, staff recommends an adjusted rate base of $22,845,182 for water and $65,280,276 for wastewater be approved. Rate base calculations for the water and wastewater systems are shown on Schedule Nos. 1-A and 1-B, respectively. Staff's adjustments are shown on Schedule No. 1-C.

Cost of Capital

GPU proposed an ROE of 7.88 percent, based on the leverage formula in effect at the time of filing. However, staff recommends the Utility's ROE be based on the current leverage formula in effect.[5] Using the current leverage formula, staff recommends an ROE of 7.84 percent. As such, staff recommends an overall cost of capital of 7.76 percent. The appropriate ROE for GPU is 7.84 percent, with a range of plus or minus 100 basis points, as shown on Schedule No. 2.

Net Operating Income

The Utility projected net operating income (NOI) for the water and wastewater systems of $1,982,444 and $4,607,009, respectively. Based on the adjustments above, staff calculated an NOI of $1,772,798 for water and $5,065,785 for wastewater. The calculated NOI for the water and wastewater systems are shown on Schedule Nos. 3-A and 3-B, respectively.

Operation and Maintenance Expenses

GPU proposed total O&M expenses of $961,268 for water and $2,075,109 for wastewater. Staff believes no adjustments are necessary and therefore recommends O&M expenses of $961,268 for water and $2,075,109 for wastewater.

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[4]Order No. PSC-2018-0271-PAA-WS, issued May 30, 2018, in Docket No. 20160220-WS, *In re: Application for original water and wastewater certificates in Sumter County, by South Sumter Utility Company, LLC.,* p. 4.
[5]Order No. PSC-2022-0208-PAA-WS, issued June 15, 2022, in Docket No. 20220006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity of water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

Net Depreciation Expense

The Utility reflected depreciation expense, net of CIAC amortization expense, of $760,015 for water and $2,653,855 for wastewater. Based on staff's adjustments to rate base, corresponding adjustments should be made to decrease net depreciation expense by $387,949 for water and by $371,128 for wastewater. These adjustments result in net depreciation expense of $372,066 for water and $2,282,727 for wastewater.

Amortization Expense

The Utility reflected amortization expense balance of $10,681 for water and wastewater to reflect amortization of organization costs. Organization costs are typically recorded in Accounts 301 and 351 and amortized pursuant to Rule 25-30.140, F.A.C. As such, staff has reclassified the organization costs for water and wastewater as depreciation expenses and included them in its calculation of net depreciation expense above.

Taxes Other Than Income

In its filing, GPU included taxes other than income (TOTI) expense of $803,972 for water and $1,832,839 for wastewater. GPU's calculation of proposed property tax expense for each system was based on the Sumter County millage rate from 2020. In addition, staff discovered the Utility's calculation of net plant for water was understated. Staff recalculated the property tax expense for each system using the most recent millage rate and net plant totals and recommends an adjustment be made to increase property tax expense by $65,428 for water and decrease property expense by $61,554 for wastewater. Staff also made a corresponding adjustment to decrease regulatory assessment fees (RAFs) by $25,579 for water and increase regulatory assessment fees by $726 for wastewater to reflect staff's recommended revenue requirement. Therefore, staff recommends a TOTI balance of $843,821 for water and $1,772,011 for wastewater.

Revenue Requirement

The Utility's projected revenues include O&M expenses, net depreciation expense, taxes other than income, as well as a return on investment. Staff notes that because GPU is a limited liability company, it has no income tax expense. The Utility proposed revenue requirements for water and wastewater of $4,518,380 and $11,179,493, respectively. Staff recommends adjusted revenue requirements of $3,949,953 for water and $11,195,631 for wastewater to be used to set initial rates for service. The calculation of GPU's projected water and wastewater revenue requirements are shown on Schedule Nos. 3-A and 3-B, respectively. Staff's adjustments are shown on Schedule No. 3-C.

Rates and Rate Structure

Gibson structured its proposed rates in accordance with Rule 25-30.033(2), F.A.C., which requires that a base facility and usage rate structure, as defined in Rule 25-30.437(6), F.A.C., be utilized for metered service. The Utility's proposed rates were designed to generate the Utility's requested revenue requirements of $4,518,380 for its water system and $11,179,493 for its wastewater system.

Staff's recommended water rates on Schedule No. 4-A reflect staff's recommended revenue requirement of $3,949,953 for the water system less projected miscellaneous revenues of $69,904. Consistent with the Utility's proposed rate structure, staff recommends a traditional base facility charge (BFC) and gallonage charge rate structure with an additional gallonage charge for discretionary usage for residential water customers. Gibson proposed a discretionary threshold of 3,000 gallons for its residential water customers. The Utility proposed recovering 40 percent of the revenues through the BFC. Staff believes the Utility's proposed water rate structure is reasonable and consistent with the Commission's methodology in determining water rate structures.

Staff's recommended wastewater rates on Schedule No. 4-B reflect staff's recommended revenue requirement of $11,195,631 for the wastewater system less projected miscellaneous revenues of $69,904. The Utility's proposed wastewater rate structure consists of a BFC, gallonage charge, and gallonage cap of 10,000 gallons for residential customers. The Utility proposed recovering 50 percent of the revenues through the BFC. Staff believes the Utility's proposed wastewater rate structure is reasonable and consistent with the Commission's methodology in determining wastewater rate structures.

The Utility's proposed rates also include water and wastewater bulk service rates. The bulk service rates are for Middleton. Middleton will be a reseller and purchasing water and wastewater treatment from Gibson. The Utility designed the bulk service rates based on common plant and expenses of both Gibson and Middleton. The Utility included RAFs in the calculation of proposed bulk service rates.

Section 367.145(1), F.S., states in part:

> The Commission shall set by rule a regulatory assessment fee that each utility must pay once a year…the amount of the regulatory assessment fee shall not exceed 4.5 percent of the gross revenues of the utility derived from intrastate business, <u>excluding sales for resale made to a regulated company</u>. (emphasis added)

Currently, Middleton is seeking approval for an original certificate to provide water and wastewater service.[6] It is Commission practice to include an allowance for RAFs in a Utility's rate calculation, thereby allowing the utility the opportunity to recover the expense through rates. If the Commission approves Middleton's application, it would be a regulated utility. As a result, pursuant to Section 367.145(1), F.S., Gibson cannot recover RAFs through the bulk rate it proposes to assess Middleton. Therefore, staff's recommended bulk service water and wastewater rates exclude an allowance for RAFs.

Further, Gibson designed its bulk service water and wastewater rates based on the meter sizes that will provide service to Middleton, which consists of three 8-inch meters and five 12-inch meters. In accordance with the standards provided by the American Water Works Association, which the Commission has historically accepted, an 8-inch meter is defined as 80 equivalent residential connections (ERCs) and a 12-inch meter is defined as 215 ERCs, which equate to a total of 1,315 [(3 x 80)+ (5 x 215)] ERCs. However, Middleton is proposing to provide services to 6,862 ERCs, which is substantially more than the ERCs based on the meter sizes. This

[6] See Docket No. 20220088, *In re: Application for certificates to provide water and wastewater service and approval of initial rates and charges in Sumter County, by Middleton Utility Company, LLC.*

disparity between the calculation of the metered ERCs and the number of ERCs behind the meter of the bulk customer could result in subsidization of Middleton's customer base by Gibson's customer base. A bulk service rate based solely on the size of the meters would not accurately measure the demand placed upon the Utility's system by Middleton.

Staff believes Middleton should be billed based on the number of ERCs behind the meter and not based on the meters through which it will receive services. The Commission has found in prior instances the appropriateness of going behind the meter to bill for services.[7] In order to equitably distribute cost among the customers to be served by Gibson, Middleton's ERCs, behind the meter, of 6,862 should be equated to an ERC in accordance with Gibson's defined ERC. Based on the demographics of Gibson's and Middleton's customer bases, Gibson proposed an ERC defined as 80 gallons per day (gpd) while Middleton proposed an ERC defined as 225 gpd. Middleton's proposed ERC is a factor of 2.8125 (225 gpd/80 gpd) more than Gibson's proposed ERC. As a result, staff recommends the appropriate number of ERCs for designing the bulk service rates for Middleton is 19,300 (6,862 ERCs x 2.8125).

Based on the above, staff's recommended water and wastewater rates, shown on Schedule Nos. 4-A and 4-B, are reasonable and should be approved. The approved rates should be effective for services rendered or connections made on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved rates until authorized to change them by the Commission in a subsequent proceeding. A ROE of 7.84 percent with a range of plus or minus 100 basis points should also be approved.

[7] Order No. PSC-96-0596-FOF-WS, issued May 7, 1996, in Docket No. 950186-WS, *In re: Request for approval of new class of service to provide for bulk service in Citrus County by Rolling Oaks Utilities, Inc.*

Issue 2: What are the appropriate miscellaneous service charges for Gibson Place Utility Company, LLC?

Recommendation: The appropriate miscellaneous service charges are shown on Schedule No. 4-C and should be approved. The Utility should file revised tariff sheets to reflect the Commission-approved charges. The approved charges should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. Gibson should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: Section 367.091, F.S., authorizes the Commission to establish miscellaneous service charges. Gibson's request was accompanied by its reason for requesting the charges as well as the cost justification required by Section 367.091(6), F.S. The purpose of these charges is to place the burden for requesting or causing these services on the cost causer rather than the general body of ratepayers.

Premises Visit and Violation Reconnection Charges

The Utility requested initial connection, normal reconnection, violation reconnection, and premise visit charges of $46.05 during normal business hours. Additionally, Gibson requested that its violation reconnection charge for its wastewater system be actual cost pursuant to Rule 25-30.460(1)(c), F.A.C. It should be noted that Gibson's request for initial connection and normal reconnection charges do not conform to the miscellaneous service charges rule. Effective June 24, 2021, Rule 25-30.460, F.A.C., was amended to remove initial connection and normal reconnection charges.[8] The definitions for initial connection charges and normal reconnection charges were subsumed in the definition of the premises visit charge. Therefore, Gibson's proposed initial connection and normal reconnection charges are obsolete based on the revised rule.

The Utility's cost justification for its requested premises visit and water violation reconnection charge is shown below in Table 2-1. Staff believes the premises visit and water violation reconnection charges are reasonable and should be approved pursuant to Rule 25-30.460, F.A.C. Gibson's requested wastewater violation reconnection charge should be actual cost pursuant to Rule 25-30.460(1)(c), F.A.C.

Table 2-1
Premises Visit and Water Violation Reconnection Charge Cost Justification

Field Labor	$34.92
Administrative Labor	$11.13
Total	$46.05

Source: Utility's Cost Justification

Late Payment Charge

The Utility requested a $5.50 late payment charge to recover administrative and supply costs for processing late payment notices. The Utility's cost justification for its requested late payment

[8] Order No. PSC-2021-0201-FOF-WS, issued June 4, 2020, in Docket No. 20200240-WS, *In re: Proposed amendment of Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges.*

charge is shown below on Table 2-2. Staff believes the requested late payment charge is reasonable and should be approved.

Table 2-2
Late Payment Cost Justification

Labor	$4.59
Supplies/Postage	$.75
Mark Up for RAFs	.26
Calculated Total	$5.60
Requested Charge	$5.50

Source: Utility's Cost Justification

Nonsufficient Funds Charges (NSF)

The Utility requested NSF charges pursuant to Section 68.065, F.S. Staff believes that Gibson should be authorized to collect NSF charges consistent with Section 68.065, F.S., which allows for the assessment of charges for the collection of worthless checks, drafts, or orders of payment. As currently set forth in Section 68.065(2), F.S., the following NSF charges may be assessed:

1) $25, if the face value does not exceed $50,
2) $30, if the face value exceeds $50 but does not exceed $300,
3) $40, if the face value exceeds $300,
4) or 5 percent of the face amount of the check, whichever is greater.

The Utility's proposed and staff's recommended miscellaneous service charges are shown below in Tables 2-3 and 2-4.

Table 2-3
Utility Proposed Miscellaneous Service Charges

	Normal Hours	After Hours
Initial Connection Charge	$46.05	N/A
Normal Reconnection Charge	$46.05	N/A
Violation Reconnection Charge	Actual Cost	Actual Cost
Premises Visit Charge	$46.05	N/A
(in lieu of disconnection)		
Late Payment Charge	$5.50	
NSF Charges	Pursuant to Section 68.065, F.S.	

Table 2-4
Staff Recommended Miscellaneous Service Charges

	Normal Hours	After Hours
Violation Reconnection Charge - Water	$46.05	Actual Cost
Violation Reconnection Charge -Wastewater	Actual Cost	Actual Cost
Premises Visit Charge	$46.05	N/A
Late Payment Charge	$5.50	
NSF Charges	Pursuant to Section 68.065, F.S.	

The appropriate miscellaneous service charges are shown in Schedule No. 4-C and should be approved. The Utility should file revised tariff sheets to reflect the Commission-approved charges. The approved charges should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. Gibson should be required to charge the approved miscellaneous service charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 3: Should the meter tampering charge requested by Gibson Place Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested meter tampering charge of actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: Rule 25-30.320(2)(i), F.A.C., provides that a customer's service may be discontinued without notice in the event of tampering with the meter or other facilities furnished or owned by the Utility. In addition, Rule 25-30.320(2)(j), F.A.C., provides that a customer's service may be discontinued in the event of an unauthorized or fraudulent use of service. The rule allows Gibson to require the customer to reimburse the Utility for all changes in piping or equipment necessary to eliminate the illegal use and to pay an amount reasonably estimated as the deficiency in revenue resulting from the customer's fraudulent use before restoring service.

Based on the above, the Utility's requested meter tampering charge of actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

Issue 4: Should the Utility's request to implement a backflow prevention assembly testing charge be approved?

Recommendation: Yes. The Utility's requested backflow prevention assembly testing charge for general service customers at actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: The Utility requested a backflow prevention assembly testing charge to recover the costs the Utility would incur for performing annual testing on behalf of non-compliant commercial customers. The DEP requires customers with cross-connections into the water system to install a backflow prevention assembly on the potable water line. In addition, the DEP requires that certain backflow prevention assemblies be field-tested at least once a year by a certified contractor. The residential customers of Gibson are not required to annually test their backflow prevention assembly devices because the type of assembly they will have, a double check valve, cannot be tested, but the DEP recommends it be replaced every five to ten years pursuant to Rule 62-555.360, F.A.C., and it is typically at the customer's expense.

It is the responsibility of the customer to annually test their backflow prevention assembly. The Utility would only administer this charge if a general service customer fails to test their backflow prevention device in accordance with the DEP requirements. This charge would be imposed after 30 days' notice to the customer and would include an estimate of the amount which will be charged. This noticing period will provide the customer a final opportunity to come into compliance before Gibson performs the necessary testing on the customer's behalf. The Utility is requesting this charge at actual cost in order to pass on the amount it will incur from a contractor performing the necessary testing. Staff believes the Utility's requested charge is reasonable and consistent with the Commission's approval of a backflow prevention assembly testing charge in a prior docket.[9]

Based on the above, the Utility's requested backflow prevention assembly testing charge for general service customers at actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

[9] Order No. PSC-2018-0271-PAA-WS, issued May 30, 2018, in Docket No. 20160220-WS, *In re: Application for original water and wastewater certificates in South Sumter County by South Sumter Utility Company, LLC.*

Issue 5: Should the collection device cleaning charge requested by Gibson Place Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested collection device cleaning charge at actual cost for general service customers should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: Gibson requested a collection device cleaning charge at actual cost for general service customers who fail to perform the required actions after receiving written notice from the Utility with an estimate of potential charges. Cleaning the collection device helps prevent damage and operational problems in the wastewater collection and treatment system by removing fats, oil, and grease (FOG) from the wastewater stream prior to it entering the collection system. Once FOG is introduced into the wastewater system, it then cools, solidifies, accumulates and restricts wastewater flow within the pipes. Restaurants are the most common type of general service customer to have higher concentrations of FOG in their discharged wastewater.

Gibson is requiring all customers with a grease interceptor be required to have a quarterly cleaning schedule, provide a cleaning manifest to the Utility, and perform any needed maintenance that has been identified by the customer's grease interceptor cleaning contractor. If a cleaning manifest is not received by the Utility on time or if necessary maintenance has not been performed, a reminder letter will be sent to the customer with an estimate of charges for cleaning the grease interceptor and giving the customer 15 days to come into compliance. If the customer fails to come into compliance by the notified deadline, the Utility will hire a contractor to perform the cleaning and the contractor's cost will be passed through to the general service customer at the actual cost to the Utility.

Staff believes the Utility's proposed collection device cleaning charge is a reasonable, proactive approach to avoid operational problems in the Utility's collection and treatment facilities. The Utility's request is consistent with Rule 20-30.225(6), F.A.C., which provides that Gibson may require that each customer be responsible for cleaning and maintaining sewer laterals to the point of delivery. Staff believes the Utility's requested charge is reasonable and consistent with the Commission's approval of a collection device cleaning charge in a prior docket.[10]

Therefore, staff recommends the Utility's request to charge a collection device cleaning charge is reasonable and should be approved. This charge may be levied if circumstances are consistent with those discussed in this issue and will be set forth in the Utility's tariff. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

[10] Order No. PSC-2018-0271-PAA-WS, issued May 30, 2018, in Docket No. 20160220-WS, *In re: Application for original water and wastewater certificates in South Sumter County by South Sumter Utility Company, LLC.*

Issue 6: Should the temporary meter deposit requested by Gibson Place Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested temporary meter deposit for general service customers at actual cost pursuant to Rules 25-30.315 and 25-30.345, F.A.C., is reasonable and should be approved. The approved deposit should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to collect the approved deposit, which covers the anticipated costs of installing and removing facilities and materials for temporary service, until authorized to change it by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: Gibson requested a temporary meter deposit for general service customers consistent with Rules 25-30.315 and 25-30.345, F.A.C., which allows the Utility to charge an applicant a reasonable charge to defray the costs of installing and removing facilities and materials for temporary service. This deposit would be collected from commercial entities requesting a temporary meter for construction activities. Once temporary meter service is terminated, Gibson will credit the customer with the reasonable salvage value of the service facilities and materials consistent with Rules 25-30.315 and 25-30.345, F.A.C.

Based on the above, the Utility's requested temporary meter deposit for general service customers at actual cost pursuant to Rules 25-30.315 and 25-30.345, F.A.C., is reasonable and should be approved. The approved deposit should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. Gibson should be required to collect the approved deposit, which covers the anticipated costs of installing and removing facilities and materials for temporary service, until authorized to change it by the Commission in a subsequent proceeding.

Issue 7: Should the Utility's requested initial customer deposits be approved?

Recommendation: No. The appropriate initial customer deposits are $46 for water and $95 for wastewater service for the residential 5/8″ x 3/4″ meter size. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill. The approved customer deposits should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding. (Bethea)

Staff Analysis: Rule 25-30.311, F.A.C., contains criteria for collecting, administering, and refunding customer deposits. Rule 25-30.311(1), F.A.C., requires that each company's tariff shall contain its specific criteria for determining the amount of initial deposits. The Utility requested initial customer deposits of $55.76 for water and $129.56 for wastewater for the residential 5/8″ x 3/4″ meter sizes and two times the average estimated monthly bill for all others. Customer deposits are designed to minimize the exposure of bad debt expense for the Utility and, ultimately, the general body of rate payers. In addition, collection of customer deposits is consistent with one of the fundamental principles of rate making which ensures that the cost of providing service is recovered from the cost causer.

Rule 25-30.311(7), F.A.C., authorizes utilities to collect new or additional deposits from existing customers not to exceed an amount equal to the average actual charge for water and/or wastewater service for two billing periods for the 12-month period immediately prior to the date of notice. The two billing periods reflect the lag time between the customer's usage and the Utility's collection of the revenues associated with that usage. Commission practice has been to set initial customer deposits equal to two months bills based on the average consumption for a 12-month period for each class of customers. Staff reviewed the projected billing data provided in Gibson's application and determined that the anticipated average residential usage will be approximately 2,430 gallons per month for both water and wastewater. Consequently, the average residential monthly bill will be approximately $23.23 for water and $47.49 for wastewater service, based on staff's recommended rates.

Based on the above, the appropriate initial customer deposits are $46 for water and $95 for wastewater service for the residential 5/8″ x 3/4″ meter size. The initial customer deposit for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill. The approved customer deposits should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding.

Issue 8: What are the appropriate service availability charges for Gibson Place Utility Company, LLC?

Recommendation: The appropriate service availability charges are a meter installation charge of $571.50 for the residential 5/8″ x 3/4″ meter size and actual cost for all other residential and general service meter sizes. The main extension charge of $823 per ERC and plant capacity charge of $306 per ERC for the Utility's water system should be approved. Additionally, a main extension charge of $1,131 per ERC and a plant capacity charge of $1,034 per ERC for the Utility's wastewater system should be approved. The recommended main extension and plant capacity charges should be based on an estimated 80 gallons per day (gpd) of water demand. The approved charges should be effective for connections made on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding. (Bethea, Hudson)

Staff Analysis: Gibson requested a meter installation charge of $571.50 for 5/8″ x 3/4″meters and actual cost for all other meter sizes, plant capacity charge of $928 per ERC, and a main extension charge of $823 per ERC for its water system. Additionally, the Utility requested a main extension charge of $1,130 per ERC and a plant capacity charge of $2,737 per ERC for its wastewater system. Gibson's service availability charges anticipate providing bulk service to Middleton. Gibson will be providing service to only its customers and Middleton, the bulk service customer. The Utility proposed that only the plant capacity charge be applicable to Middleton and not the main extension charge because Middleton will have its own internal distribution system. Further, according to the Utility, the requested charges are in compliance with Rule 25-30.580, F.A.C., in that design capacity the CIAC will not be in excess of 75 percent, and will not be less than the percentage of facilities and plant represented by the distribution and collection systems.

Rule 25-30.580(1)(a), F.A.C., provides that the maximum amount of CIAC, net of amortization, should not exceed 75 percent of the total original cost, net of accumulated depreciation, of the Utility's facilities and plant when the facilities and plant are at their design capacity. The maximum guideline is designed to ensure that the Utility retains an investment in the system. Rule 25-30.580(1)(b), F.A.C., provides that the minimum amount of CIAC should not be less than the percentage of such facilities and plant that is represented by the distribution and collection systems.

Meter Installation Charges

Gibson is requesting approval of a meter installation charge of $571.50 for 5/8″ x 3/4″ meters. All other meter sizes will be installed at the Utility's actual cost. The Utility's proposed meter installation charge of $571.50 is based on the estimated cost to install remote read water meters and the required backflow prevention device for the 5/8″ x 3/4″ meter size. Staff recommends the meter installation charges are reasonable and should be approved.

Main Extension Charges

The main extension charge is designed to allow customers to pay their pro rata share of the cost of the water distribution and wastewater collection systems, which is installed by the Utility. The Utility's main extension charge was designed based on the meter size ERCs for its service area.

Typically, the Commission approves main extension charges based on the average cost of the distribution and collection systems and the anticipated capacity in ERCs. The Utility's methodology is consistent with the manner in which the Commission develops main extension charges. Therefore, the Utility's requested charges of $823 for water and $1,131 for wastewater should be approved.

Plant Capacity Charges

A plant capacity charge allows the Utility to recover each customer's pro rata share of the cost of treatment facilities and stay within the guidelines prescribed in Rule 25-30.580, F.A.C., which provides minimum and maximum guidelines for designing service availability charges. The Utility proposed plant capacity charges of $928 for water and $2,737 for wastewater, which result in contribution levels of 46.63 percent for water and 46.20 percent for wastewater. Gibson's plant capacity charges were designed based on the meter size ERCs for both Gibson and Middleton.

Typically, the Commission approves plant capacity charges based on the average cost of the water and wastewater treatment facilities and the anticipated capacity in ERCs. The Utility designed its plant capacity charge on 13,693 ERCs. However, staff believes the number of ERCs for designing the charge should be based on the average daily demand capacity and the defined ERC in gallons per day (gpd). The Utility defined an ERC as 80 gallons gpd. The Utility indicated that the average daily demand capacity for the water treatment facilities is 3.32 million gallons per day (mgd) and the wastewater treatment facilities is 2.9 mgd, which results in capacity in ERCs of 41,500 (3,320,000/80) for water and 36,250 (2,900,000/80) for wastewater. As a result, staff recommends plant capacity charges of $306 for water and $1,034 for wastewater.

Staff's recommended main extension and plant capacity charges result in projected contribution levels of 46.21 percent for both water and wastewater, which is similar to the contribution levels proposed by the Utility. Staff believes this is consistent with Rule 25-30.580, F.A.C., and will allow Gibson to maintain an appropriate level of investment in its system. Table 8-1 below displays the Utility's proposed and staff's recommended service availability charges for its water and wastewater systems.

Table 8-1
Service Availability Charges

	Utility Proposed		Staff Recommended	
Charge	Water	Wastewater	Water	Wastewater
Meter Installation Charge	$571.50	N/A	$571.50	N/A
Main Extension Charge ERC =80 gpd	$823	$1,130	$823	$1,131
Plant Capacity Charge ERC = 80 gpd	$928	$2,737	$306	$1,034

Source: Utility's Cost Justification and Staff Calculations

Based on the above, the appropriate service availability charges are a meter installation charge of $571.50 for the residential 5/8″ x 3/4″ meter size and actual cost for all other residential and general service meter sizes. The main extension charge of $823 per ERC and plant capacity charge of $306 per ERC for the Utility's water system should be approved. Additionally, a main extension charge of $1,131 per ERC and a plant capacity charge of $1,034 per ERC for the Utility's wastewater system should be approved. The recommended main extension and plant capacity charges should be based on an estimated 80 gpd of water demand. The approved charges should be effective for connections made on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 9: Should this docket be closed?

Recommendation: No. If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively. (Stiller)

Staff Analysis: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively.

Gibson Place Utilities, LLC | **Schedule No. 1-A**
Schedule of Water Rate Base | **20200185-WS**
80% Design Capacity

	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$47,755,289	$0	$47,755,289
2	Land and Land Rights	151,008	0	151,008
3	Accumulated Depreciation	(3,438,665)	1,773	(3,436,892)
4	CIAC	(20,167,016)	(3,854,889)	(24,021,905)
5	Amortization of CIAC	1,027,813	1,249,711	2,277,524
6	Working Capital Allowance	120,158	0	120,158
7	**Rate Base**	$25,448,587	($2,603,405)	$22,845,182

Gibson Place Utilities, LLC
Schedule of Wastewater Rate Base
80% Design Capacity

Schedule No. 1-B
20200185-WS

	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$111,533,582	$0	$111,533,582
2	Land and Land Rights	1,617,500	0	1,617,500
3	Accumulated Depreciation	(12,114,001)	0	(12,114,001)
4	CIAC	(45,442,029)	4,047,133	(41,394,896)
5	Amortization of CIAC	3,285,601	2,093,101	5,378,702
6	Working Capital Allowance	259,389	0	259,389
7	**Rate Base**	$59,140,042	$6,140,234	$65,280,276

Gibson Place Utilities, LLC **Schedule No. 1-C**
Adjustments to Rate Base **20200185-WS**
80% Design Capacity

Explanation	Water	Wastewater
Accumulated Depreciation		
To reflect appropriate level of accumulated depreciation.	$1,773	$0
CIAC		
To reflect appropriate level of CIAC.	$3,854,889	($4,047,133)
Accumulated Amortization of CIAC		
To reflect appropriate level of accumulated amortization of CIAC.	$1,249,711	$2,093,101

Gibson Place Utilities, LLC
Capital Structure
80% Design Capacity

Schedule No. 2
20200185-WS

	Description	Total Capital	Subtotal Adjusted Capital	Pro rata Adjust-ments	Capital Reconciled to Rate Base	Ratio	Cost Rate	Weighted Cost
Per Utility								
1	Long-term Debt	$0	$0	$0	$0	0.00%	0.00%	0.00%
2	Short-term Debt	0	0	0	0	0.00%	0.00%	0.00%
3	Preferred Stock	0	0	0	0	0.00%	0.00%	0.00%
4	Common Equity	83,382,247	83,382,247	0	83,382,247	98.57%	7.88%	7.76%
5	Customer Deposits	1,206,383	1,206,383	0	1,206,383	1.43%	2.00%	0.03%
6	Tax Credits-Zero Cost	0	0	0	0	0.00%	0.00%	0.00%
7	Deferred Income Taxes	0	0	0	0	0.00%	0.00%	0.00%
8	**Total Capital**	$84,588,630	$84,588,630	$0	$84,588,630	100.00%		7.79%
Per Staff								
9	Long-term Debt	$0	$0	$0	$0	0.00%	0.00%	0.00%
10	Short-term Debt	0	0	0	0	0.00%	0.00%	0.00%
11	Preferred Stock	0	0	0	0	0.00%	0.00%	0.00%
12	Common Equity	83,382,247	83,382,247	3,536,827	86,919,074	98.63%	7.84%	7.73%
13	Customer Deposits	1,206,383	1,206,383	0	1,206,383	1.37%	2.00%	0.03%
14	Tax Credits-Zero Cost	0	0	0	0	0.00%	0.00%	0.00%
15	Deferred Income Taxes	0	0	0	0	0.00%	0.00%	0.00%
16	**Total Capital**	$84,588,630	$84,588,630	$3,536,827	$88,125,457	100.00%		7.76%

	LOW	HIGH
RETURN ON EQUITY	6.84%	8.84%
OVERALL RATE OF RETURN	6.77%	8.75%

Gibson Place Utilities, LLC **Schedule No. 3-A**
Statement of Water Operations **20200185-WS**
80% of Design Capacity

	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues:**	$4,518,380	$0	$4,518,380	($568,427)	$3,949,953
					-12.58%	
	Operating Expenses					
2	Operation & Maintenance	$961,268	0	$961,268		$961,268
3	Net Depreciation	760,015	(387,949)	372,066		372,066
4	Amortization	10,681	(10,681)	0		0
5	Taxes Other Than Income	803,972	65,428	869,400	(25,579)	843,821
6	Income Taxes	0	0	0	0	0
7	**Total Operating Expense**	2,535,936	(333,202)	2,202,734	(25,579)	2,177,155
8	**Operating Income**	$1,982,444	$333,202	$2,315,646	($542,847)	$1,772,798
9	**Rate Base**	$25,448,587		$22,845,182		$22,845,182
10	**Rate of Return**	7.79%		10.14%		7.76%

Gibson Place Utilities, LLC **Schedule No. 3-B**
Statement of Wastewater Operations **20200185-WS**
80% of Design Capacity

	Description	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues:**	$11,179,493	$0	$11,179,493	$16,138	$11,195,631
					0.14%	
	Operating Expenses					
2	Operation & Maintenance	$2,075,109	$0	$2,075,109		$2,075,109
3	Depreciation	2,653,855	(371,128)	2,282,727		2,282,727
4	Amortization	10,681	(10,681)	0		0
5	Taxes Other Than Income	1,832,839	(61,554)	1,771,285	726	1,772,011
6	Income Taxes	0	0	0	0	0
7	**Total Operating Expense**	6,572,484	(443,363)	6,129,121	726	6,129,847
8	**Operating Income**	$4,607,009	$443,363	$5,050,372	$15,412	$5,065,785
9	**Rate Base**	$59,140,042		$65,280,276		$65,280,276
10	**Rate of Return**	7.79%		7.74%		7.76%

Gibson Place Utilities, LLC **Schedule No. 3-C**
Adjustments to Operating Income **20200185-WS**
80% Design Capacity

	Explanation	Water	Wastewater
	Depreciation Expense - Net		
1	To reclassify CIAC amortization expense to depreciation expense.	$10,681	$10,681
2	To reflect correct amortization rate for CIAC.	(387,949)	(371,128)
	Total	($377,268)	($360,447)
	Amortization-Other Expense		
	To reclassify amortization expense to net depreciation expense.	($10,681)	($10,681)
	Taxes Other Than Income		
	To reflect the appropriate amount of property taxes.	$65,428	($61,554)

GIBSON PLACE UTILITIES, LLC
MONTHLY WATER RATES

SCHEDULE NO. 4-A
DOCKET NO. 20200185-WS

	UTILITY REQUESTED RATES	STAFF RECOMMENDED RATES
Residential and General Service		
Base Facility Charge by Meter Size		
5/8" X 3/4"	$14.11	$12.29
3/4"	$21.17	$18.44
1"	$35.28	$30.73
1-1/2" Turbine	$70.55	$61.45
2" Turbine	$112.88	$98.32
3" Turbine	$246.93	$215.08
Charge per 1,000 gallons- Residential Service		
0-3,000 gallons	$5.44	$4.50
Over 3,000 gallons	$6.80	$5.62
Charge per 1,000 gallons- General Service	$5.65	$4.67
Bulk Service		
Base Facility Charge by Meter Size		
8"	$520.33	N/A
12"	$1,398.12	N/A
Base Facility Charge (ERCs behind the meter)	N/A	$29,143.00
Charge per 1,000 gallons - Bulk Service	$1.57	$1.04
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$30.43	$25.79
6,000 Gallons	$50.83	$42.65
10,000 Gallons	$78.03	$65.13

GIBSON PLACE UTILITIES, LLC
MONTHLY WASTEWATER RATES

SCHEDULE NO. 4-B
DOCKET NO. 20200185-WS

	UTILITY REQUESTED RATES	**STAFF RECOMMENDED RATES**
Residential Service		
Base Facility Charge- All Meter Sizes	$43.75	$39.62
Charge per 1,000 gallons- Residential	$8.66	$3.24
10,000 gallon cap		
General Service		
Base Facility Charge by Meter Size		
5/8" X 3/4"	$43.75	$39.62
3/4"	$65.63	$59.43
1"	$109.38	$99.05
1-1/2" Turbine	$218.77	$198.10
2" Turbine	$350.03	$316.96
3" Turbine	$765.89	$693.35
Charge per 1,000 gallons - General Service	$10.39	$3.88
Bulk Service		
Base Facility Charge by Meter Size		
8"	$2,607.60	N/A
12"	$7,007.92	N/A
Base Facility Charge (ERCs behind the meter)		$231,214.00
Charge per 1,000 gallons - Bulk Service	$6.09	$5.83
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$69.73	$49.34
6,000 Gallons	$95.71	$59.06
10,000 Gallons	$130.35	$72.02

Schedule No. 4-C

Gibson Place Utilities, LLC

Staff Recommended Miscellaneous Service Charges

	Normal Hours	After Hours
Violation Reconnection Charge - Water	$46.05	Actual Cost
Violation Reconnection Charge -Wastewater	Actual Cost	Actual Cost
Premises Visit Charge	$46.05	N/A
Late Payment Charge	$5.50	
NSF Charges	Pursuant to Section 68.065, F.S.	