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Commission Conference Agenda
November 9, 2023

# Item 1

| ITEM NO. | CASE |
| --- | --- |
| 1 | **Election of Commission Chairman for a two-year term beginning January 2, 2024.** |

# 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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Office of Industry Development and Market Analysis (Mallow, CH Fogleman)
Office of the General Counsel (Imig, Harper) AEH

**RE:** Application for Certificate of Authority to Provide Telecommunications Service

**AGENDA:** 11/9/2023 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

**SPECIAL INSTRUCTIONS:** None

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

| DOCKET NO. | COMPANY NAME | CERT. NO. |
|---|---|---|
| 20230092-TX | Office Management Systems, Inc. | 8987 |

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 entity listed above for payment by January 30.

FILED 10/27/2023
DOCUMENT NO. 05838-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Accounting and Finance (Souchik, D. Buys) ALM
Office of the General Counsel (Sparks, Marquez) AH

**RE:** Docket No. 20230099-EI - Application for authority to issue and sell securities for 12 months ending December 31, 2024, by Tampa Electric Company.

**AGENDA:** 11/9/2023 - 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. 20230099-EI - Application for authority to issue and sell securities for 12 months ending December 31, 2024, by Tampa Electric Company.

Tampa Electric Company (Tampa Electric or Company) seeks 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 2024. The Company also seeks authority to enter into interest rate swaps or other derivative instruments related to debt securities during calendar year 2024.

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 will not exceed in the aggregate $1.4 billion during calendar year 2024, including any amounts issued to retire existing long-term debt securities. The maximum amount of short-term debt outstanding at any one time will be $1.6 billion during calendar year 2024.

In its application, Tampa Electric states it confirms that the capital raised pursuant to this application will be used in connection with the activities of the Company's regulated electric activities and not the unregulated activities of the Company or its affiliates.

Staff has reviewed the Company's projected capital expenditures in Exhibit B. The amount requested by the Company ($3 billion) exceeds its expected capital expenditures ($1.463 billion). The additional amount requested exceeding the projected capital expenditures allows for financial flexibility with regard to 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 to issue and sell securities be approved.

For monitoring purposes, this docket should remain open until May 2, 2025, to allow the Company time to file the required Consummation Report.

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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Accounting and Finance (McGowan, D. Buys) ALM
Office of the General Counsel (Imig, Marquez) AH

**RE:** Docket No. 20230100-GU - Application for authority to issue and sell securities for 12 months ending December 31, 2024, by Peoples Gas System, Inc.

**AGENDA:** 11/9/2023 - 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. 20230100-GU - Application for authority to issue and sell securities for 12 months ending December 31, 2024, by Peoples Gas System, Inc.

On January 1, 2023, a new corporate entity, Peoples Gas System, Inc., was formed as a wholly owned subsidiary of a newly formed gas operations holding company, TECO Gas Operations, Inc., which is a subsidiary of TECO Energy, Inc. As a result, this is the first independent application filed on behalf of Peoples Gas System, Inc., seeking authority to issue and sell securities as a new corporate entity.

Peoples Gas System, Inc., (PGS or Company) seeks 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 2024. PGS also seeks authority to enter into interest rate swaps or other derivative instruments related to debt securities during calendar year 2024.

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 will not exceed in the aggregate $750 million during calendar year 2024, including any amounts issued to retire existing long-term debt securities. The maximum amount of short-term debt outstanding at any one time will not exceed $500 million during calendar year 2024.

In its application, PGS states it confirms that the capital raised pursuant to this application will be used in connection with the regulated gas activities of PGS and not the unregulated activities of the Company or its affiliates.

Staff has reviewed PGS's projected capital expenditures in Exhibit B. PGS's estimated construction expenditures for 2024 is $362 million. The amount requested by the Company ($1.25 billion) exceeds its estimated capital expenditures ($362 million). The additional amount requested exceeding the estimated 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 PGS's application for authority to issue and sell securities during calendar year 2024 be approved.

For monitoring purposes, this docket should remain open until May 2, 2025, to allow the Company time to file the required Consummation Report.

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:** | October 27, 2023 |
| **TO:** | Office of Commission Clerk (Teitzman) |
| **FROM:** | Division of Accounting and Finance (Elfouly, D. Buys) ALM<br>Office of the General Counsel (Sparks) AH |
| **RE:** | Docket No. 20230105-EI - Application for authority to issue and sell securities during 12 months ending December 31, 2024, by Duke Energy Florida, LLC. |
| **AGENDA:** | 11/9/2023 - 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. 20230105-EI - Application for authority to issue and sell securities during 12 months ending December 31, 2024, by Duke Energy Florida, LLC.

Duke Energy Florida, LLC (DEF or Company) seeks the authority to issue, sell, or otherwise incur during 2024 up to $1.5 billion of any combination of equity securities, long-term debt securities, and other long-term obligations. Additionally, the Company requests authority to issue, sell, or otherwise incur during 2024 and 2025, up to $2.0 billion outstanding at any time of short-term debt securities and other obligations.

In its application, DEF states it confirms that the capital raised pursuant to this application will be used in connection with the regulated activities of the Company and not the unregulated activities of its unregulated affiliates.

Staff has reviewed the Company's projected capital expenditures in Exhibit B. The amount requested by the Company ($3.5 billion) exceeds its expected capital expenditures ($2.7 billion). The additional amount requested exceeding the projected capital expenditures allows for financial flexibility with regard to unexpected events such as hurricanes, financial market disruptions, and other unforeseen circumstances. Staff believes the requested amounts are appropriate. Staff recommends DEF's application for authority to issue and sell securities be approved.

For monitoring purposes, this docket should remain open until May 2, 2025, to allow the Company time to file the required Consummation Report.

# Item 3

FILED 10/27/2023
DOCUMENT NO. 05857-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Office of the General Counsel (Imig, Marquez) AEH
Division of Engineering (Buys, King, Ramos) TB

**RE:** Docket No. 20230107-TL – Initiation of show cause proceeding against Consolidated Communications of Florida Company for apparent violation of Rule 25-18.020(6), Florida Administrative Code (F.A.C.).

**AGENDA:** 11/09/23 – Regular Agenda – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:**

**PREHEARING OFFICER:** Graham

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

## Case Background

Section 366.04(9)(a), Florida Statutes (F.S.), Jurisdiction of Commission, requires that the Commission regulate the safety, vegetation management, repair, replacement, maintenance, relocation, emergency response, and storm restoration requirements for communications services providers' poles that have public utility (i.e., investor-owned electric utility) attachments. Rule 25-18.020, Florida Administrative Code (F.A.C.), Pole Safety, Inspection, Maintenance, and Vegetation Management, became effective and applies to communications services providers that own poles, as defined in Section 366.02(5), F.S., with attached public utility electrical overhead facilities. This rule applies to all communications services providers as defined in Section 366.02(3), F.S. This rule does not apply to poles used solely to support wireless communications service facilities or poles with no public utility electrical overhead facilities attached.

Pursuant to Rule 25-18.020(6), F.A.C., a communications services provider that falls under the rule must file an Annual Report detailing the pole inspections and vegetation management activities for the prior year is required to be filed by June 1 of each year. In addition, the Annual Report should contain activities that the communications services provider has planned for the upcoming year. Rule 25-18.020 (7), F.A.C., also requires the Commission to impose upon a non-compliant utility a penalty of $500 for the first violation, and up to $5,000 for the fifth violation of the Rule pursuant to Section 366.095, F.S.

Consolidated Communications of Florida Company (Consolidated Communications) is subject to Rule 25-18.020(6), F.A.C., because it is a communications services provider that owns poles as defined in Section 366.02(5), F.S. Florida Power & Light (FPL) and Duke Energy Florida (DEF) have pole attachments to Consolidated Communications' poles. However, Consolidated Communications did not file an Annual Report on June 1, 2023, and thus, is not in compliance with the rule.

To achieve compliance, Commission staff contacted Consolidated Communications by email on June 5, 2023, and June 12, 2023, but Consolidated Communications did not respond (Attachment A). On July 13, 2023, Commission staff sent a letter, by certified mail, to Consolidated Communications requesting the Annual Report be submitted by August 3, 2023 (Attachment B). The certified letter was received on July 25, 2023, and signed for by James Warta (Attachment C). Consolidated Communications did not respond. As a result, Consolidated Communications is not in compliance with Rule 25-18.020(6), F.A.C. at this time.

The Commission have jurisdiction pursuant to 366.04(9), F.S.

## Discussion of Issues

***Issue 1:*** Should the Commission order Consolidated Communications to show cause, in writing, within 21 days from the issuance of the order for apparent violation of Rule 25-18.020(6), F.A.C., why it failed to produce the Annual Report by June 1, 2023, as required by the rule, and why it should not be fined $500 for failure to comply with Rule 25-18.020(6), F.A.C.?

***Recommendation:*** Yes. Consolidated Communications should be ordered to show cause, in writing, within 21 days from the issuance of the order for apparent violation of Rule 25-18.020(6), F.A.C., why it failed to produce the Annual Report by June 1, 2023, as required by the rule, and why it should not be fined $500 for failure to comply with Rule 25-18.020(6), F.A.C. Alternatively, Consolidated Communications may file its Annual Report and include its $500 payment for the late filing with the Commission Clerk within the 21 day period. If the Commission is in receipt of both the Annual Report and the $500 payment within the 21 day period, staff recommends that the Commission no longer pursue its Show Cause proceedings. (Imig, Marquez, Buys)

***Staff Analysis:***

### Law

Section 366.04(9)(a), F.S., requires the Commission to regulate the safety, vegetation management, repair, replacement, maintenance, relocation, emergency response, and storm restoration requirements for communications services providers' poles. Rule 25-18.020(6), F.A.C., requires communication services providers that own poles with attached public utility electrical overhead facilities to file an annual report each year by June 1. The Rule requires the Commission to impose upon a non-compliant utility a penalty of $500 for the first violation, and up to $5,000 for the fifth violation of the Rule.

### Analysis

Consolidated Communications is a communications services provider as defined by Section 366.02(3), F.S. Consolidated Communications owns poles as defined by Section 366.02(5), F.S. Public utilities, FPL and DEF, have pole attachments, as defined by Section 366.02(6), F.S., on Consolidated Communications owned poles. Rule 25-18.020, F.A.C. applies to all communications services providers that own poles. Consolidated Communications meets the requirements of Rule 25-18.020, F.A.C.

Rule 25-18.020(6) F.A.C., requires each communications services provider to file an Annual Report with the Commission Clerk by June 1 of each year. Consolidated Communications failed to file the report by June 1, 2023. To achieve compliance, Commission staff subsequently contacted Consolidated Communications three times and received no response, and the company never filed its Annual Report with the Commission. Consolidated Communications has failed to comply with the requirements of 25-18.020(6), F.A.C.

Compliance with Rule 25-18.020 F.A.C. is not optional. Moreover, staff believes compliance with the rule is important because it involves the safety of communications services providers' poles. Consolidated Communications' failure to comply will result in a penalty assessed by the

Commission of $500 under Section 366.095, F.S., and Rule 25-18.020(7), F.A.C., as this is its first violation of Rule 25-18.020(6), F.A.C. Alternatively, Consolidated Communications may late file its Annual Report with a $500 penalty with the Commission Clerk. If the Commission is in receipt of both the Annual Report and the $500 payment within the 21 day period, staff recommends that the Commission no longer pursue its Show Cause proceedings.

## Conclusion

Staff recommends that the Commission order Consolidated Communications to show cause, in writing, within 21 days from the issuance of the order, why it did not file its Annual Report by June 1, 2023, in violation of Rule 25-18.020(6), F.A.C., and why it should not have be fined $500 for failure to comply with Rule 25-18.020(6) F.A.C. Alternatively, Consolidated Communications may late file its Annual Report with a $500 penalty with the Commission Clerk. If the Commission is in receipt of both the Annual Report and the $500 payment within the 21 day period, staff recommends that the Commission no longer pursue its Show Cause proceedings.

Staff recommends that the order incorporate the following conditions:

1. This Show Cause Order is an administrative complaint by the Florida Public Service Commission, as petitioner, against Consolidated Communications of Florida Company, as respondent.

2. Consolidated Communications shall respond to the Show Cause Order within 21 days of service on the Company, and the response shall reference Docket No. 20230107-TL, Initiation of show cause proceeding against Consolidated Communications of Florida Company for apparent violation of Rule 25-18.020(6), F.A.C.

3. Consolidated Communications has the right to request a hearing to be conducted in accordance with Sections 120.569 and 120.57, F.S., and to be represented by counsel or other qualified representative.

4. Requests for hearing shall comply with Rule 28-106.2015, F.A.C.

5. Consolidated Communications' response to the show cause order shall identify those material facts that are in dispute. If there are none, the petition must so indicate.

6. If Consolidated Communications files a timely written response and makes a request for a hearing pursuant to Sections 120.569 and 120.57, F.S., a further proceeding will be scheduled before a final determination of this matter is made.

7. A failure to file a timely written response to the Show Cause Order will constitute an admission of the facts alleged herein, and a waiver of the right to a hearing on this issue.

In the event that Consolidated Communications fails to file a timely response to the Show Cause Order, or fails to provide its Annual Report and $500 fine, the Company's will be fined $500, and a final order would be issued.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** If the Commission orders Consolidated Communications to show cause as to Issue 1, and Consolidated Communications timely responds in writing to the Show Cause Order, this docket should remain open to allow for the appropriate processing of the response. If the Commission orders Consolidated Communications to show cause as to Issue 1, and Consolidated Communications does not timely respond to the Show Cause Order, then the Commission should issue a Final Order, and this docket should remain open until the fine is collected. (Imig, Marquez)

***Staff Analysis:*** If the Commission orders Consolidated Communications to show cause as to Issue 1, and Consolidated Communications timely responds in writing to the Show Cause Order, this docket should remain open to allow for the appropriate processing of the response. If the Commission orders Consolidated Communications to show cause as to Issue 1, and Consolidated Communications does not timely respond to the Show Cause Order, then the Commission should issue a Final Order, and this docket should remain open until the fine is collected.

**From:** Penny Buys
**To:** "James.Warta@consolidated.com"; "Bardsley, Susanne M"; "ccuster@townes.net"
**Cc:** Marissa Ramos
**Subject:** "Annual Pole Reports" per Rule 25-18.020, FAC
**Date:** Monday, June 05, 2023 12:00:55 PM

Good afternoon,

This is a friendly reminder that per Rule 25-18.020(6), F.A.C., each communications service provider, who own poles with public utility electrical overhead facilities attached, is required to file with the Commission an Annual Pole report by June 1. Please file your company's report with the Commission Clerk, https://secure.floridapsc.com/ClerkOffice/EfilingPublic . In addition, please email me a copy of your company's report and let me know if you have any questions.

Thank you,

*Penelope Buys*
*Engineering Specialist*
*Division of Engineering*
*Florida Public Service Commission*
*(850) 413-6518*
*pbuys@psc.state.fl.us*

| | |
|---|---|
| **From:** | Penny Buys |
| **To:** | "James.Warta@consolidated.com"; "Bardsley, Susanne M"; "ccuster@townes.net" |
| **Cc:** | Marissa Ramos |
| **Subject:** | RE: "Annual Pole Reports" per Rule 25-18.020, FAC |
| **Date:** | Monday, June 12, 2023 10:02:36 AM |

Good morning,

This is a second reminder that per Rule 25-18.020(6), F.A.C., each communications service provider, who own poles with public utility electrical overhead facilities attached, is required to file with the Commission an Annual Pole report by June 1. Please file your company's report with the Commission Clerk, https://secure.floridapsc.com/ClerkOffice/EfilingPublic and email me a copy as well. If your company does not have IOU's attached to their poles, please let me know.

Additionally, please be mindful of subsection 7 of this Rule which lays out the penalties for non-compliance.

If you have any questions, please don't hesitate to reach out.

Thank you,

*Penelope Buys*
*Engineering Specialist*
*Division of Engineering*
*Florida Public Service Commission*
*(850) 413-6518*
*pbuys@psc.state.fl.us*

**From:** Penny Buys
**Sent:** Monday, June 05, 2023 12:01 PM
**To:** 'James.Warta@consolidated.com' <James.Warta@consolidated.com>; 'Bardsley, Susanne M' <Susanne.Bardsley@windstream.com>; 'ccuster@townes.net' <ccuster@townes.net>
**Cc:** Marissa Ramos <mramos@psc.state.fl.us>
**Subject:** "Annual Pole Reports" per Rule 25-18.020, FAC

Good afternoon,

This is a friendly reminder that per Rule 25-18.020(6), F.A.C., each communications service provider, who own poles with public utility electrical overhead facilities attached, is required to file with the Commission an Annual Pole report by June 1. Please file your company's report with the Commission Clerk, https://secure.floridapsc.com/ClerkOffice/EfilingPublic . In addition, please email me a copy of your company's report and let me know if you have any questions.

Thank you,

*Penelope Buys*
*Engineering Specialist*
*Division of Engineering*
*Florida Public Service Commission*
*(850) 413-6518*
*pbuys@psc.state.fl.us*

STATE OF FLORIDA

DIVISION OF ENGINEERING
TOM BALLINGER
DIRECTOR
(850) 413-6910

# Public Service Commission

July 13, 2023

**CERTIFIED MAIL**

Mr. James Warta
Consolidated Communications of Florida Company
26 Yarmouth Lane, Suite 100
Downingtown, PA 19335

**Re: Rule 25-18.020, Florida Administrative Code - Pole Safety, Inspection, Maintenance, and Vegetation Management: Annual Report**

Dear Mr. Warta:

On May 1, 2022, Rule 25-18.020, Florida Administrative Code (F.A.C.), became effective and applies to communication services providers that own poles with attached public utility electrical overhead facilities. Pursuant to Rule 25-18.020(6), F.A.C., an Annual Report detailing the pole inspections and vegetation management activities for the prior year is required to be filed by June 1 of each year. In addition, the report should contain activities that are planned the upcoming year. The Commission has not received a report on behalf of Consolidated Communications of Florida Company. This is our third contact attempt regarding this matter. Reminder emails were previously sent on June 5, 2023, and June 12, 2023, requesting that an annual report be filed to ensure compliance.

Compliance with Rule 25-18.020(6), F.A.C., is not optional. Please be aware that the continued failure to comply with Commission regulatory requirements may result in staff initiating a compliance proceeding pursuant to Section 366.095, Florida Statutes and Rule 25-18.020(7), F.A.C. That Rule authorizes the Commission to impose upon a non-compliant utility a penalty of $500 for the first violation up to $5,000 for the fifth violation of the Rule. Therefore, please submit Consolidated Communications of Florida Company's Annual Pole Inspection and Vegetation Management Report to the address below by **Thursday, August 3, 2023**.

Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
https://secure.floridapsc.com/ClerkOffice/EfilingPublic

Should you have any questions, please contact Mrs. Penelope Buys by phone at (850) 413-6518 or email at pbuys@psc.state.fl.us.

Sincerely,

/s/ Penelope D. Buys

Penelope D. Buys
Engineering Specialist

PB:pz

**SENDER: COMPLETE THIS SECTION**

- Complete items 1, 2, and 3.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. James Warta CERTIFIED MAIL
Consolidated Communications of Florida
26 Yarmouth Lane, Suite 100
Downingtown, PA 19335

9590 9402 6460 0346 0030 15

2. Article Number *(Transfer from service label)*

7020 1290 0000 7279 0985

**COMPLETE THIS SECTION ON DELIVERY**

A. Signature
X
☐ Agent
☐ Addressee

B. Received by *(Printed Name)*

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
- ☐ Adult Signature
- ☐ Adult Signature Restricted Delivery
- ☐ Certified Mail®
- ☐ Certified Mail Restricted Delivery
- ☐ Collect on Delivery
- ☐ Collect on Delivery Restricted Delivery
- ☐ Insured Mail
- ☐ Insured Mail Restricted Delivery (over $500)
- ☐ Priority Mail Express®
- ☐ Registered Mail™
- ☐ Registered Mail Restricted Delivery
- ☐ Signature Confirmation™
- ☐ Signature Confirmation Restricted Delivery

PS Form 3811, July 2020 PSN 7530-02-000-9053

Domestic Return Receipt

USPS TRACKING #

WILMINGTON DE 197
25 JUL 2023 PM 3 L

9590 9402 6460 0346 0030 15

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

United States
Postal Service

• Sender: Please print your name, address, and ZIP+4® in this box•

FLORIDA PUBLIC SERVICE COMMISSION
ATTN: PENELOPE BUYS
(RE: Mr. James Warta, Consolidated)
2540 SHUMARD OAK BLVD.
TALLAHASSEE, FL 32399-0850

# 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:** October 31, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Accounting and Finance (Andrews, D. Buys, Cicchetti, Gatlin, Higgins, Hinson, G. Kelley, Mason, McGowan, Norris, Przygocki, Souchik, Zaslow) ALM
Division of Economics (Guffey, Hampson, P. Kelley, Kunkler, Lang, Smith II, Ward, Wu) EJD
Division of Engineering (Ellis, King, Lewis, Ramos, T. Thompson, Wooten) TB
Office of the General Counsel (Crawford, M. Thompson, Sandy JSC

**RE:** Docket No. 20220212-GU – Petition for approval of depreciation rate and subaccount for renewable natural gas facilities leased to others, by Peoples Gas System, Inc.

Docket No. 20220219-GU – Petition for approval of 2022 depreciation study, by Peoples Gas System, Inc.

Docket No. 20230023-GU – Petition for rate increase by Peoples Gas System, Inc.

**AGENDA:** 11/09/23 – Special Agenda – Post-Hearing Decision – Participation is Limited to Commissioners and Staff

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Passidomo

**CRITICAL DATES:** 12/04/23 (8-Month Statutory Deadline)

**SPECIAL INSTRUCTIONS:** None

## Table of Contents

## Case Background

On April 4, 2023, Peoples Gas Systems (PGS or Company) filed a petition seeking the Commission's approval of a rate increase and associated depreciation rates. PGS is a natural gas distribution company providing sales and transportation of natural gas, and is a public utility subject to this Commission's regulatory jurisdiction under Chapter 366, Florida Statutes (F.S.). PGS is a wholly owned subsidiary of TECO Gas Operations, Inc., PGS provides service to approximately 470,000 customers in 39 of the Florida's 67 counties.

PGS requested an increase of approximately $139.3 million in base rates. Of that amount, about $11.6 million is associated with revenue requirements transferred from the Cast Iron/Base Steel Replacement Rider (CI/BSR). The remaining $127.6 million is necessary, according to PGS, for the Company to earn a fair return on its investment. PGS based its request on a 13-month average rate base of $2.4 billion for the projected test year ending December 31, 2024. The requested overall rate of return is 7.42 percent based on a mid-point return on equity of 11.00 percent. The Company did not request an interim rate increase.

On December 15, 2022, PGS filed its petition in Docket No. 20220212-GU (RNG Depreciation Docket) seeking approval of a new depreciation rate and subaccount for renewable natural gas facilities leased to others. On December 28, 2022, PGS filed its petition seeking approval of the Company's 2022 Depreciation Study in Docket No. 20220219-GU (Depreciation Study Docket). On April 4, 2023, PGS filed a motion seeking to consolidate the RNG Depreciation Docket, the Depreciation Study Docket, and the rate proceeding in Docket No. 20230023-GU. By Order No. PSC-2023-0128-PCO-GU, issued April 12, 2023, the three dockets were consolidated. In Order No. PSC-2023-0157-PCO-GU, the Commission suspended the proposed permanent increase in rates and charges.

PGS stated that even though it made efforts to increase cost savings and efficiency, PGS is expected to earn a return on equity of less than 8 percent in 2023, which places the Company at the bottom of its approved ROE range. PGS is seeking rate relief because of statewide growth and construction, higher depreciation expenses, changing pipeline safety and security regulations, higher inflation, and higher cost of capital in the financial markets.

The Company's last rate case, in Docket No. 20200051-GU, was resolved by the Commission's approval of a Stipulation and Settlement Agreement (2020 Agreement).[1] The Commission-approved 2020 Agreement allowed PGS to generate an additional $58 million in revenues for the projected test year ended December 31, 2021. The 2020 Agreement also authorized a return on equity of 9.90 percent. The 2020 Agreement will expire on December 31, 2023. It also authorized PGS to amortize $34 million of depreciation reserve surplus as a depreciation expense from 2020 through 2023.

By Order No. PSC-2023-0082-PCO-GU, the Commission acknowledged intervention by the Office of Public Counsel (OPC). Order No. By Order No. PSC-2023-0129-PCO-GU, the Commission granted intervention to the Florida Industrial Power Users Group (FIPUG).

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[1]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*.

The Commission acknowledged intervention by the Office of Public Counsel (OPC) and intervention was granted for the Florida Industrial Power Users Groups (FIPUG). The two parties (collectively, "Joint Parties") filed a joint post-hearing brief.

The Commission held two in-person service hearings in Pembroke Pines and Tampa on June 28 and June 29, 2023, respectively, and four virtual service hearings on July 10 and July 11, 2023. Out of the six customer service hearings, two customers expressed concerns over a potential rate increase. An administrative hearing was held September 12-15, 2023. At the hearing, the Commission approved Type 1 stipulations for the following issues: 16, 17, 18, 20, 25, 30, 39, 44, 46, and 56.[2] The Commission also approved Type 2 stipulations for the following issues: 2, 3, 5, 8, 11, 12, 14, 24, 26, 37, 40, 45, 48, and 66.[3]

The Commission received letters from ten customers that were placed in correspondence in the docket. All of the customers urged the Commission not to increase their gas rates during these financially challenging times and exclaimed that the proposed rate increases are excessive and unreasonable.

Prior to filing for this rate case, the Company decided to spinoff PGS from Tampa Electric Company (TECO) in what will be discussed as the "2023 Transaction." The 2023 Transaction was effective on January 1, 2023, and restructured the Company so that TECO would no longer be a direct parent company of PGS. Both PGS and TECO are still under the umbrella of the same parent company, Emera Incorporated (Emera).

This recommendation addresses the requested permanent rate increase. The Commission has jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.06 and 366.071, F.S.

[2]A Type 1 stipulation occurs on an Issue where the utility and intervenors agree on the resolution of the issue.
[3]A Type 2 stipulation occurs when the utility and staff, or the utility and at least one party adversarial to the utility, agree on the resolution of the issue and the remaining parties (including staff if they do not join in the agreement) do not object to the Commission relying on the agreed language to resolve that issue in a final order.

## Discussion of Issues

***Issue 1:*** Is PGS's projected test period of the twelve months ending December 31, 2024, appropriate?

***Recommendation:*** Yes, PGS's projected test period of the twelve months ending December 31, 2024, is appropriate. (Kunkler)

### *Position of the Parties*

**PGS:** Yes. PGS requests an increase in rates effective January 1, 2024. The twelve-month period ending December 31, 2024 is the most appropriate test period because it is representative of PGS' future operations and reflects the Company's expected operations during the first year its proposed rates will be in effect.

**Joint Parties:** With appropriate adjustments, the proposed 2024 test year may be representative of the period of time in which rates will be in effect.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS witness Parsons stated that the Company selected the 2024 projected test year, comprised of the twelve-month period ending December 31, 2024, as the test year in this proceeding. (TR 1857). Witness Parsons argued that utilizing the 2024 calendar year as the test year is appropriate because it is "representative of the Company's projected revenues and projected cost of service, capital structure and rate base required to provide safe, reliable, and cost-effective service to its customers during the period when the Company's new rates will be in effect." (TR 1857) PGS also note that there are "no pending or anticipated merger activities involving Peoples that would cast doubt on the reasonableness of the 2024 test year data or financial forecast." (PGS BR 7) The Company proposed the new base rates become effective for the first billing cycle of January 2024. (TR 1857)

### Joint Parties

The Joint Parties agree that with appropriate adjustments, the 2024 test year may be representative of the period of time in which rates will be in effect. (JP BR 2)

## ANALYSIS

In general, a projected test year methodology is the process whereby a Company uses forecasted data for a twelve-month period to match its average revenues with its average expenses and average rate base investment for the same period. Witness Parsons testified that, with the exception of its accelerated preparation to meet the filing schedule for this rate case, PGS's 2024 projected test year was developed "using the same process used to develop the Company's annual budgets, including capital expenditure and income statement forecasts." (TR 1939, 1868)

While the Joint Parties proposed adjustments to other issues, the Joint Parties did not cite any objections to the appropriateness of the 2024 test year itself. Further, the Joint Parties did not propose any alternative to the projected test year as proposed in this case for setting customer rates.

Staff believes that PGS's proposed 2024 test year will result in a matching of the Company's revenues to be produced during the first twelve months in which the new rates would be in effect, with average rate base investment and average expenses for the same period. Therefore, staff agrees with the Company that the projected test period of the twelve months ending December 31, 2024, is appropriate.

## CONCLUSION

Staff recommends that PGS's projected test period of the twelve months ending December 31, 2024, is appropriate.

***Issue 2:*** Should the Commission approve PGS's forecasts of customers and therms by rate class for the projected test year ending December 31, 2024? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes. The Company used linear regression models for both customer counts and average use for the test year. These models are both theoretically and statistically strong as measured by model coefficient and overall model fit statistics. The chosen modeling framework has been adopted by numerous utilities in the United States and Canada for forecasting.

***Issue 3:*** Are PGS's estimated revenues from sales of gas by rate class at present rates for the projected test year appropriate? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes. Residential and small commercial customer and sales forecasts were used to estimate the 2024 test year revenues at current rates. These forecasts were prepared using theoretically and statistically strong models that have been adopted by numerous utilities in the United States and Canada for forecasting.

***Issue 4:*** Is the quality of service provided by PGS adequate?

***Recommendation:*** Yes, the quality of service provided by PGS is adequate. (Lewis)

### *Position of the Parties*

**PGS:** Yes. PGS has delivered on its commitment to exceptional customer service as evidenced by the Company's J.D. Power customer satisfaction scores, participation in customer service hearings, comments filed by customers in this case, and its industry low FPSC customer complaint levels.

**Joint Parties:** Customer testimony suggests that PGS's quality of service does not support the magnitude of PGS's requested rate increase.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

In its brief, PGS argued that its quality of service is adequate. The Company highlighted that only two individuals spoke during the six customer service hearings, neither of which expressed a negative view of the Company's gas service. (PGS BR 7) PGS witness Sparkman testified that the Company has an evolving strategy that is focused on customer service and simplified customer experiences, which has led to PGS receiving several industry awards for its customer service. (TR 677, 699-700) Additionally, witness Sparkman argued that customer complaints filed with the Commission decreased by approximately 43 percent in 2022 and PGS has not had any Commission infractions over the last seven years. (TR 693) The Company argued it has low complaint levels and PGS witness Wesley testified that the complaint levels of PGS are lower than those presented in the last rate cases of Florida City Gas and Florida Public Utilities Company. (TR 115; EXH 26)

### Joint Parties

The Joint Parties argued that the quality of service received by customers does not justify the magnitude of PGS's requested rate increase. In support of its argument, the Joint Parties referenced the testimony received at the customer service hearings, which highlighted the requested rate increase amount of PGS. (JP BR 2)

## ANALYSIS

Pursuant to Section 366.041(1), F.S., in fixing rates the Commission is authorized to give consideration, among other things, to the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered. The Commission held two in-person service hearings in Pembroke Pines and Tampa on June 28 and June 29, 2023, respectively, and four virtual service hearings on July 10 and July 11, 2023. Out of the six customer service hearings, two customers expressed concerns over a potential rate increase. There was no customer testimony that posed any quality of service concerns. In addition, no intervening party witness addressed this matter in their prefiled testimony or during the hearing.

PGS serves approximately 470,000 customers. (TR 54) Staff witness Calhoun testified that from June 1, 2018, through May 31, 2023, 265 complaints were logged with the Commission with 99 of those being transferred to PGS. The average of these complaints, 53 per year, results in an overall complain rate of 0.01 percent per year. Of the 265 complaints, approximately 49 percent concerned billing issues, while approximately 51 percent involved quality of service issues. (TR 2081) Additionally, witness Calhoun testified that of the 265 complaints, none appeared to demonstrate a violation of Commission Rules. (TR 2082) To date, there were ten customer comments filed in the docket file, all of which expressed concerns of PGS's proposed rate increase.

Pursuant to Rule 25-7.018, Florida Administrative Code (F.A.C.), each utility shall keep a complete record of all interruptions affecting the lesser of 10 percent or 500 or more of its division meters. PGS provided two separate instances where this Rule applied. On June 13, 2022, a contractor failed to confirm the location of the gas main before commencing work. The contractor's directional drill damaged a 4" plastic main under Lutz Lake Fern Road and as a result, affected the service of 505 customers. PGS reported that it took approximately three days to restore 95 percent of the customers affected by this interruption. (EXH 9) On September 27, 2022, the service of 823 customers was interrupted due to Hurricane Ian across the Sarasota and Ft. Myers divisions. Excluding Ft. Myers Beach (143 accounts), service was restored within 48 hours of the interruption or upon customer return. (EXH 9) Both of these interruptions were beyond the control of the Company. Based on a review of all witness and customer testimony and consideration of the information presented above, staff recommends that the Company's quality of service is adequate.

## CONCLUSION

Staff recommends that PGS's quality of service is adequate.

***Issue 5:*** Should PGS's request to establish a new subaccount and annual depreciation rate applicable to its renewable natural gas (RNG) plant leased to others for 15 years be approved, and, if so, what depreciation rate and implementation date should be approved?

***Approved Type 2 Stipulation:*** Yes. The Commission shall approve a new subaccount under Account 104 (Gas Plant Leased to Others) to be denominated "Account 336.01 – RNG Plant Leased – 15 Years" and a depreciation rate of 6.7 percent for that subaccount effective January 1, 2023. The proposed new depreciation rate will ensure that the cost recovery period for the Brightmark RNG Project (Issue 17) will match the period over which the project will generate revenues, that the costs of the project will be removed by the time the customer takes ownership of the RNG plant assets at the end of the contract term and will prevent the Company from experiencing a gain or loss on the sale of the assets at the end of the contract term. The new subaccount will facilitate application of the new depreciation rate.

***Issue 6:*** Are vehicle retirements, including salvage, properly matched with the prudent level of additional vehicles included in rate base? If not, what adjustments should be made?

***Recommendation:*** No, vehicle retirements were not properly matched to the level of additional vehicles included in rate base. However, staff recommends no adjustments to net operating income or rate base because any corrective adjustment would be immaterial. (Smith)

### *Position of the Parties*

**PGS:** No adjustment should be made. While the Company did not properly match vehicle retirements with associated forecasted additions, adding the retirements to 2023 and 2024 has no impact as they would equally reduce the plant in service and accumulated depreciation. Therefore, adding retirements would not impact the 2024 test year rate base amount.

**Joint Parties:** The Company did not reflect retirements associated with the replacement of older vehicles which has the effect of overstated rate base and depreciation expense over time. Given other compensating adjustments in allocations, this is no longer a contested issue.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that, pertaining to the retirement of vehicles in the test year, no adjustment to the calculation of test year Net Operating Income (NOI) or rate base is needed. (PGS BR 8) PGS explained that the Company did not include vehicle depreciation expense in the depreciation expense component of the 2024 test year NOI. (PGS BR 8) PGS stated that it included the vehicle depreciation expense in a transportation cost allocation that was reflected in the test year Operation & Maintenance (O&M) Expense and capital expenditures. (PGS BR 8) PGS further explained that including expected vehicle retirements in 2023 and 2024 would equally reduce plant in service and accumulated depreciation and would have the effect of slightly increasing test year rate base due to the lower depreciation expense in the test year. (PGS BR 8)

PGS also argued that it has met the burden of proof of demonstrating the level of 2023 and 2024 vehicle expense is necessary for several reasons. (PGS BR 8-9) These reasons all relate to the size of PGS's territory and the number of miles that must be driven by employees to maintain the safety and reliability of PGS's system. (PGS BR 9)

### Joint Parties

The Joint Parties did not present argument on this issue. (JP BR 2)

## ANALYSIS

PGS witness Parsons testified that the Company did not reflect vehicle retirements in Account 392.01 – Auto & Truck Less Than ½ Ton on MFR G-2, pages 23 and 26. (TR 1970; EXH 7) She stated that PGS identified $1,706,817 of retirements for 2023 and $1,571,627 of retirements for 2024 that should have been reflected on MFR G-2 for that account. (TR 1970) Witness Parsons further stated that reflecting these retirements would have the effect of reducing the 2024 test year depreciation expense (as derived from the depreciation study) by $243,046. (TR 1970) However, witness Parsons explained that this reduction in depreciation expense would have had no impact on test year net operating income due to the fact that PGS charges vehicle depreciation expense "through a transportation cost allocation to O&M and capital expenditures and is not included in depreciation expense in determining NOI." (TR 1970) Staff has reviewed MFR G-2, page 23 of 26. (EXH 7) Staff has verified that these retirements were not reflected in the MFRs, as well as the fact that no depreciation expense for Account 392.01 was included in the projected test year depreciation expense calculation. (EXH 7)

With regard to NOI, witness Parsons further testified that neither the transportation cost allocation nor the FERC O&M budget were impacted by the potential increase in vehicle depreciation expense. (TR 1970-1971) Witness Parsons explained that the Company did not increase the transportation allocation to account for the increased vehicle depreciation expense in O&M, but instead simply trended the existing 2022 vehicle transportation costs forward for inflation and customer growth in areas that utilized the vehicles. (TR 1971) Therefore, witness Parsons testified that the calculation of the test year NOI would not have been affected by any adjustment to vehicle retirements in the test year. (TR 1971)

Separate from her explanation of the vehicle additions and retirement's effect on NOI, PGS witness Parsons also testified as to the effects of the vehicle retirements on rate base. Witness Parsons clarified that reflecting the vehicle retirements on MFR G-2 would equally reduce PGS's plant and reserve balances, thereby having no impact on rate base. (TR 1971) Witness Parsons added that rate base could be slightly increased due to the lower test year depreciation expense that would result from the lower plant balances in Account 392.01. (TR 1971) Witness Parsons also stated that since the increased vehicle depreciation expense was not factored into the 2023 and 2024 Capital Expenditures, there would be no rate base impacts due to the lower depreciation expense. (TR 1971-1972) Witness Parsons' Exhibit No. RBP-2, Document No. 8 shows the potential rate base and NOI impacts if vehicle retirements had been reflected in the MFRs. (EXH 33, BSP E8-553)

In its position on this issue, the Joint Parties stated that the Company did not properly reflect retirements related to new vehicles. (JP BR 2) However, the Joint Parties further explained that due to other adjustments being made in this case, this issue is no longer contested. (JP BR 2)

## CONCLUSION

Both PGS and the Joint Parties took the position that vehicle retirements did not properly match vehicle additions in rate base. However, PGS stated that no adjustments are necessary, while the Joint Parties indicated this is no longer a disputed issue due to other compensating adjustments. Therefore, even though vehicle retirements do not match vehicle additions in rate base, staff recommends no adjustments to net operating income or rate base because any corrective adjustments would be immaterial.

***Issue 7:*** What depreciation parameters (remaining life, net salvage percentage, and reserve percentage) and resulting depreciation rates for each distribution and general plant account should be approved?

***Recommendation:*** Staff's recommended depreciation parameters and resulting depreciation rates for each plant account are shown in Table 7-2. (Wu, Smith)

### *Position of the Parties*

**PGS:** The appropriate depreciation parameters and rates are those set forth in Exhibit DAW-2, Document No. 3, to the rebuttal testimony of Dane Watson. The Commission should reject the five life parameter changes proposed by OPC.

**Joint Parties:** The depreciation parameters and resulting depreciation rates are shown in OPC Witness Garrett's testimony and Exhibits DJG-18 and DJG-24 – DJG-26.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated "the Commission should find that Mr. Watson's depreciation rates and parameters as presented in Exhibit 32, Document No. 3 are appropriate." The Company argued that these rates were calculated in accordance with the applicable Commission Rule, based on a Commission-approved methodology, and utilizing the most current data and information available. (PGS BR 9) PGS stated that its witness Watson used the straight-line method, Average Life Group procedure, remaining life technique depreciation system to prepare PGS's instant depreciation study. (PGS BR 10) The Company attested that witness Watson used the same methodology to prepare the study that was used by PGS and approved by the Commission in the Company's last base rate case. (PGS BR 11)

PGS contended that OPC witness Garrett did not perform his own depreciation study, but instead considered PGS's study and proposed extending the average service lives (ASL) of five plant accounts.[4] The Company argued that witness Garrett "only utilized one placement and experience band to arrive at his service life recommendations, while depreciation treatises recommend the use of multiple bands."[5] (PGS BR 11)

PGS further asserted that witness Garrett's choice to utilize a short placement band of the years 1983-2021 violates the principles of actuarial analysis by failing to analyze trends in service lives over time. (PGS BR 11) Additionally, the Company argued that witness Garrett relied solely on the output of a statistical model and ignored company-specific experience and operational

[4]Individual plant assets in an account do not normally have identical lives or investment amounts. An account's ASL is the average number of years that the assets in the account are expected to be in-service.
[5]A placement band is the vintages (a vintage refers to the year in which an asset was purchased) of plant assets that are being studied, and it is used to show the effects of technological and material changes over a specific era. An experience band means the transactions (such as retirements) that are happening over time to those vintage years of assets, and it is used to show the effects of business and operational changes during a set period.

information, an inaccurate method for setting asset lives. (BR 11-12) PGS argued that, for each of these reasons, OPC's approach is unreasonable, and the Commission should reject its recommended adjustments to service lives. (PGS BR 12)

**Joint Parties**

The Joint Parties claimed that OPC witness Garrett correctly calculated the depreciation rates. (JP BR 3) Witness Garrett testified that he used a straight-line method, the average life procedure, the remaining life technique, and the broad group model to analyze the Company's actuarial data. (JP BR 3) The Joint Parties stated that witness Garrett recommended the adoption of different average service lives for five of the plant accounts based on his analysis of the best Iowa curve to fit the "observed life table" (OLT) curve; and he accomplished this analysis through a combination of visual and mathematical curve-fitting techniques, as well as professional judgement.[6] (JP BR 3)

Witness Garrett proposed longer lives for Accounts 37600 and 37602, respectively. The Joint Parties stated that witness Garrett focused his statistical analysis on the relatively newer vintages in Account 37600, because "the Company's bare steel replacement program that began around 2013, which focused on retiring assets from vintages spanning from the 1930s through the 1960s." (JP BR 3) The Joint Parties asserted that witness Garrett's choice of life-curve combination is a mathematically closer fit to the OLT curve than the Company's choice. (JP BR 3) The Joint Parties provided the same argument with respect to Account 37602, and asserted that witness Garrett's results showed his choice was a mathematically slightly closer fit to the OLT curve than the Company's choice. (JP BR 4)

For each of Accounts 37900, 38002 and 38200, witness Garrett also proposed a longer ASL than PGS. The Joint Parties argued that witness Garrett's results showed his choice was a mathematically closer fit to the OLT curve of Account 37900. Similarly, the Joint Parties also argued that witness Garrett's choices were a mathematically slightly closer fit to the respective OLT curve of Accounts 38002 and 38200 than the Company's choices. (JP BR 4)

While PGS witness Watson argued that witness Garrett only presented one band in his exhibits and work papers, he conceded that witness Garrett said he reviewed multiple placement and experience bands, and also conceded that his own study did not present all of the possible placement and experience bands for the accounts. (JP BR 4) The Joint Parties further argued that PGS witness Watson took issue with witness Garrett's lack of consideration of the subject matter experts' input, yet witness Watson himself "qualified his reliance on the Company's experts by saying he validates their opinions based on his own engineering experience and from doing theses studies for many years." (JP BR 4-5)

[6]Iowa Curves, which depict the retirement distributions, published in Bulletin 125, *Statistical Analysis of Industrial Reporting*, published in 1935, by Robley Winfrey of the Iowa State College Engineering Experimental Station, are widely-accepted representations of utility property retirement patterns. These are well established depreciation tools. Each curve is denoted by a letter and number. The letter defines when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL while an R curve implies that retirements tend to occur after the ASL. The number portion of the Iowa Curve designation indicates how steep or flat the curve's shape is. For example, both R1 and R3 indicate that the majority of the retirements of the account are likely to occur after the ASL; and R3 curve indicates more retirements occur closer to the ASL, compared to R1 curve indicated.

The Joint Parties asserted that "[g]iven that witness Watson has only testified on one or two occasions for a non-utility party, and he mostly develops depreciation studies while acknowledging that customer interests generally critique them, his observations may lack objectivity." (JP BR 5)

The Joint Parties concluded that witness Garrett's recommendations are "better fittings" of the Iowa Curve to the OLT curve both mathematically and also based on considerations of factors impacting the data. (JP BR 5)

## ANALYSIS

In this proceeding, parties proffered various proposals of the depreciation parameters and resulting depreciation rates. Two of the proposals remain unresolved: (1) PGS's revised depreciation study filed July 2023, that is based on the actual and estimated activities and data of plant accounts ending December 31, 2023 (2023 Study), and (2) OPC's proposed adjustments to PGS's 2023 Study.

The remaining life depreciation rate of a plant account is designed to recover the remaining unrecovered plant balance over the remaining life of the associated investment in that account.[7] Rule 25-7.045(1)(e), F.A.C., prescribes the formula for determining this rate.[8]

For each of PGS's plant accounts, the Company's witness Watson proffered a proposal of an ASL with a specific curve (retirement dispersion) to determine the average remaining life (ARL) of the account, which, in turn, is used to calculate the remaining life depreciation rate of the account.[9] OPC witness Garrett also provided an ASL-curve proposal for each of the accounts. Table 7-1 shows the parameters for the five accounts in dispute between the two proposals:

**Table 7-1**
**Differences in Proposed Depreciation Parameters**

| Account No. | Account Title | Current | | PGS Proposed (Watson) | | OPC Proposed (Garrett) | |
|---|---|---|---|---|---|---|---|
| | | ASL (yrs) | Curve Type | ASL (yrs) | Curve Type | ASL (yrs) | Curve Type |
| 37600 | Mains Steel | 65 | R1.5 | 65 | R1.5 | 70 | R1.5 |
| 37602 | Mains Plastic | 75 | R2 | 75 | R2 | 82 | R2 |
| 37900 | Meas & Reg Station Equip City | 50 | R2.5 | 52 | R2 | 60 | R2 |
| 38002 | Services Plastic | 55 | R1.5 | 55 | R2.5 | 62 | R2 |
| 38200 | Meter Installations | 44 | R1 | 45 | R1.5 | 55 | R0.5 |

Source: TR 583; EXH 116, BSP F1045; EXH 86, BSP D16-1802 – D-16-1803

[7]The remaining life depreciation rate is the type of depreciation rate used by the Commission for determining appropriate customer rates.
[8]Remaining Life Rate = (100% - Reserve % - Average Future Net Salvage %) ÷ Average Remaining Life in Years.
[9]An account's curve is a graphical representation of the retirement pattern for the plant assets of the account.

## Average Service Life and Curve

The Commission's natural gas utility depreciation rule requires a gas company to conduct a depreciation study at least once every five years.[10] To determine an account's ASL for the coming five years, historical data as well as the prospective outlook for the account are considered. Actuarial analysis, also known as the Retirement Rate Method, is commonly used in evaluating historical asset retirement experience when vintage data is available and sufficient retirement activity is present. Historical data, including plant additions, retirements, and transfers, is organized by vintage and transaction year to develop an OLT to depict the percentage of the assets surviving at each age interval.[11]

The OLT is plotted as a survivor curve and the area under the curve represents the average life of the plant assets in the account being analyzed. An OLT curve is rarely smooth and typically incomplete due to plant assets in the account not reaching zero percent surviving yet.[12] However, in order to calculate a particular account's ARL, there must be a complete curve as well as an ASL. Standard mortality curves, such as the Iowa Curves, are used to compare with, or fit, the OLT curve for this purpose. The ASL and its associated best fitted Iowa Curve together describes the life estimate of the account. This ASL-curve combination, in turn, is used to calculate the ARL of the account. Data "bands" refer to the period of placement and experience years that are analyzed. They are used in this curve-comparing/fitting process to define what portion of the OLT curve is to be evaluated. The curve-fitting process is a critical step of the service life analysis, and involves a combination of visual and mathematical curve-fitting techniques, as well as professional judgment.

In this proceeding, both witness Watson and Garrett used the Retirement Rate Method in their service life analyses, but the historical data bands analyzed by each witness were different. Witness Watson claimed that he analyzed five or more placement and experience bands for each account at issue in the proceeding where sufficient retirement data exists. He testified that:

> I ran an overall placement band with two experience bands: the overall experience band, 1983–2021, and 1997–2021 to isolate experience in those transaction years. I also ran the 1983–2021 placement band with the 1983–2018 and 1997–2021 experience bands. If sufficient data existed for life analysis, I also ran an overall band of 1997–2021.

(TR 587-588)

Witness Garrett's life analysis used placement and experience bands with both bands being from 1983-2021. He testified that:

> While I also considered the other banding periods Mr. Watson presented, I focused on OLT curves under the 1983-2021 placement and experience bands because this time period strikes a good balance between considering a sufficient amount of data for analysis and considering relatively newer data. In this particular case, most of the accounts discussed below have been affected by asset replacement programs in which

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[10]Rule 25-7.045(4)(a), F.A.C.
[11]Transaction year is the year in which the asset was retired.
[12]An OLT curve is only ever complete when all assets within the data set being analyzed are retired.

> relatively newer assets may have different life characteristics than older assets. Thus, it can be instructive to focus on relatively newer vintage years when conducting analyses.

(TR 1043)

Witness Watson disagreed with witness Garrett. He asserted that witness Garrett's selection of the data bands supporting his life analysis has the following errors:

- Violates the principles behind actuarial analysis by only using one placement and experience band (thereby not analyzing trends in life through time).
- Discards relevant data in analyzing his single band by using a novel (non-industry standard) approach that cuts off and ignores Company-specific experience.
- Ignores both company-specific operational information and reasonable engineering expectations for the life of assets.

(TR 588-589)

Witness Watson also contested that witness Garrett was not consistent in the placement and experience bands he relied on for his ASL recommendation:

- In the 2017 [PGS's] case, witness Garrett did not specifically state the placement experience band used for each account, but it appears the placement band is the longest experience available from his Exhibits and workpapers.
- In the 2020 [PGS's] case, witness Garrett used a non-existent experience band that included 12 or more years with no retirements as his only band.
- In this case, witness Garrett relied on placement and experience bands of 1983-2021 for his recommendations.

(TR 584)

Witness Watson further argued against witness Garrett's life analysis and ASL recommendations as witness Garrett did not consider information from the Company's subject matter experts. He stated:

> The lives witness Garrett selected for the five accounts at issue are beyond what would reasonably be expected for the mix and types of assets within these accounts. If the majority of the dollars in a particular account are associated with assets that have projected lives between 20 and 40 years, an overall life for the account of 60 years for that account will not be reasonable. Simply recommending the output of a statistical model without validating against operational realities or reasonable norms is not an accurate way to set asset lives.

(TR 590-591)

In responding to OPC's question whether he would agree that the Company subject matter experts are only giving their estimates with regard to different lives for different equipment, witness Watson expounded that, with their estimates, the experts are also "giving their understanding [of asset lives] based on operating those assets for many years." (TR 648) Witness Watson testified that there were two additional considerations which validated the estimates provided by the Company's experts. One consideration was witness Watson's own understanding as an engineer and his own understanding of the assets and their lives based on the number of depreciation studies he's conducted for many, many companies during his career. (TR 648) The second consideration that he included for validating the experts estimates was that the Company's opinions were in line with his expectations and the industry's expectations, concluding "they supported each other." (TR 648)

OPC also questioned whether witness Watson relied on the subject matter experts, the employees of PGS, for the Company's specific information to develop his curve. (TR 650) Witness Watson testified that he did not solely depend on such information, but instead he relied on the historical books and records of the Company to make his service life selection, and used the information from the experts to support the selection. (TR 650-651) He further expounds:

> I will look at the actual experience of the company, and I will understand if there are changes that are happening to the assets operationally that would impact what I would project, and also understand what's in the account and expected lives of the account.

(TR 651)

Based on the record evidence discussed above, staff believes that the approach that witness Watson chose to perform his asset life analysis is more comprehensive than witness Garrett's approach. It is consistent with the core concept of the Retirement Rate Method and more comprehensively incorporates the assets' specific operational information which is important in the assets' life analysis.

The account-specific analysis for the five accounts in dispute between PGS and OPC is explained below:

### *Account 37600 – Distribution Mains Steel*

The currently-approved ASL for this account is 65 years with a R1.5 curve, also denoted as 65 R1.5. PGS witness Watson proposed to retain these parameters. OPC witness Garrett proposed to increase ASL to 70 years with the same R1.5 curve. Witness Watson disagreed with witness Garrett's life proposal.

PGS personnel indicated that the driving forces of retirements for the account include inadequate capacity of the steel pipes since they were originally built when gas demand was not as prevalent as today's demand; some steel pipes have not been cathodically protected for their full life, and steel will corrode if scratched. (TR 593; EXH 32, BSP E7-323 – E7-324) Witness Watson asserted that witness Garrett's proposal "does not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]." (TR 592)

Regarding the curve-fitting process which determines the selected ASL-curve combination, witness Watson testified that his proposed combination was based on his evaluation of five different placement and experience bands. (TR 593) He argued that "witness Garrett only examines one band for his proposal," and pointed out that "[a]s stated in NARUC's *Public*

*Utility Depreciation Practices*, it is important to look at different placement bands and experience bands." (TR 593) He further averred that "[b]y selecting only one band (and having the errors discussed earlier), witness Garrett's analysis doesn't fully analyze or accurately represent the Company's historical experience." (TR 598) Witness Watson also asserted that the OLT witness Garrett used in life analysis is not long enough to meet criteria recommended by authoritative texts that witness Garrett quoted himself. (TR 593; EXH 104, BSP D16-2173 – D16-2174)

In previous dockets, witness Garrett recommended a 55 R2 life for this account and a 65 R1.5 life for this same account.[13] Witness Watson claimed that "[i]t does not seem logical that three years later, these same assets would last 7.7 percent longer than witness Garrett's recommendation [that] he supported less than three years ago – especially when he does not speak to any operational reason for the change."[14] (TR 599-600)

Staff reviewed all the graphical curve-fitting presentations together with all the data and information proffered by both witnesses. Staff believes that witness Watson's life analysis is more persuasive, and a 65 R1.5 life proposal is reasonable for the account at this point in time, because it is derived from an appropriate depreciation asset life analysis and incorporated with the Company-specific assets' operational information, and within the range of other Florida gas utilities. Staff notes that an ASL of 65 years is within the industry's current ASL range for this account, which is 40 to 65 years with an average of 56 years.[15]

### *Account 37602 – Distribution Mains Plastic*

The currently-approved ASL for this account is 75 R2. Witness Watson proposed to retain the existing parameters. Witness Garrett proposed to extend the ASL to 82 years. Witness Watson disagreed with witness Garrett's life proposal.

Witness Watson testified that this account is more mature with assets that are replaced on an ongoing basis, and Company subject matter experts indicated the retirements of the account would be focusing on pre-1984 pipe, with the newer pipe likely to last 75 years. (TR 601) He claimed that his proposal recognized both the indications in the life analysis, which included examination of 17 different fits across multiple placement and experience bands, and the account-specific information from Company experts. (TR 606) Witness Watson asserted that Witness Garrett's life proposal is excessive. (TR 605, 606) He contested that witness Garrett's proposal seems illogical as it would make PGS have assets in this account that last 17.1 percent

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[13]Docket No. 20160159-GU, *In re: Petition for approval of settlement agreement pertaining to Peoples Gas System's 2016 depreciation study, environmental reserve account, problematic plastic pipe replacement, and authorized ROE*. Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*.

[14](70 – 65) / 65 = 7.7%

[15]The industry's current ASL range is determined based upon Order Nos. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*; PSC-2022-0153-PAA-GU, issued April 22, 2022, in Docket No. 20210183-GU, *In re: Petition for approval of 2021 depreciation study, by Sebring Gas System;* PSC-2023-0103A-FOF-GU, issued April 6, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division*; PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*; and PSC-2023-0215-PAA-GU, issue July 26, 2023, in Docket No. 20230022-GU, *In re: Petition for approval of 2022 Depreciation Study by St. Joe Natural Gas Company, Inc*.

longer than witness Garrett recommended for the same assets of another Florida utility without providing an operational reason to explain the difference.[16] (TR 605-606)

The industry's current ASL range for this account is 40 to 75 years with an average of 62 years. Staff believes that a 75 R2 life proposal is reasonable for the account at this point in time, because it is derived from an appropriate depreciation asset life analysis, incorporated with the Company-specific assets' operational information, and within the range of other Florida gas utilities. It is also in line with the Commission's recognized and generally accepted principle of gradualism.[17]

### ***Account 37900 – Distribution Measuring & Regulating Equip – City Gate***

The currently-approved life for this account is 50 R2. Witness Watson proposed to moderately increase the ASL from 50 to 52 years. Witness Garrett proposed to increase the life to 60 years, and claimed that he did "not believe Watson's proposed average life of 52 years is long enough given the data presented at this time." (TR 1049). Witness Watson disagreed with witness Garrett's proposal.

This account is composed of city gate distribution measuring and regulating (M&R) station-related piping, regulators, controls, odorizers, and other equipment.[18] Witness Watson testified that PGS is beginning to build new city gates and is doing more capital improvements than in the past, and newer stations are expected to last longer than older ones. He also attested that different assets in the account may have different service lives, and Company subject matter experts indicated that "50 years seems reasonable from an operational perspective."[19] (TR 608-609; EXH 32, BSP E7-332) Witness Watson claimed that witness Garrett did not appear to factor in the life expectations for specific assets in this account as communicated by Company experts. (TR 607)

Witness Watson also argued that witness Garrett's proposal was based on examining one placement-experience band which ends at approximately 92.36 percent of the account's OLT data. (TR 609) He contested that the placement-experience band that witness Garrett used "is not statistically valid. It's too short to make any predictions from it." (TR 651)

Witness Watson further stated that witness Garrett's recommended ASL represents an increase of 15.4 percent when compared to existing parameters and contested that "[t]his level of change at one time without an operational justification is unreasonable, is not supported by the evidence, and should be rejected." (TR 612) Witness Watson additionally opined that:

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[16]In Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas*, witness Garrett recommended an ASL of 59 years this account. In Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*, witness Garrett recommended an ASL of 70 years for this account.

[17]As it pertains to depreciation and rate change, gradualism is the concept of making smaller adjustments over time as opposed to less frequent, large adjustments. See Order Nos. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, *In re: Petition for increase in rates by Progress Energy Florida*; PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.

[18]City gate is the entry point for gas being taken from a transmission system to a distribution system. PGS has over 90 city gates.

[19]E.g.: Odorizers may last 40-50 years, heaters may last 20-30 years, and regulators may last 30 years or more.

> In Docket No. 20170179-GU for Florida City Gas, witness Garrett recommended a 39 R0.5 life for this account. In Docket No. 20220069-GU for Florida City Gas, witness Garrett recommended a 45 S3 life for this account. It does not seem logical that Peoples would have assets in this account that last 33.3 percent longer than witness Garrett's recommendation for another Florida utility.

(TR 613)

After reviewing the account-specific data, information, curve-fitting graphs, and the related testimonies presented by both witnesses, staff believes that an estimate of 52 R2 life is appropriate for the account at this time. This life estimate is slightly longer than the high end of the industry's current ASL range for the account, which is 32 to 50 years with an average of 41 years, but is still in line with the Commission's recognized and generally accepted principle of gradualism.

***Account 38002 – Distribution Services Plastic***

The currently-approved ASL-curve combination for this account is 55 R1.5. Witness Watson proposed retaining the current ASL with a slight shift in retirement dispersion: 55 R 2.5. Witness Garrett proposed to increase the ASL to 62 years with an R2 curve. Witness Watson disagreed with witness Garrett's proposal.

Witness Watson argued that, as with other accounts, witness Garrett's recommendation "[did] not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]" and "only examines one band for his proposal." (TR 614) He further claimed that, with witness Garrett's recommended 1983-2021 placement and experience band, the OLT "is too short a stub to be predictive of the life of the account (only going to 84 percent surviving)." (TR 617) In his rebuttal testimony, witness Watson proffered four graphs, each visually comparing the fit of the curve to the account's actual data for placement-experience bands selected by him versus the bands selected by witness Garrett.[20] (TR 615-617) It appears to staff that the 55 R2.5 life proposal is a better fit of the actual activity in this account.

Witness Watson also argued that witness Garrett's proposal of a 7-year increase to the ASL is excessive. He claimed that this level of change without operational reasons is both unreasonable and not supported by the evidence. (TR 618) Witness Watson further pointed out that witness Garrett recommended a 54 R2.5 life and a 55 R2.5 life for this account in prior dockets.[21,22] He stated that it did "not seem logical that Peoples would have assets in this account that last 12.7 percent longer than witness Garrett's recommendation for another Florida utility." (TR 619)

Based on the review of the evidence presented, staff believes that a 55 R2.5 life proposal is appropriate at this point in time for Account 38002. The ASL is within the industry's current ASL range for the account, which is 40 to 60 years with an average of 53 years.

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[20]Respectively, placement and experience bands used by witness Watson are: 1) 1959-2021 and 1983-2021, 2) 1959-2021 and 1997-2021, and 3) 1983-2021 and 1983-2021; by witness Garrett is: 1) 1983-2021 and 1983-2021.
[21]Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas*; Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[22](62 - 55) / 55 = 12.7%

### *Account 38200 – Distribution Meter Installations*

The currently-approved parameters for this account is 44 R1. Witness Watson proposed to increase the current ASL to 45 years with a slight shift in retirement dispersion to R1.5. Witness Garrett proposed to increase the ASL to 55 years with a R0.5 dispersion. Witness Watson disagreed with witness Garrett's proposal.

At the time of preparing the 2023 Study, this account's average age of survivors and average age of retirements is 12.09 years and 13.72 years, respectively. Witness Watson testified that "[t]his information demonstrates that this is an account with newer assets and retirements that have occurred before a full cycle of activity has occurred." (TR 619) He also cited interview notes with Company subject matter experts to show the factors that influence the life of the account and argued that "witness Garrett does not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]." (TR 619-620) Witness Watson further presented several graphs, each visually comparing the fit against the account's actual data for placement-experience bands selected by him versus the bands selected by witness Garrett. Witness Watson claimed that his life proposal is a better visual match.[23] (TR 621-624)

Witness Garrett's proposed ASL represents an increase of 11 years, or a 25 percent change. Witness Watson asserted that this level of change at one time without operational reasons is unreasonable and it is not supported by the evidence. (TR 625) He further emphasized that for the same account, witness Garrett recommended a 34 S3 and a 35 R3 for this account in prior dockets, and claimed that "[i]t does not seem logical that Peoples would have assets in this account that last 57.14 percent longer than witness Garrett's recommendation for another Florida utility."[24,25] (TR 625)

Staff believes that a life proposal of a 45 R1.5 is reasonable for this account at this point in time. It is derived from an appropriate depreciation asset life analysis, incorporated with the Company-specific assets' operational information, and within the industry's current ASL range which is 34 to 45 years with an average of 41 years.[26] This proposal is also in line with the Commission's recognized and generally accepted principle of gradualism regarding the rate increase.

## Average Remaining Life

The ARL is the average number of in-service years left for plant currently in service. An account's ARL is determined by the account's age, its ASL, and the associated curve. As such, witnesses Watson and Garrett's ARL proposals are in dispute for the same five aforementioned accounts due to the difference in each account's ASL-curve proposals. (TR 583; EXH 116, BSP F1045; EXH 86, BSP D16-1800 – D16-1801; EXH 87, BSP D16-1802 – D16-1803; EXH 88, BSP D16-1804 – D16-1805) Based on staff's recommended ASL and curves for each account, the appropriate ARLs for each account are listed in Table 7-2.

[23] Respective placement and experience bands used by witness Watson are: 1) 1939-2021 and 1983-2021, 2) 1939-2021 and 1997-2021, and 3) 1983-2021 and 1983-2021; used by witness Garrett is: 1) 1983-2021 and 1983-2021.
[24] Dockets No. 20170179, *In re: Petition for rate increase by Florida City Gas*; 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[25] (55 - 35) / 35 = 57.14%
[26] *Id.*

### Net Salvage

The net salvage is gross salvage minus cost of removal. An account's net salvage percentage is based on the account's historical data, but is also prospective in outlook. No intervenor disagreed with PGS's net salvage percentage proposals presented in its 2023 Study. (EXH 116, BSP F1045; EXH 86, BSP D16-1800 – D16-1801; EXH 87, BSP D16-1802 – D16-1803; EXH 88, BSP D16-1804 – D16-1805) Staff has reviewed these proposals and believes them all to be reasonable based on the evidence in the record, including the data and corresponding analysis.

### Reserve Percentage

An account's reserve percentage represents the portion of the account's investment accumulated through depreciation expense to date unless restated to another level.[27] It is calculated by dividing the book reserve by the original cost of plant. PGS proffered the reserve percent, or reserve position, for each of its accounts. (EXH 116, BSP F1045) The parties had no dispute regarding this parameter as it was calculated directly from the actual data of each respective account.

### Depreciation Rates

For each of PGS's accounts, witness Watson calculated the remaining life depreciation rate based on his account-specific parameter proposals. The resulting remaining life depreciation rates, or depreciation rates, were used to determine PGS's proposed test year depreciation expense for the instant proceeding.[28] (EXH 116, BSP F1045) Staff verified witness Watson's calculations and confirmed that they are consistent with the prescribed formula of Rule 25-7.045(1)(e), F.A.C., for determining an account's remaining life depreciation rate.

Witness Garrett also performed the calculation for all the accounts which results in three sets of depreciation rate proposals from OPC. The first one, "Depreciation Rate Development – 2023 Study (With Book Reserve and Adjusted Parameters)," was developed by using witness Garrett's proposed depreciation parameters. It results in an overall depreciation rate of 2.47 percent for all plant accounts studied. (EXH 86, BSP D16-1800 – D16-1801) The second one, "Depreciation Rate Development – 2023 Study (With Theoretical Reserve and Adjusted Parameters)," was developed also by using witness Garrett's proposed depreciation parameters. It results in an overall depreciation rate of 2.64 percent for all plant accounts studied. (EXH 87, BSP D16-1802 – D16-1803) The third depreciation rate proposal, "Depreciation Rate Development – 2023 Study (Unadjusted Parameters)," was developed by using witness Watson's proposed depreciation parameters. It results in an overall depreciation rate of 2.69 percent for all plant accounts studied. (EXH 88, BSP D16-1804 – D16-1805)

Staff also verified witness Garrett's depreciation rate calculations. The aforementioned second depreciation rate proposal from witness Garrett leads to the amount of the depreciation theoretical reserve imbalance of $221 million that is the Joint Parties' primary recommendation for Issue 9. Staff notes that Garrett's rate proposal was developed by using a calculation method that deviates from what is prescribed by the Commission's depreciation rule pertaining to gas

[27]Rule 25-7.045, F.A.C.

[28]Rule 25-7.045(1)(e) and (m), F.A.C. prescribes the respective formulas for calculating an account's whole life depreciation rate and remaining life depreciation rate. Conventionally, the Commission uses the remaining life depreciation rare for the purpose of customer rate setting.

service by gas public utilities, Rule 25-7.045, F.A.C.[29] (TR 1062-1069; EXH 87, BSP D16-1802 – D16-1803)

Staff agrees with the depreciation rates proposed by witness Watson. These rates are derived from the depreciation parameters (ASLs, ARLs, net salvage, and reserve percentages) which are best supported by the record in this case, and the associated calculations are in accordance with Rule 25-7.045, F.A.C.

## CONCLUSION

Based on the record evidence, staff recommends the depreciation parameters and resulting depreciation rates for each plant account as shown in Table 7-2. The resultant test year depreciation expense, based on staff's recommended depreciation rates in this issue, is addressed in Issue 50.

[29]Rule 25-7.045, F.A.C. prescribes the formula to determine a plant account's remaining life depreciation rate: Depreciation base percent (or plant minus future net salvage percentages) less book reserve percent, divided by the average remaining life of the account. However, witness Garrett's proposal was determined for all accounts' depreciation rates by subtracting the theoretical reserve from the depreciation base, rather than subtracting the book reserve from the depreciation base. This substitution impacted his calculation of the remaining life rate, and is in violation of the rule.

## Table 7-2
## Staff's Recommended Depreciation Parameters and Resulting Remaining Life Depreciation Rates

| Account No. | Account Number | Existing Curve Type | Existing Average Service Life (yrs) | Existing Future Net Salvage (%) | Existing Remaining Life Rate (%) | Staff Recommended Curve Type | Staff Recommended Average Service Life (yrs) | Staff Recommended Average Remaining Life (yrs) | Staff Recommended Reserve (%) | Staff Recommended Future Net Salvage (%) | Staff Recommended Remaining Life Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DISTRIBUTION PLANT | | | | | | | | | | | |
| 37402 | Land Rights | SQ | 75 | 0 | 1.3 | SQ | 75 | 57 | 25.3 | 0 | 1.3 |
| 37500 | Structures & Improvements | L0 | 33 | 0 | 2.8 | L0 | 33 | 26 | 26.7 | 0 | 2.8 |
| 37600 | Mains Steel | R1.5 | 65 | (50) | 2.1 | R1.5 | 65 | 55 | 28.5 | (60) | 2.4 |
| 37602 | Mains Plastic | R2 | 75 | (33) | 1.6 | R2 | 75 | 67 | 20.4 | (40) | 1.8 |
| 37700 | Compressor Equipment | R2 | 35 | (5) | 3.0 | R2 | 35 | 33 | 6.9 | (5) | 3.0 |
| 37800 | Meas & Reg Station Eqp Gen | R1.5 | 40 | (10) | 2.7 | R1.5 | 40 | 31 | 26.2 | (20) | 3.0 |
| 37900 | Meas & Reg Station Eqp City | R2.5 | 50 | (10) | 2.1 | R2 | 52 | 46 | 16.0 | (20) | 2.2 |
| 38000 | Services Steel | R0.5 | 52 | (125) | 4.0 | R0.5 | 52 | 39 | 60.9 | (130) | 4.3 |
| 38002 | Services Plastic | R1.5 | 55 | (68) | 2.7 | R2.5 | 55 | 46 | 33.3 | (75) | 3.1 |
| 38100 | Meters | R2 | 19 | 3 | 5.0 | R2 | 20 | 12.4 | 41.4 | 0 | 4.7 |
| 38200 | Meter Installations | R1 | 44 | (25) | 2.2 | R1.5 | 45 | 37 | 33.1 | (30) | 2.6 |
| 38300 | House Regulators | S1 | 42 | 0 | 1.8 | S1.5 | 42 | 28 | 42.4 | 0 | 2.0 |
| 38400 | House Regulator Installs | R1 | 47 | (25) | 1.9 | R1.5 | 47 | 38 | 38.1 | (30) | 2.4 |
| 38500 | Meas & Reg Station Eqp Ind | R3 | 37 | (2) | 2.3 | R2.5 | 39 | 24 | 45.9 | 0 | 2.2 |
| 38700 | Other Equipment | L2 | 24 | 0 | 3.0 | L1.5 | 27 | 20 | 39.6 | 0 | 3.0 |
| TRANSPORTATION EQUIPMENT | | | | | | | | | | | |
| 39201 | Vehicles up to 1/2 Tons | L2.5 | 9 | 11 | 7.0 | L2.5 | 8 | 5.2 | 39.4 | 11 | 9.5 |
| 39202 | Vehicles from 1/2 - 1 Tons | L3 | 10 | 11 | 5.6 | L3 | 10 | 5.6 | 46.9 | 11 | 7.5 |
| 39204 | Trailers & Other | R2 | 27 | 15 | 2.9 | R1.5 | 30 | 26 | 17.8 | 20 | 2.4 |
| 39205 | Vehicles over 1 Ton | L2 | 12 | 4 | 6.6 | L2 | 13 | 7.5 | 49.4 | 7 | 5.8 |
| OTHER GENERAL PLANT | | | | | | | | | | | |
| 30300 | Mis Intangible Plant | SQ | 25 | 0 | 4.0 | SQ | 25 | 0 | 100.0 | 0 | 0.0 |
| 30301 | Custom Intangible Plant | SQ | 15 | 0 | 6.6 | SQ | 15 | 11.0 | 27.3 | 0 | 6.6 |
| 39000 | Structures & Improvements | L0 | 25 | 0 | 2.4 | L0 | 25 | 24 | 2.8 | 0 | 4.1 |
| 39100 | Office Furniture | SQ | 17 | 0 | 5.9 | SQ | 17 | 9.4 | 51.8 | 0 | 5.1 |
| 39101 | Computer Equipment | SQ | 9 | 0 | 11.1 | SQ | 9 | 5.4 | 57.8 | 0 | 7.8 |
| 39102 | Office Equipment | SQ | 15 | 0 | 6.7 | SQ | 15 | 5.9 | 63.1 | 0 | 6.3 |
| 39300 | Stores Equipment | SQ | 24 | 0 | 4.2 | SQ | 24 | 12.5 | 46.1 | 0 | 4.3 |
| 39400 | Tools, Shop & Garage Equip | SQ | 18 | 0 | 5.6 | SQ | 18 | 10.2 | 51.5 | 0 | 4.8 |
| 39401 | CNC Station Equipment | SQ | 20 | 0 | 5.0 | SQ | 20 | 14.9 | 24.5 | 0 | 5.1 |
| 39600 | Power Operated Equipment | L1.5 | 18 | 10 | 2.7 | L1.5 | 18 | 10.7 | 59.5 | 10 | 2.9 |
| 39700 | Communication Equipment | SQ | 13 | 0 | 7.7 | SQ | 13 | 2.3 | 97.4 | 0 | 7.7 |
| 39800 | Miscellaneous Equipment | SQ | 20 | 0 | 5.0 | SQ | 20 | 16.6 | 28.3 | 0 | 4.3 |
| GATHERING AND LNG PLANT | | | | | | | | | | | |
| 33600 | RNG Plant | R2 | 30 | (5) | 3.5 | R2 | 30 | 30 | 3.2 | (5) | 3.4 |
| 33601 | RNG Plant Leased - 15 Years | | | | | SQ | 15 | 13.5 | 5.5 | 0 | 6.7 |
| 36400 | LNG Plant | R2 | 30 | (5) | 3.5 | R2 | 30 | 30 | 1.7 | (5) | 3.5 |

Data Source: EXH 116 BSP F1045, 128 BSP F1675

***Issue 8:*** In establishing the projected test year's depreciation expense, should the approved depreciation rates be calculated using a depreciation study date of December 31, 2023 or December 31, 2024?

***Approved Type 2 Stipulation:*** Although the terms of the 2020 Agreement approved by the Commission in Order No. PSC-2020-0485-FOF-GU, suggests otherwise, the Company agrees with OPC that the depreciation rates that become effective on January 1, 2024 should be calculated using a depreciation study date of December 31, 2023.

***Issue 9:*** Based on the application of the depreciation parameters to PGS's data that the Commission has adopted, and a comparison of the theoretical reserves to the book reserves, what, if any, are the resulting imbalances?

***Recommendation:*** Based on the application of the depreciation parameters that staff recommends in Issue 7, the resulting imbalance is a surplus of $160.4 million. (Wu)

### *Position of the Parties*

**PGS:** The appropriate theoretical reserve imbalance is a surplus of $160.4 million as of December 31, 2023 based on the recommended life and net salvage parameters as reflected in Exhibit DAW-2.

**Joint Parties:** For the primary OPC expert recommendation, the resulting reserve imbalance is a depreciation reserve surplus of $221.024 million. EXH 89 D16-1807. For the other resulting imbalance per PGS's lives, see OPC witness Garrett's exhibits DJG-28. EXH 90.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated that the appropriate theoretical reserve imbalance is a surplus of $160.4 million as of December 31, 2023, based on the recommended life and net salvage parameters as reflected in Exhibit 32, Document No. 3. (PGS BR 12)

PGS argued that OPC presented an alternative calculation of the theoretical reserve surplus as of December 31, 2023, based on its proposed adjustments to PGS's depreciation parameters. (PGS BR 12) The Company contended that OPC's recommended adjustments are unreasonable, do not follow sound depreciation practice, and those adjustments and OPC's resulting theoretical reserve surplus should be rejected. (PGS BR 12)

### Joint Parties

The Joint Parties stated that OPC witness Garrett identified four options regarding the depreciation reserve surplus amount in his testimony. (JP BR 6) The Joint Parties' primary recommendation is to use OPC witness Garrett's proposed ASLs, which results in a depreciation reserve surplus of $221,024,192. The Joint Parties asserted that, should the Commission adopt all of PGS witness Watson's depreciation lives, the depreciation reserve surplus would be $159,474,313. (JP BR 6)

## ANALYSIS

The Commission's natural gas utility depreciation Rule 25-7.045(4)(k), F.A.C., provides that an account's theoretical reserve amount is determined by the account's book investment minus the account's future accruals and future net salvage. The reserve imbalance of an account is the difference between the account's calculated theoretical reserve and its book reserve. If the book reserve amount is larger than the theoretical reserve amount, this account presents a reserve surplus at a specific point in time.

PGS witness Watson calculated a $160.392 million reserve surplus for PGS's plant accounts based on his proposed depreciation parameters. (EXH 116, BSP F1045, EXH 128, BSP F1675) OPC witness Garrett calculated a $221.024 million reserve surplus by applying his proposed adjusted depreciation parameters. (EXH 89, BSP D16-1806 – D16-1807) This amount is the Joint Parties' primary recommendation regarding the reserve imbalance. (JP BR 5) Witness Garrett also calculated a $159.474 million reserve surplus by adopting PGS witness Watson's proposed depreciation parameters. (EXH 90, BSP D16-1808 – D16-1809)

Pursuant to Rule 25-7.045(4)(k), F.A.C., and the prescribed formula along with the depreciation parameters that staff recommends in Issue 7, the calculated theoretical reserve imbalance for each category of PGS's plant accounts is as shown in Table 9-1 below:

**Table 9-1**
**Theoretical Reserve Imbalance**

| Account Type | Reserve Imbalance (as of 12/31/2023) |
|---|---|
| Distribution | $152,368,138 |
| Transportation | $3,216,382 |
| General | $3,772,298 |
| Gathering and LNG Plant | $1,035,341 |
| Total Plant | $160,392,158 |

Source: EXH 116, BSP F1045 and EXH 128, BSP F1675

## CONCLUSION

Based on the application of the depreciation parameters that staff recommends in Issue 7 and application of the formula prescribed in Rule 25-7.045, F.A.C., the resulting imbalance is a surplus of $160.4 million.

***Issue 10:*** What, if any, corrective depreciation reserve measures should be taken with respect to any imbalances identified in Issue 9?

***Recommendation:*** Staff recommends using the remaining life technique to correct the reserve imbalance identified in Issue 9. (Wu)

### *Position of the Parties*

**PGS:** The surplus should be amortized over the remaining life of the assets.

**Joint Parties:** The reserve imbalances resulting as described in Issue 9 should be amortized over 10 years as explained in the testimony of OPC witnesses Garrett and Kollen in accord with Commission policy. Revenue requirements should be reduced $16.980 million.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated that its witness Watson designed his proposed depreciation rates to eliminate the theoretical depreciation reserve surplus over the remaining life of the depreciable assets and the average remaining life for the accounts where the Company proposed general plant amortization. (PGS BR 12)

PGS argued that OPC's recommendation to amortize the reserve surplus over ten years is a departure from the remaining life technique, and as such, it does not follow normal depreciation study practice. (PGS BR 12) PGS also contested that OPC's recommendation is also inconsistent with OPC's position in the recent Florida City Gas case, which was to follow the remaining life technique. (PGS BR 13)

PGS recommended that the Commission follow standard depreciation study practice and amortize the surplus using the remaining life technique. (PGS BR 13)

### Joint Parties

The Joint Parties proposed that "a relatively conservative return" of the theoretical depreciation reserve surplus should be implemented over 10 years "or a little less than half the time proposed by PGS." (JP BR 6) The Joint Parties argued that the reserve surplus reflects an overpayment from PGS's customers, and that current customers have overpaid due to excessive depreciation rates. (JP BR 7) The Joint Parties further argued that its proposed conservative return should occur for the benefit of the customers who overpaid in rates for depreciation expense and to implement a more moderate treatment of "PGS's enormous rate increase request." (JP BR 6) The Joint Parties stated, "These customers can and should receive the benefits of lower depreciation rates and base revenues in the near future through a shorter amortization period of the reserve surplus, rather than pushing those overpayment-driven benefits into the next several decades for the benefit of future generations of customers." (JP BR 7) The Joint Parties claimed that if OPC witness Kollen's proposed $221.024 million reserve surplus, calculated using OPC witness Garrett's proposed depreciation parameters and depreciation rates, is amortized in 10 years, the depreciation expense will be reduced by $17.625 million and revenue requirement will be reduced by $16.980 million. (JP BR 7)

Supporting the shorter amortization period, the Joint Parties stated that, with Order No. PSC-2010-0153-FOF-EI, the Commission ordered Florida Power & Light Company (FPL) to amortize its reserve surplus over a four-year period, and "[t]his policy is consistent with any number of prior orders dealing with imbalances that are deficits involving amortization periods between one and seven years." (JP BR 8)

The Joint Parties concluded that, "[g]iven the Company's position that they will defer to Commission policy and will not be financially harmed by the return of the overpayment of depreciation expense," the theoretical reserve surplus should be amortized over a 10 year period. (JP BR 8)

## ANALYSIS

This issue addresses whether any corrective measures should be taken with regard to the theoretical reserve imbalances identified in Issue 9. The remaining life technique is the most common method the Commission uses to address reserve imbalances (surplus or deficit). As indicated in Rule 25-7.045(1)(e), F.A.C., this method self-corrects the imbalances over the remaining life of the plant assets. Other corrective measures have also been approved by the Commission. In some cases, the Commission has approved an amortization of a certain portion of the surplus over a period of time that is shorter than the remaining life.[30] In other cases, the Commission has approved the amortization of the entire surplus over a specific period (years) shorter than the remaining life.[31]

In PGS's 2018 case, the Commission approved a reserve surplus correction using the remaining life technique. In the Company's 2020 case, the Commission approved a Settlement Agreement which permitted the amortization of a $34 million portion of the reserve surplus, which was approximately 12.6 percent of the total surplus amount.[32] Table 10-1 below shows the details:

[30]See Order Nos. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company*; PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*; PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 1600621, *In re: Petition for rate increase by Florida Power & Light Company*; PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket 20200051-GU, *In re: Petition for rate increase by Peoples Gas System;* PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*.
[31]PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[32]Order Nos: PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, I*n re: Petition for rate increase by Peoples Gas System*; PSC-2018-0501-S-GU, issued October 18, 2018, in Docket No. 20180044-GU, *In re: Consideration of the tax impacts associated with Tax Cuts and Jobs Act of 2017 for Peoples Gas System*.

**Table 10-1**
**PGS's Identified Theoretical Reserve Surplus and the Correction Measures**

| | Overall Plant Balance ($) | Overall Reserve Balance ($) | Theoretical Reserve ($) | Theoretical Reserve Surplus ($) | Surplus/Overall Plant Balance (%) | Surplus/Overall Reserve Balance (%) | Surplus/ Theoretical Reserve (%) | Corrective Measure | Portion of the Reserve Surplus Corrected ($) | Portion of the Reserve Surplus Corrected (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) = (2) - (3) | (5) = (4) / (1) | (6) = (4) / (2) | (7) = (4) / (3) | (8) | (9) | (10) = (9) / (4) |
| Instant Case | 3,186,513,154 | 889,076,505 | 728,684,347 | 160,392,158 | 5.0% | 18.04% | 22.0% | Decision Pending | | |
| 2020 Case[1] | | | | | | | | | | |
| As filed | 2,221,452,580 | 800,111,427 | 531,219,857 | 268,891,570 | 12.1% | 33.61% | 50.6% | | | |
| Per the SA[2] | | | | 268,891,570 | | | | 4 yrs Amortization | 34,000,000 | 12.6% |
| | | | | 268,891,570 | | | | Remaining life | 234,891,570 | 87.4% |
| 2018 Case[3] | 1,378,109,097 | 664,335,975 | 515,783,674 | 148,552,301 | 10.8% | 22.36% | 28.8% | Remaining life | 148,552,301 | 100.0% |

Note:
(1) Docket No. 20200051-GU.
(2) Settlement Agreement approved by Order No. PSC-2020-0485-FOF-GU; in Docket No. 20200051-GU.
(3) Approved by Order No. PSC-2018-0501-S-GU, in Docket No. 20180044-GU.

Source: EXH 116, BSP F1045 and EXH 128, BSP F1660, F1675

Intervenors contested that the surplus, when measured against the entire theoretical depreciation reserve, is between 22 percent and 33 percent. (JP BR 7) As shown in Table 10-1, based on staff's recommendation in Issue 9, the surplus amount of $160,392,158 is 22 percent when measured against the entire theoretical depreciation reserve. Staff notes that as shown in Table 10-1, in PGS's 2020 case, the surplus was 50.6 percent (or 44.2 percent after taking into account the $34 million amortization) when measured against the theoretical depreciation reserve.[33] Also shown in Table 10-1, in PGS's 2018 case, the surplus was 28.8 percent when measured against the theoretical depreciation reserve.[34] In essence, the Commission approved PGS to use the remaining life technique to correct its reserve surplus when the surplus amount was respectively 28.8 percent and 44.2 percent and measured against the entire theoretical depreciation reserve.

For the theoretical reserve surplus identified in the instant case, PGS proposed to amortize the entire amount over the remaining life of the plant assets. OPC proposed to amortize the entire amount over 10 years.

PGS witness Watson asserted that OPC's proposal "contradicts sound depreciation theory." (TR 581) He further explained that:

> Reserve imbalances change in each depreciation study (as evidenced by the decrease in surplus since the last study). Depreciation theory and the use of the remaining life technique in calculating depreciation rates will spread any surplus (or deficit) over the remaining life of the asset group.

(TR 626)

In responding to OPC's question, "apart from your recommendation [. . .] what amortization period should be used if it's shorter than the remaining life," witness Watson answered "I don't believe there is another option that would be appropriate other than the remaining life approach." (TR 653) He further argued that the exact amount of surplus at one point in time can vary based on the different ways by which an analyst chooses to look at the plant assets. Witness Watson

[33]Order No. PSC-2020-0485,-FOF-GU, see page 217.
[34]Order No. PSC-2018-0501-S-GU, see pages 39 and 42.

pointed out that the reserve surplus declined between PGS's last case and this case, and "it will drop further as moving further forward." (TR 652-653)

Staff notes that within the three years since the Commission's approval of the 2020 Settlement Agreement, applying the remaining life technique resulted in PGS's reserve surplus decreasing from $234.9 million (after amortizing $34 million from the original $268.9 million) to $160.4 million, as shown in Table 10-1. Staff believes this decrease indicates that the remaining life technique worked to significantly reduce the surplus.

Regarding the use of a method other than the remaining life technique to correct the reserve imbalance, witness Watson opined that "[it] is a policy decision, not a depreciation theory decision." (TR 626) He further testified that he believed "it is not a valid depreciation theory, that if the Commission were to do that, it would be a policy decision, not a[n . . .] appropriate depreciation theory decision." (TR 662)

OPC witness Kollen recommended that "the Commission remove the theoretical depreciation reserve surplus from the calculation of the depreciation rates and separately amortize the reserve surplus over ten years." He argued that a ten year amortization of the surplus will mitigate the customer rate increase requested by the Company in the current proceeding, and return the excessive depreciation expense that was recovered from customers in prior years to the customers who paid that expense through their base rates. (TR 1264) Specifically, the Joint Parties claimed that if OPC witness Kollen's proposed $221.024 million reserve surplus, calculated using OPC witness Garrett's proposed depreciation parameters and depreciation rates, is amortized in 10 years, the depreciation expense will be reduced by $17.625 million and revenue requirement will be reduced by $16.980 million. (JP BR 7)

Staff does not agree with the first portion of witness Kollen's recommendation. His proposal to "remove the theoretical depreciation reserve surplus from the calculation of the depreciation rates" does not comport with Rule 25-7.045(1)(e), F.A.C., Depreciation, as explained in Issue 7.

Staff agrees with witness Kollen's argument that amortization of the reserve surplus can mitigate the Company's currently requested customer rate increase, and would return the excessive depreciation expense to the current customers. When responding to a question about whether he was aware that the Commission's prior policy decisions involving accelerated surplus amortization resulted in monies returned to ratepayers sooner rather than later, due in part, to concerns about intergenerational unfairness, witness Watson testified, "I think you are going to create intergenerational unfairness by returning it as well [. . .] returning it is not going to solve any problems. It's actually going to cost your customers more in the long-term." (TR 662)

The existence of a reserve surplus means that, under present estimations, a theoretical excess recovery of plant investment has occurred to date, so there is a smaller amount of investment left to be recovered over the remaining life of the asset. As a result, current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates (all other things equal) and a lower return on rate base. However, if the identified reserve surplus is amortized, the depreciation rates set in future proceedings would be higher, plus the Company would have an increased rate base on which to earn a return, all of which would drive up costs to ratepayers.

More specifically, any amortized amount of the reserve surplus represents a reduction to the accumulated depreciation, or depreciation reserve, previously recovered by the Company from customers through rates. The identified $160.4 million reserve surplus, as of December 31, 2023, is an indication that customers, at that point in time, have excessively reimbursed PGS its investment by $160.4 million theoretically; plus they have paid the Company its cost of capital of this investment. By statute, a public utility is allowed the opportunity to recover its cost of, and earn a fair return on, plant investment that is used and useful in providing service to customers. If this $160.4 million of reserve surplus is amortized, such as what is proposed by the Joint Parties, customers can expect to pay increased depreciation expense resulting from future rate setting proceedings in order to allow that returned surplus to be collected again. In addition, customers have to pay for the Company's cost of capital on the $160.4 million from now until the associated plant investment is completely recovered again. This would impose an extra financial burden on customers.

Given the above, it is clear that, while amortizing the reserve surplus can reduce customer rates in this proceeding, higher customer rates will likely have to be imposed on customers in future rate case proceedings. Additionally, OPC provided no details as to how the amortization of the $160.4 million reserve surplus would be implemented.

Therefore, the appropriate method to correct the reserve surplus, from the standpoint of depreciation theory, is the remaining life technique. As shown in Table 10-1, the ratios of surplus to plant balance, to reserve balance, and to theoretical reserve do not provide a compelling reason to abandon the utilization of the remaining life technique for reserve surplus correction in this case. Staff believes that the remaining life technique is the appropriate corrective measure to address the $160.4 million depreciation theoretical reserve surplus identified in the current case. It is consistent with the Commission's decisions in a majority of prior depreciation studies and rate case proceedings, fair to customers as a whole, and supported by sound depreciation theory.

## CONCLUSION

Based on the record evidence and staff's analysis, staff recommends using the remaining life technique for correcting the theoretical reserve imbalance identified in Issue 9.

***Issue 11:*** What should be the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules?

***Approved Type 2 Stipulation:*** The implementation date should be January 1, 2024.

***Issue 12:*** Has PGS made the proper adjustments to remove all non-utility activities from the projected test year Plant in Service, Accumulated Depreciation, and Working Capital? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes. All required adjustments to remove non-utility items have been included in the 2024 projected test year, as shown on MFR Schedule G-1, page 4.

***Issue 13:*** Has PGS made the proper adjustments to remove all costs attributable to the operations of Seacoast Gas Transmission (SGT)? If not, what adjustments should be made?

***Recommendation:*** No. Staff recommends an additional $189,347, before gross-up, be removed from the Company's as-filed proposed revenue requirement to account for additional costs attributable to the operations of SGT. Staff also recommends the Commission direct PGS to file a comprehensive procedural review and associated cost study of the support it provides to SGT contemporaneously with its next base rate proceeding. (Higgins)

### *Position of the Parties*

**PGS:** Yes. In rebuttal testimony of witness Parsons, the Company proposed an adjustment to its calculation of corporate overhead costs to SGT that would increase the allocation by $189,347 based on a revision to the Modified Massachusetts Method ("MMM") used for determining the overhead allocation to include directly charged payroll and benefit costs from the Company and Tampa Electric. The resulting revised MMM calculation fairly allocates PGS overhead costs to SGT.

**Joint Parties:** In its filing, PGS did not demonstrate that all costs attributable to SGT were removed from the projected test year. After discovery, PGS removed an additional $190,000 in revenue requirements. The Joint Parties support this adjustment contingent upon the Company conducting a comprehensive study and filing the results of it the next rate case.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS has proposed adjustments to its original petition related to the operation costs of SGT. More specifically, the adjustments are related to the amount of corporate overhead costs attributable to SGT. The effect of the proposed adjustment in this issue is a revenue requirement reduction of $189,347. The Company also states it is willing to conduct a comprehensive study of the services and costs that SGT receives from PGS.

### Joint Parties

Throughout the proceeding and in its brief, the Joint Parties raised a number of concerns regarding the methodology by which PGS attributes costs to SGT. (JP BR 8-10) In general, the Joint Parties are concerned that ratepayers now, and in the future, could potentially be subsidizing the Company's non-regulated activities such as the operations of SGT. (JP BR 9) This concern is heightened given the additional staffing/hiring proposals being made in this case. (JP BR 9) The Joint Parties recognize the Company, in response to OPC discovery, proposed a "good faith" adjustment to account for additional costs attributable to SGT operations. (JP BR 9) However, due to the issues raised in this proceeding, the Joint Parties' request that the Commission direct PGS to conduct a comprehensive review of its relationship to SGT, and revise its procedures to accurately describe the circumstances when SGT imposes direct and indirect demands on PGS resources, including the need to maintain the availability of resources to service the needs of SGT. (JP BR 10)

## ANALYSIS

The primary purpose of this issue is to identify and ensure an appropriate amount of costs attributable to the operations of SGT is removed from PGS's 2024 projected test year. SGT is an affiliated limited liability company that conducts business in the areas of natural gas pipeline design, construction, and operation. SGT is a "sister company" to PGS, while both SGT and PGS are wholly-owned subsidiaries of Tampa Electric Company. (TR 1965)

Valuing and accounting for the labor and other cost support provided by PGS to its affiliates is being performed in the following three ways. The first is by directly charging the labor cost to the affiliate. The second method is through a standard labor distribution where a PGS employee allocates a fixed portion of their worktime to the affiliate. While the third method is through an overhead allocation method, namely and in this instance, the MMM. (TR 1966)

In this Issue, the contention is that the MMM understates the allocation of corporate overhead costs. This is a result of how the MMM functions relative to the operating profile of SGT. More specifically, the MMM allocates corporate overhead costs based on the ratios of net revenues, payroll and benefits costs, and property, plant, and equipment between PGS, TECO Partners Inc. (TPI), and SGT. Since SGT does not have any employees, the MMM - without further modification - will likely under-allocate corporate overhead costs from PGS to SGT. (TR 1967) Staff notes the initial or as-filed 2024 test year overhead costs allocated by PGS to SGT is $1,595,205. (EXH 7, BSP K253; EXH 123, BSP F1614)

In recognition of this matter, PGS proposed to include the directly-allocated or charged 2022 historical test year payroll and benefits amount of $1,150,287 in the MMM calculation. (TR 1967-1968) By doing so, the costs assigned to SGT increases by $180,225. After accounting for assumed inflation in 2023 and 2024 of 2.8 percent and 2.2 percent respectively, the adjusted cost amount equals $189,347. (EXH 33, BSP E8-552) After grossing-up for the regulatory assessment fee and bad debt expense, this figure increases (revenue requirement reduction) to $190,837. (TR 1968) Staff believes using the directly-allocated labor cost for computing an allocation for associated corporate overhead costs is a reasonable approach as it appears to be a fair representation of the actual labor support/cost provided to SGT.

There was an additional proposed SGT-related O&M adjustment of $8,359 contained within PGS witness Parson's rebuttal testimony. (EXH 123, BSP F1614; EXH 33, BSP E8-543) This adjustment is with respect to the "agreed upon [O&M] reductions with [OPC]." (EXH 123, BSP F1614) Staff notes this adjustment is related to the 2022 base recoverable O&M expense which the 2024 projected test year is partially predicated on. After grossing-up for the regulatory assessment fee and bad debt expense, this figure increases (revenue requirement reduction) to $8,425. This proposed adjustment is recommended for approval in Issue 49.

A portion of the OPC's cross-examination of witness Parsons centered around PGS's willingness to file a comprehensive cost study of the services and support it provides to SGT as part of its next base rate proceeding if directed by the Commission. (TR 2058) To that end, the Joint Parties do recommend that the Commission direct PGS to conduct a comprehensive review of its relationship to SGT, and revise its procedures to accurately describe the circumstances when SGT imposes direct and indirect demands on PGS resources, including the need to maintain the availability of resources to service the needs of SGT. (JP BR 10) When asked if the Company was willing to conduct and produce such a study, witness Parsons replied: “of course.” (TR 2058) Given the matters raised with respect to accurately and fully valuing the support PGS provides to SGT, staff believes a comprehensive procedural review and associated cost study would benefit the Commission in its analysis of the Company’s next base rate case.

In summary, with the previously-allocated $1,595,205, and the additional proposed adjustments of $8,359 and $189,347 discussed above, the total amount of overhead costs (before gross-up) proposed for removal from the 2024 projected test year attributable to SGT is $1,792,911. (EXH 7, BSP K253; EXH 123, BSP F1614) Further, staff believes the Joint Parties’ recommendation to have PGS file a cost study of the support it provides SGT as part of its next base rate case has merit.

## CONCLUSION

Staff recommends an additional $189,347, before gross-up, be removed from the Company’s as-filed proposed revenue requirement to account for additional costs attributable to the operations of SGT. Staff also recommends the Commission direct PGS to file a comprehensive procedural review and associated cost study of the support it provides to SGT contemporaneously with its next base rate proceeding.

***Issue 14:*** Has PGS made the proper adjustments to reflect Cast Iron/Bare Steel Rider (CI/BSR) investments as of December 31, 2023, in rate base? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes. The appropriate CI/BSR investment amounts as of December 31, 2023 to be transferred into rate base are $91,733,660 for plant in service, $2,808,776 for Construction Work in Progress and $1,273,990 for accumulated depreciation, as shown on Exhibit No. RBP-1, Document No. 2, lines 2-4.

***Issue 15:*** Should PGS's proposed Advanced Metering Infrastructure (AMI) Pilot be approved? If not, what adjustments should be made?

***Recommendation:*** Yes. The AMI Pilot should be approved and staff recommends that PGS provide a final report with a summary of the findings to the Commission within 90 days of completion of the AMI Pilot. No adjustments are recommended. (T. Thompson, Andrews)

### *Position of the Parties*

**PGS:** Yes. The proposed AMI Pilot is prudent and should be included in rate base and Net Operating Income. The Company's MFRs reflect $2.2 million for capital expenditures and $100,000 of O&M expenses associated with the pilot and should be approved.

**Joint Parties:** No. PGS bears the burden of proof to demonstrate the prudence of the proposed AMI pilot. Any approval of an AMI pilot should not be a basis for approval of wholesale implementation of an AMI project.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that the AMI Pilot should be approved because it will allow PGS to assess the benefits to gas customers of a technology widely used in the electric utility industry. (PGS BR 14-15) The potential benefits PGS identified include cost reductions, remote disconnection and leak and outage detection, and improved billing accuracy and customer information on individual usage. PGS contended that the Pilot was sized such that the Pilot cost was balanced with the need to provide a large enough sample to test the benefits of the Pilot. PGS asserted that the Hillsborough County area was selected as the location for the Pilot due to the ability to connect to TECO's existing AMI infrastructure. PGS averred that its AMI Pilot is similar to the pilot the Commission approved for Florida City Gas (FCG). (PGS BR 15)

### Joint Parties

The Joint Parties argued that the costs associated with PGS's AMI Pilot should be disallowed because PGS has not demonstrated the prudence of the Pilot. The Joint Parties asserted that PGS has not satisfied its burden of proof because it admitted that only a small number of gas utilities have deployed AMI technology to date, and stated that it was still evaluating opportunities to connect to TECO's existing AMI technology. The Joint Parties contended that PGS should be required to further evaluate the experimental AMI technology before customers cover the costs of the Pilot. (JP BR 10)

## ANALYSIS

PGS is requesting a research and development pilot to evaluate AMI infrastructure with two-way communication capability. As part of the pilot, PGS would collect data on the durability of the proposed smart meters, especially with regard to corrosion, and usage of two-way communications for central control of meter functions, such as remote connects and disconnects, and improved customer information on usage. The proposed pilot would be over a four-year period, with one year of installation and three years of operation, and consist of 5,000 smart devices with related back-office technology support installed in the Hillsborough County area where PGS can connect to TECO's existing AMI network. (TR 765-766; EXH 114) The estimated total cost of the AMI Pilot is $2.2 million in capital expenditures, with annual O&M expenses estimated at $100,000. (TR 766-767) PGS's AMI Pilot is largely similar to FCG's AMI Pilot, approved in its most recent base rate proceeding.[35]

PGS witness O'Connor testified that although AMI technology is widely used by electric utilities, only a small number of gas utilities have deployed this technology. (TR 764) Staff notes that the recent approval of FCG's AMI Pilot would make PGS the second gas utility in Florida to implement AMI technology. As such, the feasibility of AMI technology usage by gas utilities in Florida is still being determined. Under the AMI Pilot, PGS intends to determine whether deploying AMI technology could result in cost reductions through remote meter reading, leak and outage detection, and disconnection capabilities. The AMI Pilot would also allow PGS to evaluate improvements regarding billing accuracy and customer information on usage. (TR 766) Witness O'Connor contended that replacing 5,000 meters under the AMI Pilot would provide a large enough sample to test the benefits of smart meters with AMI technology on PGS's system without creating excessive costs, as this represents approximately seven percent of PGS's customer meters in the Hillsborough County area. (TR 765-766) Hillsborough County was selected due to it being in PGS's Tampa service area, which would allow PGS to pay TECO to connect to its existing AMI network and avoid costs associated with PGS having to create its own standalone AMI network. (TR 766; EXH 114)

No intervenor addressed this matter in their prefiled testimony or during the hearing. However, in their brief, the Joint Parties argued that the costs associated with PGS's AMI Pilot should be disallowed because PGS has not satisfied its burden of proof regarding the prudence of the Pilot. As discussed above, PGS witness O'Connor acknowledged that, while common in the electric industry, AMI technology has only been deployed by a limited number of gas utilities. (TR 764) Staff notes that, traditionally, it has been Commission practice that pilot programs serve as vehicles for utilities to explore new technologies or processes, and assess the benefits using a sample prior to permanent implementation.[36] As such, staff believes that the newness of AMI technology to the gas industry, specifically in Florida, lends credibility to PGS's proposal for a pilot program to allow this technology to be further evaluated prior to full scale implementation. Regarding PGS evaluating whether or not it could connect to TECO's existing AMI technology, PGS indicated in response to staff's discovery that it has confirmed that it can connect to TECO's existing AMI network for the Pilot. (EXH 114)

Staff has reviewed PGS's AMI Pilot request and agrees with PGS that customers and the Utility could potentially benefit from implementation of AMI technology due to the potential for reduced costs for the Utility, and, as a result, the customers. As no gas utility in Florida has

[35]Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas.*

[36]Order No. PSC-2021-0237-PAA-EI, issued June 30, 2021, in Docket No. 20200234-EI, *In re: Petition for approval of direct current microgrid pilot program and for variance from or waiver of Rule 25-6.065, F.A.C., by Tampa Electric Company.*

implemented system-wide deployment of AMI technology, staff believes that the benefits of such implementation need to first be assessed and a pilot program provides the means to do so. As such, staff recommends that PGS's proposed AMI Pilot be approved. In addition, staff recommends that PGS provide a final report with a summary of the findings to the Commission within 90 days of completion of the AMI Pilot. This summary should include the findings with regard to the project cost, meter installation, maintenance, and corrosion performance, as well as sample reports including information such as customer daily usage, remote meter communication performance, and billing accuracy impacts.

## CONCLUSION

The AMI Pilot should be approved and staff recommends that PGS provide a final report with a summary of the findings to the Commission within 90 days of completion of the AMI Pilot. No adjustments are recommended.

***Issue 16:*** Should the New River RNG project be included in rate base, and if so, are the revenues under Service Agreement pursuant to the RNG Service Tariff adequate to cover the revenue requirements of the project? If not, what adjustments should be made?

***Approved Type 1 Stipulation:*** The New River RNG Project (interconnection) was planned and executed based on and in reliance on the Company's Rate Schedule RNGS and will be included above the line in the calculation of the Company's 2024 revenue requirement, with whether to use deferral accounting for the project as proposed by OPC to be decided under subsequent issues. Subject to the Commission's approval in this docket of the Company's new Renewable Natural Gas Interconnection Service tariff (RNGIS) to be effective January 1, 2024 as agreed to with OPC, the Company will close its RNGS tariff to new projects effective August 29, 2023, so New River and Brightmark will be the only two projects it undertakes under that rate schedule.

***Issue 17:*** Should the Brightmark RNG project be included in rate base, and if so, are the revenues under Service Agreement pursuant to the RNG Service Tariff adequate to cover the revenue requirements of the project? If not, what adjustments should be made?

***Approved Type 1 Stipulation:*** The Brightmark RNG Project (bio conditioning and interconnection) was planned and executed based on and in reliance on the Company's Rate Schedule RNGS and will be included above the line in the calculation of the Company's 2024 revenue requirement, with whether to use deferral accounting for the project as proposed by OPC to be decided under subsequent issues. Subject to the Commission's approval in this docket of the Company's new Renewable Natural Gas Interconnection Service tariff (RNGIS) to be effective January 1, 2024 as agreed to with OPC, the Company will close its RNGS tariff to new projects effective August 29, 2023, so New River and Brightmark will be the only two projects it undertakes under that rate schedule.

***Issue 18:*** Should the Alliance Dairies RNG project be included in rate base, and if so, are the terms and conditions of the Biogas Incentives Agreement adequate to protect ratepayers and cover the revenue requirements of the project? If not, what adjustments should be made?

***Approved Type 1 Stipulation:*** No. The Alliance Dairies RNG Project should be accounted for on an unregulated, below-the-line basis and the Company's proposed revenue requirement should be increased by approximately $220,000 to reflect the movement of this project below the line.

***Issue 19:*** Has PGS properly reflected in the projected test year the cost saving benefits to be gained from implementation of the Work and Asset Management (WAM) system? If not, what adjustments should be made?

***Recommendation:*** Yes. PGS has properly reflected the cost saving benefits of $750,000 in reduced operation and maintenance (O&M) expenses to be gained from implementation of the WAM system in the projected test year. No further adjustments are recommended. (Wooten, Norris)

***Position of the Parties***

**PGS:** Yes, in its initial filing based on its 2024 forecast, PGS properly reflected no cost savings benefits associated with WAM in the projected test year; however, for ratemaking purposes in this case, the Company proposes to reduce test year O&M expenses by $750,000 to give customers the O&M value benefits for the first two years of implementation (2024 and 2025) identified when the Company decided to implement the WAM.

**Joint Parties:** No. PGS has incurred $34.4 million in capital costs for the new WAM system, yet it claims that WAM will not result in any savings whatsoever from efficiencies in the test year. The evidence indicates that the operation of the WAM system, in conjunction with other potential near-term actions, will lead to operational efficiencies that are not captured in the Company's projection of employee additions or savings in the level of contract labor expense.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS asserted that WAM is used by most utilities and will allow the Company to use capital and O&M resources more effectively through better planning and work management. (PGS BR 15) PGS witness Richard testified there were no cost savings benefits associated with WAM in its initial filing, but later identified $750,000 in cost savings by reducing O&M costs in its revised revenue requirement for the 2024 test year. (PGS BR 15; TR 1768) PGS proposed a reduction of $750,000 to O&M expense in an effort to combine the 2024 and 2025 expected O&M cost-saving benefits in the 2024 test year to recognize the WAM benefits. (PGS BR 16) PGS argued that the adjustment made by the Company to reflect WAM cost savings for ratemaking purposes is reasonable. (PGS BR 16)

### Joint Parties

The Joint Parties stated that they are not seeking disallowance of the cost of WAM or denying the efficiency provided by WAM. (JP BR 11) The Joint Parties argued that PGS is requesting full cost recovery for WAM initially filed its case without reflecting any savings in the test year. (JP BR 11) The Joint Parties further argued that WAM should be a basis for limiting hiring. (JP BR 11-12)

## ANALYSIS

The WAM system is a centralized asset management program that would consolidate the management of new construction, system reliability, maintenance and compliance into a single interconnected system. (TR 1618) Additionally, this program would allow PGS to track all planning, design, construction, use, and retirement of PGS's assets throughout the life of each asset. (TR 760) WAM was initially deployed in two phases, with Phase 1 implemented in November 2022 and Phase 2 implemented in May 2023. Phase 1 was intended to address the needs of the Engineering, Construction and Technology (ECT) team and Phase 2 was intended to address the needs of the Gas and Safety Operations teams. (TR 1756, 1758) The initial implementation cost of the WAM project was $34.3 million. (EXH 151; TR 1782) PGS determined that WAM required additional functionality beyond the initial implementation, which will be integrated by the end of September 2023. PGS required an additional $4.4 million in capital associated with the additional functionality, which PGS has not included for rate recovery in this proceeding. (TR 1764, 1782)

PGS's Gas and Safety Operations teams formerly utilized five independent legacy systems, some of which are no longer supported by their respective vendors, in completing their work. The legacy systems handled compliance activities, service and emergency orders, work tracking for distribution services, leak remediation tracking, and locate responses ticketing whose functions would be incorporated within WAM into a single program. (TR 761-762, 1756, 1776)

### *WAM Efficiency Savings*

PGS witness Richard testified that the implementation of WAM would facilitate PGS's ability to more efficiently execute work planning, enhance customer service, enhance system safety and provide centralized asset management. WAM would also reduce the risk associated with PGS's reliance on independent legacy systems, allow for the digitization and standardization of processes that are currently manually completed, and allow for integration with existing financial and customer systems. (TR 1615-1618) PGS witness O'Connor claimed that WAM would enable PGS to more easily coordinate work activities, better manage the scheduling and dispatch of work, increase optimization of work, and improve data collection that allows for more informed decision making. (TR 815) The witness also claims that once WAM is fully implemented the length of time required for jobs would be quantifiable which would allow PGS to optimize employee work duties. (TR 861-862) PGS anticipates that cost-savings would be realized as WAM provides efficiency improvements by more effective use of capital and O&M resources. (EXH 187; TR 1615-1616) Cost-savings would come in the form of PGS avoiding hiring new team members and contractor services. (TR 818, 1769-1770)

Witness Richard indicated in direct testimony that there were minimal cost-savings in the 2024 test year associated with the project. (TR 1618) In agreeance, witness O'Connor asserted in direct testimony that as WAM is intended to streamline PGS's future productivity and efficiency, and has only been implemented since 2023, immediate cost savings were not expected. (TR 802) The witness further asserted that the first one to two years of WAM's implementation would include team members becoming more familiar with the system, PGS obtaining data that would be utilized to facilitate software optimization, and fully integrating WAM's features and functions into existing systems. (TR 802-803) However, in the late filed exhibit to witness

Richard's first deposition, "WAM Benefits Realization Metrics 2022 Update," PGS indicated WAM was projected to provide O&M and capital benefits starting in 2023. (EXH 187) Witness Richard testified that the document was created in November 2020 while seeking approval for the original business plan and updated in March 2022 after PGS became more familiar with the WAM technology. (TR 1784) The witness clarified that due to project delays, the first full year of operation was delayed from 2023 to 2024 along with all subsequent benefits. (TR 1787-1788)

Exhibit 187 shows that PGS expected a total O&M savings of $363,000 and $726,000, in 2024 and 2025 respectively. The exhibit additionally indicates that PGS expected a capital savings of $144,750 and $289,500 in 2024 and 2025, respectively. (EXH 187) At the hearing, witness Parsons provided an exhibit updating the Company's revenue requirement to reflect revisions from her rebuttal testimony and positions updated prior to the hearing. (TR 1988-1989; EXH 218) In the revised revenue requirement, PGS revised its estimate to reflect $750,000 of cost-savings in the 2024 test year associated with the WAM implementation. (TR 854; EXH 218) The Company indicated that it intended to bring forward the 2025 O&M cost-savings into the test year as a proxy for anticipated offset labor costs due to WAM and would achieve these cost savings via reducing O&M costs, which would likely come from reducing internal and external labor costs. (TR 876, 1768, 1777, 1788-1789) Witness O'Connor testified that achieving the $750,000 reduction in O&M expense for 2024 would be difficult for PGS to achieve. (TR 1783)

Staff notes that the proffered amount of $750,000 in reduced O&M expense exceeds the expected test year O&M WAM savings by approximately $386,786 and the expected year two savings by $23,571. Staff believes that bringing forward year two savings into the test year will provide immediate savings for PGS customers that would otherwise go unrealized due to the lag expected with PGS gathering data and optimizing its processes. Because of these facts, staff believes the proffered $750,000 amount to be an adequate proxy for savings expected from WAM. The adjustment of $750,000 to O&M expense is reflected in Issue 49, which addresses projected test year O&M expenses.

No party disputed the efficiencies gained by WAM. In fact, in its brief, the Joint Parties stated that it was not seeking disallowance of the cost related to WAM. (JP BR 11) However, the Joint Parties argued that the cost-savings that WAM is projected to provide are not being fully realized in the projected test year, such as curtailing the need for additional employee hiring. (JP BR 11-12) Staff believes that the evidence in the record shows that the Company is adequately recognizing those savings by bringing forward year two savings into the 2024 test year. The Company's need for additional employees is discussed in Issue 42.

## CONCLUSION

PGS has properly reflected the cost saving benefits of $750,000 in reduced O&M expenses to be gained from implementation of the WAM system as a proxy for anticipated offset labor costs due to WAM is appropriate and no further adjustments should be made.

***Issue 20:*** Should any adjustments be made to the amounts included in the projected test year for acquisition adjustment and accumulated amortization of acquisition adjustment?

***Approved Type 1 Stipulation:*** No. As shown on MFR Schedule B-6, page 1, as of December 31, 2022, the Company has fully amortized the $5,031,897 of acquisition adjustments and the related net rate base amount is $0.

***Issue 21:*** What level of projected test year plant in service should be approved?

***Recommendation:*** Based on the stipulation in Issue 18 and staff's recommendation in Issue 42, staff recommends that projected test year plant in service be reduced by $11,844,552. As such, the appropriate level of projected test year plant in service should be $3,296,475,850. (Hinson, Wooten)

***Position of the Parties***

**PGS:** The appropriate projected test year plant in service is $3,298,318,785, which is a reduction of $11,530,336 from the $3,309,849,121 shown on MFR Schedule G-1, page 1, line 1 due to the removal of Alliance plant in service. The Commission should reject OPC's proposed adjustment to the forecasted 2024 plant in service.

**Joint Parties:** The Commission should approve no more than $3,274,834,064 of projected test year plant in service. $33.331 million of purely projected plant in service should be removed from determination of the test year revenue requirements.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS stated that the appropriate amount of plant in service for the projected test year of 2024 is $3,298,318,785, which includes reductions due to the removal of the Alliance RNG project. (PGS BR 17; EXH 7, BSP K169) PGS projected over $1 billion in capital expenditures to support customer growth, enhance customer service, and enhance the safety and reliability of its system. (PGS BR 17; TR 1912-1913; EXH 23, BSP D12-1006) PGS witness Richard asserted that PGS's capital investments are made to serve increasing customer demand in the areas of growth projects; reliability, resiliency, and efficiency (RRE) projects; and legacy pipe replacement projects, and not just to grow rate base. (PGS BR 17; TR 1592-1593, 1606-1612)

PGS explained that the Company determines its capital costs based on the scale of the customer or project in order to develop a capital budget that reflects a reasonable total amount of capital spending. (PGS BR 17; TR 1597-1599) However, PGS stated that construction distribution system projects' costs have increased over the recent years and are projected to continue to rise due to higher materials costs; strong industry demand for external contractors; governmental, regulatory, and compliance requirements, including permitting and maintenance of traffic requirements; higher costs to retire, remove, and restore existing plant; and new construction safety protocols and enhanced construction management, inspection, and quality control activities. (PGS BR 17-18; TR 1594-1595)

PGS explained that the Joint Parties' use of 5-year averages, in its recommended reduction to projected test year plant in service, fails to recognize the Company's capital governance changes that have improved the capital budgeting process and capital spending controls, including building a new budgeting tool for distribution work to better predict a division's work. (PGS BR 18; TR 1234-1235) PGS asserted that these improvements allow the Company to improve its budgeting process and reduce variances between budgeted and actual capital costs. (PGS BR 18-19; TR 1639-1643; EXH 28, BSP E3-88) PGS argued that the Joint Parties' claim that the Company will not spend its 2023 and 2024 capital budget should be rejected, as well as any proposed capital adjustments, as the Company spent more than budgeted on capital in 2022 and projects to spend its 2023 capital budget. (PGS BR 19; TR 1837)

**Joint Parties**

The Joint Parties stated that the Commission should make adjustments to PGS's request for 100 percent of its projected rate base for 2023 and 2024 due to concerns with the Company's ability to spend up to its projected levels. (JP BR 12; TR 1234-1235) Furthermore, the Joint Parties claimed that PGS is having difficulty closing CWIP despite proposing an ambitious 2023 budget. (JP BR 12) The Joint Parties argued that PGS's "Capital Management Improvement Plan" would be effective in 2024 at the earliest, and these tools are still a work in progress. (JP BR 12; TR 1712-1720; EXH 174C)

The Joint Parties stated that PGS has failed to fully spend its capital budget in each of the most recent five years, with an average weighted underspending of 6.5 percent. (JP BR 12; TR 2130, 1233-1234) The Joint Parties stated that in 2021, the last rate case test year, PGS appeared to go under budget by 2.6 percent, but the Joint Parties pointed out this fails to account for major additions to the rate base. (JP BR 13) In 2021, $48 million was added to the rate base for an LNG and RNG project, with PGS using its Integrated Resource Process as reason that the Commission should approve the projects; however, the Joint Parties pointed out that the LNG project was never completed and the RNG project was completed two years late, which goes against the idea that PGS met the 2021 capital budget. (JP BR 12-13; TR 1167, 1667, 1704-1705, 1831; EXH 208) The Joint Parties also cited PGS's delayed Summerville-Dade City Connector and the FGT to JEF projects. (JP BR 13; TR 1644, 1684, 1700; EXH 220)

The Joint Parties acknowledged that delays are expected, but claimed that the problem with delays relative to the rate base are that they lead to customers being overcharged and shareholders benefitting if actual capital spending comes in under budget. (JP BR 13; TR 1672; EXH 171) Witness Kollen argued that the Company's track record gives precedence for the Commission to be cautious in approving all of the requested projected base rate. (JP BR 13) The Joint Parties cited further evidence regarding PGS's development of projected plant in service additions, claiming that it is a false foundation for the 2023 capital budget. (JP BR 13; EXH 7, BSP K177, K213) The Joint Parties stated that witness Parsons testified that in 2023, year-to-date closures of CWIP fell short of plant in service to the amount of over $220 million, which the Joint Parties used to question the Company's ability to meet 2024 budgets, as actual plant closure in 2022 also fell short of projections and carried over to 2023. (JP BR 13-14; TR 2040; EXH 210) The Joint Parties further posited that the 2022 and 2023 budgets, where PGS had or is expected to have underrun CWIP closures to plant in service, should be considered the best evidence and suggests that 2024 capital expenditures will not be met. (JP BR 14; EXH 7, BSP K 169, K178) The Joint Parties acknowledged that the Company argued against the Joint Parties' conclusions, citing its new budgeting, governance, and asset management process improvement measures. (JP BR 14) While the Joint Parties accepts the implementation of these programs as useful for the future, it claimed that because the measures are untimely and cannot influence the accuracy of the capital budget, that they should not be used to justify the approval of the rate base in this case. (JP BR 14; TR 1577-1578, 1599, 1639) The Joint Parties based this assessment on the fact that the 2023 and 2024 budgets were established in the summer of 2022. At that time, the Company's new measures were still under development or not yet developed, and therefore can't provide cost controls for the test year. (JP BR 14; TR 1643, 1714-1716, 1725-1726, 1731-1732; EXH 179C; EXH 206) The Joint Parties used this line of reasoning to recommend a disallowance of $33.331 million of purely projected rate base from the test year, which yields an adjusted revenue requirement of $2.963 million in return on rate base and $905,000 in depreciation expense after gross-up. (JP BR 15; TR 1235)

## ANALYSIS

In its initial filing, PGS requested $3,308,320,402 for projected test year plant in service.[37] (EXH 7, BSP K169) PGS witness Parsons stated in her direct testimony that PGS applied the same accounting principles, methods, and practices that the Company employed for its historical data and the forecasted data for the 2024 projected test year to create the budget for 2024. (TR 1870) OPC witness Kollen declared in his testimony that the capital budget was created outside of the Company's normal course of business and is excessive considering the Company does not use all budgeted funds it has had approved in prior years for capital projects. (TR 1230-1232) In her rebuttal testimony, witness Parsons stated that the timing of the budget was different than previous years in order to meet the schedule of this rate case and to account for use of a forecasted test year. (TR 1939) Witness Parsons also noted that PGS has not used budgeted funds in prior years due to the impact of the COVID pandemic, which created unique and unprecedented operational changes. (TR 1940)

PGS maintained its stance that the budget is reasonable and prudent, and is needed to support customer growth, enhance customer service, and enhance the safety and reliability of its system. (TR 1912-1913; EXH 23, BSP D12-1006) Contrary to PGS, the Joint Parties maintained in its brief that PGS failed to capture all circumstances that might impact an underspend and failed to meet its burden of demonstrating that its projections are fully reliable. (JP BR 12-13)

The Company has requested test year cost-recovery for $362 million associated with capital projects. (EXH 23, BSP D12-1011) For all capital projects, staff requested detailed information that included the project need, project capital, and how the Company determined the project was the least-cost alternative. For the major expansion projects, such as the Sumterville-Dade City Connector, staff additionally requested the Company provide all alternatives considered and a detailed cost breakdown. (EXH 113-114) Upon reviewing the Company's responses, staff determined that PGS selected projects that were reasonable and the least-cost alternative when possible. Staff recommends approval of PGS's capital projects reflected in the projected test year.

However, fallout adjustments from other issues should be made to reduce projected test year plant in service. The stipulation in Issue 18 addresses the removal of the Alliance RNG project from the Company's request, but it only cites the total corresponding adjustment to revenue requirement. Based on a detailed breakdown of the cost components for the Alliance RNG

[37] The projected test year balance of plant in service, less the Company's adjustment to reflect Common Plant allocations.

project, the fallout adjustment to projected test year plant in service should be a reduction of $11,530,336. (EXH 128, BSP 10) Further, if the Commission approves staff's recommendation in Issue 42 to disallow recovery of the new Real Estate employee positions, the balance should be decreased by $314,216 to remove the capitalized salaries and benefits associated with the three positions. As in Issue 42, the total adjustment reflects the payroll and benefits data for each specific position. (EXH 139, BSP 27-01) In total, projected test year plant should be decreased by $11,844,552. As such, the appropriate level of projected test year plant in service should be $3,296,475,850.

## CONCLUSION

Based on the stipulation in Issue 18 and staff's recommendation in Issue 42, staff recommends that projected test year plant in service be reduced by $11,844,552. As such, the appropriate level of projected test year plant in service should be $3,296,475,850.

***Issue 22:*** What level of projected test year plant accumulated depreciation and amortization should be approved?

***Recommendation:*** Based on the stipulations in Issues 5 and 18 and staff's recommendation in Issues 7 and 50, projected test year accumulated depreciation and amortization should be decreased by $258,577. As such, the appropriate level of projected test year accumulated depreciation and amortization should be $922,567,707. (Andrews, Wu)

### *Position of the Parties*

**PGS:** This fallout issue depends on the outcome of the other rate base and depreciation issues. The Company's five adjustments to accumulated depreciation reflected in its revised net revenue requirement increase are reflected in Exhibit 218.

**Joint Parties:** The Commission should approve $904,439,158 of projected test year accumulated depreciation and amortization.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated that it has made five adjustments to accumulated depreciation that are reflected in its revised net revenue requirement increase, but the level of projected test year plant accumulated depreciation and amortization depends on the outcome of the other rate base and depreciation issues. (PGS BR 19; EXH 218, BSP G1-250 – G1-251)

### Joint Parties

The Joint Parties stated that the resolution of this issue is dependent upon the Commission's decision regarding Issue 21. (JP BR 15)

## ANALYSIS

This is a fallout issue. Based on a detailed breakdown of the cost components for the Brightmark and Alliance RNG projects, the fallout adjustments to the stipulations in Issues 5 and 18 should be an increase of $477,092 for the accelerated depreciation of Brightmark assets and a reduction of $507,203 for the removal of Alliance. (EXH 128, BSP 10) Based on staff's recommendation in Issues 7 and 50 regarding the Company's updated Depreciation Study and corrections to the New River RNG project depreciation, fallout adjustments should be made to decrease the projected test year balance by $127,147 and $101,319, respectively. In total, projected test year accumulated depreciation and amortization should be decreased by $258,577. As such, the appropriate level of projected test year accumulated depreciation and amortization in service should be $922,567,707.

## CONCLUSION

Based on the stipulations in Issues 5 and 18 and staff's recommendation in Issues 7 and 50, projected test year accumulated depreciation and amortization should be decreased by $258,577. As such, the appropriate level of projected test year accumulated depreciation and amortization should be $922,567,707.

***Issue 23:*** What level of projected test year Construction Work in Progress (CWIP) should be approved?

***Recommendation:*** Based on staff's recommendation in Issue 49, projected test year CWIP should be increased by $2,125,283. As such, the appropriate level of projected test year CWIP is $26,434,732. (Andrews)

### *Position of the Parties*

**PGS:** The appropriate projected test year CWIP should be $24,309,448 as shown on MFR Schedule G-1, page 1, line 2.

**Joint Parties:** The level of CWIP to be approved may be dependent upon the resolution of Issue 21 and the ultimate decision on the level of plant in service as it is affected by the accuracy of the PGS's budget process. PGS has not adequately demonstrated that the level of CWIP is justified based on the deficiencies in the budgets for 2023 and 2024 that were prepared in 2022.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated that, as shown in Issue 21, the Company budgeting process is reliable and CWIP should not be adjusted according to the Joint Parties' proposal. (PGS BR 20; TR 1868-69, 1910-1917) PGS claimed that due to the Company updating its 2023 budget and reflecting this in its 2024 budget, the Joint Parties' use of budgeted amounts of CWIP for 2021 is misplaced. (PGS BR 20; TR 2039) PGS acknowledged that actual CWIP for 2022 varied from the budget primarily due to large projects that accrued AFUDC; however, the Company explained that the CWIP variances created by these projects would not affect rate base or CWIP. (PGS BR 20; TR 1917, 2040) Furthermore, the Company asserted that it exceeded its 2022 budget and expects to spend its capital budget for 2023, and believes the test year CWIP balance should not be adjusted. (PGS BR 20; TR 1837)

### Joint Parties

The Joint Parties stated that the resolution of this issue is dependent upon the Commission's decision regarding Issue 21. (JP BR 15)

## ANALYSIS

This is a fallout issue. In Issue 21, staff is not recommending any adjustments to the projected test year associated with the budgeted level of capital expenditures. As such, staff does not recommend any related adjustments to CWIP.

As discussed in Issue 49, staff is recommending an adjustment to decrease O&M expenses by $2,125,283 to increase the amount of A&G expense being capitalized. OPC witness Kollen proposed the A&G expense adjustment in his testimony, but he did not recognize the corresponding increase in rate base that would result in the capitalization of additional expense.

PGS witness Parsons testified that if the Commission made an adjustment to increase the capitalization of A&G, it should also increase rate base. (TR 2072) Further, OPC witness Kollen testified that once the A&G credit is then capitalized to relevant construction projects, it is included in CWIP before being included in plant in service. (TR 1245) As such, staff believes an adjustment to CWIP is an appropriate method to reflect the corresponding increase to rate base. Therefore, based on staff's recommendation in Issue 49 to increase the transfer of A&G expense, projected test year CWIP should be increased by $2,125,283. The appropriate level of projected test year CWIP should be $26,434,732.

## CONCLUSION

Based on staff's recommendation in Issue 49, projected test year CWIP should be increased by $2,125,283. As such, the appropriate level of projected test year CWIP should be $26,434,732.

***Issue 24:*** Has PGS made the proper adjustments to the Working Capital Allowance to reflect under recoveries and over recoveries in the projected test year related to the Purchased Gas Adjustment, Energy Conservation Cost Recovery, and CI/BSR? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes. The Company has made the proper adjustments to the Working Capital Allowance to reflect under recoveries and over recoveries in the projected test year related to the Purchased Gas Adjustment, Energy Conservation Cost Recovery, and CI/BSR as shown in MFR Schedule G-1, pages 2 and 3.

***Issue 25:*** What amount of projected test year unamortized rate case expense should be included in working capital?

***Approved Type 1 Stipulation:*** None. The Company did not include unamortized rate case expense in working capital for the 2024 projected test year.

***Issue 26:*** What level of projected test year working capital should be approved?

***Approved Type 2 Stipulation:*** The appropriate amount of projected test year working capital is a negative $28,047,011 as shown on MFR Schedule G-1, page 1, line 11.

***Issue 27:*** What level of projected test year rate base should be approved?

***Recommendation:*** The appropriate level of projected test year rate base should be $2,357,327,760. (Hinson)

### *Position of the Parties*

**PGS:** The appropriate amount of projected test year rate base is $2,355,546,414. This amount reflects the $2,366,788,452 of adjusted rate base shown on MFR Schedule G-1, page 1, and the $288,298 adjustment included in Issue 22 to decrease accumulated depreciation and amortization and the removal of the Alliance project plant in service of 11,530,336 in Issue 21.

**Joint Parties:** The Commission should approve no more than $2,346,211,000 of projected test year rate base.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that the Joint Parties' proposal to increase the allocation of administrative and general ("A&G") expenses to rate base should be rejected, as PGS has shown its allocation of A&G expenses are reasonable. (PGS BR 20; TR 2072) PGS recommended using the Company's revised proposed rate base of $2,355,546,414, unless the Commission accepts the Joint Parties' proposal on Issue 49, in which case a corresponding increase to rate base should be made to reflect the increase of allocated A&G expense. (PGS BR 20; TR 2072; EXH 218, BSP G1-250 – G1-251)

### Joint Parties

The Joint Parties stated that the resolution of this issue is dependent upon the Commission's decision regarding Issues 21, 49, and 57. (JP BR 15)

## ANALYSIS

This is a fallout issue of Issues 21, 22, 23, and 26, which address the projected test year balance of each rate base component. Based on the stipulation of Working Capital in Issue 26 and staff's recommended adjustments to the projected test year balances of plant in service, accumulated depreciation and amortization, and CWIP in Issues 21, 22, and 23, respectively, the appropriate level of rate base for the projected test year should be $2,357,327,760.

## CONCLUSION

The appropriate level of projected test year rate base should be $2,357,327,760.

***Issue 28:*** What amount of projected accumulated deferred taxes should be approved for the projected test year capital structure?

***Recommendation:*** The amount of accumulated deferred taxes to be included in the projected test year capital structure should be $277,551,630. (Zaslow)

### *Position of the Parties*

**PGS:** The amount of accumulated deferred taxes to be included in the capital structure for the projected test year is $279,720,428.

**Joint Parties:** The Commission should approve at least $286,705,000 in accumulated deferred taxes for the projected test year capital structure.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS witness Parsons argued the amount of accumulated deferred income taxes (ADITs) to include in the capital structure is $279,720,428. (PGS BR 21) This reflects three adjustments to the $280,240,209 amount shown on MFR Schedule G-3, page 2. (EXH 7, BSP K278) The first adjustment ($4,486 decrease) was related to changes in accumulated depreciation, as discussed in Issue 22. The second adjustment was to remove the deferred taxes associated with the Alliance Dairies RNG project, as discussed in Issue 18 ($489,300 decrease). The third adjustment was for the decrease in rate base discussed in Issue 27, allocated pro rata over all sources of capital ($25,995 decrease). (PGS BR 21)

### Joint Parties

OPC witness Kollen argued that the correct amount of ADITs to include in the capital structure is $286,705,000. (JP BR 15-16) This is the result of witness Kollen's recommendation of $904,439,158 for accumulated deprecation and amortization (see Issue 22), which corresponds to an increase of $6,464,791 in ADITs when reconciled to the capital structure pro rata over all sources of capital. (JP BR 15-16; TR 1270)

## ANALYSIS

PGS's and the Joint Parties' recommended amount of ADITs in the projected test year capital structure differs slightly. PGS requested a total ADITs balance of $280,240,209 to include in the projected test year capital structure, which is presented on MFR Schedule G-3, page 2. (EXH 7, BSP K278) PGS witness Parsons subsequently made three adjustments to PGS's as-filed request. The first adjustment was a $4,486 decrease of deferred taxes related to the Company's proposed net adjustment in accumulated depreciation (see Issue 22). (PGS BR 21) The second adjustment is to remove the deferred taxes associated with Alliance Dairies RNG project, a $489,300 decrease (see Issue 18). (PGS BR 21) The third adjustment was a $25,995 decrease to deferred taxes related to the removal of the Alliance Dairies RNG project plant in service (see Issue 27). (PGS BR 21) The end result is a final requested ADITs balance of $279,720,428. OPC witness

Kollen recommended a total ADITs balance of $286,705,000. (TR 1271) The difference in the Joint Parties' recommended amount arises from witness Kollen's recommendation to change depreciation expenses. This results in a $6,464,791 increase in ADIT's as well as a $532,000 decrease to the base revenue requirement. (JP BR 15-16)

There is no difference in opinion between PGS and the Joint Parties with regard to the effects of the stipulation on Issue 18 regarding the Alliance Dairies RNG project, which resulted in a $489,300 decrease in ADITs. (PGS BR 21; JP BR 15-16) In Issue 27, staff is recommending total rate base amount of $2,357,327,760. When this amount is reconciled pro rata over all sources, excluding customer deposits, to staff's recommended capital structure, the corresponding amount of ADITs based on a ratio of 11.77 percent (see Issue 36) should be $277,551,630.

## CONCLUSION

For the aforementioned reasons, staff recommends the appropriate amount of ADITs to include in the projected test year capital structure should be $277,551,630.

***Issue 29:*** What cost rate should be approved for the unamortized investment tax credits for the projected test year capital structure?

***Recommendation:*** Due to the removal of the Alliance Dairies RNG project from rate base, PGS does not have any unamortized investment tax credits in the projected test year capital structure. However, the appropriate cost rate for unamortized investment tax credits for the projected test year capital structure should be 8.03 percent. (Zaslow)

***Position of the Parties***

**PGS:** The cost rate of the unamortized investment tax credits to include in the projected test year capital structure is 8.49 percent, as shown on MFR Schedule G-3, page 2, line 6.

**Joint Parties:** The Commission should approve $3.157 million at a 6.73% cost rate for the unamortized investment tax credits in the projected test year.

## PARTIES' ARGUMENTS

### PGS

PGS witness Parsons argued that because the Alliance Dairies RNG project will be moved below the line (see Issue 18) that there will be no unamortized investment tax credits (ITCs) in the projected test year capital structure, and therefore the issue is essentially moot. (PGS BR 21)

### Joint Parties

OPC witness Kollen stated that all the applicable Joint Parties adjustments that affect the cost rate of unamortized ITCs are appropriate, and result in cost rate for the test year of 6.73 percent. (JP BR 16; TR 1271)

## ANALYSIS

This is a fallout issue. The appropriate cost rate for unamortized ITCs is determined by the jurisdictional capital structure and associated cost rates of long-term debt, short-term debt, and common equity. Based on staff recommendations in Issues 31, 32, 35, and 36, the cost rate of the unamortized ITCs is calculated using the sum of the weighted average cost of the appropriate jurisdictional capital structure and cost rates of long-term debt, short-term debt, and common equity, as shown in Table 29-1.

**Table 29-1**
**Projected Test Year Investment Tax Credits Component Cost**

| Capital Component | Jurisdictional Adjusted Capital | Capital Ratio | Component Costs | Weighted Average Cost |
|---|---|---|---|---|
| **Long-Term Debt** | $830,722,209 | 40.48% | 5.54% | 2.24% |
| **Short-Term Debt** | $99,496,189 | 4.85% | 4.85% | 0.24% |
| **Common Equity** | $1,122,029,733 | 54.67% | 10.15% | 5.55% |
| **Total** | $2,052,248,131 | | | 8.03% |

Source: Staff recommendations in Issue 36

Staff notes that when PGS filed its petition, the ITCs for the projected test year capital structure included the Alliance Dairies RNG project. Due to fallout from Issue 18, that project has been moved outside of rate base, meaning that the basis for including the associated ITCs in the projected test year capital structure is no longer applicable. This means that the dollar amount of the ITCs should be zero for the projected test year capital structure.

## CONCLUSION

Due to fallout from Issue 18, there should not be any unamortized ITCs included in the projected test year capital structure. However, the appropriate cost rate for unamortized ITCs for the projected test year capital structure should be 8.03 percent.

***Issue 30:*** What amount and cost rate for customer deposits should be approved for the projected test year capital structure?

***Approved Type 1 Stipulation:*** The amount of customer deposits for the 2024 projected test year is $27,528,000. The cost rate of the customer deposits to include in the projected test year capital structure is 2.53 percent, as shown on MFR Schedule G-3, page 2, line 4.

***Issue 31:*** What cost rate of short-term debt should be approved for the projected test year capital structure?

***Recommendation:*** The appropriate cost rate short-term debt of the projected test year capital structure should be 4.85 percent. (Zaslow)

### *Position of the Parties*

**PGS:** The appropriate amount of short-term debt for the projected test year is $99,662,408, and the cost rate is 4.85 percent.

**Joint Parties:** The Commission should approve a 3.81 percent cost rate for short-term debt for the projected test year.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued the appropriate cost rate for short-term debt for inclusion in the projected test year capital structure is 4.85 percent as shown on MFR G-3, page 4. (PGS BR 21-22; TR 1917; EXH 7, BSP K278) PGS witness McOnie argued that the cost rate reflects PGS's forecasted short-term interest expense on a stand-alone basis on its credit quality (TR 1123), witness McOnie testified that the short-term debt cost rate is based upon on the Secured Overnight Financing Rate (SOFR) plus credit spreads and program fees. (PGS BR 21-22; TR 1117) Witness McOnie contended that the short-term debt cost rate in PGS's 2020 rate case, approved by the Commission in the 2020 Agreement, was 1.15 percent.[38] (TR 1118) Witness McOnie argued that since 2020, the underlying overnight borrowing rate increased by approximately 425 basis points. This is a result of the U.S. Federal Reserve increasing the overnight borrowing rate. This is the main cause for the rise in short-term borrowing costs. (PGS BR 22; TR 1118) Witness McOnie further argued that the Commission has consistently allowed utilities to recover the short-term debt costs for the projected test year through base rates, and should not reverse this precedent. (PGS BR 22; TR 1127) Witness McOnie claimed that a departure from past precedents by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and the Company's ability to generate cash flow. (PGS BR 22; TR 1131)

### Joint Parties

OPC witness Kollen argued that PGS is not entitled to recover its predicted market-based cost rate of 4.85 percent for short-term debt. (JP BR 16-17; TR 1229-1230) Witness Kollen further argued that the Commission should set PGS's cost of short-term debt at 3.81 percent to retain the lower cost debt previously allocated to the Company when it was a subsidiary of TECO and to shift new costs resulting from the 2023 Transaction away from customer rates, as further discussed in issue 72. (JP BR 16-17; TR 1229-1230) Additionally referring to PGS's requested

[38] Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System.*

Private Letter Ruling (PLR) from the Internal Revenue Service (IRS) regarding the 2023 Transaction, witness Kollen argued the Commission is not required to recognize the higher cost of the new debt for ratemaking purposes, regardless of the structure of the 2023 Transaction and the PLR from the IRS.[39] (TR 1229; TR 108-109) Witness Kollen argued that the IRS has no statutory authority, nor does the PLR itself direct the Commission, to provide recovery of the Company's requested cost of debt. (TR 1229) The Joint Parties noted that the last forecasted earnings surveillance report (ESR) for the consolidated PGS and Tampa Electric operations ending December 31, 2022 (submitted February 28, 2022) showed a 0.39 percent cost for short-term debt. (EXH 196, BSP G2-1110)

## ANALYSIS

OPC witness Kollen did not provide any specific arguments regarding the appropriateness of PGS's proposed cost rate for short-term debt of 4.85 percent. Rather, witness Kollen argued that because the separation of PGS from TECO will result in higher costs to PGS customers, the Commission should approve a lower cost of debt to shift the effects from the 2023 Transaction away from customer rates. (TR 1229) The amount witness Kollen used to quantify the additional costs to customers from the 2023 Transaction was about $8.9 million, and was determined from PGS's response to discovery. (EXH 133, BSP F6932 – F6933) The Joint Parties argued that the Commission should set the Company's cost of short-term debt below the market-based cost for PGS's projected test year. (TR 1229) Witness Kollen recommended a cost rate for short-term debt of 3.81 percent, combined with his recommended cost rate for long-term debt, which together would reduce the revenue requirement by $8.895 million and nullify the increased costs to customers resulting from the 2023 Transaction. (TR 1230, 1271)

PGS witness McOnie explained, and staff agrees, that the Commission has consistently accepted that short-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. (TR 1129-1130) Staff notes that in rate cases with a projected test year, as is the case here, it is common practice for a utility to estimate debt cost rates for prospective debt issuances and calculate the cost of short-term and long-term debt accordingly.[40] Witness McOnie contended that a departure from past precedent by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability. (TR 1131)

Staff reviewed the Joint Parties' reference to PGS's earnings surveillance report short-term debt cost rate of 0.39 percent, and notes that the referenced ESR is a forecast for the 2022 year that was submitted February 28, 2022. (JP BR 17; EXH 196, BSP G2-1106) This was before the U.S. Federal Reserve increased the overnight borrowing rate, and thus the cited ESR could not take this factor into consideration. Further, PGS's historic base year cost rate for short-term debt (ending December 31, 2023) is 4.22 percent (as seen in MFR Schedule G-3, page 1 of 11) and reflects the changes to overnight borrowing rates not reflected in the Joint Parties' cited source.

[39]A private letter ruling, or PLR, is a statement by the IRS that interprets tax law at the request of a taxpayer (TR 108–109).

[40]Order No. PSC-10-0153-FOF-EI, issued March 17, 2020, *In re: Petition for increase in rates by Florida Power & Light Company*, p. 109-110, Order No. PSC-10-0029-PAA-GU, issued January 14, 2010, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation*, p. 10.

(EXH 7, BSP K277). Staff further notes that short-term debt is, by definition, for a period of one year or less. Therefore, using a cost rate from previous years is inappropriate.

Staff notes that most of the Joint Parties' arguments in this issue relate to the 2023 Transaction's effect on PGS's projected cost rate for its short-term debt which are mostly identical to their arguments in Issue 32 for PGS's projected cost rate for long-term debt. Therefore, staff will address the Joint Parties' arguments related to the 2023 Transaction in Issues 32 and 72.

## CONCLUSION

Staff reviewed PGS's estimate for the projected test year short-term debt cost rate, which is based on the SOFR plus credit spreads and program fees, and believes PGS's estimate to be reasonable. (EXH 112C; TR 1117) With this in mind, and additionally taking into consideration that the Joint Parties did not provide any specific arguments as to the market-based appropriateness of PGS's proposed short-term debt cost rate, staff agrees with PGS. Staff recommends the Commission approve a cost rate for short-term debt of 4.85 percent for the projected test year capital structure.

***Issue 32:*** What cost rate of long-term debt should be approved for the projected test year capital structure?

***Recommendation:*** The appropriate cost rate of long-term debt for the projected test year capital structure is 5.54 percent. (D. Buys)

### *Position of the Parties*

**PGS:** The appropriate amount of long-term debt for the projected test year is $827,335,811 and the cost rate is 5.54 percent and is shown on MFR G-3, page 3.

**Joint Parties:** The Commission should approve a 4.61 percent cost rate for long-term debt for the projected test year.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that OPC did not present testimony contesting the Company's forecasted long-term debt cost rate, but proposed that the incremental borrowing expenses attributable to the 2023 Transaction be disallowed. (PGS BR 22) PGS addressed that proposal in Issue 72. PGS argued its proposed 5.54 percent long-term debt rate reflects the Company's forecasted long-term debt borrowing costs on a stand-alone basis, reflecting forecasted market conditions and the Company's credit quality. (PGS BR 22; TR 1119-1120) PGS explained the Company plans to issue $825 million of long-term debt in three tranches with differing terms to mitigate the long-term costs of debt and refinancing risks. (PGS BR 23; TR 1120-22) PGS estimated its cost rates based on underlying U.S. Treasury rates sourced by Bloomberg, plus a forecasted spread for a typical gas distribution company with a BBB+ credit rating. (PGS BR 23; TR 1120; EXH 21, BSP D10-699) PGS argued that the increase in long-term interest rates since the Company's last base rate proceeding is attributable to the efforts of the Federal Reserve to combat inflation by increasing its overnight borrowing rate. (PGS BR 23; TR 1120-1121; EXH 21, BSP D10-700) PGS asserted that the Commission has consistently concluded that utilities should recover their projected debt costs through base rates and a departure from this practice would negatively impact rating agency assessments of the Company's regulatory environment and cash flow generating ability. (PGS BR 23; TR 1129-1131) PGS confirmed the Company is in the process of obtaining an independent, standalone credit rating and is making progress toward that goal. (PGS BR 23; TR 1113-1120) PGS argued the Company's proposed amount of long-term debt for the test year reflects the $832,185,531 of long-term debt on MFR G-3, page 2, adjusted for the decrease in rate base in Issue 27, and increased for a pro-rata allocation over investor sources of capital offset for change in accumulated deferred income taxes in Issue 28. (PGS BR 23; EXH 137, BSP F7047)

### Joint Parties

The Joint Parties argued that PGS's customers will have to pay a higher rate for long-term debt than they otherwise would have if the 2023 Transaction had not occurred. (JP BR 18; TR 1229) The Joint Parties argued the 2023 Transaction requires PGS to issue new and significantly higher cost of debt to "repay" the entirety of its share of long-term debt acquired by TECO. (JP BR 18; TR 1111-1112, 1225) PGS's requirement to "repay" the debt is due to the Intracompany Debt Agreement (IDA) that needs to be paid back by December 31, 2023, to avoid a potential tax liability of $150 million. (JP BR 18) The Joint Parties argued this harms PGS's customers for the foreseeable future and will permanently increase PGS's cost structure until all new debt fully matures 30 years from now. (JP BR 18) In addition, the Joint Parties argued the effect of paying off the IDA at a blended cost rate of 5.57 percent results in an increase in the overall weighted cost of debt of 29 basis points and an increase in revenue requirement of approximately $7.1 million. (JP BR 18; EXH 198, BSP G2-1125) The Joint Parties argued that the reallocation of lower-cost legacy debt from PGS to TECO for ratemaking purposes, which is replaced with higher cost debt, is a subsidization by PGS customers for the benefit of TECO customers. (JP BR 18; TR 1126-1129) The Joint Parties argued that PGS will incur additional costs, i.e., independent audit fees and credit rating agency fees, associated with issuing its own debt that it did not incur while a division of TECO. (JP BR 18; TR 1127-1128) The Joint Parties argued that the consolidated surveillance report for PGS and TECO for December 2022 shows a 3.81 percent cost rate for long-term debt. (JP BR 196; EXH, BSP G2-1110)

In its brief for Issue 36, the Joint Parties argued that although PGS witness McOnie asserted that PGS's capital structure and ROE are two of the key variables that rating agencies consider when reviewing a utility's debt level and cash flow as part of the rating agencies' process to assign a credit rating, he ignored the impact the 2023 Transaction would have on PGS's financial strength and access to capital. (JP BR 27) The Joint Parties argued that PGS would have a credit rating of BBB+ if it was still a division of TECO, but the 2023 Transaction will likely cause a one notch lower credit rating for PGS. (JP BR 27-28) The Joint Parties also argued that all three credit rating agencies have reduced TECO's credit rating outlook from stable to negative as a result of the spin-off of PGS. (JP BR 27-28) Further, the Joint Parties argued PGS plans to use the private placement market to purchase its debt capital will cost more than accessing debt capital in the public market through TECO. (JP BR 28) The Joint Parties argued the impact of the Company's decision to undertake the 2023 Transaction is to increase financing costs to customers. (JP BR 28) The Joint Parties recommended that the Commission should approve a cost rate of 4.61 percent to retain the savings from the lower-cost debt previously allocated to it, regardless of the Company's actual cost of the new debt issued to replace the former allocation. (JP BR 19; TR 1229)

## ANALYSIS

According to PGS, as a result of the 2023 Transaction, PGS must begin securing its own debt capital by borrowing from lenders and pay off the Intercompany Debt Agreement (IDA) with TECO by December 31, 2023, so the PGS spin-off will be considered a non-taxable asset transfer for Federal income tax purposes. (TR 1112) Failure by PGS to pay off the IDA would create a potential Federal income tax liability of $150 million for PGS and its customers. (TR 167; EXH 162) The Joint Parties did not refute PGS's position on the potential tax liability, but rather argued that PGS should not have structured the 2023 Transaction in the manner it did. (TR 1228-1229) The 2023 Transaction requires PGS to issue its own debt by December 31, 2023, pursuant to the terms of the IDA between TECO and PGS. (TR 1225) Prior to the 2023 Transaction, TECO issued all long-term debt and short-term debt sufficient to meet the debt financing requirements for both its electric business and its PGS gas division. (TR 1225) The debt then was allocated between the electric business and the PGS division based on the respective financing requirements for each year. (TR 1225) The 2023 Transaction ended this relationship and prospectively reallocates the existing long-term debt originally issued by TECO on behalf of PGS back to TECO. (TR 1225)

Both the Joint Parties and PGS agree that the 2023 Transaction increased PGS's long-term debt cost for the 2024 projected test year. (TR 1222, 1114) PGS estimated the impact of the 2023 Transaction will increase the cost of long-term debt from 3.97 percent in 2022 to 5.54 percent in 2024. (TR 1114) PGS has not quantified any short-term financial benefits from the 2023 Transaction. (TR 110, 169) However, PGS witness Wesley explained the 2023 Transaction provides long-term benefits by isolating PGS from potential incidents (natural disasters or detrimental business issues not related to PGs) that could impair TECO's ability to provide capital to PGS. (TR 111)

Joint Parties did not contest PGS's forecasted long-term debt cost rate of 5.54 percent. OPC witness Garrett did not specifically address the long-term debt cost rate in his testimony, and he used PGS's proposed cost of long-term debt of 5.54 percent in his recommended authorized rate of return for PGS. (TR 966) Instead, the Joint Parties argued that the Commission should set PGS long-term debt rate at 4.61 to recognize the historical debt that was allocated from TECO when PGS was a division of TECO. (TR 1229-1230) Witness Kollen asserted the effect of the Joint Parties' recommendation is a $8.895 million reduction in revenue requirement for long-term and short-term debt combined. (TR 1223, 1230)

In its brief, the Joint Parties cited to an earnings surveillance report (ESR) for the consolidated PGS and TECO operations for December 31, 2022, and argued it showed a long-term debt cost rate of 3.81 percent. (JP BR 18-19; EXH 196, BSP G2-1110). Staff reviewed the document and notes that the referenced ESR is a forecasted ESR that was submitted on February 28, 2022. Staff notes that this was before the U.S. Federal Reserve Board increased interest rates, and thus, the cited forecast, at that time, could not have taken this factor into consideration. Staff further notes that PGS's historic base year cost rate for long-term debt (ending December 31, 2023) is 4.58 percent (as seen in MFR Schedule G-3, page 1 of 11) and reflects the changes to interest rates not reflected in the Joint Parties' cited source. (EXH 7, BSP K277)

As shown on MFR Schedule G-3, page 8, the long-term debt cost rate of 5.54 percent is based on forecasted debt issuances of $825 million during 2023 and $100 million in 2024. (TR 1120; EXH 7, BSP K284) PGS witness McOnie testified the $825 million inaugural debt issuance during 2023 is forecasted to occur using three tranches of differing terms; $325 million of 5-year notes at 5.40 percent, $300 million of 10-year notes at 5.47 percent, and $200 million of 30-year notes at 6.00 percent. (TR 1119; EXH 7, BSP K284) Witness McOnie explained the Company cannot predict the specific time of year this will occur, but the Company budgeted the 2023 issuance to occur on September 30, 2023. (TR 1119) Evidently, the issuance date will be later than September 30, 2023, as explained by witness McOnie, possibly in late October, November or December. (TR 1164-1165) However, the 2024 issuance still assumes a June 30, 2024, financing date for $100 million of 10-year notes at 5.37 percent. (TR 1119) The embedded cost of long-term debt as a result of combining the four tranches of debt issuances is 5.54 percent as shown on MFR Schedule G-3, page 3. (EXH 7, BSP K279).

PGS intends to engage credit rating agencies in 2023 to assess the stand-alone credit rating of PGS and assign an indicative credit rating[41] as part of the rating evaluation service provided by the rating agencies. (TR 1113) Witness McOnie explained the rating agencies will assess the outcome of the instant rate case in addition to other business and financial risk assessments and provide a final credit rating. (TR 1113) PGS is targeting a credit rating of BBB+, which is two notches above the minimum investment grade rating of BBB-. (TR 1113, 1180)

In its brief for Issue 36, the Joint Parties argued that as a result of the 2023 Transaction, TECO's credit rating outlook from all three rating agencies changed from stable to negative. (JP BR 27-28) In its brief, the Joint Parties asserted that in September 30, 2022, TECO had a BBB+ credit rating from S&P, A3 from Moody's, and A from Fitch, with a stable outlook. In the December 31, 2022 TECO 10-K, the potential business risk related to the $150 million potential tax liability as of January 1, 2023, related to the spin-off of PGS was addressed. TECO's credit rating outlook changed to negative in December 2022 for all three rating agencies. The credit agencies' outlook continued to remain negative for TECO as of June 30, 2023. (JP BR 27-28; TR 1144-1147; EXH 192 BSP G2-873; EXH 193, BSP G2-876) However, witness McOnie explained the negative outlook will continue to be the case for a twelve-to-eighteen-month period. (TR 1147) Witness McOnie also explained the reason for the negative outlook:

> Tampa Electric is part of the Emera family of companies. Emera was placed on negative outlook due to the legislative action in Nova Scotia that pertained to Bill 212, I believe, that capped Nova Scotia Power rates rate increase at 1.8 percent per filed document. Each of the rating agencies viewed the political interference extremely negative to the regulatory process. In addition to that, the credit metrics were down from the higher gas prices at Tampa Electric, and there was an under-recovery period during -- leading into the end of 2022. So, these two factors combined, along with the delay in cash flows from the Labrador Island link, caused each of the rating agencies to place Emera on negative outlook. Because Tampa Electric is one of our group of families, its rating agency practice is to put the entire group on negative outlook.

(TR 1149-1150)

According to witness McOnie, the main drivers for the increase in the long-term cost of debt in the 2024 test year is the increase in the U.S. Treasury Bond rates. (TR 1120) PGS's requested cost rate for its newly issued long-term debt is based on the prevailing yield on U.S. Treasury Bonds plus an additional credit risk spread associated with a BBB+ credit rating. (TR 1119-1120) Witness McOnie's direct testimony filed on April 2, 2023, indicated the forecasted rate for 30-year U.S. Treasury Bonds was 3.89 percent and 3.76 percent for the third and fourth quarters of 2023, respectively. (EXH 21, D10-699) During cross examination, OPC witness Garrett confirmed that as of September 13, 2023, the yield on 30-year U.S. Treasury Bonds was 4.34 percent. (TR 1077) Witness McOnie explained the Federal Reserve's decision to increase

[41]An indicative credit rating is one that is unpublished and confidential which reflects the analysis of one or more hypothetical scenarios for a company.

interest rates to mitigate inflation caused short-term interest rates to increase more than long-term interest rates which is commonly referred to as an inverted yield curve. (TR 1121) That is, short-term debt is more costly than long-term debt. (TR 1121) However, the interest rates for 30-year U.S. Treasury Bonds have remained anchored to approximately 4.00 percent due to expectations that the economy will slow down in the future. (TR 1121-1122)

Staff agrees with witness McOnie that issuing three tranches of debt for terms of five, ten and thirty years would be prudent and mitigate refinancing risk. (TR 1122) Issuing a 30-year note would mitigate the risk of continued rising interest rates because the prevailing rate on 30-year U.S. Treasury Bonds is in line with its long-term average yield of 4.46 percent. (TR 1122; EXH 21, BSP D10-700) The 5-year and 10-year notes should afford PGS the opportunity to refinance at short-term interest rates that are more reflective of their 30-year averages of 3.38 percent and 3.90 percent, respectively. (TR 1122; EXH 21, BSP D10-700) Currently, short-term debt cost rates are much higher than their historical averages. (EXH 21)

PGS proposed an additional adjustment to ensure the accuracy of its long-term debt cost rate. Because the long-term debt cost rate is prospective and based on assumed debt issuances by PGS that have yet occurred, PGS proposed a long-term debt true-up mechanism that is discussed in Issue 71. (TR 1122) PGS believes the long-term debt true-up mechanism will provide a fair one-time adjustment to base rates reflecting the actual long-term debt cost achieved in 2023. (TR 1122)

OPC witness Kollen recommended the Commission should approve a long-term debt cost rate of 4.61 percent. (TR 1271) Witness Kollen obtained his recommended long-term debt cost rate from PGS's discovery response to OPC's First Set of Interrogatories, No. 100, wherein the Company quantified the effect of the legal separation of PGS from TECO. (TR 1271, EXH 133, Attachment 16, BSP 385) The long-term debt cost rate of 4.61 percent was derived from a blended rate of 4.04 percent for the historical debt issued by TECO on behalf of PGS and a forecasted cost rate of 5.64 percent and 5.54 percent for two new issuances of long-term debt. (EXH 133, Attachment 16, BSP 385)

OPC witness Kollen asserted that Emera structured the 2023 Transaction, including the Intercompany Debt Agreement, for its benefit and that it will harm PGS customers. (TR 1129) The Joint Parties argued that the structure of the 2023 Transaction and the consequences of its implementation will deny PGS of the benefits of the lower-cost, historical debt that had been issued specifically to PGS to meet its financing requirements. (TR 1225) Witness Kollen contended the reallocation of the historical lower-cost, long-term debt from PGS back to TECO benefits TECO's customers and, is in essence, a subsidy from PGS to TECO in the amount of $7.1 million annually until TECO's base rates are reset in its next rate case sometime in 2025. (TR 1226, 1228) Further, witness Kollen asserted PGS failed to explain why it did not consider a separate intercompany loan from TECO to PGS that would preserve the historical lower-cost debt beyond 2023. (TR 1227)

Witness McOnie disagreed with witness Kollen's assertion and explained the Company evaluated whether to continue the historical borrowing arrangement between the two utilities or preserve the allocation of lower-cost, long-term debt to PGS as part of the 2023 Transaction, but decided that entering into an IDA along with PGS issuing its own short-term and long-term debt to repay the IDA in 2023 and fund future capital needs was the best long-term solution for PGS and its customers. (TR 1127-1128) PGS argued that the objective of the 2023 Transaction was to insulate PGS from TECO from the contagion risk[42] of the other respective affiliates through legal, operating, and financial structures. (TR 1133-1134) Witness McOnie explained that PGS has implemented organizational changes to structurally isolate itself from its TECO affiliate through its own separate management team, separate accounting records, and adheres to arm's length transaction protocols when doing business with affiliates. (TR 1134) Further, Emera decided that PGS establishing its own borrowing arrangement and ceasing its reliance on TECO as a creditor and source of capital was the best way to achieve bankruptcy remoteness.[43] (TR 1134)

On rebuttal, witness McOnie testified the Commission has a long history of allowing utilities to recover their projected long-term and short-term borrowing costs through customer rates, and the Commission should not depart from this practice in this case. (TR 1129) Witness McOnie explained that the Commission has consistently accepted that long-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. (TR 1129-1130) Staff notes that in rate cases with projected test years, as is the case here, it is common practice for the utility to estimate debt cost rates for prospective debt issuances and calculate the cost of long-term debt accordingly.[44] Witness McOnie contended that a departure from past precedent by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability respectively. (TR 1131) As pointed out by witness McOnie, since the forecasted long-term borrowing costs are market-based, and reflect actual interest obligations, a disallowance of the recovery of the full interest expense amount could potentially be considered unconstructive by rating agencies. (TR 1131)

PGS witness McOnie rebutted Joint Parties' argument that the 2023 Transaction results in a subsidy in favor of TECO and its customers and asserted that to the extent that the 2023 Transaction benefits TECO and its customers in the short term, the Joint Parties should also recognize that TECO's historical practice of borrowing on behalf of PGS benefitted PGS's customers through lower interest rates and avoided stand-alone expenses such as independent audit and credit rating agency fees. (TR 1127) Witness McOnie asserted that except for interest rate differences associated with different credit ratings, PGS and TECO will over time borrow at approximately the same interest rates, because the long-term debt issued at historically low interest rates and enjoyed by the customers of both utilities will over time be replaced with new debt at the then current market rates. (TR 1128)

Staff believes the Joint Parties' argument for the Commission to set PGS's cost of long-term debt below it's actual forecasted market-based cost is not persuasive and there is no evidence in the

[42]Contagion risk is the spread of financial difficulties or economic crisis between affiliates.
[43]Bankruptcy remoteness is a company within a corporate group whose bankruptcy has as little impact as possible on other entities within the group.
[44]Order No. PSC-10-0153-FOF-EI, issued March 17, 2020, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company, p. 109-110*, Order No. PSC-10-0029-PAA-GU, issued January 14, 2010, in Docket No. 20090125-GU, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation, p. 10*.

record that Emera's decision to spin off PGS involved malfeasance or was a deliberate plan to benefit TECO at the expense of PGS's customers. (See Issue 72) Emera made a business decision to spin off PGS into a new company for which the Commission has no authority to approve or deny. (TR 1223) The Joint Parties' argument that PGS customers are entitled to past debt cost rates that were obtained by TECO under the previous divisional organizational relationship was not based on any Commission precedent or legal argument, nor was it convincing. If Emera sold PGS to another entity as opposed to spinning it off, PGS would not be entitled to the historical long-term debt cost from TECO. In this case, PGS demonstrated that its 2023 Transaction meets IRS requirements for a tax-free transaction which includes PGS divesting from TECO and issuing its own debt. (TR 1112) Otherwise, PGS could be liable for \$150 million capital gain tax. The Joint Parties' recommendation to not allow PGS to recover its actual market-based cost of long-term debt in the Company's allowed overall rate of return will reduce PGS revenue below a level necessary to recover its interest expense. This revenue reduction would consequently not allow PGS to earn its authorized return on equity and could be considered non-compensatory.

## CONCLUSION

Based on the aforementioned, staff recommends a forecasted long-term debt cost rate of 5.54 percent should be approved for the projected test year ending December 31, 2024.

***Issue 33:*** Has PGS made the proper adjustments to remove all non-utility investments from the projected test year common equity balance? If not, what adjustments should be made?

***Recommendation:*** Yes, PGS has made the proper adjustments to remove all non-utility investments from the projected test year common equity balance and staff recommends no additional adjustments should be made. (McGowan)

***Position of the Parties***

**PGS:** Yes.

**Joint Parties:** No position.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS asserted it made the proper adjustments to remove all non-utility investments from the projected test year common equity balance as shown on MFR G-3, page 2, and Exhibit RBP-1, Document No. 9, attached to witness Parsons' direct testimony and Exhibit 218 (revised revenue increase). (EXH 7, BSP K278; EXH 23, BSP D12-1036; EXH 218, BSP G1-250 – G1-251)

### Joint Parties

The Joint Parties took no position on this issue in its brief.

## ANALYSIS

In its initial filing, PGS presented its projected test year capital structure based on a 13-month average as of December 31, 2024, consisting of common equity in the amount of $1,124,006,187 (adjusted) on MFR Schedule G-3, page 2, line 1. (EXH 7, BSP K278). Exhibit RBP-1, Document No. 9, attached to PGS witness Parsons' direct testimony, detailed the Company's projected test year reconciliation of capital structure to rate base that showed its specific adjustments to remove non-utility investments from common equity. (EXH 23, BSP D12-1036) The reconciled items with specific adjustments to the projected test year common equity balance reflected within Exhibit RBP-1, Document No. 9, included a total of three adjustments to the following: (1) Property Held for Future Use; (2) Investments in Subsidiaries; and (3) Non-utility Adjustments to Rate Base. (EXH 23, BSP D12-1036) In addition, a Type II Stipulation was approved for Issue 12 that all required adjustments to remove non-utility items from Plant in Service, Accumulated Depreciation, and Working Capital have been included in the projected test year, as shown on MFR Schedule G-1, page 4. (EXH 7, BSP K172) Typically, if all non-utility activities have been removed from rate base, corresponding adjustments are made to remove non-utility activities from the capital structure. Staff reviewed the Company's adjustments and concur with PGS that the non-utility items have properly been removed from common equity.

Further, no argument was proffered on behalf of the Joint Parties concerning whether or not PGS has made the proper adjustments to remove all non-utility investments from the projected test year common equity balance.

## CONCLUSION

Yes, PGS has made the proper adjustments to remove all non-utility investments from the projected test year common equity balance and staff recommends no additional adjustments should be made.

***Issue 34:*** What equity ratio should be approved for the projected test year capital structure?

***Recommendation:*** An equity ratio of 54.7 percent based on investor sources is appropriate and should be approved for the projected test year capital structure. (D. Buys)

***Position of the Parties***

**PGS:** The appropriate equity ratio for the projected test year capital structure is 54.7 percent (investor sources). OPC's proposed equity ratio would not be sufficient to maintain the Company's financial integrity, is far below actual levels since 1998, and should be rejected.

**Joint Parties:** The Commission should approve a 49.2 percent equity ratio.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS argued its requested equity ratio of 54.7 percent from investor sources is the same equity ratio previously approved by the Commission in the 2020 Settlement Agreement by Order No. PSC-2020-0485-FOF-GU[45] and is consistent with the equity ratios that have been maintained by the Company since 1998. (PGS BR 24; TR 1115-116; EXH 31, BSP E6-232) PGS contended that an equity ratio of 54.7 percent is entirely consistent with two Florida-based peers given the 55.1 percent equity ratio approved by the Commission for Florida Public Utilities Company and the 59.6 percent equity ratio approved for Florida City Gas. (PGS BR 24; TR 1116, 1135; EXH 31, BSP E6-232) PGS also argued the Company's 54.7 percent equity ratio compares favorably to the equity ratios maintained by the gas companies in witness D'Ascendis' proxy group that he used to develop his recommended return on equity for PGS. (PGS BR 25; TR 319-320) PGS argued the maintenance of the requested equity ratio, coupled with an appropriate ROE, should lead to adequate coverage ratios, and provide the financial strength and credit parameters necessary to achieve the Company's targeted credit rating of BBB+ and assure access to capital. (TR 1116) PGS argued Joint Parties' proposed equity ratio of 49 percent would not be sufficient to maintain the Company's financial integrity. (PGS BR 24; TR 1135) PGS contended that financial integrity refers to a relatively stable condition of liquidity and profitability in which the Company can meet its financial obligations to investors while maintaining the ability to attract investor capital as needed on reasonable terms, conditions, and costs. (PGS BR 23; TR 1099) PGS argued a more highly leveraged capital structure with a lower overall authorized return will render it more difficult for PGS to achieve credit metrics sufficient to support its targeted rating of BBB+. (PGS BR 24; TR 1135)

### Joint Parties

The Joint Parties argued that PGS's equity ratio should be set to equal the average equity ratio of the gas utilities in witness Garrett's proxy group which equates to 49.2 percent. (JP BR 19-20; TR 1031, 1269) The Joint Parties contended that PGS witness D'Ascendis' conclusion that

[45]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In Re: Petition for rate increase by Peoples Gas System.*

PGS's proposed equity ratio is reasonable because it is within the range of the equity ratios of his gas proxy group is flawed. (JP BR 20) The Joint Parties argued that every company in the gas utility proxy group has an equity ratio of less than 49 percent, with the exception of Atmos Energy Corp. which has an equity ratio of 62 percent. (JP BR 20; EXH 77) The Joint Parties contended that since PGS's equity ratio is higher than the proxy group average, it has less financial risk than the gas utility proxy group.[46] (JP BR 20; TR 1031) The Joint Parties argued that OPC witness Garrett demonstrated that PGS's proposed equity ratio is clearly too high and results in excessively high capital costs and utility rates. (JP BR 20; TR 1027, 1034) In addition, witness Garrett contended that competitive firms maximize their value by minimizing their weighted average cost of capital (WACC) by recapitalizing and increasing their debt financing. (JP BR 19; TR 1027-1029) Witness Garrett opined that because utilities have low levels of risk and operate a stable business, they can afford to operate with relatively higher levels of debt (lower equity ratio) to achieve their optimal capital structure. (TR 1030) The Joint Parties also argued that because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation. (JP BR 19; TR 1027) The Joint Parties argued that under a rate base, rate of return model, a higher WACC results in higher rates, all else held constant. (JP BR 19; TR 1029) The Joint Parties contended the rate base, rate of return model does not incentivize utilities to operate at the optimal capital structure, and consequently, utilities can increase their revenue requirement by increasing their WACC, not by minimizing it. (JP BR 19; TR 1029) Thus, the Joint Parties argued, there is no incentive for a regulated utility to minimize its WACC by lowering its equity ratio, and therefore, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC. (JP BR 19; TR 1029)

## ANALYSIS

In its filing, PGS requested a projected test year capital structure consisting of an equity ratio of 54.7 percent based on investor-supplied capital for rate setting purposes. (TR 1115; EXH 7, BSP K278) PGS's current equity ratio of 54.7 percent was approved by the Commission as part of the 2020 Settlement Agreement in the Company's last rate case by Order No. PSC-2020-0485-FOF-GU.[47] (TR 1115-1116) PGS witness D'Ascendis testified that PGS requested equity ratio of 54.7 percent is consistent with the range of common equity ratios maintained by the gas utility proxy group, and therefore, is appropriate for ratemaking. (PGS BR 25; TR 319-320) For 2022, the range of the equity ratios of the six gas utilities in the proxy group was 34.43 percent to 62.61 percent with an average equity ratio of 48.83 percent. (EXH 30, BSP E5-167) Witness D'Ascendis testified that in order to continue to provide safe and reliable service to its customers, PGS must meet the needs and serve the interests of its various stakeholders, including its customers, shareholders, and bondholders. (TR 318) The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment, so that the Company has access to capital on reasonable terms in order to make necessary investments. (TR 318)

[46]Both PGS witness D'Ascendis and OPC witness Garrett used the same gas utility proxy group in their equity ratio analysis.
[47]Order No. PSC-2020-0485-FOF-GU.

OPC witness Garrett's contended that regulated utilities can generally afford to have higher debt levels than other industries because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (lower equity ratios). (TR 1030) Further, OPC witness Garrett contended that under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. (JP BR 19; TR 1029) The Joint Parties asserted that because there is no incentive for a regulated utility to minimize its WACC a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC. (JP BR 19; TR 1029-1030) Staff believes OPC witness Garrett's arguments are based on basic financial theory and are misapplied to ratemaking and not persuasive. Staff believes simply setting PGS equity ratio to the average of the gas utility proxy group for the sole purpose of lowering rates without analyzing the effect on the Company's individual financial metrics is not a convincing argument.

To assess a reasonable equity ratio for PGS, witness Garrett examined the capital structures of the gas utility proxy group and the debt ratios in other industries. (TR 1030) Based on his analysis, witness Garrett concluded the average equity ratio of the gas utility proxy group is 49 percent, which he noted is lower than PGS's proposed equity ratio of 54.7 percent. (TR 1031) In addition, witness Garrett testified that there are nearly 2,000 companies in the U.S. with debt ratios higher than 50 percent and equity ratios lower than 50 percent. (TR 1031) Witness Garrett compared the equity and debt ratios of Cable Television, Power and Telecom (other utilities) which are all below 50 percent. (JP BR; TR 1031) Witness Garrett concluded PGS's proposed debt ratio is clearly too low (and its equity ratio is too high). (TR 1031) Witness Garrett asserted PGS's high equity ratio results in excessively high capital costs and utility rates and recommended that PGS's equity ratio should be no more than 49 percent. (TR 1033-1034)

PGS witness McOnie disagreed with OPC's proposal to reduce PGS equity ratio. In rebuttal, witness McOnie asserted that in credit rating agencies' view the regulatory environment is a key consideration in determining the creditworthiness of an energy utility. (TR 1135-1136) The regulator determines an appropriate capital structure and establishes the allowed return on equity, and these are two of the key variables that go into determining a utility's revenue requirement, and by extension, the debt level and cash flow generating capability of the company. (TR 1136) Witness McOnie contended a change to either or both will have an impact on the company's financial metrics and creditworthiness. (TR 1136) PGS's obligation to serve its customers and the significant capital expenditure requirements needed to maintain and grow its system is better served by stronger financial integrity. (TR 1136) Witness McOnie concluded that the maintenance of the requested capital structure, coupled with an appropriate return on equity, should lead to adequate coverage ratios, and provide the financial strength and credit parameters necessary to achieve the Company's targeted credit rating and assure access to capital. (TR 1135-1136)

Witness Garrett admitted that he did not perform any quantitative analysis on what affect his recommendation to reduce PGS's equity ratio and allowed ROE would have on PGS's financial metrics, or financial integrity. (TR 1069) While this line of questioning was regarding witness Garrett's ROE testimony and not specifically about the equity ratio, witness Garrett testified that "There is no analysis that I performed that I did not present in my testimony and work papers." (TR 1070) Therefore, it is a reasonable presumption that witness Garrett did not consider the effect of his recommended equity ratio of 49.0 percent in combination with his recommended ROE of 9.0 percent on PGS forecasted credit metrics and financial integrity. It is a widely accepted paradigm in the financial community that the equity ratio and allowed return on equity are inextricably related. As explained by witness Garrett:

> The cost of equity of any particular company is necessarily connected with its capital structure. This is because there is a direct relationship between risk and return. That is, the higher (lower) risk, the higher (lower) expected return. All else held constant, companies with higher amounts of leverage have higher levels of financial risk. Since we are using a proxy group of companies to assess a fair cost of equity estimate for PGS, we must also factor in the capital structures of those companies into the analysis – failing to do so is an analytical error. Since PGS's debt ratio is lower and the equity ratio is higher than the proxy group average, it has less financial risk than the proxy group. This discrepancy in debt ratio and equity ratio must be accounted for.

(TR 1031)

Based on the risk-return paradigm, a company with a higher equity ratio in its capital structure, all else being equal, will have less financial risk and should have a comparatively lower return on equity. Staff agrees with PGS that witness Garrett's recommendation to reduce the equity ratio and the ROE at the same time would result in a significant reduction to the revenue requirement of PGS and could possibly have a negative affect on the quality of PGS's credit metrics and financial integrity. (PGS BR 23; TR 1135)

## CONCLUSION

Based on record evidence, and in conformity with past Commission practice of using a capital structure that approximates the Company's actual sources of capital,[48] PGS's projected equity ratio of 54.7 percent for the projected test year is reasonable and appropriate. Accordingly, staff recommends the appropriate equity ratio is 54.7 percent as a percentage of investor-supplied capital.

[48]Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division, p. 57.*

***Issue 35:*** What return on equity (ROE) should be approved for establishing PGS's projected test year revenue requirement

***Recommendation:*** The appropriate ROE for establishing PGS's projected test year revenue requirement is 10.15 percent with a range of plus or minus 100 basis points. (D. Buys)

### *Position of the Parties*

**PGS:** The appropriate authorized return on equity (ROE) for the projected test year is a midpoint of 11 percent with a range of plus or minus 100 basis points. OPC's proposed rate of return on equity is not reasonable and should be rejected.

**Joint Parties:** The Commission should approve a 9.00 percent ROE.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that competent, substantial evidence in the record supports an ROE of 11.0 percent with a range of plus or minus 100 basis points. (PGS BR 25) PGS cited the Commission's Order in its decision regarding the 2022 Florida City Gas rate case and argued that the Commission explained:

> Neither case law nor statute mandates that the awarded ROE be tied to the result of a particular financial model. Instead, the Commission will establish a reasonable ROE that is consistent with *Hope* and *Bluefield* and supported by competent, substantial evidence in the record. The Commission has a long history of establishing an ROE midpoint and a range of 100 basis points on either side to create a range of reasonableness and ensure rate stability.

(PGS BR 25)

PGS argued that witness D'Ascendis's approach to estimating PGS's required return on equity (ROE) by applying multiple generally accepted cost of common equity models to a proxy group consisting of six comparable publicly traded companies is reasonable and appropriate. (PGS BR 26) PGS asserted that witness D'Ascendis and OPC witness Garrett agree that an ROE analysis should be based on the use of multiple models and both witnesses used two of the same cost of equity models (the DCF Model and CAPM)[49] and shared the same proxy group of companies. (PGS BR 26; TR 322, 960, 980-981) PGS argued that witness D'Ascendis's ROE analysis constitutes competent, substantial evidence that the Commission may rely on in establishing a reasonable ROE that is consistent with *Hope* and *Bluefield*.[50] (PGS BR 26-27) PGS argued that

[49]DCF Model and CAPM refer to the Discounted Cash Flow Model and the Capital Asset Pricing Model. These cost of equity models are discussed in greater detail, infra.

[50] *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). These cases are discussed in greater detail, infra.

while OPC witness Garrett followed the same general approach to estimating an ROE as witness D'Ascendis, the results of his analysis are unreasonable and lack credibility. (PGS BR 27) In its brief, PGS pointed out that in PGS's last rate case in 2020, witness Garrett recommended that the Commission adopt a ROE of 9.5 percent. (PGS BR 27; TR 1070) PGS argued that although witness Garrett agreed that capital costs have increased since 2020, he nonetheless recommended that the Commission reduce PGS's authorized ROE by 90 basis points to 9.0 percent. (PGS BR 27; TR 1069-1071; EXH 131, BSP F1853) Hence, PGS argued that witness Garrett's recommended ROE is simply irreconcilable with the now higher cost of capital and should be rejected. (PGS BR 27)

Finally, PGS argued that the Commission recently approved effective equity returns or weighted cost of equity (equity ratio times equity return) of approximately 5.65 percent and 5.66 percent for Florida Public Utilities Company (FPUC) and Florida City Gas (FCG), respectively. (PGS BR 27; TR 1194) PGS argued that given PGS's proposed equity ratio of 54.7 percent, to obtain a comparable weighted cost of equity of 5.65 percent, the ROE would work out to be approximately 10.33 percent (5.65% ÷ 54.7% = 10.33%). (PGS BR 27; TR 1194) PGS concluded that although FPUC and FCG may different than PGS, the Commission should consider its recent decisions and the upward trend in interest rates when setting the Company's mid-point return on equity. (PGS BR 27)

**Joint Parties**

The Joint Parties argued the Commission should reject PGS's exorbitant proposed ROE of 11.0 percent and adopt witness Garrett's more reasonable ROE of 9.0 percent, or in the alternative, award PGS the most current annual national average for natural gas local distribution companies of 9.4 percent. (JP BR 27, 23; TR 965; EXH 185) The Joint Parties argued an ROE of 9.0 percent gradually moves PGS's current authorized ROE of 9.9 percent, which is excessive based on current market conditions, toward the actual, current market-based ROE of 8.5 percent based on witness Garrett's application of the CAPM. (JP BR 20; TR 965-966, 1072)

The Joint Parties argued the DCF Model and CAPM used by witness Garrett are consistent with the legal standards set forth in the *Hope* and *Bluefield* decisions.[51] (JP BR 21; TR 972-973) The Joint Parties argued witness Garrett's recommended ROE of 9.0 percent complies with the *Hope* and *Bluefield* standards and allows PGS to maintain its financial integrity and satisfy the claims of its investors. (JP 21; TR 972-973) The Joint Parties argued that the results from witness Garrett's cost of equity models closely estimate PGS's true cost of equity which comports with the U.S. Supreme Court's decision in the *Hope* case. (JP 21; TR 973-974) The Joint Parties argued that witness Garrett correctly stated that the legal standards do not mandate that awarded ROEs must exactly match the cost of capital, but instead must reflect the true cost of capital. (JP BR 22; TR 972) The Joint Parties contended that ROEs awarded through the regulatory process may be influenced by outside factors such as settlements and other political factors, not true market conditions, and relying on awarded ROEs from other jurisdictions bears little relation to market-based cost of equity. (JP 22; TR 974-975) The Joint Parties argued since 1990, utilities have been awarded ROEs above the market return. (JP 22; TR 976-977) The Joint Parties argued

[51]*Bluefield Water Works and Improvement Co. v. Public Service Commission,* 262 U.S. 679, 692 (1923)*; Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944). These cases are discussed in greater detail, infra.

witness Garrett's estimated market cost of equity is 9.3 percent, and because utility stocks are less risky than the market, they should be below the market cost of equity. (JP 22; TR 977) The Joint Parties further argued the failure to closely track the actual market-based cost of capital is detrimental to customers and Florida's economy because these much higher returns result in an inappropriate transfer of wealth from Florida ratepayers to shareholders. (JP BR 22; TR 975) The Joint Parties argued that because witness Garrett is an attorney who has practiced law at a regulatory commission, his legal interpretation that the *Hope* and *Bluefield* cases allows for gradualism and supports his true market-based cost of equity is appropriate. (JP BR 22) Whereas, witness D'Ascendis, who is not an attorney, failed to recognize the main issue that awarded ROEs generally have been greater than the actual market-based cost of equity. (TR 977) The Joint Parties also disagreed with witness D'Ascendis's interpretation of *Hope* and *Bluefield* that the investor-required ROE should equal the allowed ROE, and that the *Hope* and *Bluefield* standards are not as rigid as he contended. (JP 22; TR 269-297, 962) The Joint Parties' argument supporting witness Garrett's gradualism theory was best explained in witness Garrett's summary of his testimony:

> Despite the fact that the indicated cost of equity for PGS under my CAPM analysis is only 8.5 percent, it is my opinion that a nine-percent awarded ROE for PGS is reasonable under the circumstances. This is primarily due to the fact that PGS's current awarded ROE of 9.9 percent is significantly higher than a reasonable estimate of the company's market-based cost of equity. One could argue that it is preferable for awarded ROEs to gradually change rather than abruptly. An awarded ROE of 9.0 percent would partially mitigate the excess wealth from Florida customers to shareholders, while gradually moving the company toward [the] actual market-based cost of equity.

(TR 1059)

## ANALYSIS

The ROE is the allowed cost of common equity included in a utility's regulatory capital structure to determine the overall rate of return used to establish a revenue requirement. PGS's common equity is not publicly traded, and as such, a market-based cost rate for the Company cannot be directly observed. (TR 312-313, 981) Consequently, both PGS witness D'Ascendis and OPC witness Garrett applied cost of equity financial models to a proxy group of publicly traded gas distribution companies (gas proxy group) with similar risk to PGS to derive estimates of the investor required ROE. OPC witness Garrett used the same gas proxy group as that of witness D'Ascendis. (TR 313-314, 784) Both OPC and PGS witnesses used the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM) to estimate the cost of equity. (TR 322, 964) Witness Garrett applied the Hamada Formula to his CAPM to account for the difference between his recommended equity ratio of 49.0 percent and PGS requested equity ratio of 54.7 percent. (TR 1034-1036) In addition, witness D'Ascendis employed two risk premium models (RPM): a predictive risk premium model and a risk premium using an adjusted total market approach. (TR 328) Witness D'Ascendis also applied the DCF Model, CAPM and RPM to a non-price regulated group of companies he argued were similar in total risk to the gas proxy group and obtained a result of 12.3 percent. (TR 301, 381-382; EXH 30, BSP 60) Witness D'Ascendis did not consider the results from his non-price regulated proxy group in his determination of his recommended range of indicated ROEs for PGS. (TR 301, 381-382) Consequently, in the interest of brevity, staff's recommendation will not include an analysis of witness D'Ascendis's non-price regulated proxy group testimony.

In his rebuttal testimony, witness D'Ascendis updated the results of the cost of equity models used in his direct testimony. (TR 380-381) Therefore, staff believes it is more appropriate to evaluate witness D'Ascendis ROE model results used in his rebuttal testimony than his direct testimony because the market-based data is more recent and reflects recent interest rates. Witness D'Ascendis used the same ROE models and methodology in his rebuttal testimony as he did in his direct testimony. (TR 381)

In general, witness D'Ascendis employed assumptions and methods that produced a high ROE estimate, while OPC witness Garrett used assumptions and methods that produced a low ROE estimate. (TR 403; TR 839) As a result of their respective assumptions used in the cost of equity models, staff's recommended ROE is greater than OPC's recommended ROE of 9.0 percent and lower than PGS's requested ROE of 11.0 percent. The range of results of the witnesses' cost of equity models is 7.50 percent to 11.74 percent. The witnesses' cost of equity model results are summarized in Table 35-1.

**Table 35-1**
**Summary of Cost of Equity Model Results**

| ROE Model | PGS witness D'Ascendis | OPC witness Garrett |
|---|---|---|
| DCF – with analyst growth estimates | 9.60% | 8.30% |
| DCF – with sustainable growth estimates | | 7.50% |
| CAPM | 11.74% | 8.50% |
| CAPM with Hamada Formula | | 8.10% |
| Risk Premium | 11.42% | |
| Range of Results | 9.60% - 11.74% | 7.50% - 8.50% |
| Average of Results | 10.92% | 8.10% |
| Recommended ROE | 11.00% | 9.00% |

Source: EXH 30, BSP E5-165; TR 964

## Legal Standard

The landmark *Hope* and *Bluefield* U.S. Supreme Court cases established standards for setting a fair rate of return for equity investment in utilities providing service to the public. (TR 972; TR 302-304) Under the *Hope* and *Bluefield* decisions, the U.S. Supreme Court established that a fair rate of return should be commensurate with the returns on investments in other enterprises having corresponding risks, should be sufficient to assure confidence in the financial integrity of the utility, support reasonable credit quality, and allow a company to raise capital at reasonable costs and terms. (TR 303-304, 973; PGS BR 25) Therefore, PGS witness D'Ascendis asserted, it is important that the authorized ROE reflect the risks and prospects of PGS's operations and supports the Company's financial integrity from a stand-alone perspective as measured by its combined business and financial risks. (TR 305)

Witness D'Ascendis acknowledged that in prior rate cases for PGS, the Commission has approved the use of multiple cost of equity models that satisfy the terms for determining a fair rate of return as laid out by *Hope* and *Bluefield*. (TR 322-323) In particular, he contends that the Commission recognized the market-based approaches such as the DCF model and the CAPM as being consistent with the market-based standards of a fair return enunciated in *Hope* and *Bluefield*. (TR 322-323) In its brief, PGS made the following statement regarding the Commission's decision in Order No. PSC-10-0153-FOF-EI for Florida Power & Light Company's (FPL) rate case:

> The Commission has previously stated that the models used by Mr. D'Ascendis "are generally recognized as being consistent with the market-based standards of a fair return enunciated in the Hope and Bluefield decisions."

(PGS BR 26)

Staff believes PGS's statement is in need of clarification. First witness D'Ascendis did not testify in the 2009 FPL rate case. Second, upon review of Order No. PSC-10-0153-FOF-EI, the Commission actually stated:

> Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the *Hope* and *Bluefield* decisions.[52]

To be clear, in the Order cited by PGS, the Commission did not approve witness D'Ascendis's models as he presented them in this case. Further, witness D'Ascendis's Predictive Risk Premium Method (PRPM) using the Generalized Autoregressive Conditional Heteroscedasticity (GARCH) approach was developed in 2011 and was not used by any witnesses in the 2009 FPL rate case. (EXH 132, BSP F3031)

Witness Garrett opined that the *Hope* standard makes it clear that the allowed return should be based on the actual cost of capital. (TR 974) Witness Garrett contended that his ROE of 9.0 percent will comply with the U.S. Supreme Court's standards established in *Hope* and *Bluefield* and allow PGS to maintain its financial integrity and satisfy the claims of its investors. (TR 974) Witness Garrett further opined that an allowed ROE that is set far above the actual cost of equity is contrary to the *Hope* and *Bluefield* standards and results in an excess transfer of wealth from the customers to the utility. (TR 975) Witness Garrett's gradualism theory is based on his narrow interpretation of the *Hope* and *Bluefield* standards which he opined supports his argument that the "actual market-based cost of equity" is equal to the results of his estimated cost of equity and would support the financial integrity of the Company simply because his recommended ROE gradually reduces the Company's ROE, but is still higher than the results of his cost of equity analysis or the Company's actual cost of equity. (TR 1069-1070) Witness D'Ascendis testified that the national average of awarded ROEs for natural gas companies in 2022 ranged from 9.0

[52]Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light, p. 121.*

percent to 10.2 percent, with an average of around 9.6 percent. (TR 480; EXH 174, BSP G2-4C) Staff notes that based on the comparable awarded ROEs for other natural gas companies in the U.S., witness Garrett's recommended ROE may not be commensurate with returns on investments in other enterprises having corresponding risks, and it is certainly at the bottom of the range of awarded ROEs.

Staff believes that witness Garrett failed to demonstrate that his recommended ROE of 9.0 percent would satisfy the *Hope* and *Bluefield* requirement that the awarded ROE would support PGS's financial integrity so as to maintain its credit quality and attract capital on reasonable terms. Witness Garrett admitted that he did not perform any separate analysis to determine if his recommended adjustments to reduce PGS's current allowed ROE by 90 basis points and equity ratio from 54.7 percent to 49 percent would "maintain" PGS's credit quality. (TR 1069-1070) OPC witness Kollen calculated that the impact of witness Garrett's recommended ROE and equity ratio would be a reduction to revenue requirement of $38.5 million. (TR 1213) As explained by PGS witness McOnie, credit rating agencies evaluate business risk, financial risk, and regulatory risk to determine a company's credit rating. (TR 1135-1136) Financial risk is based on financial ratios covering cash flow and leverage (debt ratio) analysis. (TR 1106) The primary business risk credit rating agencies focus on is regulatory risk. (TR 1106) Regulatory risk is based upon transparency, predictability, and stability of the regulatory environment, timeliness of operating and capital cost recovery, regulatory independence, and financial stability. (TR 1106) Regulation in Florida has historically been supportive of maintaining the credit quality of the State's utilities, and that has benefited customers by allowing utilities to provide for their customers' needs consistently and at a reasonable cost. (TR 1106) Witness McOnie testified that a more highly leveraged capital structure with a lower overall authorized ROE will render it more difficult for the Company to achieve credit metrics sufficient to support its targeted rating of BBB+. (TR 1135) Hence, the record makes it clear that any substantial change to reduce PGS's cash flow could lower its credit rating.

### Proxy Group Gas Companies

Because PGS is not publicly traded and does not issue publicly traded equity securities, a group of publicly traded companies that have comparable risk characteristics to PGS must be used as a proxy that the cost of equity models may be applied to determine the required ROE. (TR 312-313; TR 981) Witness D'Ascendis selected six companies from the Value Line Investment Survey's Natural Gas Utility Group. (TR 314) The gas proxy group includes Atmos Energy Corp., New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., and Spire, Inc. (TR 315) Witness D'Ascendis testified that the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards. (TR 313)

OPC witness Garrett did not take issue with witness D'Ascendis's proxy group and opined, "There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups." (TR 981)

Staff believes the proxy group of gas companies used by both PGS witness D'Ascendis and OPC witness Garrett is reasonable and comparable to PGS for the reasons explained by witness D'Ascendis. (TR 312-314)

## Cost of Equity Models

### *Discounted Cash Flow Model*

The DCF model is based on the theory that a stock's current price represents the present value of all expected future cash flows in the form of dividends discounted at the appropriate risk-adjusted rate of return. (TR 323-324, 989) In its basic form, the DCF model is expressed as the dividend yield of a stock, plus the expected long-term growth rate: ROE = (dividend ÷ stock price) + growth rate. (EXH 104, BSP D16-2164; TR 323-324) This is known as the single-stage constant growth DCF model. (TR 323) Both witnesses used an adjusted version of the single-stage constant growth DCF model by adjusting the annual dividend for expected growth expressed as: ROE = [(dividend (1 + growth rate)) ÷ stock price] + growth rate. (EXH 104, BSP D16-2164; TR 323-324) Witness Garret used the full value of the growth rate in his DCF calculation to adjust the dividend upwards, whereas witness D'Ascendis used ½ of the growth rate. Although witness D'Ascendis testified that DCF theory calls for using the full growth rate, he used one-half the growth rate in his DCF calculations because the utilities in the gas proxy group increase their quarterly dividends at various times of the year which staff agrees is a reasonable assumption. (TR 325) Staff believes the witnesses' use of an adjusted DCF model to account for growth in dividend payments from the utilities is appropriate. (TR 325, 983)

Witness D'Ascendis's DCF model results for the six proxy group gas companies in his rebuttal testimony ranged from 8.81 percent to 11.44 percent with an average of 9.72 percent. (EXH 30, BSP E5-169) Witness Garrett's DCF model results using a sustainable growth rate ranged from 6.6 percent to 8.3 percent with an average of 7.5 percent. (EXH 69) Witness Garrett also calculated a DCF result using analysts' estimated dividend growth rate published by Value Line and obtained a range from 4.7 percent to 10.3 percent with an average of 8.3 percent. (EXH 69)

The difference between witness Garrett's and witness D'Ascendis's DCF model results are primarily caused by differences in their estimated growth rates. (TR 795) Witness Garrett's average growth rate for the proxy group is 4.7 percent using analysts' growth rate estimates of the dividends declared and 3.9 percent using a sustainable growth rate based on the Gross Domestic Product (GDP) of the U.S. economy. (EXH 69) Witness D'Ascendis's average growth rate for the proxy group is 6.12 percent based on an average of three sources of published analysts' estimates from Value Line, Zacks, and Yahoo! Finance. (EXH 30, BSP E5-169) Witness D'Ascendis relied on analysts' five-year forecasts of earnings per share growth in his DCF analysis. (TR 326) Witness D'Ascendis explained that over the long run there can be no growth in dividends per share without growth in earnings per share. (TR 326) Witness D'Ascendis asserted that analysts' earnings expectations have a more significant influence on market prices than dividend expectations, and therefore, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component in the DCF model. (TR 326)

Witness Garrett argued that witness D'Ascendis incorrectly used short-term growth rate estimates from third-party analysts in the DCF model analysis which should use long-term growth estimates. (TR 994) Witness Garrett argued that analysts' earnings forecasts are short-term growth rate projections which are unreasonably high and are not sustainable in the long term. (TR 992-993) Witness Garrett asserted that a fundamental concept in finance is that no firm can grow forever at a rate higher than the growth of the economy in which it operates as measured by the GDP. (TR 987-988) Witness Garrett testified that the Congressional Budget Office's 2022 long-term budget outlook forecast for the U.S. GDP is 3.90 percent, and thus, the growth rate in the constant growth DCF model should be no more than 3.90 percent. (TR 987) Witness Garrett opined that theoretically the stable growth DCF model should consider only sustainable growth rates which are appropriate for estimating the growth for utilities, because they are in the sustainable growth stage of the industry life cycle. (TR 985) Witness Garrett contended that once a company is in the maturity stage of the industry life cycle it is not necessary to consider higher short-term growth rates in the DCF model, but rather it is preferable to analyze the cost of capital using a stable growth DCF model with a sustainable growth rate. (TR 986) Witness Garrett opined it is reasonable to assume that a regulated utility would grow at a rate that is less than GDP. (TR 987) On cross-examination, witness Garrett agreed that quantitatively utilities earnings can grow by more than the GDP for an extended period of time, but asserted that when choosing a growth rate one has to be careful that it is not too high. (TR 1075; EXH 104, BSP D16-2166)

Witness D'Ascendis took issue with witness Garrett's growth rate of 3.90 percent based on the forecasted GDP. Witness D'Ascendis asserted that witness Garrett's growth rate is not based on any measure of company-specific growth, or growth in the utility industry in general. (TR 399) Further, GDP is a measure of the total output of goods and services in an economy and is not a market-based measure. (TR 401) Witness Garrett's dividend yield is calculated using the proxy group utilities' individual market price and expected dividends, but his growth rate is the same for all companies. (TR 399) Witness D'Ascendis contended that under the DCF model's strict assumptions, expected growth and dividend yields are inextricably linked, and assuming the same growth rate for all companies has no basis in theory or practice. (TR 399)

Staff believes witness Garrett's argument to use the GDP growth rate in his DCF model is not supported by persuasive evidence. Staff agrees with witness D'Ascendis that the growth rate should reflect a measure of the utilities' individual growth, and not a generic measure of the output of the entire economy. However, staff agrees with witness Garrett that witness D'Ascendis use of earnings per share growth rates overestimated the growth of cash flows from the companies. Earnings per share are not actual cash flows realized by the investor, whereas dividends declared is a more accurate measure of the cash flow provided to the investor. (TR 989; EXH 104, BSP D16-2164-2166) Both witnesses' models using analyst forecasts from well-established and recognized sources are comparable and reasonable. (EXH 69; EXH 30, BSP E5-169) Therefore, staff believes equal weight should be given to the witnesses' DCF model results using analyst forecasts. The average of both witnesses' DCF model results is 9.0 percent.

### *Capital Asset Pricing Model*

The CAPM is a market-based model that estimates the cost of equity for a stock as a function of a risk-free return plus a market risk premium. (TR 344) The market risk premium is defined as the incremental return of the stock market as a whole, less the risk-free rate multiplied by the beta for the individual security. (EXH 104, BSP D16-2167-2168) The beta is expressed as the volatility of an individual security compared against the stock market as a whole. (TR 344) A beta value of 1.0 indicates the individual security has the same volatility as the stock market. (TR 344) A beta value of less than 1.0 is considered less risky than the stock market as a whole and a beta value greater than 1.0 is considered more risky. (TR 344) The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the market equity risk premium expressed in this equation: ROE = risk-free rate + Beta × (market return – risk-free rate). (TR 344, 1004; EXH 104, BSP D16-2167-2168) Witness D'Ascendis used two variations of the CAPM, the traditional CAPM and the Empirical CAPM or ECAPM. (TR 345) The average of the mean and median of the results of his application of the CAPM and ECAPM in his rebuttal testimony is 11.74 percent. Witness Garrett used the traditional form of the CAPM to calculate a cost of equity of 8.5 percent. (EXH 74)

#### ***Risk Free Rate***

Although witness D'Ascendis and Garrett used different methods to estimate the risk-free rate, both witnesses used the same risk-free rate of 3.8 percent based on the 30-year U.S. Treasury Bonds. Witness D'Ascendis based his estimate on the average of the forecasted expected yields for the six quarters ending in the third quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033. (TR 348; EXH 30, BSP D9-636-637) Witness Garrett based his estimate on the 30-day average of the then current 30-year U.S. Treasury Bond yields from April 14, 2023, through May 25, 2023. (TR 47; EXH 70)

#### ***Beta Coefficient***

Witness D'Ascendis used a slightly lower beta coefficient in his application of the CAPM than witness Garrett. Witness Garrett used the average beta coefficient of 0.84 for the gas proxy group as published by Value Line. (TR 47-48) Witness D'Ascendis also used the beta coefficient of 0.84 from Value Line, but he also included the average beta coefficient of 0.685 for the gas proxy group as published by Bloomberg and averaged the Value Line beta with the Bloomberg beta to derive a final average beta of 0.76. (TR 348; EXH 30, BSP D9-640)

#### ***Market Equity Risk Premium***

The most significant difference between the witnesses' application of the CAPM is their respective estimates of the market equity risk premium (MRP). The MRP is an estimate of the expected return on the stock market less the estimated risk-free rate. (TR 1006-1007) Witness D'Ascendis derived a MRP of 10.0 percent as compared to witness Garrett's estimated MRP of 5.6 percent. (EXH 30, BSP E5-188; EXH 74) To derive his MRP, witness D'Ascendis used six different measures from three sources. (EXH 30, BSP E5-189) Three of witness D'Ascendis measures used historical market data from Kroll that averaged 8.85 percent. The other three used projected returns on the market, two using market-based data from Value Line and a third using market-based data from Bloomberg. (TR 348-349; EXH 30, BSP E5-189) The projected MRP using the projected market data averaged 11.17 percent. Witness D'Ascendis estimated MRP of 11.17 percent using projected data indicates the total return on the stock market is expected to average 15 percent per year. (EXH 30, BSP E5-189)

However, for Measure 6[53] in witness D'Ascendis MRP derivation, there is a discrepancy between his market-based MRP using Bloomberg data as presented in his direct testimony versus

[53]Measure 6 is the Bloomberg Projected MRP based on the total return on the market using the S&P 500 index.

his rebuttal testimony. (EXH 20, BSP D9-640; EXH 30, BSP E5-189) In his direct testimony witness D'Ascendis presented a total return on the market of 11.06 percent and a MRP of 7.15 percent based on Bloomberg data for the S&P 500 Index. (EXH 20, BSP D9-630) In his rebuttal testimony, witness D'Ascendis presented a total market return of 15.68 percent and a MRP of 11.88 percent for the Bloomberg data. (EXH 30, BSP E5-189) This result is suspect as all the other MRP measures in Document No. 5, page 2, in witness D'Ascendis's rebuttal analyses decreased from his direct testimony to his rebuttal testimony. (EXH 20, BSP D9-640; EXH 30, BSP E5-189) Therefore, it is reasonable to assume that it is unlikely the total return on the market based on the S&P 500 using Bloomberg data would increase by 42 percent (11.06 percent to 15.68 percent) when all the other market-data based measures used by witness D'Ascendis decreased. (EXH 30, BSP E5-189) Consequently, staff believes the 11.06 percent total return on the market in his direct testimony should be used in place of 15.68 percent used in his rebuttal testimony, which would result in a revised MRP of 7.26 percent for Measure 6.

As pointed out by witness Garrett, a MRP based on historical data is convenient and easy to calculate; however, there are disadvantages to relying on a historical MRP for the application of the CAPM. (TR 1007) Because the CAPM application in this case should be forward-looking, using historical data is not ideal. (TR 1007-1009) Therefore, witness Garrett relied on MRPs reported in expert surveys and his application of the implied MRP which witness Garrett contended is the best method to use. (TR 1009) Witness Garrett applied a variation of the DCF model to the current value of the S&P 500 to calculate an expected return on the entire market of 9.3 percent. (TR 1010-1012) Witness Garrett's ERP was developed using the average of four estimates. The first ERP of 5.7 percent was obtained from a 2023 survey published by the IESE Business School. (TR 1009) Witness Garrett explained the survey involves conducting a survey of experts including professors, analysts, chief financial officers and other executives around the country about what they believe the MRP is. (TR 1009) A second MRP estimate published by Kroll (formerly Duff & Phelps) was 6.0 percent. (TR 1012) A third estimate using an implied MRP methodology from Dr. Aswath Damodaran[54] indicated a MRP of 5.1 percent. (TR 1012) The average of all four estimates used by witness Garrett was 5.6 percent. (TR 1013; EXH 73)

In addition to the traditional CAPM, witness D'Ascendis also applied the ECAPM to the gas proxy group and derived an average indicated ROE of 12.0 percent. (TR 345) Witness D'Ascendis asserted that the traditional CAPM underestimates the ROE for companies with low betas as is the case with the gas proxy group and the ECAPM accounts for this tendency. (TR 345-347) The average results from witness D'Ascendis's application of the ECAPM in his rebuttal testimony was 60 basis points higher than his traditional CAPM results (12.0 percent as compared to 11.4 percent) (EXH 30, BSP E5-188) Witness Garrett disagreed with witness D'Ascendis and asserted there are three problems with witness D'Ascendis use of the ECAPM. (TR 1019) First, the Value Line betas for the gas proxy group have already been adjusted upward to account for the low-beta bias. (TR 1019) Second, there is empirical evidence that Value Line betas overstate betas from low-beta industries like utilities. (TR 1019) Third, witness Garrett contended that witness D'Ascendis's ECAPM and CAPM applications include overestimates of the MRP. (TR 1019) When compared with other independent sources for the MRP which range from 5.6 percent to 6.0 percent, witness D'Ascendis's MRP is nearly twice as high as the

[54]Aswath Damodaran is a Professor of Finance at the Stern School of Business at New York University and is renowned for his work in the field of investment valuation and has written several books on the subject.

average MRP from reputable sources, and as a result, is overstated and less reliable. (TR 1015-1016) Further, witness D'Ascendis's estimated projected market return of 15 percent that he used in his MRP calculation is unreasonably high. (EXH 30, BSP E5-189)

Witness D'Ascendis contended that witness Garrett's use of surveys to estimate the MRP in the CAPM are not widely used by practitioners. (TR 410) Witness D'Ascendis cited to Dr. Damodaran, who was also cited and relied upon by witness Garrett, that few practitioners are inclined to use surveys because they are too sensitive to recent stock price movements, not objective based on to whom the surveys are presented and the questions asked, and they are more reflective of the recent past than forecasts into the future. (TR 410-412) Further, witness D'Ascendis asserted the determination of the MRP as calculated by Kroll is not transparent, although witness D'Ascendis uses Kroll information is his own derivation of the MRP. (TR 412-413; EXH 30, BSP E5-189) Lastly, witness D'Ascendis contended that witness Garrett's implied MRP is based on a series of questionable assumptions and followed the approach described by Dr. Damodaran's method to calculate an implied MRP. (TR 413-416) Witness D'Ascendis's main concern with witness Garrett's implied MRP calculation was the growth rate of 6.64 percent used in his DCF application. (TR 415) Witness D'Ascendis recalculated witness Garrett's implied MRP using an updated growth rate of 9.79 percent and obtained a required return on the market of 10.0 percent and a MRP of 6.2 percent, but asserted that the revised results still produce ROE estimates far below any reasonable measure. (TR 415; EXH 30, BSP E5-207) Using the traditional CAPM, witness Garrett's revised CAPM using a MRP of 6.2 percent produced a result of 9.0 percent. (9.0% = 3.8% + 0.84(10% - 3.8%)) Witness Garrett agreed that since the time he filed his direct testimony the risk-free rate he used in his CAPM has increased, and as a result, the results of his CAPM using analyst growth forecasts would be closer to 9.0 percent rather than 8.5 percent. (TR 1076-1078)

In his CAPM MRP calculation, witness D'Ascendis included a MRP result of 10.88 percent by applying the PRPM to Kroll Historical Data and staff believes it should be disregarded as discussed below. As discussed above, witness D'Ascendis's Measure 6 MRP should be revised from 11.88 percent to 7.26 percent. With those two adjustments, witness D'Ascendis CAPM MRP would be 8.91 percent instead of 10.01 percent. With the adjusted MRP of 8.91 percent, witness D'Ascendis CAPM would be 10.66 percent (10.66% = 0.77(8.91%) + 3.8%)

### *Risk Premium Model*

The RPM recognizes that common equity capital has a greater investment risk than debt capital, and as a result, investors require higher returns on common stocks than bonds to compensate them for bearing the additional risk. (TR 327) Witness D'Ascendis derived an estimated ROE of 11.42 percent using the average of two different RPMs: a RPM using his adjusted total market approach (TMARPM), and a predictive RPM (PRPM) developed by his firm. (JP BR 25; TR 328; EXH 30, BSP E5-176) The TMARPM result was 11.0 percent and the PRPM result was 11.82 percent. (EXH 30, BSP E5-176) Witness Garrett did not include an additional risk premium analysis in his testimony citing that the CAPM is a risk premium model. (TR 1018)

#### *Total Market Approach RPM*

In his TMARPM, witness D'Ascendis estimated a projected yield on A2-rated public utility bonds of 5.47 percent, which is equivalent to the average bond rating of the gas proxy group, and added an equity risk premium (ERP) of 5.54 percent to the A2-rated public utility bond yield for a result of 11.0 percent. (TR 333; EXH 30, BSP E5-178) To estimate a projected A2-rated bond yield, witness D'Ascendis added a 0.71 percent yield spread to the forecasted Aaa-rated corporate bond yield of 4.76 percent as published by Blue Chip Financial Forecasts. (TR 333-334; EXH 30, BSP E5-178) Witness D'Ascendis estimated a yield spread of 0.71 percent by calculated the difference between an Aaa-rated corporate bond and an A2-rated corporate bond as published by Bloomberg Professional Service. (TR 333-334; EXH 30, BSP E5-179) The projected A2-rated public utility bond yield as estimated by witness D'Ascendis was 5.47 percent. (EXH 30, BSP E5-178, Line No. 3)

To estimate the ERP in his TMARPM, witness D'Ascendis used the average of three different derivations: a beta-adjusted total market ERP, an ERP based on the S&P Utilities Index, and an ERP based on a regression analysis of the awarded authorized ROEs for natural gas distribution utilities. (TR 333; EXH 30, BSP E5-182)

For his beta-adjusted total market approach, witness D'Ascendis relied on six different ERP measures reflecting the ERP for the stock market as compared to Moody's average Aaa and Aa rated corporate bond yields. (TR 334-340; EXH 30, BSP E5-183) His total market ERP results ranged from 5.82 percent to 10.92 percent with and average of 8.95 percent. (EXH 30, BSP E5-183) Witness D'Ascendis multiplied the average beta of the gas proxy group to his average total market ERP to obtain a beta-adjusted forecasted ERP of 6.89 percent. (EXH 30, BSP E5-183) As discussed in the PRPM section below, staff recommends that all of witness D'Ascendis's analyses using the PRPM be disregarded. Consequently, witness D'Ascendis ERP of 9.77 percent derived from Kroll Equity Risk Premium based on the PRPM on Line 3 in Document No. 4 should be disregarded. (EXH 30, BSP E5-183) With this adjustment, his average equity risk premium would have been 6.76 percent as opposed to 6.89 percent.

For his S&P Utilities Index ERP, witness D'Ascendis calculated three ERP estimates based on long-term historical holding period returns for large company common stocks less the average historical yield on Moody's A2-rated public utility bonds for the period 1928 to 2021, and two ERP estimates based on the expected returns of the S&P Utilities Index. (TR 340-336) His results ranged from 4.2 percent to 5.44 percent with an average of 4.83 percent. (EXH 30, BSP E5-186) As discussed in the PRPM section below, staff recommends that all of witness D'Ascendis's analyses using the PRPM be disregarded. Consequently, witness D'Ascendis forecasted ERP of 5.44 percent based on the PRPM in Document No. 4, Line No. 3, should be disregarded. (EXH 30, BSP E5-186) With this adjustment, his average equity risk premium would have been 4.63 percent as opposed to 4.83 percent.

For his third ERP estimate, witness D'Ascendis used a regression analysis to estimate the difference between regulatory awarded ROEs and the yields on Moody's A2-rated public utility bonds for 818 rate cases during the period from January 1, 1980, through July 20, 2023, and obtained a result of 4.90 percent. (TR 342; EXH 30, BSP E5-187) This was in increase of 19 basis points from his direct testimony. (EXH 20, BSP D9-639)

As a result of staff's adjustments to remove witness D'Ascendis's ERP estimates using his PRPM, witness D'Ascendis's ERP would be 5.43 percent and his TMARPM result would be 10.9 percent.

OPC witness Garrett disagreed with witness D’Ascendis use of risk premium models in addition to the CAPM, which witness Garrett asserted is itself a risk premium model that has been utilized by companies for decades for the purpose of estimating the cost of equity. (TR 1018) In particular, witness Garrett contended that witness D’Ascendis risk premium models rely in part on utility bond yields dating back to 1928, which is of questionable relevance because a cost of equity estimation is a forward-looking process. (TR 1017) Further witness Garrett asserted that witness D’Ascendis’s ERP regression analysis model that compared regulatory awarded ROEs dating back to 1980 to then-current bond yields effectively perpetuate the discrepancy between awarded ROEs that are consistently higher than the market-based cost of equity. (TR 1017)

### *Predictive RPM*

Witness D’Ascendis utilized a risk premium method that estimates a risk-return relationship by analyzing the volatility of past economic time series data and using that result to predict future levels of risk and risk premiums. (TR 329) This method was developed from the work of Robert F. Engle who shared the Nobel Prize in Economics in 2003 for his ARCH model. ARCH is an acronym for Autoregressive Conditional Heteroscedasticity. (EXH 20, BSP D9-657) Witness D’Ascendis, along with other colleagues, applied a generalized form of the ARCH model, or GARCH to develop the PRPM. (TR 329-330) Witness D’Ascendis explained that the inputs to his GARCH model are the historical returns on the common shares of each of the gas proxy group’s companies, minus the historical monthly yield on long-term U.S. Treasury securities through July 2023. (TR 330) Using GARCH, he calculated each of the gas proxy group companies’ projected equity risk premium using Eviews© statistical software. (TR 330) When the GARCH model is applied to the historical return data, it produced a predicted GARCH variance series and a GARCH coefficient. (TR 330-331) Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it produces the predicted annual equity risk premium. (TR 331) He then added the forecasted 30-year U.S. Treasury bond yield of 3.80 percent to each company’s PRPM-derived equity risk premium to arrive at an indicated ROE for each company. (TR 331; EXH 30, BSP E5-177) Witness D’Ascendis’s PRPM produced a range of results of 8.66 percent to 19.1 percent for the gas proxy group, with an average of 11.61 percent. (EXH 30, BSP E5-177) Witness D’Ascendis eliminated the highest result of 19.1 percent for One Gas, Inc. because it was too high and the GARCH coefficient was not statistically significant. (TR 517-518) In comparison, the DCF Model and CAPM results for One Gas, Inc. were 8.84 percent and 10.91 percent, respectively. (TR 519, EXH 30, BSP E5-169, E5-188)

In April 2013, witness D’Ascendis co-authored an article published in The Electricity Journal that compared the results of his PRPM with the results of the DCF Model and the CAPM for estimating the cost of equity. (EXH 132, BSP F3030-F3035) Witness D’Ascendis agreed that in the article it states that “Figures 2-5 clearly show that, for the most part, the PRPM produces a higher average indicated ROE than both the DCF and CAPM.” (TR 516, EXH 132, BSP F3034) The authors concluded that in their opinion, “the PRPM benefits ratemaking with an additional model to estimate ROE.” To that end, the authors have been including the PRPM in their rate-of-return testimonies and the model has been presented publicly in several venues. (EXH 132, BSP F3034) Witness D’Ascendis also agreed that the PRPM he utilized in his testimony in the instant case produced higher results than his CAPM and DCF Model. (TR 515-516)

As pointed out by the Joint Parties in their brief, witness D'Ascendis testified on behalf of utility companies in over 130 rate cases and his testimony that included his PRPM was partly accepted only twice. (JP BR 25; TR 436, 524; EXH 20, BSP D9-659-664) Witness D'Ascendis alluded to two water rate cases, one each in South Carolina, and North Carolina, in which he testified and included his PRPM method. (TR 445-446; EXH 117, BSP F1055 – F1058) In the South Carolina rate case for Carolina Water Service, Inc., witness D'Ascendis testified the ROE should fall within a range of 10.45 percent to 10.95 percent and the South Carolina Commission ultimately found a ROE of 10.50 percent, at the low end of witness D'Ascendis's range, is supported by the evidence. (TR 445-446; EXH 117, BSP F1055) The South Carolina Commission didn't specifically discuss or approve witness D'Ascendis's PRPM method but found his arguments persuasive and apparently used the average of the results of all his cost of equity models, including the PRPM, of 10.51 percent as a basis for its decision. (TR 445-446) In the North Carolina case for Carolina Water Service, Inc., the North Carolina Commission found witness D'Ascendis's RPM using his total market approach, not his PRPM, to be credible. (TR 447-448; EXH 117, BSP 1055-1056) The North Carolina Commission found that analyses using interest rate forecasts rely unnecessarily on projections and approved the use of current interest rates rather than projected near-term or long-term interest rates. (TR 447: EXH 117, BSP F1058)

Witness D'Ascendis admitted that his PRPM produces a ROE which is forward-looking and not associated with a definite time period. (TR 448; EXH 181, BSP G2-611) Further, witness D'Ascendis agreed that while other utility witnesses use the PRPM method, no other practitioners use the PRPM and combine it within their testimony the way he does. (TR 469) Witness D'Ascendis also confirmed that his PRPM is not easily verified by using simple algebra which is possible for the DCF Model and CAPM and requires the use of statistical software to derive and test. (TR 523-524)

As discussed above, witness D'Ascendis's PRPM suffers from a lack of transparency, is used only by a few ROE witnesses testifying on behalf of utilities, has not been widely relied upon by other regulatory jurisdictions, and routinely produces ROE results that are higher than both the DCF Model and CAPM which are widely accepted and relied upon by the regulatory community. Staff believes there is persuasive evidence in the record that the PRPM method developed and used by witness D'Ascendis in all his cost of equity analyses produces an unreasonably excessive ROE and should disregarded.

## Flotation Costs

OPC witness Garrett contended that PGS is asking the Commission to award PGS a cost of equity that is more than 150 basis points above its market-based cost of equity and it is especially inappropriate to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal. (TR 1026-1027) Therefore, the Joint Parties argued that flotation costs should be disallowed from a technical and policy standpoint. (TR 1026) OPC witness Garrett disagreed with the inclusion of flotation costs in the cost of equity for PGS. (TR 1025) Witness Garrett also opined that when an underwriter markets a firm's securities to investors, the investors are well aware of the underwriter's fees and have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price. (TR 1025-1026) As a result, witness Garrett opined, there is no need for PGS's shareholders to receive additional compensation to account for costs they have already considered and to which they agreed. (TR 1026) Witness Garrett contended that investors of competitive firms do not expect additional compensation for flotation costs, and therefore it would not be appropriate for the Commission to stand in place of competition to award a utility's investors with additional compensation. (TR 1026) Staff believes witness Garrett's argument is not persuasive and agrees with witness D'Ascendis that it is appropriate to include a flotation cost adjustment when using ROE models to estimate the cost of equity.

In PGS's last rate case in 2008, the Commission did not make a specific adjustment for flotation costs, but in its Order it stated that the Commission has traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor required return. (TR 357) Witness D'Ascendis asserted it is important to recognize flotation costs in the allowed ROE because there is no other mechanism in ratemaking paradigm through which such costs can be recovered. (TR 357) Historical flotation costs are a permanent loss of investment income to the utility and should be accounted for. (TR 358-359) Witness D'Ascendis explained that for each dollar that is issued at market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. (TR 359) Because these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10.00 percent is for the net investment, $0.95, to earn more than 10.00 percent to net back to the investor a fair return on that dollar. (TR 359) Witness D'Ascendis contended that all of the cost of equity models assume no transaction costs and an adjustment to the cost of equity needs to be made to account for the flotation costs and make the utility whole. (TR 359) Consequently, it is appropriate to include a flotation cost adjustment when using ROE models to estimate the cost of equity. (TR 360) Witness D'Ascendis calculated the flotation cost adjustment based on the actual flotation costs of Emera Incorporated and adjusted the dividend yield in his DCF Model to estimate the effect of the flotation cost on the DCF cost rate. (TR 360; EXH 30, BSP E5-199) Staff believes witness D'Ascendis's method to determine the flotation cost is credible and provided persuasive evidence for his recommendation to include a flotation cost of 9 basis points.

## Business Risk Adjustment

To reflect PGS's specific business risks, witness D'Ascendis made an upward adjustment of 20 basis points to reflect PGS smaller relative size, high level of customer growth, overall performance, and capital investment plans. (PGS BR 26; TR 301-302) Witness Garrett argument that firm-specific business risk factors are not rewarded by the market and systemic risk, i.e., interest rate risk, inflation risk, and other risks that affect all stock market listed companies, is the only type of risk for which investors expect a return. (TR 1020) Witness Garrett asserted that investors do not require additional compensation for assuming these firm-specific risks. (TR 1021) Witness Garrett opined that investors eliminate firm-specific risk through diversification and do not expect a higher return for assuming the firm-specific risk in any one company. (TR 985) For the reasons cited herein, staff agrees with witness Garrett that business risk is reflected in the stock price investors pay for a stock and a specific adjustment to the cost of equity for business risk is not necessary.

### *Small Size Premia*

Witness D'Ascendis asserted that because PGS is smaller in size relative to the gas proxy group, PGS is less able to cope with significant events that affect sales, revenues, and earnings. (TR

361) Therefore, since smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. (TR 361-363) Witness D'Ascendis cited to three sources supporting his assertion that investors require higher returns on stocks of small firms than on otherwise similar stocks of large firms. (TR 363; EXH 132, Attachment 16, BSP 6611, 6586-6607, 6619-6621) Witness D'Ascendis contended that consistent with the financial principle of risk and return, increased relative risk due to small size must be considered in the allowed rate of return on common equity. (TR 363) Therefore witness D'Ascendis argued, the Commission's authorized ROE in this proceeding must appropriately reflect the unique risks of PGS, including its smaller relative size, which is justified and supported by evidence in the financial literature. (TR 363) Witness D'Ascendis quantified a small size risk adjustment for PGS based on its estimated market capitalization as compared to the market capitalization of the gas proxy group. (TR 364) Witness D'Ascendis estimated that the average market capitalization of the gas proxy group is 3.7 times that of PGS. (TR 364; EXH 30, BSP E5-200) Based on Kroll Associates Size Premia Decile Portfolio, the applicable premium for PGS would be 79 basis points. (EXH 30, BSP E5-200)

OPC witness Garrett disagreed with witness D'Ascendis's size adjustment and recommended the Commission should reject PGS's proposed size premium. (TR 1023) Witness Garrett explained the size premium arose from a study in 1981 conducted by Banz, which indicated that during the period of 1936 through 1975 common stock of small firms had on average higher risk-adjusted returns that larger firms. (TR 1021) Witness Garrett cited from the book, *Triumph of the Optimists*, published in 2002, that there were subsequent empirical studies that found the size effect phenomenon disappeared within a few years and the authors of the study concluded it is inappropriate to automatically expect there to be a small-cap premium on every stock. (TR 1022; EXH 156, Attachment 4, BSP 199-200) Further, witness Garrett cited an article by Kalesnik and Beck that stated in part:

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.

(TR 1023; EXH 156, Attachment 4, BSP 372-378)

OPC witness Garrett made a persuasive argument that small company stocks do not necessarily outperform large company stocks, and therefore, an upward size adjustment to the market-based ROE is not warranted. (TR 1021-1024)

### *Capital Investment and Customer Growth*

Witness D'Ascendis asserted that as addressed in PGS witness Fox's direct testimony, PGS has experienced strong customer growth over the last five years and projects it will continue to experience relatively strong growth over the next five years. (TR 366) PGS plans to invest over $1 billion of capital from January 1, 2022 to December 31, 2024, to support its growth. (TR 366) Witness D'Ascendis asserted that the allowed ROE should enable PGS to finance capital expenditure requirements at reasonable rates, and maintain its financial integrity. (TR 368)

Witness D’Ascendis contended that credit rating agencies recognize risks associated with increased capital expenditures, and from a credit perspective the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. (TR 369) Witness D’Ascendis asserted that PGS has the highest ratio of projected capital expenditures to net plant as compared to the gas proxy group which indicates an increased business risk. (TR 371) In his direct testimony, witness D’Ascendis calculated PGS’s ratio of forecasted capital expenditures to net plant at 60 percent as compared to 39.5 percent for the median ratio of the gas proxy group based on 2021 information; a difference of 20.5 percentage points. (TR 499; EXH 132, BSP 7773) In his rebuttal testimony, witness D’Ascendis updated his calculation and derived a capital expenditure to net plant ratio of 33 percent for PGS as compared to a median of 26.5 percent for the gas proxy group based on 2022 information; a difference of 6.5 percent. (TR 500) On cross examination, witness D’Ascendis agreed that the decrease in the difference from 20.5 percent to 6.5 percent indicated the relative risk for PGS on this measure decreased:

> I would say, yeah, based on -- based on these numbers, but I don't know whether or not they -- well, I guess, yeah, I mean, I would agree with that, but the debt would still be outstanding, like, the capital would still be outstanding. But, yes, I would agree that going forward, the company is less risky than when they were when they filed based on this measure.

(TR 501)

Witness D’Ascendis projected capital expenditures to net plant business risk measure suffers from a lack of credible evidentiary support and should be given little weight. Witness D’Ascendis agreed that the gas proxy group consists primarily of holding companies which are larger than PGS and have a significantly higher amount of net plant. (TR 503) By operation of math, a higher amount of net plant would reduce the ratio of projected capital expenditures to net plant. (TR 504) Further, witness D’Ascendis agreed that a better comparison would have been to use the operating gas companies owned by the holding companies, but the projected net plant for operating companies are not available. (TR 502-504) Finally, by witness D’Ascendis’s own admission PGS’s business risk by this measure has decreased from 2021 to 2022.

## Financial Risk

Financial risk is created by the introduction of debt into the capital structure. (TR 310) The higher proportion of debt in the capital structure, the greater the financial risk. (TR 310) Consistent with the basic principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk. (TR 310-311) PGS requested an equity ratio of 54.7 percent which is higher than the average equity ratio of the gas proxy group of 48.83. (TR 506-507; EXH 30, BSP E5-168) Based on the risk-return relationship, PGS has lower financial risk than the gas proxy group. (TR 507) However, witness D’Ascendis did not consider a downward adjustment to his recommended ROE to reflect the lower financial risk. (TR 507) He explained that the operating utilities under the publicly traded holding companies have a more comparable equity ratio and if taken together (holding company and operating company equity ratios). In his opinion, there is not a difference in risk to the capital structure. (TR 507) Witness D’Ascendis agreed that the operating subsidiary companies do not issue stock, so he relied on the holding companies market data in his cost of equity analyses to derive his recommended ROE. (TR 509) Witness D'Ascendis agreed he could not perform a ROE analysis on the operating companies because they are not publicly traded and do not have market data. (TR 508-509) According to financial theory, it is most appropriate to use the equity ratio of the publicly traded company proxy group to assess financial risk because the stock prices used in witness D'Ascendis's ROE analysis are based on the equity ratios of the holding companies. (TR 508-509) Using the subsidiary operating companies to assess financial risk would be meaningless. OPC witness Garrett recommended an equity ratio of 49 percent for PGS based on the average of the gas proxy group. (TR 1031) Witness Garrett did not make a specific adjustment for financial risk to his ROE analysis because there is not a difference between his recommended equity ratio and that of the average of the proxy group. (TR 1031) However, witness Garrett did quantify the effect of using a higher equity ratio of the gas proxy group in his CAPM analysis by using the Hamada Model. (TR 1034-1037) His calculation demonstrated that the difference in equity ratios of 54.7 percent to 49 percent, or financial risk, equated to a reduction of 40 basis points to the ROE. (TR 1037; EXH 79)

## CONCLUSION

After making staff's recommended adjustments to the witnesses ROE models discussed herein, the adjusted range of results for the gas proxy group is 9.0 percent to 10.9 percent. Record evidence supports the risk-return concept that utilities with lower financial risk should be allowed lower returns. The record evidence demonstrates PGS has a higher equity ratio than the average of the gas proxy group, and as such, it has less financial risk. Therefore, a downward adjustment to PGS's ROE should be recognized to reflect PGS's lower financial risk as compared to the gas proxy group. In addition, the record evidence is clear that capital costs have increased since PGS's last rate case in 2020 in which the Commission authorized an ROE of 9.9 percent, and interest rates have increased during the course of this proceeding which may not be fully recognized in the financial cost of equity models presented by the witnesses. Therefore, on balance, staff believes the record evidence supports an ROE of 10.15 percent for PGS. This return is above the recent national average of awarded ROEs of approximately 9.5 percent and should enable PGS to generate the cash flow needed to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, maintain sufficient levels of liquidity to fund unexpected events, and sustain confidence in Florida's regulatory environment among credit rating agencies and investors. Accordingly, staff recommends the appropriate ROE for establishing PGS's projected test year revenue requirement is 10.15 percent with a range of plus or minus 100 basis points.

***Issue 36:*** What capital structure and weighted average cost of capital should be approved for establishing PGS's projected test year revenue requirement?

***Recommendation:*** A capital structure consisting of 54.7 percent common equity, 40.5 percent long-term debt, and 4.8 percent short-term debt as a percentage of investor sources should be approved for the 13-month average test year ending December 31, 2024. A weighted average cost of capital of 7.016 percent should be approved for establishing PGS's projected test year revenue requirement and setting rates in this proceeding. (D. Buys)

### *Position of the Parties*

**PGS:** The appropriate capital structure and average cost of capital is shown in the below table, and the resulting average cost of capital is 7.41 percent, but needs to be updated based on the results of other issues, including elimination of ITC in Issue 29.

**Joint Parties:** The Commission should approve a weighted average cost of capital of 5.87 percent and the capital structure shown in the testimony of OPC's experts.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS
PGS witness Parsons testified that the appropriate capital structure consists of 54.7 percent common equity, 40.5 percent long-term debt, and 4.8 percent short-term debt from investor sources. (TR 1917-1918) This is presented in Table 36-1, below. PGS witness McOnie contended the capital structure containing an equity ratio of 54.7 percent as proposed by PGS is consistent with the capital structure previously approved for PGS by the Commission and is entirely consistent with the capital structures and equity ratios approved by the Commission for FPUC (55.1 percent) and FCG (56.9 percent). (TR 1135) Witness McOnie asserted that PGS's proposed capital structure is appropriate for ratemaking purposes as it is both typical and important to have significant proportions of common equity in its capital structure. (TR 1135) PGS argued Issue 36 is a fallout issue that depends on the decisions made on other capital structure issues. (PGS BR 28) Table 36-2 reflects PGS's requested overall weighted average cost of capital (WACC) and reflects the Company's positions on Issue 28, Issue 31, Issue 32, and Stipulated Issue 30. (PGS BR 28) In its brief for Issue 32, PGS argued the Company's proposed amount of long-term debt for the test year reflects the $832,185,531 of long-term debt on MFR G-3, page 2, adjusted for the decrease in rate base in Issue 27, and increased for a pro-rata allocation over investor sources of capital to offset for the change in accumulated deferred income taxes in Issue 28. (PGS BR 23; EXH 137, BSP F7047)

### Joint Parties
The Joint Parties argued OPC witness Kollen testified that the WACC is 5.87 based on witness Garrett's 49 percent equity ratio and 9.0 percent ROE. (JP BR 27; TR 1271) The Joint Parties argued that witness Garrett's combined ROE and capital structure recommendation is a combined $38.515 million reduction to PGS's requested base rate increase. (JP BR 27) The Joint Parties argued the Company's decision to undertake the 2023 Transaction with all its potential

risks was executed solely at the discretion of the Company and its impact is an increase of financing costs to customers. (JP BR 28) The Joint Parties argued that PGS would have a credit rating of BBB+ if it was still a division of Tampa Electric, but the 2023 Transaction will likely cause a one notch lower rating for PGS. (JP BR 27) Joint Parties argued the Commission should take every opportunity to minimize the impacts of the 2023 Transaction to PGS's customers by adopting the WACC proposed by OPC witnesses Kollen and Garrett. (JP BR 28) Staff notes that most of the Joint Parties arguments in this issue relate to the 2023 Transaction's effect on credit ratings, the cost rate for long-term debt, and the expectation by PGS for it's customers to pay a higher-than market cost of capital to support the Company's preferred credit ratings. Therefore, staff will address the Joint Parties' arguments related to those subjects in Issue 32.

## ANALYSIS

The capital structure and WACC is a fall-out issue that incorporates the amounts and cost rates of the capital sources into a final WACC. The cost rates and amounts of the capital components are recommended in Issues 28 through 35. In MFR Schedule G-3, page 2 of 11, PGS presented its requested projected test year capital structure based on a 13-month average as of December 31, 2024, consisting of common equity in the amount of $1,124,006,187 (54.7 percent), long-term debt in the amount of $832,185,531 (40.5 percent) and short-term debt in the amount of $99,671,451 (4.8 percent) as a percentage of investor-supplied capital. (TR 1115; EXH 7, BSP K278) The initial capital structure submitted by PGS is summarized in Table 36-1.

**Table 36-1**
**PGS Initial Adjusted Capital Structure and WACC**

| Capital Component | Amount (Adjusted) | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Common Equity | $1,124,006,187 | 47.49% | 11.00% | 5.22% |
| Long-Term Debt | $832,185,531 | 35.16% | 5.54% | 1.95% |
| Short-Term Debt | $99,671,451 | 4.21% | 4.85% | 0.20% |
| Customer Deposits | $27,528,183 | 1.16% | 2.53% | 0.03% |
| Deferred Taxes | $280,240,209 | 11.84% | 0.00% | 0.00% |
| Investment Tax Credits | $3,156,892 | 0.13% | 8.49% | 0.01% |
| Total | $2,366,788,452 | 100% | | 7.42% |

Source: EXH 7, BSP K278

In her rebuttal testimony, PGS witness Parsons included adjustments to rate base and the amount of ADITs related to depreciation adjustments. (EXH 33, BSP E8-543) Based on those adjustments, PGS's adjusted proposed capital structure for the 2024 test year as presented in its brief is summarized in Table 36-2.

**Table 36-2**
**PGS Revised Adjusted Capital Structure and WACC**

| Capital Component | Amount (Adjusted) | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Common Equity | $1,118,145,545 | 47.47% | 11.00% | 5.22% |
| Long-Term Debt | $827,335,811 | 35.12% | 5.54% | 1.94% |
| Short-Term Debt | $99,662,408 | 4.23% | 4.85% | 0.21% |
| Customer Deposits | $27,525,625 | 1.17% | 2.53% | 0.03% |
| Deferred Taxes | $279,720,428 | 11.87% | 0.00% | 0.00% |
| Investment Tax Credits | $3,156,598 | 0.13% | 8.49% | 0.00% |
| Total | $2,355,546,414 | 100% | | 7.41% |

Source: PGS BR 28

The Joint Parties recommended the Commission set PGS's equity ratio at 49 percent with a ROE of 9.0 percent. (TR 965) The Joint Parties also recommended the Commission set PGS's long-term and short-term debt cost rates at 4.61 percent and 3.81 percent, respectively. (TR 1271) OPC witness Kollen also made adjustments that increased the ADIT balance in the capital structure. (TR 1270) The Joint Parties' recommended adjusted capital structure and WACC are summarized in Table 36-3.

**Table 36-3**
**OPC Recommended Adjusted Capital Structure and WACC**

| Capital Component | Amount (Adjusted) | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Common Equity | $1,008,304,000 | 42.60% | 9.00% | 3.83% |
| Long-Term Debt | $941,736,000 | 39.79% | 3.81% | 1.83% |
| Short-Term Debt | $99,358,000 | 4.24% | 4.85% | 0.16% |
| Customer Deposits | $27,525,625 | 1.17% | 1.16% | 0.03% |
| Deferred Taxes | $286,705,000 | 12.11% | 0.00% | 0.00% |
| Investment Tax Credits | $3,157,000 | 0.13% | 6.73% | 0.01% |
| Total | $2,366,788,000 | 100% | | 5.87% |

Source: JP BR 28; TR 1271

In Issue 34, staff recommends an equity ratio of 54.7 percent. In Issue 35, staff recommends a cost of equity of 10.15 percent. Staff agrees with PGS's proposed capital structure as presented in MFR Schedule G-3, page 2 of 11, with the adjusted capital component amounts described in PGS witness Parson's rebuttal testimony. In her rebuttal testimony, PGS witness Parsons included adjustments to rate base and the amount of ADITs related to depreciation adjustments as discussed in Issue 28. (EXH 33, BSP E8-543) The Commission also approved a stipulation for Issue 18 to remove the Alliance project from rate base that resulted in an adjustment to remove the associated ADITs and ITCs from the capital structure. Because all of the ITCs were realized through the investment in the Alliance project, the ITC balance was decreased to zero. PGS noted in its brief that the capital structure and WACC would have to be updated to reflect that adjustment and the Commission's decisions regarding other capital structure issues. (PGS BR 28) In addition, the Commission approved a stipulation to the amount and cost rate for customer deposits of $27,528,000 at 2.53 percent. The capital structure should be reconciled with staff's recommended rate base adjustments over investor sources and deferred taxes after the proper adjustments to the ADIT balance are included. If the Commission approves staff's recommendation in Issues 27 through 35, staff's recommended capital structure is summarized in Table 36-4.

**Table 36-4**
**Staff Recommended Adjusted Capital Structure and WACC**

| Capital Component | Amount (Adjusted) | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Common Equity | $1,122,029,733 | 47.604% | 10.15% | 4.83% |
| Long-Term Debt | $830,722,209 | 35.24% | 5.54% | 1.95% |
| Short-Term Debt | $99,496,189 | 4.22% | 4.85% | 0.20% |
| Customer Deposits | $27,528,000 | 1.17% | 2.53% | 0.03% |
| Deferred Taxes | $277,551,630 | 11.77% | 0.00% | 0.00% |
| Investment Tax Credits | $0 | | 8.03% | 0.00% |
| Total | $2,357,327,760 | 100% | | 7.02%* |

Source: Staff Work Papers *The actual WACC is 7.016% that is used for revenue requirement calculation.

## CONCLUSION

A capital structure consisting of 54.7 percent common equity, 40.5 percent long-term debt, and 4.8 percent short-term debt as a percentage of investor sources should be approved for the 13-month average test year ending December 31, 2024. A weighted average cost of capital of 7.016 percent should be approved for establishing PGS's projected test year revenue requirement and setting rates in this proceeding.

***Issue 37:*** Has PGS made the proper adjustments to remove the Purchased Gas Adjustment, Natural Gas Conservation Cost Recovery Clause, and CI/BSR Revenues and Expenses from the projected test year? If not, what adjustments should be made?

***Approved Type 2 Stipulation:*** Yes, as shown on MFR Schedule G-2, pages 2-3.

***Issue 38:*** Has PGS made the proper adjustments to remove all non-utility activities from projected test year operating expenses, including depreciation and amortization expense? If not, what adjustments should be made?

***Recommendation:*** Although not completely removed in PGS's original filing, adjustments for non-utility activities are addressed by staff's recommendation in Issue 13 and the stipulation in Issue 44. As such, no further adjustments are necessary. (Andrews, Gatlin)

***Position of the Parties***

**PGS:** Yes.

**Joint Parties:** See discussion in Issue 13.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

The Company testified that all appropriate adjustments have been made to remove all non-utility activities from operation expenses as shown in MFR Schedule G-2, pages 2-3 and in Exhibit 218, the revised revenue increase. (PGS BR 29; EXH 7, BSP K220-K221; EXH 218, BSP G1-250 – G1-251)

### Joint Parties

The Joint Parties have concerns about PGS's basis for attributing costs associated with SGT. (JP BR 9) The Joint Parties argued that the current standard is based on an impermissibly narrow basis and allows for engineering-related costs to be attributed to SGT when the Company is actively working on a Seacoast project. (JP BR 9; TR 1810; EXH 222) The Joint Parties argued that this standard does not consider the workload put onto the Engineering, Construction, and Technology (ECT) department for potential SGT projects. (JP BR 9) The Joint Parties stated that there is evidence in 2022 where there were non-work order projects underway or being evaluated, but those activities did not have any cost allocated to SGT. (JP BR 9; TR 1806-1810; EXH 211C, 215C)

The Joint Parties emphasized its concern for the current standard of PGS executing tasks for an unregulated affiliate company and more so that PGS is requesting to increase its employee headcount by a seven member team that would work within the Company's business development organization on projects that could be affiliated with SGT. (JP BR 9; TR 1746-1748) The Joint Parties are concerned the hiring needs proposed for the projected test year could be driven by the needs of SGT because SGT projects have the potential to redirect resources of PGS's ECT team at any given time. (JP BR 9; TR 1800; EXH 175C, OPC BSP 9) The Joint Parties concluded that due to these factors the Company should mitigate the authorization of funding needed to hire the capital management team. (JP BR 9)

The Joint Parties argued that the Company could leverage its regulated operations funded by its customers to subsidize its unregulated ventures of SGT. (JP BR 9) The Company was understanding of the concerns and acted in good faith by making a reduction in the revenue requirement of $190,000. (JP BR 9) The Joint Parties agreed with the Company's reduction and understood that the Company utilized a method that has not been challenged. (JP BR 9) Therefore, the Joint Parties recommended that the Commission instruct the Company to redefine its method of attributing costs to SGT. (JP BR 9-10) The Joint Parties ascertained that the cost allocation manual (CAM) by TECO was not designed to determine the separation of costs between PGS and SGT. (JP BR 10; TR 2053; EXH 222) In the CAM it states, "Periodically, PGS may provide a service to its affiliates. When this occurs, PGS will direct charge that affiliate for these services. Direct charges are expenses directly tied back to service provided to an affiliate." (JP BR 10; EXH 222, BSP G2-436) The Joint Parties deduced from the Company's CAM that the approach is informal and does not provide an efficient approach of attributing the costs from PGS to SGT. (JP BR 10)

The Joint Parties concluded the need for the Commission to instruct the Company to complete a comprehensive review of the relationship with SGT, with a focus on the procedures when SGT requires direct and indirect support from PGS, including the Company's need to maintain open availability of resources to service SGT needs. (JP BR 10) The Joint Parties also requested that the Commission direct the study to be filed in the next rate case and applied in any projected test year revenue. (JP BR 10)

## ANALYSIS

As addressed in Issue 13, PGS agreed to reduce O&M expense by $189,347 to increase PGS's overhead cost allocation to SGT as shown in Exhibit 218. (EXH 218) The Joint Parties agreed with the methodology of this adjustment and, in lieu of seeking an additional adjustment, requested that the Commission direct the Company to revisit its method of attributing costs to SGT. (JP BR 9-10) As discussed in Issue 13, staff believes a comprehensive procedural review and associated cost study would benefit the Commission in its analysis of the Company's next base rate case.

As reflected in the stipulation in Issue 44 and PGS witness Parsons' testimony, the Company agreed upon an adjustment to reduce projected test year O&M expense by $500,000 to remove expenses associated with lobbying, charitable contributions, sponsorships, and institutional and image advertising. This adjustment is comprised of several adjustments including audit findings identified by staff witness Brown. Witness Brown's testimony identified several adjustments that reduced PGS's 2022 base rate recoverable O&M, including the reclassification of expenses related to the Tampa Bay Buccaneers as non-utility. (EXH 105, BSP D17-2221) The adjustment presented by witness Parsons reflects the inflationary factors applied to the projected test year. Staff does not recommend any further adjustments.

## CONCLUSION

Although not completely removed in PGS's original filing, adjustments for non-utility activities are addressed by staff's recommendation in Issue 13 and the stipulation in Issue 44. As such, no further adjustments are necessary.

***Issue 39:*** What amount of projected test year Uncollectible Accounts and Bad Debt should be included in the Revenue Expansion Factor?

***Approved Type 1 Stipulation:*** The Bad Debt Expense is $1,611,232, as shown on MFR Schedule G-2, page 19b, line 7, and the bad debt rate of 0.2805 percent was incorporated into the Revenue Expansion Factor, as shown on MFR Schedule G-4.

***Issue 40:*** What non-labor trend factors should be used for inflation and customer growth for the projected test year?

***Approved Type 2 Stipulation:*** The appropriate non-labor trend factor for inflation is 2.80 percent and 2.20 percent for 2023 and 2024, respectively. The appropriate non-labor trend factor for customer growth is 3.81 percent and 3.23 percent for 2023 and 2024, respectively.

***Issue 41:*** What amount of projected test year contractor and contract services cost should be approved?

***Recommendation:*** Staff recommends that $20,827,232 in projected test year contractor and contract services cost should be approved. This amount reflects an adjustment of $206,000 associated with displaced outside services and approximately $3.9 million associated with Stipulated Issue 18. (Wooten, Norris)

***Position of the Parties***

**PGS:** The appropriate amount of projected test year contractor and contract services cost should be $24,989,844. This amount reflects a total of $25,179,844 included in PGS' filing less an adjustment of $190,000 for the decrease in the projected test year standalone audit fees based.

**Joint Parties:** The Joint Parties recommend a reduction in the level of test year contractor and contract services cost by $206,000 for in-house hiring from outside contractors.

***Staff Analysis:***

## PARTIES ARGUMENTS

### PGS

PGS argues that the appropriate amount of projected test year contractor and contract services cost is $24,989,844 which reflects an adjustment of $190,000 for the decrease in the projected test year standalone audit fees. (PGS BR 29) PGS asserts that contractors allow the Company to quickly adjust the size of its workforce to meet operational, performance, and geographic needs. (PGS BR 29-30) PGS also asserts that the Company works to balance internal labor and contract labor costs, has already taken steps to reduce contractor expenses and that the proposed mix of labor and contracted services is necessary to properly maintain adequate levels of safety, reliability, and customer service. (PGS BR 30)

### Joint Parties

The Joint Parties assert that PGS did not reduce contractor expenses by an amount that justified the increase in employees. (JP BR 29) The Joint Parties also assert that the Company filled 22 pipeline locator positions and 2 administrative support positions which displaced outside contract services. (JP BR 29-30) The Joint Parties argue that total cost savings provided by these replaced positions is approximately $206,000 and should be removed from the contractor and contract services cost. (JP BR 30)

## ANALYSIS

In PGS's original filing, it stated that the appropriate amount of projected test year contractor and contract services costs that should be approved is $25,179,844. (EXH 147, BSP 3) PGS later updated this total to $24,989,844 to account for a $190,000 adjustment based on standalone audit fees. (TR 1982)

PGS witness Wesley testified that due to customer growth and increased work activity the Company has become more reliant on outside contractors. (TR 82, 119) Witness Wesley asserted that from 2022 to 2024 PGS is expected to add approximately 28,000 new residential customers and 1,200 new commercial customers. (TR 73) PGS has experienced an increase in total work orders, attributed to customer growth, for all 14 of PGS's service territories which is anticipated to continue into 2024. (EXH 27) The evidence in the record shows that for all service areas from 2020 to 2024 there is a projected 18 percent increase in total work orders. (EXH 27) Specifically, PGS witness O'Connor projected that work volumes in the Company's Jacksonville service area for service, compliance, locates and meter readings are forecasted to experience double digit percentage growth in 2024. (TR 790-791) No parties disputed that customer growth has led to increased work activities. Witness O'Connor maintained that the use of contractors allows the Company to meet immediate needs related to operations, compliance, safety, maintenance, customer service and emergency response activities associated with the increase in work orders. (TR 742)

Witness O'Connor testified that in order to meet the higher workload and reduce the Gas Operation team's dependence on contractors, 38 new apprentices were trained in 2022. (TR 743) The witness further testified that as internal labor headcount increases, PGS evaluates contractor expenses in an effort to reduce contractor costs. (TR 801) During cross-examination, the witness stated that when a new employee is hired a contractor cannot be immediately replaced. (TR 855) The witness explained that because it takes approximately 18 months to train a new employee, the Company would maintain an outside contractor while the employee is trained. (TR 789, 800, 855) The witness further explained that because of this overlap, there is no immediate cost savings between internal and external costs associated with new positions. (TR 743) The witness argued that the overlap of internal and external labor is necessary to manage the transition to internal labor while simultaneously maintaining safety, reliability and customer service levels. (TR 801) Additionally, PGS has to make considerations regarding future contractor availability and contractual terms that may disallow contracts to be immediately terminated. (TR 855) Due to the newly trained Gas Operations team employees, PGS reduced contractor expenses in the test year by $1.1 million by eliminating contractors for locates, leak surveys, and other work activities. The witness clarifies that this reduction was primarily driven by financial considerations and reductions of contractor expenses is not sustainable long-term because continued balancing of employees and contractors is necessary to meet workload requirements. (TR 758; EXH 7, 139)

OPC witness Kollen testified that PGS is already staffed for continued growth and that the Company did not reduce contractor expenses to match PGS's requested increase in employees. (TR 1238-1239) In response to witness Kollen, witness O'Connor rebutted that there is no equivalent exchange between internal and external labor and the Company manages external labor to align with the required workload. (TR 800; EXH 139) The witness further rebutted that outside service expenses have decreased from previous years which is attributed to the increase in headcount. (TR 800) The evidence in the record shows that from 2020 to 2022, total outside service costs increased by $2,622,425 but from 2022 to 2024 are projected to decrease by $1,037,859. (EXH 27) Furthermore, the evidence in the record also shows that as internal labor headcount increased in 2023, Gas Operations reflected a $1.6 million reduction in contractor costs. (EXH 7, 27)

Staff agrees with the Company that the extended time required to train new employees may require an overlap of new internal labor with external labor in order to address the increase in work activities. Staff believes the Company's $1.1 million reduction in test year contractor expenses, to account for new employees, serves as an example of PGS appropriately reducing contractor expenses once employees are available. In addition, PGS witness Bluestone testified that in 2023, PGS hired 118 positions and 24 of these positions would displace the use of outside services. (EXH 202) The witness affirmed that of the 24 positions filled, 22 positions were pipeline locators and two were administrative specialists who have or will displace the use of outside services. Witness Bluestone further affirmed that there is a cost-savings of approximately $200,000 associated with the 22 displaced contracted pipeline locators and $6,000 associated with the two displaced contracted administrative specialists. (EXH 202) Staff notes that the Company did not remove these costs from its requested contractor and contract services cost. Staff believes the requested test year contractor expenses are necessary to maintain current and future system reliability, due to the increased work activities in PGS's service areas. However, staff agrees with the Joint Parties and recommends an adjustment of $206,000 associated with the displaced outside services. In its brief, the Joint Parties agreed with the removal of $206,000 in contractor and contract services due to positions being filed that displaced outside services. (JP BR 30)

Lastly, PGS stated that $3.9 million of contractor costs in the projected test year were attributed to the Alliance Dairies RNG project. (EXH 146) The stipulation in Issue 18 addresses the removal of the Alliance RNG project from the Company's request and a corresponding adjustment removing the $3.9 million of O&M expense associated with Alliance is reflected in Issue 49. Therefore, staff recommends a reduction of $3.9 million to the appropriate projected test year contractor and contract services cost.

Staff's recommended adjustments should be made to the projected test year contractor and contract services cost of $24,989,844, as reflected in PGS's updated filing. Therefore, staff recommends the appropriate projected test year contractor and contract services cost should be $20,827,232.

## CONCLUSION

Staff recommends that $20,827,232 in projected test year contractor and contract services cost should be approved. This amount reflects an adjustment of $206,000 associated with displaced outside services and approximately $3.9 million associated with the stipulation in Issue 18.

***Issue 42:*** What number of projected test year employees should be approved for ratemaking purposes?

***Recommendation:*** The number of projected test year employees that should be approved for ratemaking purposes is 824. As such, projected test year salaries and benefits should be decreased by $1,283,841. (Hinson, Gatlin, Wooten)

### *Position of the Parties*

**PGS:** The Company has proven the need for each of its proposed additional employees and how those proposed additions moderate the need for outside contractor services in the test year, so OPC's staffing adjustments should be rejected. The appropriate number of projected 2024 test year employees should be an average of 837 after vacancy allowances. The 837 average count includes the following by month: January to February – 830, March to May – 834, May to December – 840. The 837 average employees in 2024 reflects the additional 90 and 64 employees shown on MFR Schedule G-2, pages 19c-19e. However, based on its position on Issues 16, 17, and 18, the Company proposes to reduce projected 2024 operating expenses by $37,882 to reflect its updated plans to forgo cost recovery for one Business Development Manager for RNG.

**Joint Parties:** The number of projected test year employees should remain at 746, the 2023 level as of the hearing, or a maximum of 777, which eliminates the requested 21 unfilled positions included in the request. The requested 2024 increases in employees and related expenses should be excluded from the projected test year revenue requirement.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated in its brief that the number of employees for the projected test year should be an average of 837 after vacancy allowances, including its revised plans to forgo cost recovery for one Business Development Manager for RNG. (PGS BR 30; TR 78; TR 1350) The 837 average the Company proposed is comprised of an additional 90 employees in 2023 and 64 employees in 2024. (PGS BR 30-31; TR 1350; TR 1382-1303; EXH 133, BSP F6986) Of the additional 90 employees, 63 were replacement positions at the end of December 2022. (PGS BR 30-31; TR 1350; TR 1382-1303; EXH 133, BSP F6986) PGS witness Bluestone argued that the increase in team members is to strengthen the workforce to provide safe and reliable service to the growing Company's system. (PGS BR 31; TR 1350-1351) Bluestone maintained that each budgeted position is carefully considered, with justifications identified by a functional team leader for each position. (PGS BR 31; TR 1365)

PGS contended that the Joint Parties' recommendation to remove all of the proposed new employees does not consider the current market challenges, nor the reasonable projection of additional needed employees to operate the system safely and reliably. (PGS BR 31; TR 1324) PGS argued that through its combined testimony and discovery responses it has provided sufficient justifications for each proposed position, while the Joint Parties only made a generalized argument on the proposed additional positions. (PGS BR 31-32; TR 1943; EXH 133, BSP F6986; EXH 139, BSP F7077, F7095; EXH 164, BSP G2-493 – G2-497) PGS concluded that the Joint Parties' recommended adjustments of $9.762 million for staffing increases and $1.162 million for office supplies, and expenses for additional employees should be rejected by the Commission. (PGS BR 32)

PGS witness O'Connor testified that Gas Operations are increasing due to customer growth, and the Company's projections show that service-related work will grow by 6 percent annually, locate requests will increase 6 percent annually, and meter reading activities will increase 4 percent annually. (PGS BR 32; TR 786, 789) Witness O'Connor stated that to keep up the growth in the industry, PGS will need more trained team members, because currently PGS in unable to keep up with industry standard of responding to 98.5 percent of damage calls within 60 minutes. (PGS BR 32; TR 785, 849-850)

PGS witness Richard rationalized the need for new team members in the Engineering, Construction, and Technology area in 2023 and 2024 due to the growth in size and complexity of the Company. (PGS BR 32; TR 1645) Witness Richard affirmed that the Company plans to hire 41 employees in the ECT area in 2023 and 2024, with 17 being replacements and 24 being new positions. (PGS BR 32; TR 1645) Witness Richard justified each new position and explained the breakdown of the positions to be five in the Supply Chain; four in the Gas Control and Measurement and Regulation; seven in the support of the Capital Management; and the remaining eight positions will support the Design, Engineering, and Construction area. (PGS BR 32; TR 1645-1652)

PGS witness Bluestone addressed the need of 18 additional team members in support positions including three team members in Human Resources; six team members in Strategy, Marketing, and Communications; three team members in Regulatory and Pipeline Safety; three team members in Process Improvements and Analytics; and three team members in Real Estate. (PGS BR 32-33; TR 1366-1371) PGS witness Parsons attested to the need of the eight Finance positions. (PGS BR 33; TR 1941-1942)

## Joint Parties

The Joint Parties presented several arguments on why PGS should have to reduce the number of employees in the projected test year. Among those arguments made are: PGS had eliminated 21 vacant positions in the Gas Operations and Pipeline Safety fields, PGS did not reduce contractor expenses adequately to justify the increase of new employees, PGS's actual employees reflected significant vacancies compared to employees budgeted, additional employees are discretionary, the Company already has sufficient team members for the continued customer growth and related infrastructure, and the requested positions do not include efficiencies from WAM. (JP BR 31-32; TR 1238-1239, 1241, 2041; EXH 132, BSP F2722) The Joint Parties also argued that all 65 requested positions for the 2024 projected test year should be removed due to being discretionary by the Company. (JP BR 32) The Joint Parties concluded that the Commission should find the projected test year employees to be 746, the headcount at the time of the hearing, or a maximum amount of 777, to reflect the 30 additional positions that witness Bluestone attested were unfilled in 2023. (JP BR 32)

Witness Kollen testified that the additional employees are discretionary and the Company already has sufficient team members for the continued customer growth and related infrastructure. (JP BR 31-32; TR 1238-1239, 1241) Witness Kollen also noted that the forecasted 2023 and 2024 employee counts were significantly greater compared to the actual employee count from 2019 through March 2023. (JP BR 30; TR 1237)

The Joint Parties stated that the Company forecasted 798 team members by December 31, 2023, and as of August 15, 2023, there are 746 team members, with 61 positions filled and 30 unfilled positions. (JP BR 31; EXH 132, BSP F2722; EXH 199, BSP G2-852) The Joint Parties asserted that witness Bluestone's testimony confirmed most new team members filled existing positions reflected by the fact that of the 61 positions filled, 46 were backfilled and/or replacements, while 15 were new positions. (JP BR 31; TR 1387) The Joint Parties affirmed that the Company must provide sufficient evidence for the requested increase in team members to be reasonable and prudent. (JP BR 31) The Joint Parties asserted that PGS has failed to provide justification considering the comparison of the base year and prior years. (JP BR 31; TR 1241)

The Joint Parties also provided an alternative approach to adjusting the test year level of employees, should the Commission prefer a more targeted approach. (JP BR 32) The Joint Parties cited insufficient blanket statements as to the proposed staffing, impending WAM transformation, questionable hiring of contractor forces, and the lack of metrics to determine the need for new hires. (JP BR 33; TR 809-810, 818, 821, 856; EXH 164)

The Joint Parties provided targeted arguments on the new team members specifically in the ECT and Gas Operations areas. (JP BR 32) The Joint Parties argued that the Commission should prohibit the cost of the 2024 component of the Capital Management Team because it is part of a project that is considered to bring benefits in the budgeting and cost control beyond the test year. (JP BR 32) The Joint Parties argued that due to the hiring not projected to occur before the second half of 2024 that the matching principle needs to be applied to ensure that costs and revenues are within the same period. (JP BR 32; TR 1714, 2062) The Joint Parties contended that under the current timeline, the ECT hires will not have any impact on the 2025 budget will most likely impact projects and capital budgeting for 2026. (JP BR 32) Joint Parties also contended that PGS failed to demonstrate the need for the 29 proposed new hires in Gas Operations. (JP BR 32-33)

The Joint Parties used testimony from PGS witness O'Connor to highlight their concerns with insufficient justification and the lack of metrics related to hiring. The Joint Parties cited the identical justification provided by witness O'Connor for 61 positions regardless of the type of position. (JP BR 33; TR 821; EXH 164) The Joint Parties continued that no objective metrics were utilized to determine geographical distribution of the proposed new hires. (JP BR 33; TR 809-810) The Joint Parties reasoned that the amount of new employees is not appropriate due to witness O'Connor's testimony that PGS was rated the highest in a national survey for its service and that it does not have any safety compliance issues. (JP BR 33; TR 880-883) The Joint Parties contested that by hiring more employees in an area where tasks per employee is considerably higher than the Company's average, as stated by witness O'Connor, it could lower efficiency. (JP BR 33; TR 869; EXH 139, BSP F7096) The Joint Parties also questioned hiring new employees in areas where tasks per employee are below the Company's average because the

Company has not provided a sufficient metric on its proposed hiring locations. (JP BR 33; TR 867-868; EXH 188, BSP G2-338 – G2-352) The Joint Parties argued that PGS's explanation provided in response to OPC Interrogatory No. 13 was generic and that the data pulled from Exhibits 27 and 188 does not provide a legitimate reason for the geographical locations of the proposed new hires. (JP BR 33; EXH 45, BSP D15-1602 – D15-1608)

The Joint Parties agreed that WAM will be beneficial to the Company by providing metrics that the Company can utilize in hiring both team members and contractors and will produce a reduction in costs overall. (JP BR 33; TR 762-763, 815-816, 862, 880; EXH 187, BSP G2-544 – G2-546) The Joint Parties disputed the 15 apprentices projected to be hired for the 2024 test year because of the lengthy time to train in order for them to work independently. The Joint Parties further disputed whether the apprentices would be needed with the implementation of WAM. (JP BR 33; TR 878)

The Joint Parties claimed that by hiring individuals from its contracted services, the Company may have reduced its need to hire backfills or apprentices because they already have experience and knowledge of the industry. (JP BR 34) The Joint Parties raised concerns that the cost of contracted services could be lower in the projected test year because of the loss of workers now hired at PGS coupled with a difficult hiring environment. (JP BR 34) The Joint Parties attested to not being able to acquire sufficient data on this topic due to information coming out at the hearing and the Joint Parties continued that this should be considered a failure on the Company to meet its burden of proof. (JP BR 34)

## ANALYSIS

PGS requested recovery of 154 new employees in the projected test year. (EXH 7, BSP K258) Ninety of the employees were to be added in 2023 and the remaining 64 employees in 2024. (EXH 7, BSP K258) To explain the need for these new employees, PGS witnesses Rutkin, Parsons, Richard, O'Connor and Bluestone provided direct and rebuttal testimony to explain why the additional employee count is necessary and prudent for PGS.

Witness Rutkin stated that PGS intends to add new Gas Supply and Development positions in the next couple of years, equivalent to six replacement positions in 2023 and two replacement positions and three new positions in 2024. (TR 951) Witness Rutkin said that these additional positions are needed so that the Gas Supply and Development team can continue to support PGS's efforts to provide safe and reliable gas systems to its growing customer base. (TR 952)

Witness O'Connor stated that additional team members are required in Gas Operations to meet future work requirements and to maintain safe and reliable operations to serve customers. (TR 726) For 2023, 38 additional employees are needed and 36 additional employees are needed for 2024. (TR726) The new positions are needed to perform the incremental level of work activities driven by Florida's growth, to comply with increasingly stringent compliance requirements and evolving risks across pipeline safety, damage prevention, and emergency management. (TR 726)

Witness Richard stated that the ECT team will have 33 new employees added in 2023 and eight new employees added in 2024, for a total of 41 additional employees. (TR 1629) These additional employees will support customer growth, capital management, support services, a growing natural gas system through 24 hours monitoring of the natural gas system, and deliver greater value to customers through strategic materials and supplies contract management. (TR 1630-1631)

Witness Bluestone stated in her direct testimony that in order for PGS to strengthen its HR function, the Company will need three new employees in HR to review internal processes and systems to ensure they appropriately support the Company's growth, assist the Company's team members with career advancement goals, and provide Company leaders with tools to keep PGS's team members engaged. (TR1318) Witness Bluestone did not address the additional employees for the Strategy, Marking, and Communications, Real Estate, or Regulatory teams in her direct testimony, although she sponsored them on MFR Schedule G-2 page 19e. (EXH 7, BSP K260)

Despite the many justifications for the additional employees provided by PGS witnesses in its direct testimony and throughout discovery, OPC witness Kollen proposed that the Commission reject all new employee positions. (TR 1241) Witness Kollen argued that the additional employees should be rejected because: the additions are discretionary, PGS is already staffed for continued growth in customers and the related infrastructure, the Company's actual employees reflected significant vacancies compared to budgeted, PGS did not reduce contractor costs by an amount that justifies the increase in new employees, and the additional employees do not reflect efficiencies in WAM. (TR 1238-1239, 1241)

In his rebuttal testimony, witness O'Connor disagreed with OPC witness Kollen's assertion that the addition of employees is discretionary and that PGS is already sufficiently staffed for future work needs. (TR 798) Witness O'Connor asserted that if PGS does not increase headcount, locators will be required to perform more locates each day which could sacrifice quality and safety. (TR 798) As a result, higher compliance work volumes would be completed by team members working overtime and potentially cause burn-out or poor performance. (TR 799) Witness O'Connor also asserted in his rebuttal testimony that each service area must be considered to evaluate its ability to meet projected workload requirements, and he maintained that witness Kollen did not perform that evaluation. (TR 799) Witness O'Connor also disagreed with witness Kollen's assertion that PGS has not reduced contractor expense by an amount that justifies the increase in new employees by noting that the outside services expenses for Gas Operations has decreased from past years. (TR 800) Witness O'Connor asserted that high work activity and inflation are driving an increase in O&M costs, but regardless of that, PGS found a balance between internal and external labor. (TR 800) To further rebut witness Kollen's assertion on contractor costs, witness O'Connor pointed out that there is not an immediate one-for-one offset with an outside contractor as PGS's headcount increases. (TR 800)

In her rebuttal testimony, witness Parsons addressed eight new employees in the Finance department, three of which were replacement positions. (TR 1941) Witness Parsons stated that these eight employees are needed to support the new requirements related to PGS's independent financings associated with the 2023 Transaction and replace the support being provided by TECO, provide financial and project evaluation support to the Gas Supply and Development team, and support enhanced financial profitability analysis to ensure appropriate revenue projections and rate analysis. (TR 1942) In addition to the justification provided for the additional Finance positions in her rebuttal testimony, witness Parsons also asserted that the

Company has proven its need for its forecasted new team members based on the growth of its system and increased work activity, the majority of which is non-discretionary; based on her rebuttal and direct testimony, responses to OPC Interrogatories 13 and 201; and the direct testimony of witnesses Wesley, O'Connor, Richard, and Bluestone, as well as the rebuttal testimonies of witnesses O'Connor, Richard, and Bluestone. (TR 1941)

In his rebuttal testimony, witness Richard maintained that the gas system is growing in size and complexity and requires additional resources to ensure safe and reliable service. (TR 1645) To further his point, witness Richard explained why each additional employee is needed by justifying all positions for each team and employee he sponsored in MFR schedule G-2. (TR 1646-1652; EXH 7, BSP K260)

The Joint Parties updated their position from witness Kollen's recommendation in their post-hearing brief and proposed that the number of employees should remain at 746, the 2023 level as of the hearing, or a maximum of 777. (JP BR 30) The Joint Parties stated that customers should only fund positions that are filled as of the hearing or likely to be filled by the end of 2023, as the Commission should only approve the revenue requirement for which PGS had satisfied its burden of proof. (JP BR 31) The Joint Parties also included an alternative method of removing employee positions and honed in on positions sponsored by witness O'Connor within Gas Operations. (JP BR 33-34) The Joint Parties argued that witness O'Connor provided contradictory evidence that fell short of the burden of proof for the 61 positions he sponsored, disputed his testimony regarding the metrics used for geographic hiring, and raised an issue with the employment of contractual labor. (JP BR 33)

In regards to the issues the Joint Parties raised with witness O'Connor at the hearing, staff believes he adequately covered the issues raised. Witness O'Connor explained that the job descriptions are intentionally broad to cover all possible tasks that would be expected of a team member over the course of training. (TR 823-824) In terms of the geographic hiring, he explained that the process is quite dynamic and specific to each service area, including the projected workload, existing workforce, and level of experience within the workforce. (TR 824-825, 850) The significant arguments presented in the Joint Parties' brief regarding the employment of contractual labor are solely based on the witness affirming that some of the new hires may have come from the contractor workforce. (TR 856) Witness O'Connor added that the Company maintains a constructive relationship with its contractors in the instances when the contracted workforce finds and takes interest in posted PGS positions. (TR 856)

Staff has reviewed all information provided by PGS and agrees that the additional employees sponsored by witnesses Richard, O'Connor, and Parsons were fully supported in their testimony and throughout the record. Staff also agrees that the three HR positions sponsored by witness Bluestone were fully supported in her testimony and throughout the record. (TR 1412-1413) Staff is recommending additional O&M adjustments to reflect efficiencies from WAM and an additional reduction in contractual services in Issues 19 and 41, respectively, based on the record evidence available, and no further adjustments related to these issues are necessary.

However, the Company did not provide adequate justification for the 15 positions in Strategy, Marketing, and Communications; Real Estate; Process Improvement and Analytics; and Regulatory and Pipeline Safety positions. In witness Bluestone's rebuttal testimony, she disputed

OPC witness Kollen's assertion that the addition of employees was discretionary by referring to the testimonies of witnesses O'Connor, Richard, and Parsons. (TR 1365-1366) When asked about the positions she sponsored, witness Bluestone referenced the Company's response to OPC Interrogatory 13. (TR 1366) In the response to Interrogatory 13, witness Bluestone did not provide an explanation for the positions, but instead provided a brief description of each position. (EXH 45, BSP D15-1603 – D15-1608) Witness Bluestone further described the functions of the team members in her rebuttal testimony and in response to discovery, but did not provide detail on why the additional positions are necessary for the Company. (TR 1367-1370) At the hearing, witness Bluestone stated that although she felt she could provide some knowledge on the needs and challenges in those functional areas, she is not the functional expert for those teams and does not have the personal knowledge to explain why the positions she sponsored in her rebuttal testimony are necessary and prudent for business. (TR 1414-1416) Staff does not recommend these positions be recovered for ratemaking purposes, because these positions were not adequately supported in testimony or record evidence.

Considering all information provided from all parties, staff recommends that all Strategy, Marketing, and Communications; Real Estate; Process Improvement and Analytics; and Regulatory and Pipeline Safety team members be disallowed from the projected test year number of employees for ratemaking purposes. As such, projected test year salaries and benefits should be reduced by $1,245,959 to reflect the removal of these positions. The total adjustment reflects the payroll and benefits data for each specific position. (EXH 139, BSP 27-01; EXH 128, BSP F1657) In addition to the removal of these 15 positions sponsored by witness Bluestone, staff recommends the Business Development Manager for RNG position be disallowed as proposed by PGS, resulting in an additional reduction of $37,882. (EXH 218; PGS BR 30) Staff also recommends removal of the Company's corresponding increase in A&G expense associated with the additional employees in the projected test year, as addressed in Issue 49. (EXH 132, BSP 7844)

In total, projected test year salaries and benefits should be reduced by $1,283,841 to reflect staff's recommended removal of the 16 employees. Staff believes that PGS has provided sufficient record evidence to support 824 employees in the projected test year for ratemaking purposes.

## CONCLUSION

The number of projected test year employees that should be approved for ratemaking purposes is 824. As such, projected test year salaries and benefits should be decreased by $1,283,841.

***Issue 43:*** What amount of projected test year salaries and benefits, including incentive compensation, should be approved?

***Recommendation:*** The amount of projected test year salaries and benefits, including incentive compensation, should be $74,642,638. (Hinson, Andrews)

***Position of the Parties***

**PGS:** The Company's proposed salaries and benefits amount targets total compensation for employees at the market median, reflects reasonable payroll escalation factors, and should be approved. The appropriate amount of projected test year salaries and benefits expenses, including incentive compensation, is: $77,135,028.

**Joint Parties:** Limiting the employee count to the 2023 hearing level of 746 (eliminating the requested 29 additional 2023 positions) results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $5.997 million. In the alternative, eliminating the requested 2024 increase in employees (64) and related expenses and limiting approval of an employee count to a maximum of 777, results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $3.844 million. Further, the more reasonable 4.0 percent and 3.0 percent escalation factors for trended payroll in 2023 and 2024, respectively, should be applied. The effect of this adjustment is $1.918 million, after gross-up, for Commission assessment fees and bad debt expense. By limiting the requested merit pay increases for employees, the Commission should reduce the payroll and payroll related projected test year costs by an additional $1,918,000.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS testified that the appropriate amount of the projected test year salaries expense is $56,832,906, which reflects a reduction of $25,137 due to the salary of one business development manager for RNG that is discussed further in Issue 42. (PGS BR 33; EXH 7, BSP K256) PGS contended the appropriate amount of the projected test year short-term incentive compensation included in FERC Account 920 is $8,046,556, and reflected in that amount is a reduction of $3,444 due to the mitigation of short-term incentive of one business development manager for RNG as discussed in Issue 42. (PGS BR 33; EXH 7, BSP K257) The Company testified that the appropriate amount of projected test year employee pension and benefits included in FERC Account 926 is $12,255,566, which included a reduction of $9,301 of the benefits and loading of one business development manager for RNG as discussed in Issue 42. (PGS BR 33-34; EXH 7, BSP K254)

PGS witness Bluestone testified that in order for the Company to attract and retain skilled and experienced team members it is crucial for the Company to offer a fair and market-based compensation and benefits package. (PGS BR 34; TR 1324) Witness Bluestone continued that PGS's total compensation and benefits package includes base salary, short-term incentive, long-term incentive, pension or 401K, paid time off, employee common share purchase plan, and medical, dental, and vision insurance plans. (PGS BR 34; TR 1324) Witness Bluestone described the Company's practice of benchmarking its total compensation against applicable markets for compensation. (PGS BR 34; TR 1339-1340) She contended that this provided evidence that the compensation practice and amounts are reasonable and appropriate for the 2024 projected test year. (PGS BR 34; TR 1339-1340) Witness Bluestone continued that the Company utilized an independent consultant, Mercer, to evaluate its healthcare plan and its pension and retirement savings plans. (PGS BR 34; TR 1345-1346) Based on a recent study, the Company ascertained that its healthcare plan and its pension and retirement savings plans are consistent with the median of the Company's peer groups. (PGS BR 34; TR 1344; EXH 14, BSP D6-402)

The Company argued that its budgeted 5 percent annual merit increase for non-union employees for 2023 and 2024 is justified because the actual wage increases of 2.2 percent for both 2020 and 2021 were lower than the overall level of inflation of 4.7 percent and 8 percent, respectively. (PGS BR 35; TR 1354, 1371) Witness Bluestone emphasized the importance of having a budgeted merit increase of 5 percent in order to attract and retain team members but insisted that it does not mean that the actual merit raises for 2023 and 2024 will reach the budgeted 5 percent. (PGS BR 35; TR 1372-1373)

### Joint Parties

As the Joint Parties previously argued in Issue 42, the Commission should only fund 746 positions that were filled at the time of the hearing, or at most 777 positions to include approximately 30 positions that remain unfilled in 2023. (JP BR 34) This recommendation by the Joint Parties resulted in a proposed annual reduction in payroll and payroll related costs for staffing reductions, after being grossed up to \$5.997 million. (JP BR 34-35) The Joint Parties also recommended that the requested 64 employees in the 2024 projected test year be removed, resulting in an annual reduction in payroll and payroll related costs for staffing reductions in the amount of \$3.844 million, after being grossed-up. (JP BR 34-35)

OPC witness Kollen testified that a 5 percent escalation factor for the trended payroll expenses in 2023 and 2024 is unreasonable based on the Company's historic factors and general inflation assumptions. (JP BR 35; TR 1244) Witness Kollen noted that the 5 percent trended factor was greater than any contractual union increase for 2023 and 2024 and exceeded inflation for 2023 and 2024 of 2.8 percent and 2.2 percent, respectively. (JP BR 35; TR 1244, 1248) Witness Kollen recommended utilizing escalation factors of 4 percent and 3 percent for the trended payroll in 2023 and 2024, respectively. (JP BR 35; TR 1244) Witness Kollen's recommendation resulted in an adjustment of \$1.918 million after being grossed-up for the Commission assessment fees and bad debt expense. (JP BR 35; TR 1244)

The Joint Parties emphasized that the Company's pay is nearly at the national market average with a compensation ratio of 0.97 as of January 23, 2023, with the national market average being 1.0. (JP BR 35; TR 1392) Therefore, they argued that the 5 percent merit raises for 2023 and 2024 are not necessary in order for the Company to catch up to CPI as stated by PGS witness Bluestone. (JP BR 35; TR 1372) The Joint Parties contested that a 5 percent escalation factor was necessary in order for the Company to achieve competitive contracting, signing bonuses, moving expenses, and raises of existing employees and added that witness Bluestone testified that the Company's merit increases would most likely be under 5 percent. (JP BR 35; TR 1379)

The Joint Parties also noted that a 5 percent wage differential is included in the test year for the areas of Miami, Ft. Myers, Jupiter, and Ft. Lauderdale due to the increased cost of living and labor cost, as presented by witness Bluestone's testimony. (JP BR 35; TR 1391)

The Joint Parties claimed the Company does not have justification for such a high increase considering that it is almost 2 percent higher than PGS's merit increases from 2018 through 2021 and 1.25 percent higher than 2022. (JP BR 35; EXH 203, BSP G2-866) The Joint Parties continued the argument on the fact that PGS has given merit raises every year the last five years, in an amount greater than the CPI; therefore, the Company does not need to catch up. (JP BR 35; EXH 203, BSP G2-866) Witness Kollen's recommended merit increases of 4 percent and 3 percent for 2023 and 2024, respectively, are greater than the projected CPI of 2.8 percent and 2.2 percent for 2023 and 2024, respectively. (JP BR 35)

The Joint Parties recommended 3 adjustments to the projected test year salaries and benefits, including a reduction of $5.997 million due to eliminate 29 requested positions in 2023; a reduction of $3.844 million to eliminate 64 requested positions in 2024, and a reduction of $1.918 million to reflect escalation factors of 4 percent and 3 percent for 2023 and 2024, respectively. (JP BR 36)

## ANALYSIS

Witness Bluestone stated in her direct testimony that PGS benchmarks its total compensation and benefits against applicable markets using relevant Company benchmarks for both compensation and benefits. (TR 1359) She testified that the Company's costs come in at the median of the market. (TR 1359) To align total direct compensation (TDC) with the market, PGS first benchmarked positions against the labor market using data from the U. S. Mercer Benchmark database and the Willis Tower Watson MMPS Survey. (TR 1338) With the information provided from these sources, PGS determined the compensation range, calculated the TDC and measured it against the market to determine where the team members' compensation fell. (TR 1338)

PGS formed a TDC package that consists of base pay, a short-term incentive plan (STIP), and a long-term incentive plan (LTIP). (TR 1328) The STIP links PGS's success to financial incentives for PGS's team members for achieving the Company's annual goals and objectives, allowing eligible team members to receive STIP payments based on the balanced scorecard and the particular team member's performance multiplier. (TR 1334) LTIP is administered through the Emera Performance Share plan that gives a grant of a performance share unit that has value tied to the value of Emera, Inc.'s common stock. (TR 1336)

Witness Bluestone declared that PGS has salaries that are at the median of the market and in support of PGS's compensation philosophy that attracts, retains, and develops and incentives talent. (TR 1359) PGS used the compensation ratio, which is a measurement of pay that compares a team member's base compensation to the median compensation for similar positions within the target market. (TR 1327) To have a compensation ratio of 1.0 would indicate that the team member's base compensation would be at market. (TR 1327) The Company's team members were at an average .97 compensation ratio, which meant that the Company was paying just below the market median. (TR 1356; EXH 17, BSP D6-398)

PGS benefits are administered as a shared service through TECO and the benefit plans are held at the TECO Energy Incorporated level. (TR 1340) PGS used the Mercer Benefits Valuation Analysis (BENVAL) study to compare the relative value a company's overall benefit plan and its various components with other companies' plans contained within the Benefits Data Source United States database. (TR 1341) PGS has an index score that is slightly above the market for retirement, medical, dental, and short-term and long-term disability. Because of that, witness Bluestone stated in her direct testimony that this is what allows PGS to be competitive and attract skilled team members in the marketplace. (TR 1342)

PGS retained Mercer Health Benefits to project future plan costs for the self-funded plans to evaluate the design and cost of its health care programs. (TR 1343) To ensure its healthcare costs are reasonable, PGS partnered with industry experts such as Mercer, Blue Cross Blue Shield, and others, and has implemented a customized, comprehensive, best-in-market clinical care management program, directed members to high quality doctors and hospitals, improved member engagement, purchased stop-loss coverage through a coalition, implemented wellness initiatives, and implemented a pharmacy program that includes utilization oversight. (TR 1345)

PGS has multiple pension and retirement savings plans that are evaluated by an independent consultant, Mercer, to provide actuarial assumptions and methods used for the pension valuation. (TR 1347) Witness Bluestone declared that the actuarial assumptions and methods are reasonable and consistent with Financial Accounting Standards Board standard and industry practice and provide a reasonable basis for determining the level of pension costs included in PGS's cost of service studies. (TR 1348)

The Joint Parties did not provide an objection to PGS's compensation or benefits plan, nor did they propose alternative options for compensation and benefits, including incentive compensation. Staff has reviewed all documentation provided by PGS related to its compensation and benefits plans and agrees with the Company that these costs are reasonable and prudent. However, the Joint Parties did take issue with the escalation factors used to trend payroll expenses in the projected test year.

PGS asserted in its brief that the appropriate amount of projected test year salaries and benefits, including incentive compensation, should be $77,135,028. (PGS BR 33) The Joint Parties asserted in its brief that based on the recommended adjustments laid out in Issue 42 regarding the limited number of employees they recommend and the alternative number of employees recommended, the annual reduction in payroll and payroll related expenses should be reduced by $5.997 million or $3.844 million, respectively. (JP BR 34) Further, the Joint Parties recommended a reduction of $1.918 million to adjust for the requested merit increase rates of 4 percent and 3 percent for 2023 and 2024, respectively. (JP BR 34)

Witness Bluestone stated in her direct testimony that the Company is projecting a 5 percent merit increase for 2023 and 2024. (TR 1354) In response, OPC witness Kollen stated that the 5 percent merit increase requested by PGS is significantly greater than increases PGS has given in past years. (TR 1243) OPC witness Kollen also pointed out the 5 percent merit increase is greater than the 2.8 percent and 2.2 percent trended inflation escalation factors for 2023 and 2024, respectively. (TR 1243) Because of this, OPC witness Kollen recommended that the merit increases be lowered to 4 percent and 3 percent in 2023 and 2024, respectively, to be consistent with PGS's historic practice of tracking general inflation for employees. (TR 1244) Witness Bluestone maintained in her rebuttal testimony that the 5 percent merit increases are reasonable because PGS's actual wage rate increases for 2020 and 2021 were lower than the overall level of inflation for those years and PGS needs to "catch up" with inflation. (TR1371)

Staff recommends a merit increase of 4 percent for 2023 and 2024. According to the "PGS Average Salary Increase Compared to Market" in witness Bluestone's direct testimony, PGS has been just below the market in salary increases for prior years and raising the salary increase to 5 percent for 2023 would place PGS above the market salary budget by almost 1 percent. (EXH 17, BSP D6-399). Witness Bluestone argued that the actual merit increases for 2023 and 2024 would likely be less than 5 percent, but the Company must have the budgeted dollars to be competitive when contracting new hires, meet growing compensation demands due to market demands, and adjust compensation of existing employees who are at risk of being recruited away. (TR 1372) Staff agrees with witness Kollen's recommendation to limit the merit increase to 4 percent for 2023. (TR 1244) As shown in witness Bluestone's direct testimony, the market salary increase for 2023 is about 4 percent, and witness Bluestone stated in her direct and rebuttal testimony that PGS used the market median to make projections for salaries. (TR 1329, 1373; EXH 17, BSP D6-399) Staff agrees that PGS should have the budgeted dollars for the reasons witness Bluestone provided in her testimony, and to be consistent with the projected market growth, staff recommends a 4 percent merit increase for 2024. (EXH 203, BSP G2-866)

Based on staff's recommended adjustments in Issue 13 to increase the allocation of labor to SGT and to decrease the number of employees in Issue 42, projected test year salaries and benefits, should be reduced by $189,347 and $1,283,841, respectively. (EXH 218, BSP E8-543) Salaries and benefits in the projected test year should also be reduced by $1,057,084 to account for staff's recommended 1 percent decrease in merit increases for 2023 and 2024, resulting in a total decrease of $2,530,272. As such, projected test year salaries and benefits should be $74,642,638.

## CONCLUSION

The amount of projected test year salaries and benefits, including incentive compensation, should be $74,642,638.

***Issue 44:*** Has PGS made the proper adjustments to remove lobbying, charitable contributions, sponsorships, and institutional and image advertising from the projected test year? If not, what adjustments should be made?

***Approved Type 1 Stipulation:*** Not in its original filing; however, as reflected in Witness Parsons' rebuttal testimony, the Company has agreed to make an adjustment to the projected test year O&M expense of $500,000 to remove lobbying, charitable contributions, sponsorships, and institutional and image advertising. These adjustments arise from Commission Staff Audit findings, agreed upon reductions during a review of these items by Office of Public Counsel, and PGS self-disclosed reductions related to review of these items.

***Issue 45:*** What amount of projected test year Economic Development Expense should be approved?

***Approved Type 2 Stipulation:*** The appropriate amount of added Economic Development expense in the 2024 test year is $265,498. This amount reflects the $367,920 stated in the direct testimony of Witness O'Connor, pages 60-61 less a reduction of $102,422 for the adjustments described in Issue 44 related to economic development.

***Issue 46:*** What amount of projected test year annual storm damage accrual and storm damage reserve cap should be approved?

***Approved Type 1 Stipulation:*** The Company agrees to maintain its existing annual storm damage accrual of $380,000 and its existing storm reserve target of $3.8 million without prejudice to its ability to seek relief pursuant to Section 25-7.0143(1)(j), Florida Administrative Code.

***Issue 47:*** What adjustments, if any, should be made to projected test year expenses being incurred by, or charged to, PGS related to merger & acquisition development or pursuit activity?

***Recommendation:*** No adjustments should be made to projected test year expenses related to merger & acquisition development or pursuit activity. (Przygocki)

***Position of the Parties***

**PGS:** None. The Company's proposed 2024 test year O&M expenses do not include merger or acquisition related costs.

**Joint Parties:** The Joint Parties believe that this issue is moot.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS witness Parsons stated in her rebuttal testimony that there are no merger and acquisition costs included in the Company's 2024 test year O&M expenses. (PGS BR 35; TR 1976) PGS witness Wesley confirmed on cross examination and confidential discovery responses that there is not an anticipated merger or acquisition to affect the 2024 projected test year. (PGS BR 35; TR 233-243; EXH 177C, G2-521) Therefore, the Company contended that it does not need to make an adjustment for merger and acquisition activity in the projected test year. (PGS BR 35)

### Joint Parties

The Joint Parties stated that this issue is moot. (JP BR 36)

## ANALYSIS

PGS witness Parsons affirmed in her rebuttal testimony that the Company did not incur any outside services costs associated with merger and acquisition activity, nor did it receive any allocated costs from Emera or any affiliate associated with such activity. (TR 1976) She further testified that since 2022 actual costs are the basis for the 2024 budget, there are no costs associated with merger and acquisition activity in the projected test year. (TR 1976) The Joint Parties declared the issue moot in its post-hearing brief. (JP BR 36) As such, staff does not recommend any adjustments to projected test year expenses related to merger and acquisition development or pursuit activity.

## CONCLUSION

No adjustments should be made to projected test year expenses related to merger and acquisition development or pursuit activity.

***Issue 48:*** What amount of projected test year Rate Case Expense should be approved? What amortization period should be used?

***Approved Type 2 Stipulation:*** The appropriate rate case expense is $2,778,647 and amortization period should be three years. This amount is a reduction from the $3,247,810 shown on MFR Schedule C-13.

***Issue 49:*** What amount of projected test year O&M expenses should be approved?

***Recommendation:*** The appropriate amount of projected test year O&M expenses should be $140,129,467. (Przygocki, Andrews, Wooten)

### *Position of the Parties*

**PGS:** The appropriate amount of projected test year adjusted O&M expenses is $144,856,712.

**Joint Parties:** The Commission should reduce the projected test year O&M Expenses by at least $46,595,000. PGS's under allocation of A&G expense to construction is addressed here given that it is the bottom-line O&M issue.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS's proposed amount of O&M expense is $144,856,712, which reflects the adjusted amount of O&M expense of $150,817,212 listed on MFR Schedule G-2, page 1, line 5. (PGS BR 36) The adjustments are discussed by PGS witness Parsons in her rebuttal testimony and are as follows: a reduction of $500,000 discussed in Issue 44, a reduction of $189,347 for increased overhead cost allocation to SGT discussed in Issue 13, a reduction of $190,000 for the decrease in standalone audit fees discussed in Issue 41, A reduction of $60,234 for updated treasury analyst costs, a reduction of $37,882 for removal of RNG business development manager discussed in Issue 42, a reduction of $750,000 for WAM costs discussed in Issue 19, a reduction of $3,956,653 for removal of Alliance as discussed in Issue 18, a reduction of $120,000 for storm reserve adjustment as discussed in Issue 46, and a reduction of $156,384 for a revised rate case expense amortization as discussed in Issue 48. (PGS BR 36; TR 1968; EXH 33, BSP E8-552; TR 1982; EXH 218, BPS G1-251; TR 1983; EXH 139, BSP F7089)

PGS ascertained that the O&M expense in the 2024 projected test year is reasonable and necessary and is about $13 million below the $158.3 million benchmark. (PGS BR 36; TR 120) PGS argued that the Commission should not approve the Joint Parties' recommendation of reducing O&M expense and should not accept the $2.125 million reduction to A&G expense presented by the Joint Parties. (PGS BR 36-37; TR 1213) PGS asserted that its proposed A&G allocation of $11 million in the 2024 test year is $3 million more than the allocation of 2020 and $2 million more than the allocation in 2021, it is consistent with the actual amount allocated in 2022, and it is reasonable due to the number of employees who charge time to A&G accounts and work on the Company's capital program. (PGS BR 37; TR 1946; EXH 33, BSP E8-554 – E8-586; TR 2012) PGS continued that if the Commission decides to reduce A&G expenses, then a corresponding adjustment to increase rate base in Issue 27 will need to be made. (PGS BR 37; TR 2072)

### Joint Parties

The Joint Parties asserted that the O&M expense for the 2024 projected test should be reduced by at least $46,595,000. (JP BR 36) The Joint Parties argued that the Company's under-allocation of A&G expense to construction will be addressed in this issue due to it being a bottom-line O&M issue. (JP BR 36)

OPC witness Kollen noted that the $11 million transferred in 2022 for A&G allocations and proposed by the Company to be held constant for both 2023 and 2024 is an error. (JP BR 36-37) Witness Kollen proposed increasing this allocation by either 34.9 percent, if the proposed new hires are approved, or 19.3 percent, if the proposed new hires are excluded. (JP BR 36-37; TR 1247) The Joint Parties argued that this is a conservative percentage used by witness Kollen in his adjustment of the A&G transfer. (JP BR 37; TR 1247)

The Joint Parties contended that the Company's proposed accounting treatment overstates the revenue requirements. (JP BR 38) The Joint Parties continued their contention that the most problematic issue with this is that a post-rate case increase in the transfer from the last rate case test year, 2021, provided an immediate increase in the Company's earnings, while the customers' rates stayed as established in the last rate case. (JP BR 38; TR 2010)

The Joint Parties recommended that even though the Company testified the amount to transfer is at its discretion, PGS did not demonstrate the reasonableness or prudence of the cost due to not performing any necessary studies or analysis required by the Uniform System of Accounts (USOA). (JP BR 38; TR 2010-2011, 2015, 2019-2020) Therefore, the Company did not meet its burden of proof. (JP BR 38) The Joint Parties asserted that the Commission should reject the fixed amount of the A&G transfer based on the lack evidence provided alone. (JP BR 38)

The Joint Parties urged the Commission to consider the effects of allowing the Company to make its own subjective assessment of this type of transfer. (JP BR 38) In the scenario that the Commission set the rates based on the $11 million transfer and then the Company revised the test year income statement to transfer additional expenses to capital, it would result in rates that are excessive and would force customers to pay certain costs twice. (JP BR 38) The Joint Parties stated that this scenario happened after the 2020 rate case, when amounts approved for recovery as O&M expense were transferred to capital. (JP BR 38-39)

The Joint Parties testified that no evidence was provided by the Company to determine if the major project, FGT to Jacksonville Export Facility, would be ongoing in the test year. (JP BR 39) Therefore, the Company's recommendation to remove this project from proposed test year recovery should be disregarded. (JP BR 39) Furthermore, the Joint Parties stated that the project does not need to be included in any test year rate base or even plant in service to draw an allocation of A&G expenses. (JP BR 39)

The Joint Parties also asserted that by the USOA standards it is required to base allocations on direct timecard distributions, or a special study provided by the Company. (JP BR 39; TR 2019-2020; EXH 221) The Joint Parties noted that the Company did not complete either of those necessities. (JP BR 39) The Joint Parties cited Rule 25-7.014(1), F.A.C., that sets requirements and prohibitions on the ratemaking process based on the test year accounting and in any post-test year revision of the A&G transfer. (JP BR 39)

Witness Kollen observed the lack of consistency in the relationship between the capital spent and the A&G expense. (JP BR 39) The Joint Parties noted that the Company stated the allocation should correspond to the capital spent but evidence provided by the Company does not support that standard. (JP BR 39-40) The Joint Parties concluded that due to the Company not meeting its burden of proof or providing a justification on the fixed A&G transfer, the A&G transfer should be increased by $2.1423 million, before gross-up. (JP BR 40)

## ANALYSIS

Although this issue is a fallout issue of stipulations and staff's recommendations on other NOI issues, as listed in Tables 49-1 and 49-2, additional expenses included in projected test year O&M expenses will also be addressed.

### A&G Transfer

OPC witness Kollen proposed that an adjustment be made to reduce O&M expense by $2.125 million to increase the amount of A&G expense that should be capitalized to construction work. (TR 1247) The basis of this adjustment is that there is an $11 million credit included in Account 922 in the projected test year 2024, which is used to allocate A&G expense in Accounts 920 and 921 to capital expenditures. (TR 1246) Witness Kollen testified that the Company significantly increased the capital expenditures and the A&G expenses compared to the historic base year 2022. (TR 1246) Yet the Company held the Account 922 credit for A&G allocation to capital constant from 2022 to 2024. (TR 1246)

PGS witness Parsons testified in her rebuttal that the Company deemed it reasonable to keep the A&G allocation to capital at $11 million in the 2023 and 2024 budgets as it had already increased the allocation from $8 million in 2020. (TR 1946) Additionally, witness Parsons testified that the 2024 capital budget, excluding the FGT to Jacksonville Export Facility project, would be $314.2 million, which is lower than the capital expenditures in 2020 and 2022, which were $339 million and $325.2 million, respectively. (TR 1946; EXH 33, BSP E8-564)

In their brief, the Joint Parties argued that the relationship between the A&G transfer to capital and capital expenditures are not consistent. (JP BR 39) From 2019 to 2020, capital expenditures increased by 68 percent but the A&G transfer remained constant at $8 million. (JP BR 39; EXH 26, BSP G2-299) From 2020 to 2021, capital expenditures decreased by 9 percent but the A&G transfer increased from $8 million to $9 million. (JP BR 39; EXH 26, BSP G2-299) Then, from 2021 to 2022, capital expenditures gradually increased by 2.6 percent but the A&G transfer increased from $9 million to $11 million. (JP BR 39; EXH 26, BSP G2-299)

Additionally, the Joint Parties argued that the USOA states that expenses allocated to direct construction costs are not permitted to be added arbitrarily, but that allocation should be based on direct time card distribution or a special study. (JP BR 39; EXH 221 BSP G2-289 – G2-290) PGS witness Parsons testified that the Company has not been able to refresh past studies given resource constraints. (TR 2020) The Joint Parties argued that the Company failed to meet its burden of proof by performing any type of study to justify holding the A&G transfer to capital steady while A&G increased significantly from the historic base year 2022 to the projected test year 2024. (JP BR 40)

Witness Kollen based his proposed adjustment on the increase in A&G expenses from the historical base year 2022 to the projected test year 2024. (TR 1247) Witness Kollen testified that the Company forecasted an increase in A&G Accounts 920 and 921 expense of 34.9 percent from 2022 to 2024. (TR 1247; EXH 7, BSP K253) However, without including the increase in payroll to these accounts related to new employees the Company forecasted an increase of 19.3 percent for these accounts. (TR 1247; EXH 7, BSP K253) Witness Kollen conservatively proposed using the 19.3 percent to increase the $11 million A&G allocation to capital, resulting in his proposed adjustment to reduce O&M expenses by $2.125 million. (TR 1247)

Staff agrees with the Joint Parties' argument that, without an up-to-date study to justify the amount of A&G expense being allocated to capital projects, the Company did not meet its burden of proof to justify keeping the A&G transfer constant from 2022 to 2024. Staff agrees with witness Kollen's methodology for keeping the A&G transfer consistent with the growth in A&G from 2022 to 2024. Therefore, staff recommends reducing O&M expense by $2,125,283.

### Audit Fees & Treasury Support

In her rebuttal testimony, witness Parsons testified that PGS was able to negotiate down audit fees from its 2024 standalone audit by $190,000, after the MFRs were filed. (TR 1982) Witness Parsons also testified that the Company was able to update its 2024 budgeted Treasury support costs. (TR 1983) The Company was able to add a treasury analyst position with a cost allocation to PGS of $50,000 and trustee costs of $40,000 in order to remove the 2024 budgeted Tampa Electric Treasury team cost allocation of $150,234 to PGS. (TR 1983) The Joint Parties did not dispute these adjustments. (TR 1988) Therefore, staff recommends that projected test year O&M expenses should be reduced by $190,000 to reflect the Company's adjustment to reduce the one time audit fee for 2024, and $60,234 ($150,234 - $40,000 - $50,000) to reflect the net reduction of costs for treasury support.

### Fallout

Projected test year O&M expense should reflect the fallout of stipulations and staff's recommendation in other issues, as reflected in the tables below.

**Table 49-1**
**Fallout Adjustments from Stipulated Issues**

| Issue No. | Description | Amount |
|---|---|---|
| 18 | Remove Alliance O&M | ($3,956,653) |
| 44 | Lobbying, Contributions, Sponsorships, & Advertising | (500,000) |
| 46 | Reduce Storm Reserve Accrual | (120,000 |
| 48 | Reduce Rate Case Expense Forecast | (156,384) |
| | Total | ($4,733,037) |

Source: EXH 218, BSP G1-251; Staff Work Papers

**Table 49-2**
**Fallout Adjustments from Staff's Recommendations**

| Issue No. | Description | Amount |
|---|---|---|
| 13 | Increase Allocation to SeaCoast | ($189,347) |
| 19 | WAM Efficiency O&M Reductions | (750,000) |
| 41 | Reduce Redundant Outside Service | (206,000) |
| 42 | Remove Unsupported New Employees | (1,245,959) |
| 42 | Remove BDM Position | (37,882) |
| 42 | Remove Employee Expense Related To Unsupported Employees | (92,919) |
| 43 | Reduce Annual Increase to 4 Percent | (1,057,084) |
| | Total | ($3,579,191) |

Source: EXH 218, BSP G1-251; EXH 132, BSP 7844; Staff Work Papers

## CONCLUSION

The appropriate amount of projected test year O&M expenses for PGS should be $140,129,467.

***Issue 50:*** What amount of projected test year Depreciation and Amortization Expense should be approved?

***Recommendation:*** Based on the stipulations in Issues 5 and 18 and staff's recommendation in Issues 7, 8, and 50, projected test year Depreciation and Amortization Expense should be decreased by $342,002. As such, the appropriate amount of projected test year Depreciation and Amortization Expense should be $87,271,967. (Andrews, Wu)

### *Position of the Parties*

**PGS:** The appropriate amount of Depreciation and Amortization Expense for the 2024 projected test year used for calculating NOI is $87,271,966.

**Joint Parties:** The Commission should reduce the projected test year Depreciation and Amortization Expense by at least $26,404,000.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS claimed the appropriate approved amount of Depreciation and Amortization Expense for the 2024 projected test year to calculate NOI is $87,271,966. (PGS BR 37) PGS derived this figure from taking the total Depreciation and Amortization Expense of $87,613,968 then reducing expenses by $252,303 based on an updated depreciation study and rates, $359,701 due to the removal of the Alliance RNG Project, and $51,505 to reflect the reclassification of the New River RNG Project assets to different accounts. (PGS BR 37-38; EXH 7, BSP K19; EXH 218, BSP G1-251; EXH 128, BSP F1664; TR 1970, 1979-1980) PGS also noted that if the Commission decides on a 15 year depreciation period for the Brightmark RNG Project pipeline extension, then depreciation expense will increase by $321,507. (PGS BR 38; TR 1981; EXH 218, BSP G1-251) PGS recognized that OPC witness Garrett proposed extending the service lives of five accounts based on People's study; however, PGS argued that for similar reasons as stated in Issue 6, the Joint Parties' recommendations are unreasonable and no adjustments should be made based on witness Garrett's testimony. (PGS BR 38; TR 967, 1044-1053)

### Joint Parties

The Joint Parties recommended that the Commission should reduce test year Depreciation and Amortization Expense by at least $26,404,000. (JP BR 40) The Joint Parties based its position on OPC witness Garrett's recommendation that the Commission accept the application of the December 31, 2023 depreciation study date as well as longer lives for the five accounts listed in Issue 7. (JP BR 40) The Joint Parties explained that witness Garrett made these recommendations based on the Iowa Curve that was found to best fit the observed life table curve as well as other previously discussed factors, in Issue 7, affecting the data. (JP BR 40) OPC witness Kollen testified that this reduction results in a $7.257 million reduction in depreciation expense and a $6.991 million reduction in the base revenue requirement. (JP BR 40; TR 1213, 1262; EXH 129) Witness Kollen also testified that the stipulated study date of December 31, 2023 would result in a net reduction in base revenue requirement of $16.980

million, offset in part by witness Garret's changes to depreciation expense. (JP BR 40; TR 1264-1265) The Joint Parties proposed the Commission adopt these changes, which would lead to a reduction of at least $26,404,000 to the projected test year Depreciation and Amortization Expense. (JP BR 40)

## ANALYSIS

This is a fallout issue. Based on the depreciation rates and the projected test year plant in service recommended in Issues 7 and 21, respectively, the implementation date of the depreciation rates stipulated in Issue 11, the accelerated depreciation period for RNG plant leased to others stipulated in Issue 5, as well as the outcome of the stipulations in Issues 8 and 18, staff recommends several adjustments to the amount of projected test year depreciation and amortization expense that PGS proposed in MFR Schedule G-2.

First, depreciation expense should be reduced by $252,303 to reflect staff's recommendations in of Issue 7 and 8. (TR 1978; EXH 32, BSP 116 F1040, 128 F1667) This adjustment is a results of PGS's update to its originally-filed depreciation study and the calculation of depreciation rates as of December 31, 2023 rather than December 31, 2024. Second, depreciation expense should also be reduced by $359,701 to reflect the removal of the Alliance RNG Project, as addressed by the stipulation in Issue 18. (TR 1979; EXH 32, BSP 116 F1040, 128 F1664) Third, depreciation expense should be reduced by $51,505 based on PGS's proposed reclassification of certain New River RNG Project assets to different plant accounts. (TR 1980; EXH 32, BSP 114 F754, 116 F 1040, 128 F1665 and F1667) Finally, an increase to depreciation expense in the amount of $321,507 is recommended to recognize the accelerated depreciation of the Brightmark RNG Project-associated pipeline extension over 15 years, per the stipulation in Issue 5. (TR 1980; EXH 32, 114 F754, 116 F1040, 128 F1665 and F1667) As such, projected test year depreciation and Amortization Expense should be decreased by $342,002. The appropriate level of projected test year Depreciation and Amortization Expense should be $87,271,967

## CONCLUSION

Based on the stipulations in Issues 5 and 18 and staff's recommendation in Issues 7, 8, and 50, projected test year Depreciation and Amortization Expense should be decreased by $342,002. As such, the appropriate amount of projected test year Depreciation and Amortization Expense should be $87,271,967.

***Issue 51:*** What amount of projected test year Taxes Other than Income should be approved?

***Recommendation:*** Based on the stipulation in Issue 18 and staff's recommendation in Issues 42 and 43, projected test year Taxes Other than Income (TOTI) should be decreased by $2,271,748. As such, the appropriate amount of TOTI for the projected test year should be $29,429,593. (G. Kelley)

### *Position of the Parties*

**PGS:** The appropriate amount of projected 2024 test year Taxes Other than Income is $29,604,654.

**Joint Parties:** The amount of Taxes Other than Income that should be approved is a fallout number.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated that the appropriate level of TOTI in the projected 2024 test year is $29,604,654. (PGS BR 38) The Company initially proposed a total of $31,701,341 in TOTI. (PGS BR 38; EXH 7, BSP K219) PGS noted an error in the property tax forecast work papers and recommends that property tax be adjusted downward by $2,008,000 to correct this error. (PGS BR 38; TR 1951) PGS further noted that property tax should be reduced by $88,687 for the removal of the Alliance Diaries RNG project. (EXH 139, BSP F7089) PGS argued that the use of the experience trend factor is reasonable and consistent with the Company's experience and presented historical data, including a 5-year average, demonstrating the higher taxable values derived by taxing authorities than that proposed by PGS. (PGS BR 38-39)

### Joint Parties

The Joint Parties stated that since PGS corrected an error by reducing the property tax by $2.008 million, it has dropped their objection to the use of the five-year trending analysis. (JP BR 41)

## ANALYSIS

In MFR Schedule G-2, page 1, PGS showed a total TOTI for the projected test year of $31,701,341. (EXH 7, BSP K219) Through OPC discovery, PGS witness Parsons stated the Company estimated a property tax expense of $24,462,000 in 2024. (EXH 58) However, PGS acknowledged an error in the calculation of its 2024 tangible personal property and property tax expense experience trend factor. (TR 1951-1953, 1981-1982) The experience trend factor is used to account for the difference between estimated taxes and actual tax payed. As filed, the trend factor was 13.7 percent corresponding to a property tax expense of $24,462,000. (EXH 33, BSP E8-567) After correcting the error, the trend factor became 3.7 percent corresponding to a property tax expense of $22,454,000. (EXH 59) This results in a decrease of $2,008,000.

In direct testimony, OPC witness Kollen argued that an experience trend factor based on 2021 valuation was unjustified and unreasonable, due to being much great than the 2022 factor, 0.8 percent. (TR 1255) In rebuttal testimony, PGS witness Parsons argued that a 3.7 percent experience trend factor was within reason and supported this notion with the historical average of the past five years, 2018 - 2022. (TR 1952-1953) The 5-year average experience trend factor was 3.9 percent. (TR 1953) During the hearing, witness Parsons stated that the 0.8 percent factor in 2022 was anomalous and stated using one point in time is not the best practice in some cases. (TR 2029) PGS witness Parsons restated that a 3.7 percent factor is conservative, being lower than the historical 5-year average of 3.9 percent including the anomalous 0.8 percent. (TR 2029-2030) Staff agrees with the assessment of witness Parsons and believes an experience trend factor of 3.7 percent is reasonable.

Furthermore, based on stipulations and staff's recommendation in previous issues, additional corresponding adjustments to TOTI are necessary. Per the stipulation in Issue 18, property tax should be decreased by $88,687 for the removal of Alliance Dairies RNG. A reduction to salaries and benefits in Issues 42 and 43, results in a corresponding reduction of $175,061 to payroll taxes. Therefore, staff recommends that TOTI be reduced by a total of $2,271,748. As such, the appropriate amount of TOTI for the projected test year should be $29,429,593.

## CONCLUSION

Based on the stipulation in Issue 18 and staff's recommendation in Issues 42 and 43, projected test year TOTI should be decreased by $2,271,748. As such, the appropriate amount of TOTI for the projected test year should be $29,429,593.

***Issue 52:*** What amount of Parent Debt Adjustment is required by Rule 25-14.004, Florida Administrative Code?

***Recommendation:*** The amount of a Parent Debt Adjustment required by Rule 25-14.004, Florida Administrative Code, is $3,213,476. (D. Buys)

### *Position of the Parties*

**PGS:** Emera Incorporated is the ultimate parent company used for purposes of calculating a parent debt adjustment as provided for in Rule 25-14.004. Based on its proposed equity ratio of 54.7 percent, the parent company debt adjustment should be $3,084,000.

**Joint Parties:** The Parent Debt Adjustment required by the rule is $2,762,000 based on the level of common equity recommended by the Joint Parties. To the extent the Commission approves a greater amount of equity in the Company's capital structure, there should be a concomitant increase in the adjustment.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

The Company's proposed Parent Debt Adjustment amount of $3,084,000 is based on the Company's proposed 54.7 percent equity ratio and complies with the current parent debt adjustment rule as explained in the direct testimony of PGS witness Parsons. (PGS BR 39; TR 1876, 1976; EXH 4, BSP K80) There is no difference between the adjustment methodology used by PGS and the one used by the Joint Parties. (PGS BR 39) The difference in amounts arises from the Joint Parties' use of a lower equity ratio, which the Commission should not adopt for the reasons explained in Issue 34. (PGS BR 39)

### Joint Parties

The Joint Parties argued the Parent Debt Adjustment required by the rule is $2,762,000 based on the level of common equity recommended by the Joint Parties. To the extent the Commission approves a greater amount of equity in the Company's capital structure, there should be a concomitant increase in the adjustment. (JP BR 41)

## ANALYSIS

PGS included a Parent Debt Adjustment of $3,084,000 pursuant to Rule 25-14.004, F.A.C., Effect of Parent Debt on Federal Corporate Income Tax, as shown in MFR Schedule C-26. (TR 1876, 1925-1926; EXH 7) The Company proposed to follow the same methodology in the 2024 projected test year as it did in its last rate case in Docket No. 20200051-GU.[55] (TR 1876) The methodology used by PGS comports with Rule 25-14.004(4), F.A.C., as described herein:

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[55]Order No. PSC-2020-0485-FOF-GU, Issued December 10, 2020, in Docket No. 20200051-GU, *In Re: Petition for rate increase by Peoples Gas System.*

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

The Joint Parties did not oppose a Parent Debt Adjustment in this case. In its response to Staff's 2nd Set of Interrogatories, No. 20, OPC stated that if the Commission adopts OPC's recommendation regarding the capital structure, the Parent Debt Adjustment reduction to income tax expense would be $2,762,000, a reduction of $322,000 from PGS's Parent Debt Adjustment of $3,084,000. (EXH 131) The parent debt adjustment would be based on an equity balance of $965,336,000 instead of PGS requested equity balance of $1,119,871,358. (EXH 131) Joint Parties' recommended adjustment to lower the common equity balance would result in an increase of $435,000 to their recommended revenue requirement for PGS. (EXH 131) Both PGS and Joint Parties agreed that a Parent Debt Adjustment pursuant to Rule 25-14.004, F.A.C., is applicable in this case.

Based on staff's recommended adjustments to the capital structure and common equity balance in Issue 36, the recommended common equity balance for PGS is $1,122,029,733. The parent debt adjustment based on the adjusted common equity balance is $3,213,476 (1.13% × 25.345% × $1,122,029,733 = $3,213,476). This results in an increase to the Company's proposed parent debt adjustment of $129,476. Consequently, the amount of projected test year income tax expense in Issue 53 should be decreased by $129,476. This would decrease revenue requirement by $174,793 ($129,476 × 1.35 = $174,793)

## CONCLUSION

Staff recommends the appropriate amount of a Parent Debt Adjustment required by Rule 25-14.004, F.A.C., is $3,213,476.

***Issue 53:*** What amount of projected test year Income Tax Expense should be approved?

***Recommendation:*** Based on the stipulation in Issue 18 and staff's recommendation in Issues 49, 50, 51, and 52, projected test year Income Tax Expense should be increased by $1,798,523. As such, the appropriate amount of Income Tax Expense for the projected test year, including current and deferred income taxes and interest synchronization, should be $4,891,698. (Przygocki)

***Position of the Parties***

**PGS:** The appropriate amount of projected 2024 test year Income Tax Expense is $3,770,671.

**Joint Parties:** This is a fallout issue. The Joint Parties have not separately quantified the level of Income Tax Expense that would remain after consideration of its revenue requirement adjustments. The Joint Parties' adjustments are made on an incremental revenue requirement basis.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS acknowledged that Income Tax Expense is dependent on the results of any adjustments approved by the Commission. Based on PGS's revised revenue requirement, the Company's proposed a 2024 test year Income Tax Expense of $3,770,671, which is the net test year Income Tax Expense of $3,093,175 including an income tax offset of $677,496. (PGS BR 39; EXH 7, BSP K219)

### Joint Parties

The Joint Parties stated that this is a fallout issue, which depends on the adjustments made to revenue requirement. (JP BR 41)

## ANALYSIS

This is a fallout issue. Based on the stipulation in Issue 18 and staff's recommendation in Issues 49, 50, 51, and 52, projected test year Income Tax Expense should be increased by $1,798,523. As such, the appropriate amount of Income Tax Expense for the projected test year, including current and deferred income taxes and interest synchronization, should be $4,891,698.

**Table 53-1**
**Staff Adjusted Income Tax Expense**

| | |
|---|---|
| MFR Amount Requested | $3,093,175 |
| Staff Fallout Adjustments: | |
| Parent Debt Adjustment | ($129,476) |
| Interest Synchronization | 22,684 |
| Other Issues—Federal Income Tax | 1,491,852 |
| Other Issues—State Income Tax | 413,464 |
| Total Staff Adjustments | $1,798,523 |
| | |
| Staff Adjusted Amount | $4,891,698 |

Source: Excel MFR G Schedules; EXH 132, BSP 1761-1762; Staff Work Papers

## CONCLUSION

Based on the stipulation in Issue 18 and staff's recommendation in Issues 49, 50, 51, and 52, projected test year Income Tax Expense should be increased by $1,798,523. As such, the appropriate amount of Income Tax Expense for the projected test year, including current and deferred income taxes and interest synchronization, should be $4,891,698.

***Issue 54:*** What amount of projected test year Total Operating Expenses should be approved?

***Recommendation:*** The appropriate amount of projected test year Total Operating Expenses should be $262,284,692. (Przygocki)

### *Position of the Parties*

**PGS:** The appropriate amount of Total Operating Expenses for the projected 2024 test year is $266,008,087.

**Joint Parties:** This is a fallout issue. The Joint Parties have not separately quantified the level of Total Operating Expenses that would remain after consideration of its revenue requirement adjustments. The Joint Parties adjustments are made on an incremental revenue requirement basis.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS proposed total operating expenses of $266,008,087, which is a decrease in Total Operating Expenses of $7,721,692 (PGS BR 40; EXH 7, BSP K219)

### Joint Parties

The Joint Parties stated that this is a fallout issue, which depends on the adjustments made to revenue requirement. (JP BR 41)

## ANALYSIS

This is a fallout issue of Issues 49, 50, 51, and 53, which address the projected test year amount of each component of Total Operating Expenses. Based on staff's recommended adjustments to the projected test year amounts of O&M Expense, Depreciation and Amortization Expense, TOTI, and Income Tax Expense in Issues 49, 50, 51, and 53, respectively, the appropriate amount of projected test year Total Operating Expenses should be $262,284,692.

## CONCLUSION

The appropriate amount of projected test year Total Operating Expenses should be $262,284,692.

***Issue 55:*** What amount of projected test year Net Operating Income should be approved?

***Recommendation:*** Based on the stipulation in Issue 18 and staff's recommendation in Issue 54, the appropriate amount of projected test year Net Operating Income should be $78,056,236. (Przygocki)

***Position of the Parties***

**PGS:** The appropriate amount of Net Operating Income in the projected test year is $74,332,841.

**Joint Parties:** This is a fallout issue. The Joint Parties have not separately quantified the level of Net Operating Income that would remain after consideration of its revenue requirement adjustments. The Joint Parties adjustments are made on an incremental revenue requirement basis.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS stated that this is a fallout issue, and the net operating income will need to be calculated to reflect adjustments approved by the Commission on other issues. (PGS BR 40) The Company's proposed net operating income of $74,332,841 reflects two adjustments made to the initial proposed net operating income of $72,337,240 as shown on MFR Schedule G-2, page 1, line 17. (PGS BR 40; EXH 7, BSP K19) PGS stated the first adjustment is a decrease of $7,721,692 in total operating expenses as determined in Issue 54 and the second adjustment of $5,726,092 is for the removal of the Alliance project revenue, also reflected in the Company's revised revenue requirement. (PGS BR 40; EXH 218, BSP G1-249 – G-1-251)

### Joint Parties

The Joint Parties stated that this is a fallout issue and maintained that PGS has not quantified the amount of the appropriate net operating income that would remain after the revenue requirement adjustments. (JP BR 41)

## ANALYSIS

This is a fallout issue of projected test year revenues and staff's recommended Total Operating Expense in Issue 54. Projected test year revenues should be decreased by $5,726,092 to reflect the stipulation to remove the Alliance RNG project in Issue 18. (EXH 218). Based on the stipulation in Issue 18 and staff's recommendation in Issue 54, the appropriate amount of projected test year Net Operating Income should be $78,056,236.

## CONCLUSION

Based on the stipulation in Issue 18 and staff's recommendation in Issue 54, the appropriate amount of projected test year Net Operating Income should be $78,056,236.

***Issue 56:*** What revenue expansion factor and net operating income multiplier should be approved for the projected test year?

***Approved Type 1 Stipulation:*** The appropriate revenue expansion factor in this case is 74.0723 percent and the net operating income multiplier proposed in this case is 1.3500, as shown on MFR Schedule G-4, page 1.

***Issue 57:*** What annual operating revenue increase should be approved for the projected test year?

***Recommendation:*** The appropriate annual operating revenue increase for the projected test year should be $117,902,534. This amount includes a base rate increase of $11.2 million for revenue associated with the rate base transfer of CI/BSR investment. (Andrews, Norris, T. Thompson)

### *Position of the Parties*

**PGS:** The appropriate operating revenue increase for the projected test year is $135,341,798, which includes the transfer of $11,647,804 of CI/BSR revenue requirements to base rates. The Commission should reject OPC's proposal to use deferral accounting for the New River and Brightmark RNG projects.

**Joint Parties:** The Commission should approve a base revenue increase – including the transfer of Cast Iron/Bare Steel Rider revenues - of no more than $42,903,000. Resolution of the cost deferral related to the stipulated Issues 16 and 17 issue requires a revenue neutral revenue requirement recognition of the two customer-backed RNG projects.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS stated this is a fallout issue, and the annual operating revenue increase will need to be calculated to reflect any adjustments approved by the Commission on all other issues. (PGS BR 41) The Company's proposed annual operating revenue increase of approximately $135.3 million reflects a net decrease of approximately $3.9 million from the Company's original request as discussed in the testimony of PGS witness Parsons. (PGS BR 41; EXH 7, BSP K289)

PGS argued that the Commission should not approve the Joint Parties' proposed use of deferral accounting for the New River and Brightmark RNG projects. (PGS BR 41) PGS attested that the annual contract revenues will not recover the annual revenue requirement in the early years and surpass the revenue requirement in the later years, as typical with all fixed-rate, long-term customer contracts. (PGS BR 41) The Company affirmed that there is nothing improper about its accounting method which is a function of the depreciation expense reducing the net book value of an asset over the course of the asset's useful life. (PGS BR 41; TR 1950) The Company argued that the Joint Parties' proposal of deferral accounting for the two RNG projects that were developed with the Company's approved RNG tariff is inconsistent with Commission practice on the treatment of contract revenues and revenue requirement of other long term customer projects. (PGS BR 41; TR 1538-1539; TR 1950) Additionally, PGS argued that the application of deferral accounting would create an administrative burden to the Company. (PGS BR 41)

### Joint Parties

The Joint Parties stated that the Commission should approve a base revenue increase of no more than $42,903,000, including the transfer of CI/BSR revenues. (JP BR 41) The Joint Parties also discussed whether the Commission should approve a revenue neutral revenue requirement related to RNG projects, Brightmark and New River. (JP BR 41-42) The Joint Parties stated that if the projects remain in the test year revenue requirement, it will inflict a revenue requirement increase of $1.5 million onto the customers. (JP BR 42; TR 1292, 1992) The Joint Parties noted the two main concerns with allowing the $1.5 million increase of the revenue requirement are that customers in 2024 and for the next several years will have to endure most of the costs, and there is no assurance that the customers will remain with the Company long enough to receive any benefit. (JP BR 42)

OPC witness Kollen supported creating a deferred asset as a solution to align costs to match with the customer contract revenue and shield the rest of the customers from taking on the cost. (JP BR 42; TR 1292) The Joint Parties noted that the Company reasoned the administrative burden and expense associated with creating a deferred asset would not be favorable, but if the Commission approved a deferral then the Company could achieve the neutral revenue requirement as proposed by the Joint Parties. (JP BR 42; TR 2045; EXH 57) However, the Joint Parties contested that the cost tracking and accounting for this process is provided in the regulated cost of the test year revenue requirement and the administrative burden is not an adequate argument to reject the deferred asset. (JP BR 42) The Joint Parties affirmed that the Company did not present sufficient evidence that the revenue requirement including the RNG projects is reasonable or prudent, and therefore witness Kollen's recommendation to neutralize the $1.533 million revenue requirement with a deferred asset should be accepted. (JP BR 42-43; TR 1992; EXH 56, BSP D15-1651; EXH 57)

## ANALYSIS

Although this issue is a fallout of stipulations and staff's recommendations in previous issues, the remaining point of contention regarding the renewable natural gas (RNG) projects stipulated in Issues 16 and 17 will also be addressed, as agreed upon by the parties at the hearing. (TR 2084-2086)

### New River and Brightmark RNG Projects

The costs associated with PGS's New River and Brightmark RNG projects are included in rate base per the stipulations to Issues 16 and 17. (EXH 158) RNG is biogas extracted from above ground decomposing waste, such as animal and food waste, which has been upgraded to a pipeline quality similar to natural gas. Both of the RNG projects were developed under PGS's Commission-approved RNG Service Tariff, which is now closed to new participants and being replaced with PGS's new RNG Interconnection Service Tariff per the stipulations to Issues 16 and 17. (EXH 158)

The New River and Brightmark RNG projects involve production and transportation of RNG, with capital investments of $8.2 million and $42.7 million, respectively. (TR 936-940) The projects' respective counterparties, Opal Fuels and Brightmark, are responsible for the payments over the 20 and 15 year project terms. (TR 937-939) The counterparties are required to pay levelized rates designed to recover the revenue requirements for the projects over the life of the contracts pursuant to each project's RNG Service Agreement. (TR 937; TR 939-940; EXH 128)

As explained by OPC witness Kollen, although project revenues offset project costs over the terms of the contracts, there is a difference between the revenues and project costs in the test year, which increases the revenue requirement for all customers in the test year. (TR 1250) As reflected in the Company's original petition, there are revenue requirement deficiencies in the test year of approximately $144,104 for New River, and approximately $1,389,000 for Brightmark. (EXH 114) Because rates are established using only test year values, customers would be responsible for the test year deficiencies until the Commission resets PGS's rates.

OPC witness Kollen's testimony initially only recommended the removal of the revenue requirement associated with the mismatch of RNG revenues and costs, so that all customers are neither harmed not benefited from the RNG projects. (TR 1251) His recommendation did not include any specific basis or method for adjusting the costs in excess of revenues in the test year. He further testified that he did not oppose the use of deferral accounting to address the mismatch, so long as the deferrals were not included in rate base since the levelized revenues associated with the projects already embed a return on rate base. (TR 1252; TR 1287) At the hearing, witness Kollen provided additional support for reflecting the project as "revenue neutral" through the deferral of the costs. (TR 1294-1296) He explained that the test year would reflect the deferral of the mismatch in the first year of the contract, when costs exceed revenues, and over time, when revenues are greater than costs, the deferrals would start to reduce the balance to zero by the end of the contracts. (TR 1294-1295)

PGS witness Parsons testified that although the annual contract revenues from the customers will not recover the annual revenue requirement in the early years, they will exceed the annual revenue requirement in the latter years. (TR 1950) She further argued that there is nothing improper about this situation, as it is a function of how depreciation expense reduces the net book value of assets subject to a fixed-rate, long term customer contract over the useful life of the assets. (TR 1950) PGS witness Parsons compared the Company's proposed treatment of contract revenues and the revenue requirement as being consistent with the Commission's treatment of other long-term customer projects, specifically pipeline extensions. (TR 1950) PGS affirmed that this standard rate development is not unique to PGS's RNG Tariff and maintained that most utilities formulate rates on this Commission-approved fundamental regulated principle. (EXH 128 F1677) The Company explained that this approach provides rate certainty over the contract term, which is important to customers committing to long-term agreements. (EXH 128 F1677)

Witness Parsons emphasized the administrative burden of deferral accounting for the two projects, which she characterized as being no different than most of the Company's other projects. (TR 2045) She contended that they weren't any different than many of the Company's other projects that don't meet their revenue requirement in the early years, so it wasn't ideal to expend the additional resources to treat them differently. (TR 2045) In response to discovery, PGS stated that it had no precedent to base a request for deferral accounting on a customer contract. (EXH 139, BSP F7092)

As proposed by PGS, net benefits would not begin to accrue for the New River and Brightmark RNG projects until 2034 and 2037, respectively, based on each project's cumulative present value revenue requirement analysis. (EXH 115) Based on the Company's analysis, the New

River and Brightmark RNG projects would start showing revenue sufficiency in 2027 and 2029, respectively. (EXH 115, BSP 1685, 1687) However, this analysis and the calculation of the revenue deficiency in the test year does not reflect the adjusted capital structure components, accumulated depreciation, or depreciation expense recommended by staff.

The cost of service-based rate was developed in compliance with the tariff applicable to both RNG projects and recovered revenue requirement is comprised of the capital investment, a return on the investment, depreciation, O&M costs, and property taxes. (EXH 114, BSP 32; EXH 128 F1677) Using the Company's work papers, staff recalculated the revenue requirement impact associated with each project based on staff's recommended capital structure in Issue 36, and adjustments to accumulated depreciation and depreciation expense for both projects in Issues 22 and 50, respectively. With contract revenues held constant, the New River RNG project revenues exceed costs in staff's recommended revenue requirement by approximately $32,000 and the Brightmark revenue deficiency is reduced to approximately $921,000, resulting in a net revenue deficiency of less than $900,000. In total, this represents approximately 0.20 percent of staff's total revenue requirement. Unadjusted for staff's recommendation, the revenue deficiency is approximately 0.33 percent.

The Commission has previously cited Financial Accounting Standards Board's Accounting Standards Codification 980 Regulated Operations (FASB ASC 980) in previous decisions regarding the approval of regulatory assets.[56] The recognition and establishment of regulatory assets are addressed in ASC 980, which allows a regulated entity to capitalize all or part of an incurred cost that would otherwise be charged to expense, provided that: 1) it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes; and 2) based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

What witness Kollen proposed is an open-ended authorization to record the deferrals of costs in excess of revenue requirement until the revenues exceed costs, at which point the deferrals would start to reduce until the end of the contracts when they would be zero. (TR 1292, 1295) In the projected test year, he describes it as a negative expense of $1.6 million to record as a deferral. (TR 1294) As previously described, the total RNG project costs include several components, but only three of the components are incurred expenses—depreciation, property taxes, and O&M. They comprise less than half of the revenue requirement associated with each project combined, yet those would be the only costs eligible for deferral. The Joint Parties had no support or suggestion for a specific method of assigning costs to be deferred. The process would also require tracking the excess costs or revenues for each project annually, and it is not as simplistic as authorizing a regulatory asset in a lump sum to be amortized over a prescribed period.

[56]Order Nos. PSC-14-0698-PAA-GU, issued December 18, 2014, in Docket No. 20140016, *In re: 2014 depreciation study by Florida Public Utilities Company*; PSC-13-1093-PAA-EI, issued May 6, 2013, in Docket No. 20120303, *In re: Petition for approval for an accounting order to record in a regulatory asset or liability the unrealized and realized gains and losses resulting from financial accounting requirements related to interest rate derivative agreements, Progress Energy Florida, Inc*.

The relative size of the total excess in the current test year (0.20 percent), which will ultimately benefit customers with its continued inclusion in rates, in conjunction with the administrative burden cited by the Company, does not support treating these projects differently in the projected test year with the imposition of deferral accounting. As such, staff does not recommend making an adjustment to address the revenues and costs associated with the New River and Brightmark RNG projects.

### Fallout

Based on staff's recommendations in previous issues, the appropriate total annual operating revenue increase for the projected test year should be $117,902,534, as reflected in the table below. The revenue increase reflects the revenues associated with the transfer of CI/BSR investments, as stipulated in Issue 14. Based on the Company's original request, the amount of CI/BSR transferred revenues was $11.6 million. (TR 1866) Staff used the Company's work papers to recalculate the revenues associated with the CI/BSR transfer using staff's recommended capital structure. (EXH 132, BSP 1882) Based on staff's recommendation, the amount of CI/BSR transferred revenues is $11.2 million.

**Table 57-1**
**Staff's Recommended Annual Operating Revenue Increase**

| | |
|---|---|
| Operating Revenue Increase | $117,902,534 |
| CI/BSR Revenue | (11,156,958) |
| Incremental Revenue Increase | $106,745,576 |

Source: MFR Schedule G-5; EXH 132, BSP 1882; Staff Work Papers

## CONCLUSION

The appropriate annual operating revenue increase for the projected test year should be $117,902,534. This amount includes a base rate increase of $11.2 million for revenue associated with the rate base transfer of CI/BSR investment.

***Issue 58:*** Should the Commission approve PGS's proposed cost of service study?

***Approved Type 2 Stipulation:*** Yes. The Company's cost of service study appropriately reflects cost causation, and each allocation factor is consistent with the factors that drive the underlying costs of providing service to customers.

***Issue 59:*** If the Commission grants a revenue increase to PGS, how should the increase be allocated to the rate classes?

***Approved Type 2 Stipulation:*** The increase shall be allocated to the rate classes to achieve an equalized rate of return for the Residential and Commercial rate classes and as shown for the Company's proposed increase and rates on Document Nos. 6, 9, 10, 11, and 12 of Exhibit No. GT-1.

***Issue 60:*** What customer charges should be approved?

***Recommendation:*** This is a fallout issue and will be decided at the December 5, 2023 Commission Conference. (P. Kelley, Hampson)

### *Position of the Parties*

**PGS:** This is a fallout issue based on the revenue requirement approved by the Commission and its decisions on issues that impact the inputs to the Company's stipulated cost of service methodology.

**Joint Parties:** No position.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued that this is a fallout issue based on the revenue requirement approved by the Commission and its decisions on issues that impact the inputs to the Company's stipulated cost of service methodology. (PGS BR 41)

### Joint Parties

The Joint Parties did not provide an argument.

## ANALYSIS

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

## CONCLUSION

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

***Issue 61:*** What per therm distribution charges should be approved?

***Recommendation:*** This is a fallout issue and will be decided at the December 5, 2023 Commission Conference. (P. Kelley, Hampson)

***Position of the Parties***

**PGS:** This is a fallout issue based on the revenue requirement approved by the Commission and its decisions on issues that impact the inputs to the Company's stipulated cost of service methodology.

**Joint Parties:** No position.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS argued that this is a fallout issue based on the revenue requirement approved by the Commission and its decisions on issues that impact the inputs to the Company's stipulated cost of service methodology. (PGS BR 42)

### Joint Parties

The Joint Parties did not provide an argument.

## ANALYSIS

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

## CONCLUSION

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

***Issue 62:*** What miscellaneous service charges should be approved?

***Approved Type 2 Stipulation:*** The Commission shall approve the Company's proposed miscellaneous service charges as shown on Document No. 3 of Exhibit No. KLB-1. They are fair, just, and reasonable.

***Issue 63:*** Should the Commission approve PGS's revised annual residential rate reclassification review?

***Approved Type 2 Stipulation:*** Yes. The proposed revisions are reasonable and shall be approved.

***Issue 64:*** Should the Commission approve PGS's revision to the Residential and Commercial Generator rate design?

***Approved Type 2 Stipulation:*** Yes. The proposed revisions are reasonable and shall be approved.

***Issue 65:*** Should the Commission approve PGS's revised termination fee for the Natural Choice Transportation Program (Tariff Sheet No. 7.803-3)?

***Approved Type 2 Stipulation:*** Yes. The proposed revisions are reasonable and shall be approved.

***Issue 66:*** Should the Commission approve PGS's revised Individual Transportation Administration Fee (Tariff Sheet No. 7.805)?

***Approved Type 2 Stipulation:*** No. The Company's existing Individual Transportation Fee should remain in effect.

***Issue 67:*** Should the Commission approve PGS's new Minimum Volume Commitment provision (Tariff Sheet No. 5.601) and associated Agreement (Tariff Sheet Nos. 8.126-8.126-11)?

***Approved Type 2 Stipulation:*** Yes. The proposed revisions are reasonable and shall be approved.

***Issue 68:*** Should the Commission approve PGS's non-rate related tariff modifications?

***Approved Type 2 Stipulation:*** Yes. The proposed revisions are reasonable and shall be approved.

***Issue 69:*** Should the Commission approve PGS's proposed tariffs reflecting the Commission-approved target revenues?

***Recommendation:*** This is a fallout issue and will be decided at the December 5, 2023 Commission Conference. Within five business days of today's vote, the Company should be required to file a revised cost of service and tariffs to reflect the Commission-approved revenue increase. (Guffey)

### *Position of the Parties*

**PGS:** Yes. Once the Commission approves the Company's customer and per therm charges, the Company should submit updated tariff sheets reflecting the new rates and charges, including those approved by stipulation, and the Staff of the Commission should be given administrative authority to approve the updated tariff pages.

**Joint Parties:** No position.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS
PGS argued that once the Commission approves the Company's customer and per therm charges, the Company should submit updated tariff sheets reflecting the new rates and charges, including those approved by stipulation, and the Staff of the Commission should be given administrative authority to approve the updated tariff pages. (PGS BR 42)

### Joint Parties
The Joint Parties did not provide an argument.

## ANALYSIS

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

## CONCLUSION

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

***Issue 70:*** What is the effective date for PGS's revised rates and charges?

***Recommendation:*** This is a fallout issue and will be decided at the December 5, 2023 Commission Conference. (Guffey)

***Position of the Parties***

**PGS:** The revised base rates and charges approved in this case should be effective with the first billing cycle in January 2024.

**Joint Parties:** No position.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS
PGS argued that the appropriate effective date for the Company's revised rates and charges should be the first billing cycle in January 2024. (PGS BR 42)

### Joint Parties
The Joint Parties did not provide an argument.

## ANALYSIS

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

## CONCLUSION

This is a fallout issue and will be decided at the December 5, 2023 Commission Conference.

***Issue 71:*** Should the Commission approve PGS's proposed long-term debt cost rate true-up mechanism?

***Recommendation:*** Yes. The Commission should approve PGS's proposed long-term debt cost rate true-up mechanism. (Souchik)

### *Position of the Parties*

**PGS:** Yes. The proposed mechanism is appropriate under the circumstances and fairly protects the general body of ratepayers.

**Joint Parties:** Based solely on the unique factual circumstance where an electric company has spun off its gas division in this case, and if the Commission deems the 2023 Transaction to be prudent in decision and execution, the Joint Parties will not object to the one-time long-term debt cost rate true-up mechanism -- for debt that is issued unrelated to that required to replace the Tampa Electric Company debt allocated to PGS pre-transaction -- after the gas company's first debt issuance; however, the Commission should disallow the incremental interest expense and other financing costs of the 2023 Transaction.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS argued the Company's one-time long-term debt cost rate (LTDR) true-up mechanism is described in direct testimony of witness Parsons and should be approved for the reasons she explains therein. (PGS BR 42; TR 1926-1929) PGS will be seeking its own financing based on its own business profile and credit rating in late 2023. (PGS BR 42; TR 1111-1112, 1926) PGS argued that although the Company's forecasted long-term debt interest rates are reasonable, there is uncertainty about the actual cost rates when the long-term debt is eventually issued. (PGS BR 42; TR1926) PGS asserted its LTDR true-up mechanism will ensure that the Company's 2024 base rates will reflect the Company's actual cost of long-term debt which is fair to both the customers and the Company. (PGS BR 42; TR 1926) PGS argued its true-up mechanism would likely be viewed as credit positive by rating agencies. (PGS BR 42; TR 1193)

### Joint Parties

The Joint Parties argued the Commission should not find that the 2023 Transaction is prudent in Issue 72. However, the Joint Parties agreed that if the Commission finds otherwise, the Commission should require PGS to true-up the long term debt cost rate after the Company's first long-term debt issuance. (JP BR 43) The Joint Parties argued that if the Commission disallows the incremental costs of long-term debt that would not have occurred but for the 2023 Transaction, the Commission should only require the Company to true-up the LTDR after the first debt issuance on a one-time basis limited to the specific facts of TECO spinning off PGS. (JP BR 43)

## ANALYSIS

PGS proposed to use a one-time LTDR true-up mechanism adjustment to the base rates reflecting its actual cost for its inaugural long-term debt issuance in determining the projected test year revenue requirements. (TR 1926) PGS witness Parsons testified that the Company is seeking its own financing based on the business risk profile and credit rating of PGS as a stand-alone entity. (TR 1926) The purpose for the true-up mechanism is to reflect the actual market-based cost rates for PGS's debt issuances in its capital structure and rates. (TR 1926) Because PGS's inaugural long-term debt issuance will occur after the final hearing, a new 13-month average LTDR should be calculated as shown in MFR Schedule G-3, page 3. (TR 1927; EXH 7, BSP K284) PGS projected that its inaugural debt issuance will be approximately $825 million. (TR 1927) A new calculation of the forecasted long-term debt cost rate for the projected test year would be updated to reflect the actual debt issuance principal amount and components of annual cost. (TR 1927)

Witness Parsons explained that any change in the projected inaugural debt issuance principal amount of $825 million assumed in the Commission approved cost of long-term debt would be offset by a specific adjustment so that the projected test year 13-month average principal amount of long-term debt does not change. (TR 1927) Second, an adjustment would be made to replace the Commission approved LDTR used in determining the Company's approved WACC with the trued-up weighted average cost of long-term debt (Issue 36). (TR 1927-1928) The resulting adjusted WACC would be carried over to update the Commission approved Net Operating Income (Issue 55), and if there is an increase or decrease in revenue requirement, the difference would be passed on to customers through a limited proceeding to adjust base rates. (TR 1928) PGS proposed that it would quantify the LTDR true-up impact to the revenue requirement through a one-time adjustment to base rates within 120 days after the Company completes its inaugural debt issuance. (TR 1928) PGS proposed that the change to base rates would be applied to all customer classes consistent with the method approved by the Commission in Order No. PSC-2018-0501-S-GU, which changed PGS's base rates as a result of the Tax Cuts and Jobs Act of 2017.[57] The method approved in that Order was for the Company to submit the proposed tariff sheets reflecting the approved revenue requirement increase or decrease for administrative approval by staff.

PGS proposed that for the time period between when the new Commission approved base rates go into effect (first billing cycle in January 2024) and the implementation date of the LTDR true-up adjusted base rates, the Company will defer the rate impact of the LTDR true-up to its balance sheet for refund or collection through the CI/BSR[58] in the subsequent year. (TR 1229) If the amount of the LTDR true-up is less than $500,000, PGS proposed to defer the impact of the LDTR true-up to its balance sheet for collection or refund through the CI/BSR in the subsequent year, and will continue that process annually until the Company's next base rate proceeding or other base rate adjustment being made through a limited proceeding. (TR 1929)

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[57]Order No. PSC-2018-0501-S-GU, issued October 18, 2018, in Docket No. 20180044-GU, *In re: Consideration of the tax impacts associated with Tax Cuts and Jobs Act of 2017 for Peoples Gas System, p. 8.*

[58]PGS's Cast Iron/Bare Steel Replacement Rider was approved by Order No. PSC-12-0476-TRF-GU, issued on September 18, 2012, in Docket No. 20110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

The Joint Parties did not object to the one-time LTDR true-up mechanism for new debt that is issued unrelated to that required to replace the TECO debt allocated to PGS prior to the 2023 Transaction. (JP BR 43) OPC witness Kollen agreed that PGS's proposed LTDR true-up would allow for a one-time adjustment to base rates to reflect the actual costs of long-term debt compared to the projected costs included in the Company's application, whether the actual debt rates are higher or lower than projected. (TR 1272) Witness Kollen contended that only the new long-term debt incremental to his recommended allocation of the former embedded long-term debt from TECO should be subject to the LTDR true-up. (TR 1278) Witness Kollen asserted that the amount of long-term debt that was originally issued for PGS by TECO should be maintained in PGS's embedded cost of debt and should not be subject to the LTDR true-up mechanism. (TR 1278-1280) Witness Kollen explained that if the Commission accepted his recommendation, there would be approximately $500 to $600 million of existing debt that was issued by TECO for PGS that would not be subject to the LTDR true-up. (TR 1281) As discussed in Issue 32, staff recommends that the Commission not accept the Joint Parties' argument to maintain the portion of long-term debt originally issued by TECO on behalf of PGS and recommends to approve PGS's forecasted long-term debt cost rate of 5.54 percent. Because PGS's proposed long-term debt cost rate was unknown at the time the record in this proceeding closed, the Company's proposed LTDR true-up mechanism is a prudent method to ultimately set the cost of long-term debt to reflect PGS's actual market-based cost.

Further, as explained in Issue 32, the Commission has consistently accepted that long-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. (TR 1129-1130) In rate cases with projected test years, as is the case here, it is common practice for the utility to estimate debt cost rates for prospective debt issuances and calculate the cost of long-term debt accordingly.[59] Staff agrees with PGS witness McOnie that a departure from past precedent by not allowing the recovery of market-based interest rates could impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability respectively. (TR 1131) As pointed out by witness McOnie, since the forecasted long-term borrowing costs are market-based, and reflect actual interest obligations, a disallowance of the recovery of the full interest expense amount could potentially be considered unconstructive by rating agencies. (TR 1131) The recovery of interest expense for PGS is accounted for through the rate of return (WACC) applied to the rate base to determine the revenue requirement. If the WACC and subsequent revenue requirement do not include the actual cost of debt, the Company would experience either an under or over recovery of its interest expense. Therefore, a LTDR true-up mechanism will benefit both PGS and its customers by adjusting the Commission approved long-term debt cost rate in Issue 32 to match the PGS's actual cost in its inaugural long-term debt issuance and ensure PGS is recovering its actual cost of debt through rates.

## CONCLUSION

Based on the aforementioned, the Commission should approve PGS's proposed long-term debt cost rate true-up mechanism.

[59]Order No. PSC-10-0153-FOF-EI, issued March 17, 2020, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company*, p. 109-110; Order No. PSC-10-0029-PAA-GU, issued January 14, 2010, in Docket No. 20090125-GU, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation, p. 10*.

***Issue 72:*** What adjustments, if any, should be made to the projected test year related to the spin-off of PGS?

***Recommendation:*** No adjustments should be made to the projected test year related to the spin-off of PGS. (Cicchetti, Gatlin)

### *Position of the Parties*

**PGS:** None. The 2023 Transaction adopted a commonly used business structure for Peoples and is prudent. It will sequester risks and allow Peoples to focus on providing safe and reliable gas service to customers and meet the growing demand for gas in Florida. The type of recurring incremental costs (audit fees, credit rating agency fees, interest expense) are the kind of expenses routinely incurred by regulated utilities and recovered through base rates. The level of projected short-term and long-term interest expense reflect the Company's forecasted, market-based borrowing costs on a stand-alone basis.

**Joint Parties:** The Commission should disallow all costs associated with the discretionary 2023 Transaction and reduce the requested revenue requirement by at least $9,699,000.

### *Staff Analysis:*

## PARTIES' ARGUMENTS

### PGS

PGS ascertained that there is no adjustment to be made to the 2024 projected test year due to the spin-off of PGS from Tampa Electric. (PGS BR 43) PGS argued that the 2023 Transaction was a well thought out decision by the Company that put the long-term best interest of the customers first. (PGS BR 43; TR 108-110; TR 1133-1134) PGS witness Wesley stated that the 2023 Transaction will help protect PGS against risks associated with being attached to an electric company and this transaction was completed on a tax free basis so that none of the involved parties incur a tax burden. (PGS BR 43; TR 110-111; TR 109, 164) The Company continued that the 2023 Transaction was completed to adopt a legal structure similar to many other regulated and unregulated utilities. (PGS BR 43) PGS disagreed with the Joint Parties argument that PGS has disingenuous motives for the timing of the 2023 Transaction and asserted that it has a history of ensuring that its customers are taken care of and there is no documentation of PGS making any decisions to bring harm to its customers. (PGS BR 43-44; TR 104-105)

Regarding PGS's new supply chain, PGS asserted that the new supply chain was planned and created separate from the 2023 Transaction and the costs that were associated with the implementation of the new supply chain team should not be included in the incremental costs of the 2023 Transaction. (PGS BR 44; TR 106-107; TR 174-179) The Company stated the new supply chain positions are a reduction to the allocations from Tampa Electric, decreasing from $839,000 in 2022 to $382,000 in 2024. (PGS BR 44; TR 1646) Regarding interest expense, the Company testified it only requested to recover projected costs of market-based, long-term and short-term debt, through its base rates. (PGS BR 44; TR 1129-1130) PGS contends that this is a practice the Commission has regularly allowed. (PGS BR 44; TR 1129-1130)

The Company testified that it considered multiple interests when deciding on moving forward with the 2023 Transaction, including the consequence to its customers and the Commission. (PGS BR 44-45; TR 104-105) The 2023 Transaction was designed to protect customers from the risk of harm in the long-term and for customers to benefit from the hard to quantify benefits of the spin-off. (PGS BR 45; TR 104-105) PGS testified that the new structure of the Company will allow it to be in control of the metrics of new market debt issuances and to optimize the amount of short-term and long-term debt based on only the needs of the Company. (PGS BR 45; TR 88) This new structure also gives the Company the ability to manage its own affairs in order to maintain its credit rating and reflect its own risk profile associated with the cost of debt. (PGS BR 45; TR 89) PGS argued it serves a different territory than Tampa Electric, PGS is growing differently than Tampa Electric, and the risks that both companies encounter are different which is why it was time for PGS to become a separate legal entity. (PGS BR 45; TR 110)

PGS testified that when the Company first came to be under Tampa Electric in 1997 it was relatively small compared to Tampa Electric, but now it has extended its service territory around the state well beyond the territory that Tampa Electric serves. PGS now serves more than half the number of customers served by Tampa Electric. (PGS BR 45; TR 89-90) The Company admittedly currently has the same board as Tampa Electric, but over time it will be able to fill the board of directors with different members that can solely focus on gas and the Company's statewide service area. (PGS BR 45; TR 90) PGS asserted that by becoming its own entity in the 2023 Transaction it has protected its customers in the event of a catastrophic event at Tampa Electric which could cause financing and operating disruptions at PGS. (PGS BR 45; TR 111)

### Joint Parties

The Joint Parties recommended that the Commission not allow $9.693 million in incremental costs associated with the 2023 Transaction, which would cause a reduction of $9.699 million in the revenue requirement. (PGS BR 43; TR 1223-1224) The incremental costs that the Joint Parties included are additional interest expense, cost of audited stand-alone statements, additional rating agency fees, and the additional treasury analyst position. (PGS BR 43; TR 1223-1224) The bulk of the incremental costs associated with the 2023 Transaction noted by the Joint Parties is the approximately $8.9 million associated with incremental interest expense. $7.1 million corresponds to the $570 million long-term debt to be exchanged under the intercompany loan agreement and $1.8 million is related to the rating differentials and short-term debt changes. (PGS BR 43-44; TR 1181) The Joint Parties asserted the Company has failed to meet its burden of proof to demonstrate why customers should be responsible for the cost of the Company's one-sided decision to spinoff PGS from Tampa Electric. (JP BR 43) The Joint Parties contended that the only evidence provided by the Company referencing the 2023 Transaction is intangible, unquantified, and represents only proposed potential benefits. (JP BR 43) Since Emera purchased Tampa Electric, and as such PGS, in 2016 it considered a spinoff. In 2019, Emera began its due diligence and analyzed the risks and benefits of completing the transaction. (JP BR 43-44; TR 126, 130; EXH 160C) The analysis performed by Emera contained a low-end and high-end estimate of the one-time cost Emera would endure, however the analysis did not include data on costs or benefits to the customers. (JP BR 44; TR 260, EXH 160C) According to the Joint Parties, the Company chose to carry out the 2023 Transaction at a time and in a manner that saved Emera shareholders $150 million in tax liability. (JP BR 44) The Joint Parties stated the timing of the 2023 Transaction created an approximate $9.69 million annual cost which PGS has requested to be recovered for the foreseeable future. (JP BR 44; TR 128, 1222; EXH 37, 198) The Joint Parties asserted that Emera had total control of when the spinoff would take place and it chose a time that was costly to customers due to the higher interest rates and the current credit rating issues faced by Emera and Tampa Electric that will trickle down to PGS's credit rating and financing costs in the future. (JP BR 44; TR 86-87; EXH 54C, BSP 9558, EXH 167C, OPC BSP 4)

The Joint Parties stated that there is scarce evidence to support any benefits to the customers resulting from the 2023 Transaction. (JP BR 45) The Joint Parties asserted PGS witness Wesley admitted that there would be higher financing costs short-term due to the 2023 Transaction but included two benefits to the customers. (JP BR 45; TR 86-87, 89-90) The Joint Parties stated the first benefit noted by the Company is that it has the option to create its own board of directors separate from Tampa Electric. (JP BR 45; TR 90) However, the Joint Parties argued, that since the 2023 Transaction, PGS has only added one member to the board of directors and that member was also added to the board of Tampa Electric. (JP BR 45; TR 168) The Joint Parties ascertained that this is only a potential benefit, and it seems the Company is not actively changing the board. (JP BR 45)

The Joint Parties indicated the second benefit to customers of the 2023 Transaction noted by witness Wesley is the claimed risk mitigation of having the assets and liabilities of Tampa Electric and PGS in separate legal entities. (JP BR 45; TR 90) The Joint Parties contested that this benefit may ever occur due to the fact no one is able to predict a catastrophic event. (JP BR 45) The Joint Parties contended that the customers are already paying for risk mitigation through the recoverable insurance premiums and fees, and that the Company has proposed an increase to $7.9 million in insurance premiums and fees for the 2024 test year. (JP BR 45; EXH 7, BSP K257)

The Joint Parties asserted the Commission should deem the decisions made by PGS associated with the 2023 Transaction imprudent due to the lack of evidence provided by the Company showing quantifiable benefits to the customers. (JP BR 46) The Joint Parties argued the evidence shows that the structure and timing of the 2023 Transaction will save Emera shareholders $150 million in tax liability but cost PGS customers almost $10 million annually for the foreseeable future. (JP BR 46) The Joint Parties maintained the Commission should adjust PGS's requested revenue requirement to reflect a reduction of $9,699,000. (JP BR 46)

## ANALYSIS

The Joint Parties argued PGS has failed to meet its burden of proof and the Commission should disallow all costs associated with the 2023 Transaction and reduce the requested revenue requirement by at least $9,699,000. (JP BR 46) Witness Wesley, in her direct testimony, presented the Company's rationale for the 2023 Transaction including the benefits to customers. (TR 89) Witness Wesley testified that the 2023 Transaction: 1) Provides a better platform for PGS as it grows and changes with evolving natural gas markets; 2) Enables PGS to populate its board with board members more familiar with the natural gas industry; 3) Allows PGS to manage the timing and amount of market debt issuances enabling more flexibility; and, 4) Benefits customers by placing the assets and liabilities of the electric and gas operations in separate legal entities, thereby insulating customers from the effects of catastrophic events. (TR

88-90) Further, witness Wesley indicated PGS will continue to benefit from the provision of shared services from Tampa Electric. Witness Wesley stated, “For instance, we will continue to receive support from Tampa Electric’s legal, information technology, and customer experience team members. Our shared billing platform and online systems enable high quality customer contact at a more affordable cost-to-quality ratio than Peoples Gas might be able to afford on its own.” (TR 88)

The Joint Parties further argued PGS, in its 2019 due diligence review, did not include or even attempt to quantify any costs or benefits to customers. (JP BR 44) However, the 2019 due diligence report and both witness Wesley’s direct and rebuttal testimonies addressed the consequences of a catastrophic event. (EXH 160C, TR 90; TR 111) In her testimonies, witness Wesley stated:

> Our customers also benefit from the risk mitigation effect that placing the assets and liabilities of gas and electric operations in separate legal entities will provide. Tampa Electric and Peoples will work diligently to be safe and avoid catastrophic accidents. However, events like the 2010 San Bruno explosion and the deadly 2020 Zogg Wildfire – on the gas and electric systems of Pacific Gas and Electric Company in California – show how accidents on one side of a dual system utility can threaten the other side. The new corporate structure and governance of Peoples, as Peoples Gas System, Inc., helps insulate Peoples’ customers from the impact of events that may occur in the future at Tampa Electric, and vice versa. (TR 90)
>
> Of course, one of the significant, potential long-term benefits of the 2023 Transaction to customers will only be realized if Tampa Electric – our former debt capital provider – experiences a catastrophic natural disaster (e.g., a major hurricane hitting Tampa) or a different type of incident that (a) impairs its ability to provide debt capital to Peoples or (b) otherwise implicates Peoples’ customers in a business issue not directly related to the provision of service to Peoples customers. We hope that these kinds of events never occur but hope by itself is usually not a good strategy. (TR 111)

It is generally accepted that a catastrophic event involving a mid-size or large utility, such as those cited by witness Wesley, could result in billions of dollars of damage and liability. The types and sizes of catastrophic events that could occur to an electric or gas utility are only limited by one’s imagination. Making a list of all of them and their associated costs is neither useful nor necessary to determine it is beneficial to customers to legally separate Tampa Electric and PGS. In addition to the direct costs associated with a catastrophic event, a utility could have its bond rating lowered and have its ability to attract capital impaired. Both of which can be costly to a utility and its customers both in terms of dollars and quality of service. Consequently, staff believes that even though PGS did not explicitly quantify the dollar benefit of legally separating from Tampa Electric, it nonetheless has carried its burden of proof regarding the benefits to customers.

Finally, in its brief, the Joint Parties argued that, “Instead of deciding to undertake the 2023 Transaction at a time and in a manner that would mitigate and minimize the rate impact on customers, the Company chose to carry out the transaction at a time and in a manner that will save Emera shareholders $150 million in tax liability.” (JP BR 44) In her rebuttal testimony, witness Wesley stated, “The PLR Tampa Electric requested and received does not ‘require’ Tampa Electric and Peoples to do anything, but it does assure them that the 2023 Transaction will not create a taxable capital gain or otherwise be considered a taxable event if the 2023 Transaction is executed as described in the PLR request.” (TR 109)

Staff believes it is important to note that Emera shareholders will not receive a $150 million gain from the 2023 Transaction. As pointed out by witness Wesley, by executing the 2023 Transaction as described in the PLR request, a $150 million tax liability will be avoided. Staff believes the 2023 Transaction can reasonably be described as a reorganization. As such, Tampa Electric and PGS reorganized and did so in a way that did not incur a tax liability – which is good business practice. It would be inappropriate to conclude that 2023 Transaction was executed to achieve a $150 million gain for Emera’s shareholders at the expense of PGS’s customers.

## CONCLUSION

Based on the above analysis, staff recommends no adjustments be made to the projected test year related to the spin-off of PGS.

***Issue 73:*** **WITHDRAWN**

***Issue 74:*** Should PGS be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

***Recommendation:*** Yes. PGS should be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (Hinson)

***Position of the Parties***

**PGS:** Yes. Peoples does not object to this requirement.

**Joint Parties:** Yes.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS

PGS stated that it did not object to the requirement to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (PGS BR 46)

### Joint Parties

The Joint Parties agreed that the Company should be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (JP BR 46)

## ANALYSIS

Consistent with Commission practice, PGS should be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case.

## CONCLUSION

Consistent with Commission practice, PGS should be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case.

***Issue 75:*** Should this docket be closed?

***Recommendation:*** This docket should remain open for the Commission to determine the final rates at the December 5, 2023 Commission Conference. (M. Thompson)

***Position of the Parties***

**PGS:** Yes. This docket should be closed after the Commission has issued its final order and the time for filing an appeal has expired.

**Joint Parties:** No.

***Staff Analysis:***

## PARTIES' ARGUMENTS

### PGS
PGS stated that the docket should be closed after the time for filing an appeal has run. (PGS BR 46)

### Joint Parties
The Joint Parties stated that the docket should not be closed. (JP BR 47)

## ANALYSIS

This docket should remain open for the Commission to determine the final rates at the December 5, 2023 Commission Conference.

## CONCLUSION

ANALYSIS

This docket should remain open for the Commission to determine the final rates at the December 5, 2023 Commission Conference.

COMPARATIVE AVERAGE RATE BASE

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24

ATTACHMENT 1

| ISSUE NO. | | TOTAL PER BOOKS | COMPANY ADJS. | COMPANY ADJUSTED | STAFF ADJS. | STAFF ADJUSTED |
|---|---|---|---|---|---|---|
| | UTILITY PLANT | | | | | |
| | PLANT IN SERVICE | $3,319,121,612 | | | | |
| | Adjust for Non-Utility Common Plant | | (1,528,719) | | | |
| | 2024 CI/BS Rider | | (9,272,491) | | | |
| 18 | Removal of Alliance RNG Project | | | | (11,530,336) | |
| 21 | Removal of Capitalized Salaries & Benefits | | | | (314,216) | |
| | TOTAL PLANT IN SERVICE | $3,319,121,612 | ($10,801,210) | $3,308,320,402 | ($11,844,552) | $3,296,475,850 |
| | ACQUISITION ADJUSTMENT | $5,031,897 | | | | |
| | TOTAL ACQUISITION ADJUSTMENT | $5,031,897 | $0 | $5,031,897 | $0 | $5,031,897 |
| | CONSTRUCTION WORK IN PROGRESS | $135,611,359 | | | | |
| | 2024 CI/BS Rider | | (1,178,306) | | | |
| | Remove AFUDC - Eligible CWIP | | (110,123,605) | | | |
| 23 | Increased A&G Transfer | | | | 2,125,283 | |
| | TOTAL CONSTRUCTION WORK IN PROGRESS | $135,611,359 | ($111,301,911) | $24,309,448 | $2,125,283 | $26,434,732 |
| | TOTAL UTILITY PLANT | $3,459,764,868 | ($122,103,121) | $3,337,661,747 | ($9,719,269) | $3,327,942,478 |
| | DEDUCTIONS | | | | | |
| | ACCUM. DEP. & AMORT. - PLANT & ACQ. ADJ. | ($923,335,229) | | | | |
| | Adjust for Non-Utility Common Plant | | 468,554 | | | |
| | 2024 CI/BS Rider | | 40,391 | | | |
| 18 | Removal of Alliance RNG Project | | | | 507,203 | |
| 22 | Updated Depreciation Study | | | | 127,147 | |
| 22 | New River RNG - Depreciaton Corrections | | | | 101,319 | |
| 22 | Brightmark RNG - Updated Pipeline Depreciation Rate | | | | (477,092) | |
| | TOTAL ACCUM. DEP. & AMORT. - PLANT & ACQ. ADJ. | ($923,335,229) | $508,945 | ($922,826,284) | $258,577 | ($922,567,707) |
| | CUSTOMER ADVANCES FOR CONSTRUCTION | ($20,000,000) | | | | |
| | TOTAL CUSTOMER ADVANCES FOR CONSTRUCTION | ($20,000,000) | $0 | ($20,000,000) | $0 | ($20,000,000) |
| | TOTAL DEDUCTIONS | ($943,335,229) | $508,945 | ($942,826,284) | $258,577 | ($942,567,707) |
| | NET UTILITY PLANT | $2,516,429,639 | ($121,594,176) | $2,394,835,463 | ($9,460,691) | $2,385,374,771 |
| | WORKING CAPITAL ALLOWANCE | ($9,101,011) | | | | |
| | Projected Test Year Adjustments | | (18,946,000) | | | |
| | TOTAL WORKING CAPITAL ALLOWANCE | ($9,101,011) | ($18,946,000) | ($28,047,011) | $0 | ($28,047,011) |
| | TOTAL RATE BASE | $2,507,328,628 | ($140,540,176) | $2,366,788,452 | ($9,460,691) | $2,357,327,760 |

 

CAPITAL STRUCTURE

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24
13 Month Average

ATTACHMENT 2

| **COMPANY POSITION** | PGS PER BOOKS | SPECIFIC | PRO RATA | PGS ADJUSTED | RATIO | COST RATE | WEIGHTED COST |
|---|---|---|---|---|---|---|---|
| COMMON EQUITY | $1,191,009,138 | ($3,979,951) | ($63,023,001) | $1,124,006,187 | 47.49% | 11.00% | 5.22% |
| LONG TERM DEBT | 878,846,154 | 0 | (46,660,623) | 832,185,531 | 35.16% | 5.54% | 1.95% |
| SHORT TERM DEBT | 106,020,088 | (760,062) | (5,588,575) | 99,671,451 | 4.21% | 4.85% | 0.20% |
| CUSTOMER DEPOSITS | 28,892,062 | 0 | (1,363,878) | 27,528,183 | 1.16% | 2.53% | 0.03% |
| DEFERRED TAXES | 301,187,438 | (7,062,782) | (13,884,447) | 280,240,209 | 11.84% | 0.00% | 0.00% |
| TAX CREDIT - WEIGHTED | 3,313,300 | 0 | (156,408) | 3,156,892 | 0.13% | 8.49% | 0.01% |
| TOTAL | $2,509,268,180 | ($11,802,795) | ($130,676,933) | $2,366,788,452 | 100.00% | | 7.42% |

| **STAFF POSITION** | ADJUSTED PER BOOKS | SPECIFIC | PRO RATA | STAFF ADJUSTED | RATIO | COST RATE | WEIGHTED COST |
|---|---|---|---|---|---|---|---|
| COMMON EQUITY | $1,191,009,138 | ($3,977,495) | ($65,001,910) | $1,122,029,733 | 47.60% | 10.15% | 4.83% |
| LONG TERM DEBT | 878,846,154 | 1,812 | (48,125,757) | 830,722,209 | 35.24% | 5.54% | 1.95% |
| SHORT TERM DEBT | 106,020,088 | (759,843) | (5,764,056) | 99,496,189 | 4.22% | 4.85% | 0.20% |
| CUSTOMER DEPOSITS | 28,892,062 | (1,364,062) | 0 | 27,528,000 | 1.17% | 2.53% | 0.03% |
| DEFERRED TAXES | 301,187,438 | (7,556,568) | (16,079,241) | 277,551,630 | 11.77% | 0.00% | 0.00% |
| TAX CREDIT - WEIGHTED | 3,313,300 | (3,313,300) | 0 | 0 | 0.00% | 8.03% | 0.00% |
| TOTAL | $2,505,954,880 | ($13,656,157) | ($134,970,963) | $2,357,327,760 | 100% | | 7.02% |

COMPARATIVE NET OPERATING INCOME

PEOPLES GAS SYSTEMS ATTACHMENT 3
DOCKET NO. 20230023-GU Page 1 of 2
PTY 12/31/24

| ISSUE NO. | | TOTAL PER BOOKS | COMPANY ADJS. | COMPANY ADJUSTED | STAFF ADJS. | STAFF ADJUSTED |
|---|---|---|---|---|---|---|
| | OPERATING REVENUES | | | | | |
| | Operating Revenues | $576,955,550 | | | | |
| | Fuel Revenue Adjustment | | ($229,472,342) | | | |
| | 2024 CI/BS Rider | | (1,298,393) | | | |
| | Lease of Plant Held for Future Use | | (117,796) | | | |
| 57 | Removal of Alliance RNG Project | | | | (5,726,092) | |
| | TOTAL REVENUES | $576,955,550 | ($230,888,531) | $346,067,020 | ($5,726,092) | $340,340,928 |
| | OPERATING EXPENSES: | | | | | |
| | COST OF GAS | $228,428,641 | | | | |
| | Eliminate Fuel Expense | | (228,428,641) | | | |
| | TOTAL COST OF GAS | $228,428,641 | ($228,428,641) | $0 | $0 | $0 |
| | OPERATION & MAINTENANCE EXPENSE | $151,258,200 | | | | |
| | 2024 CI/BS Rider | | (299,014) | | | |
| | Employee Activities | | (79,176) | | | |
| | Economic Development | | (18,420) | | | |
| | Maintenance of General Plant | | (38,449) | | | |
| | Maintenance of Structures & Improvements | | (5,930) | | | |
| 13 | Increased SeaCoast Allocation | | | | (189,347) | |
| 18 | Removal of Alliance RNG Project | | | | (3,956,653) | |
| 19 | WAM O&M Efficiency Reductions | | | | (750,000) | |
| 41 | Reduction to Outside Services | | | | (206,000) | |
| 42 | Reduction to Projected Number of Test Year Employees | | | | (1,245,959) | |
| 42 | Removal of BDM Position | | | | (37,882) | |
| 43 | Reduction of Annual Merit Increases | | | | (1,057,084) | |
| 44 | Lobbying, Contributions, Sponsorships, & Advertising | | | | (500,000) | |
| 46 | Reduction to Storm Reserve Accrual | | | | (120,000) | |
| 48 | Rate Case Expense Reduction | | | | (156,384) | |
| 49 | Corresponding Employee Expense Reduction | | | | (92,919) | |
| 49 | Reduction to Standalone Audit Fees | | | | (190,000) | |
| 49 | Reduction to Treasury Support Costs | | | | (60,234) | |
| 49 | Increased A&G Expense Allocation to Capital | | | | (2,125,283) | |
| | TOTAL O & M EXPENSE | $151,258,200 | ($440,988) | $150,817,212 | ($10,687,745) | $140,129,467 |
| | DEP. & AMORT. EXP. - PLANT | $87,776,676 | | | | |
| | Adjust for Non-Utility Common Plant | | (43,270) | | | |
| | 2024 CI/BS Rider | | (119,438) | | | |
| 18 | Removal of Alliance RNG Project | | | | (359,701) | |
| 50 | Updated Depreciation Study | | | | (252,303) | |
| 50 | New River RNG - Depreciaton Corrections | | | | (51,505) | |
| 50 | Brightmark RNG - Updated Pipeline Depreciation Rate | | | | 321,507 | |
| | TOTAL DEPRECIATION & AMORTIZATION | $87,776,676 | ($162,708) | $87,613,968 | ($342,002) | $87,271,967 |

COMPARATIVE NET OPERATING INCOME

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24

ATTACHMENT 3
Page 2 of 2

| ISSUE NO. | | TOTAL PER BOOKS | COMPANY ADJS. | COMPANY ADJUSTED | STAFF ADJS. | STAFF ADJUSTED |
|---|---|---|---|---|---|---|
| | AMORTIZATION EXP. - OTHER | $1,000,000 | | | | |
| | TOTAL AMORTIZATION EXP. - OTHER | $1,000,000 | $0 | $1,000,000 | $0 | $1,000,000 |
| | TAXES OTHER THAN INCOME | $32,748,644 | | | | |
| | TOTI Corresponding to Fuel Revenues | | (1,043,800) | | | |
| | 2024 CI/BS Rider | | (3,504) | | | |
| 18 | Removal of Alliance RNG Project | | | | (88,687) | |
| 51 | Fallout Adj. - Payroll Tax | | | | (175,061) | |
| 51 | Property Tax Correction | | | | (2,008,000) | |
| | TOTAL TAXES OTHER THAN INCOME | $32,748,644 | ($1,047,304) | $31,701,341 | ($2,271,748) | $29,429,593 |
| | INCOME TAX EXPENSE | | | | | |
| | Income Taxes | ($16,432,949) | | | | |
| | Income Taxes - Deferred | 22,489,825 | | | | |
| | Taxes Corresponding to Test Year Adjustments | | (3,289,038) | | | |
| | Interest Synchronization | | 325,338 | | | |
| 52 | Fallout Adj. - Parent Debt | | | | (129,476) | |
| 53 | Fallout Adj. - Interest Synchronization | | | | 22,684 | |
| 53 | Fallout Adj. - Federal Income Taxes | | | | 1,491,852 | |
| 53 | Fallout Adj. - State Income Taxes | | | | 413,464 | |
| | TOTAL INCOME TAXES | $6,056,876 | ($2,963,701) | $3,093,175 | $1,798,523 | $4,891,698 |
| | GAIN ON SALE OF PROPERTY | ($495,917) | | | | |
| | TOTAL GAIN ON SALE OF PROPERTY | ($495,917) | $0 | ($495,917) | $0 | ($495,917) |
| | TOTAL OPERATING EXPENSES | $506,773,120 | ($233,043,341) | $273,729,779 | ($11,445,087) | $262,284,692 |
| | NET OPERATING INCOME | ($166,432,192) | $2,154,811 | $72,337,240 | $5,718,996 | $78,056,236 |

NET OPERATING INCOME MULTIPLIER

PEOPLES GAS SYSTEMS ATTACHMENT 4

DOCKET NO. 20230023-GU

PTY 12/31/24

| DESCRIPTION | COMPANY PER FILING | STIPULATION |
|---|---|---|
| REVENUE REQUIREMENT | 100.0000% | 100.0000% |
| REGULATORY ASSESSMENT RATE | 0.5000% | 0.5000% |
| BAD DEBT RATE | 0.2805% | 0.2805% |
| NET BEFORE INCOME TAXES | 99.2195% | 99.2195% |
| STATE INCOME TAX RATE | 5.5000% | 5.5000% |
| STATE INCOME TAX | 5.4571% | 5.4571% |
| NET BEFORE FEDERAL INCOME TAXES | 93.7624% | 93.7624% |
| FEDERAL INCOME TAX RATE | 21.0000% | 21.0000% |
| FEDERAL INCOME TAX | 19.6901% | 19.6901% |
| REVENUE EXPANSION FACTOR | 74.0723% | 74.0723% |
| NET OPERATING INCOME MULTIPLIER | 1.3500 | 1.3500 |

COMPARATIVE REVENUE DEFICIENCY CALCULATIONS

PEOPLES GAS SYSTEMS ATTACHMENT 5
DOCKET NO. 20230023-GU
PTY 12/31/24

| | | COMPANY ADJUSTED | | STAFF RECOMMENDED |
|---|---|---|---|---|
| RATE BASE (AVERAGE) | | $2,366,788,452 | | $2,357,327,760 |
| RATE OF RETURN | X | 7.42% | X | 7.02% |
| REQUIRED NOI | | $175,542,307 | | $165,389,334 |
| ACHIEVED NOI | | 72,337,240 | | 78,056,236 |
| NET REVENUE DEFICIENCY | | $103,205,067 | | $87,333,098 |
| REVENUE EXPANSION FACTOR | | 1.3500 | | 1.3500 |
| REVENUE DEFICIENCY | | $139,330,211 | | $117,902,534 |
| Cast Iron/Bare Steel Revenues | | (11,693,817) | | (11,156,958) |
| INCREMENTAL REVENUE INCREASE | | $127,636,394 | | $106,745,576 |

# 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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Office of Industry Development and Market Analysis (Wooten, Nave) CH
Office of the General Counsel (Sparks) AEH

**RE:** Docket No. 20230076-TP – 2024 State certification under 47 C.F.R. §54.313 and §54.314, annual reporting requirements for high-cost recipients and certification of support for eligible telecommunications carriers.

**AGENDA:** 11/09/23 – Regular Agenda – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** La Rosa

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

## Case Background

In October 1997, the Commission designated Incumbent Local Exchange Carrier (ILEC) Windstream Florida, LLC as an eligible telecommunications carrier (ETC).[1] In April 2021, Windstream Communications, LLC, an affiliate of Windstream Florida, LLC, requested an ETC designation by the Commission in order to receive federal Rural Digital Opportunity Fund (RDOF) high-cost support in Florida for areas outside Windstream Florida, LLC's ILEC territory.[2] The Commission instructed Windstream Communications, LLC to seek its ETC designation directly from the FCC because Windstream Communications, LLC was seeking an ETC designation for broadband and VoIP services outside of the Commission's jurisdiction.

[1] Docket No. 19970644-TP.
[2] Docket No. 20210070-TX.

Windstream Communications, LLC was granted an ETC designation by the FCC on January 12, 2022.[3]

Windstream Florida, LLC and Windstream Communications, LLC (collectively Windstream) were among several carriers requesting certification from the Commission for 2024 federal high-cost support during this year's certification proceeding in the instant docket during June and July. Specifically, Windstream Communications, LLC requested certification for federal high-cost support for its Study Area Code (SAC) 219027 while Windstream Florida, LLC claimed no federal support was expected to be received in its SAC 210336 in 2024.[4] Staff advised Windstream to follow the FCC-designated certification process because all expected support was to be received by the FCC-designated ETC Windstream Communications, LLC. The Commission certified eight other carriers as eligible to receive federal high-cost support on September 12, 2023.[5] Staff subsequently filed the necessary certifications with the FCC and the Universal Service Administrative Company (USAC) on September 15, 2023.

On September 25, 2023, USAC notified staff that Windstream Communications, LLC SAC 219027 had yet to be certified. After discussions with both FCC and USAC staff, it was revealed that a new process had recently been developed requiring state and federal level certification for carriers, like Windstream, that receive RDOF support in both ILEC and competitive areas with separate SACs within a state. With this new process, USAC disperses support to a single SAC per carrier in a state, regardless of whether the support is used in that SAC or commingled with another SAC assigned to that company, its affiliate, or its holding company. USAC decided to disperse all Windstream RDOF funding for Florida to SAC 219027. It is apparently a new and rare occurrence and so has not yet been generally disseminated to the states. Windstream refiled its request for certification with this Commission on September 29, 2023.

The Commission has jurisdiction pursuant to 47 C.F.R. §54.313 and §54.314, as well as Chapter 364, F.S.

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[3] FCC, "Windstream Designated as an ETC in RDOF-Eligible Areas in FL and NY," released January 12, 2022, https://www.fcc.gov/document/windstream-designated-etc-rdof-eligible-areas-fl-and-ny, accessed September 26, 2023.

[4] Study Area Codes (SACs) are FCC-designated geographic areas within a state where federal universal service funds should be invested. Each ETC is assigned at least one SAC in each state it receives support, and each SAC is exclusive to one carrier. The ILEC Windstream Florida, LLC's Florida-assigned SAC is 210336 and the competitive carrier Windstream Communications, LLC's Florida-assigned SAC is 219027.

[5] The carriers certified were: Bright House Networks Information Services (Florida), LLC; CenturyLink of Florida, Inc.; Consolidated Communications of Florida Company; Frontier Florida LLC; ITS Telecommunications Systems, LLC d/b/a Blue Stream Fiber; Northeast Florida Telephone Company d/b/a NEFCOM; Quincy Telephone Company d/b/a TDS Telecom; and Smart City Telecommunications LLC d/b/a Smart City Telecom.

## Discussion of Issues

***Issue 1:*** Should the Commission certify to USAC and the FCC that Windstream Florida, LLC and Windstream Communications, LLC are eligible to receive federal high-cost support?

***Recommendation:*** Yes. The Commission should certify to USAC and the FCC that Windstream Florida, LLC and Windstream Communications, LLC are eligible to receive federal high-cost support. (Wooten, Nave)

***Staff Analysis:*** On September 29, 2023, Windstream requested certification from the Commission under 47 C.F.R §54.314 and 47 U.S.C. §254(e) to receive federal high-cost universal service support. The carriers have submitted an affidavit attesting that they have used the federal high-cost support received in the preceding calendar year and will use the federal high-cost support received in the coming calendar year only for the provision, maintenance, and upgrading of facilities and services for which the support is intended. The affidavit included both of Windstream's SACs, meaning certification is sought for both Windstream Florida, LLC and Windstream Communications, LLC.

Under 47 C.F.R. §54.314(c)(1), the Commission "may file a supplemental certification for carriers not subject to the (s)tate's annual certification." Therefore, staff recommends that the Commission certify to USAC and the FCC that both Windstream Florida, LLC and Windstream Communications, LLC are eligible to receive federal high-cost support.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. This docket should be closed upon issuance of a Final Order. (Sparks)

***Staff Analysis:*** This docket should be closed upon issuance of a Final Order.

# Item 6

FILED 10/27/2023
DOCUMENT NO. 05841-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Accounting and Finance (Norris) ALM
Division of Economics (Hampson) EJD
Office of the General Counsel (Stiller, Dose) JSC

**RE:** Docket No. 20230017-EI – Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricanes Ian and Nicole, by Florida Power & Light Company.

**AGENDA:** 11/09/23 – Regular Agenda – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Graham

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

## Case Background

By Order issued March 23, 2023, the Commission approved Florida Power & Light Company's (FPL or Company) petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover $1.3 billion for the incremental restoration costs related to Hurricanes Ian and Nicole and to replenish the storm reserve.[1] This amount included $18.8 million in interest.

The Commission also approved the alternate storm charge calculation FPL proposed in its petition, which combined the recovery of incremental storm costs associated with Hurricanes Ian

[1]Order No. PSC-2023-0110-PCO-EI, issued March 23, 2023, in Docket No. 20230017-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricanes Ian and Nicole, by Florida Power & Light Company*.

and Nicole with the remaining amounts to be collected for Hurricanes Michael, Sally, and Zeta, which have been previously approved by the Commission for Gulf Power Company (GPC).[2] This alternate calculation estimated a total of $1.5 billion for incremental restoration costs related to Hurricanes Michael, Sally, Zeta, Ian, and Nicole, to replenish the storm reserve, and included $21.6 million in interest. FPL filed its petition pursuant to the provisions of the 2021 Settlement Agreement (2021 Settlement) approved by the Commission in Order No. PSC-2021-0446-S-EI.[3]

On September 5, 2023, FPL filed a supplemental petition to reduce the interim storm surcharge based on its internal review and finalization of the invoices and storm costs associated with Hurricanes Ian and Nicole. As a result of this internal process, the estimated incremental storm restoration cost related to the two storms decreased from the original estimate of $1.3 billion to $1.1 billion. Thus, the total estimate reflected in the alternative storm charge calculation decreased from $1.5 billion to $1.3 billion. FPL has proposed amended reduced interim storm restoration charges applicable to all rate classes, effective with the first billing cycle of January 2024 and continuing through March 2024, subject to a final true-up.

The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

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[2]Order No. PSC-2019-0221-PCO-EI, issued June 3, 2019, in Docket No. 20190038-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Michael, by Gulf Power Company*; and Order No. PSC-2022-0406-FOF-EI, issued November 21, 2022, in Docket No. 20200041-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Sally, by Gulf Power Company*.
[3]Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company*.

## Discussion of Issues

***Issue 1:*** Should the Commission authorize FPL to implement an amended interim storm restoration recovery charge?

***Recommendation:*** Yes. The Commission should authorize FPL to implement an amended interim storm restoration recovery charge, subject to refund. Once the total actual storm costs are known, FPL should be required to file documentation of the storm costs for Commission review and true up of any excess or shortfall. (Norris)

***Staff Analysis:*** As stated in the Case Background, FPL filed a supplemental petition to reduce the interim storm surcharge based on its internal review and finalization of the invoices and storm costs associated with Hurricanes Ian and Nicole. As a result of this internal process, the estimated incremental storm restoration cost related to the two storms decreased from the original estimate of $1.3 billion to $1.1 billion. Thus, the estimate of total costs reflected in the alternative storm charge calculation decreased from $1.5 billion to $1.3 billion. Included in that total is FPL's request to replenish the storm reserve to the pre-storm level of $219.9 million.

The initial interim petition was filed pursuant to the provisions of the 2021 Settlement approved by the Commission in Order No. PSC-2021-0446-S-EI. Storm restoration costs for Ian and Nicole were incurred during the term of the 2021 Settlement. Based on the updated estimates for the two storms, the current interim storm surcharge would result in an over-recovery of approximately $200 million if allowed to remain effective through March 2024.

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over/under recovery, and associated interest, will be considered by the Commission at a later date. However, staff recommends amending the interim storm surcharge to reflect the known and measurable changes identified by the Company in advance of the final disposition.

Based on a review of the information provided by FPL in its supplemental petition, staff recommends that the Commission authorize the Company to implement an amended interim storm restoration recovery charge subject to refund. Once the total actual storm costs are known, FPL should be required to file documentation of the storm costs for Commission review and true-up of any excess or shortfall.

***Issue 2:*** Should the Commission approve FPL's proposed amended interim storm restoration recovery charge tariff as shown in Attachment A to the recommendation?

***Recommendation:*** Yes. The Commission should approve FPL's proposal to revise the interim storm restoration recovery surcharges and associated tariff, as shown in Attachment A to this recommendation. The tariff should become effective the first billing cycle of January 2024. The interim storm restoration surcharges should be subject to final true-up once the final total actual storm-related costs are known and filed. (Hampson)

***Staff Analysis:*** FPL has proposed to decrease the currently effective interim storm restoration recovery surcharges based on the Company's internal review of storm costs, as discussed in Issue 1. In paragraph 10 of the petition, FPL states that the updated surcharges are allocated to the rate classes consistent with the rate design approved in FPL's most recent rate case.[4] Staff has reviewed the allocation to rate classes and believes that the allocations provided in Appendix D to the petition are consistent with those approved in FPL's most recent rate case. Furthermore, staff has reviewed the derivation of the surcharges provided in Appendix D to the petition. Staff agrees that the surcharges have been calculated correctly, using projected kilowatt hour (kWh) sales for January through March 2024. The proposed interim storm restoration recovery factors should remain in effect until a final true-up is approved by the Commission.

The proposed interim storm restoration surcharges are shown on First Revised Tariff Sheet No. 8.030.7, provided in Appendix F to the petition. For residential customers the proposed surcharge would be 0.665 cents per kWh, which equates to a total surcharge of $6.65 for a 1,000 kWh monthly bill. The current surcharge is 1.53 cents per kWh, which equates to a total surcharge of $15.30 for a 1,000 kWh monthly bill. The storm cost recovery surcharge would be included in the non-fuel energy charge on customer bills.

Staff recommends that the Commission approve FPL's proposal to revise the interim storm restoration recovery surcharges and associated tariff, as shown in Attachment A to this recommendation. The tariff should become effective the first billing cycle of January 2024. The proposed interim storm restoration recovery factors should remain in effect until a final true-up is approved by the Commission. The interim storm restoration surcharges should be subject to final true-up once the final total actual storm-related costs are known and filed.

[4]Order No. PSC-2021-0446-S-EI.

***Issue 3:*** Should this docket be closed?

***Recommendation:*** No. This docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted. (Stiller)

***Staff Analysis:*** No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted.

FLORIDA POWER & LIGHT COMPANY

First Revised Sheet No. 8.030.7
Cancels Original Sheet No. 8.030.7

(Continued from Sheet No. 8.030.3)

## 2022 CONSOLIDATED INTERIM STORM RESTORATION RECOVERY

APPLICATION:

The Consolidated Interim Storm Restoration Recovery Surcharge is designed to recover incremental storm-related costs incurred by the Company related to Hurricanes Michael, Sally, Zeta, Ian, and Nicole. The factor is applicable to the Energy Charge under FPL's various rate schedules.

| Rate Schedule | ¢/kWh |
|---|---|
| ALL KWH - RS-1, RTR-1 | ~~1.530~~0.665 |
| GS-1, GST-1 | ~~1.414~~0.590 |
| GSD-1, GSD-1EV, GSDT-1, HLFT-1, SDTR-1 | ~~0.675~~0.276 |
| GSLD-1, GSLD-1EV, GSLDT-1, CS-1, CST-1, HLFT-2, SDTR-2 | ~~0.661~~0.263 |
| GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3 | ~~0.521~~0.209 |
| GSLD-3, GSLDT-3, CS-3, CST-3 | ~~0.039~~0.015 |
| OL-1 | ~~4.624~~1.679 |
| OS-2 | ~~2.409~~0.826 |
| SL-1, PL-1, LT-1, OS I/II | ~~1.526~~0.547 |
| SL-1M | ~~0.955~~0.306 |
| SL-2 | ~~0.711~~0.259 |
| SL-2M | ~~1.808~~0.607 |
| SST-1(T), ISST-1(T) | ~~0.058~~0.062 |
| SST-1(D1), SST-1(D2), SST-1(D3), ISST-1(D) | ~~1.892~~0.419 |
| CILC-1(D) | ~~0.481~~0.186 |
| CILC-1(G) | ~~0.583~~0.225 |
| CILC-1(T) | ~~0.028~~0.011 |
| MET | ~~0.660~~0.246 |
| GSCU-1 | ~~2.591~~0.942 |

(Continued on Sheet No. 8.031)

**Issued by: Tiffany Cohen, ~~Executive Director, Rate Development & Strategy~~VP Financial Planning and Rate Strategy**
**Effective: ~~April 1, 2023~~**

# 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-**

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**DATE:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Accounting and Finance (D. Buys, Mason, McGowan, Norris) ALM
Division of Economics (Hampson) EJD
Office of the General Counsel (M. Thompson, Sandy) JSC

**RE:** Docket No. 20230019-EI – Petition for recovery of costs associated with named tropical systems during the 2019-2022 hurricane seasons and replenishment of storm reserve, by Tampa Electric Company.

**AGENDA:** 11/9/23 – Regular Agenda – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Graham

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

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## Case Background

On January 23, 2023, Tampa Electric Company's (TECO or Company) filed a petition for a limited proceeding seeking authority to implement a storm restoration recovery charge to recover $130.9 million for the incremental restoration costs related to Tropical Storms Alberto, Nestor, and Eta, and Hurricanes Dorian, Elsa, Ian, and Nicole (Collectively, "the storms"), the implementation of the GPS software ARCOS, as well as the replenishment of its storm reserve. Included in the $130.9 million is interest charged for Hurricanes Ian and Nicole. TECO filed its petition pursuant to the provisions of the 2021 Stipulation and Settlement Agreement (2021 Settlement).[1]

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[1] See Order No. PSC-2021-0423-S-EI, issued on November 10, 2021, in Docket Nos. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company*, and *20200264-EI, In re: Petition for approval of 2020 depreciation*

By order issued March 27, 2023, the Commission approved TECO's tariff revisions and an interim storm restoration recovery charge, effective with the first billing cycle of April 2023 through March 2024, subject to a final true-up.[2]

On August 16, 2023 the Company filed a supplemental petition requesting an amended interim storm surcharge to reflect an increase of $3.6 million in incremental storm costs, for a total of $134.5 million, based on updated actual and accrued costs. TECO also requested to modify the 12-month recovery period approved by the Commission, to extend cost recovery through the last billing cycle of December 2024. The current recovery period approved in Order No. PSC-2023-0116-PCO-EI was for the period April 2023 through the last billing cycle of March 2024.

On September 29, 2023, TECO filed a petition for approval of final/actual storm restoration costs and the associated true-up process related to the Storms. A formal evidentiary hearing has been scheduled for May 1-2, 2024.

The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

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*and dismantlement study and capital recovery schedules, by Tampa Electric Company*. Pursuant to the Future Process Improvements in the Storm Cost Settlement Agreement, TECO was required to establish a policy under which vendor crews would be tracked "to the maximum extent possible" using GPS software such as ARCOS. Tampa Electric began implementation of the ARCOS application in 2019.

[2] Order No. PSC-2023-0116-PCO-EI issued on March 27, 2023, in Docket No. 20230019-EI.

## Discussion of Issues

***Issue 1:*** Should the Commission authorize TECO to implement an amended interim storm restoration recovery charge and modified recovery period?

***Recommendation:*** Yes. The Commission should authorize TECO to implement an amended interim storm restoration recovery charge, subject to refund, and modified recovery period. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, will be considered by the Commission at a later date. (Mason)

***Staff Analysis:*** As stated in the Case Background, TECO filed a supplemental petition requesting an amended interim storm surcharge to reflect an increase of $3.6 million in incremental storm costs, for a total of $134.5 million, based on updated actual and accrued costs. TECO also requested to modify the 12-month recovery period approved by the Commission, to extend cost recovery through the last billing cycle of December 2024.

The initial interim petition was filed pursuant to the provisions of the 2021 Settlement. Pursuant to Section II.B of the Process Improvements portion of the 2019 Storm Cost Settlement Agreement, the Company commissioned an external audit to review the incremental storm restoration costs for Hurricane Ian. In its amended petition, TECO asserted that the total, actual incremental storm restoration costs for Hurricane Ian were $120,851,632, an increase of $1,635,341, as affirmed by the PricewaterhouseCoopers audit.

The Company also received additional invoices through July 31, 2023, for a total of $122,727,694 million in costs associated with Hurricane Ian. TECO additionally updated its final costs for Hurricane Nicole, which results in an increase of $78,753. All other costs remained the same. The Company's updated costs result in a total increase of $3.6 million in incremental storm costs, for a total of $134.5 million. TECO requested a modified recovery period to spread cost recovery for the remaining unrecovered incremental storms costs over an additional nine months to reduce the impact of the increase on monthly customer bills.

Pursuant to Paragraph 8b of the 2021 Settlement, the Company may petition the Commission to increase the initial 12-month recovery at rates greater than $4.00 per 1,000 kWh if the total costs are in excess of $100 million in a given calendar year, inclusive of the amount needed to replenish the storm reserve. Based on the total recovery requested in its initial petition, $130.9 million or $10.22 per 1,000 kWh, TECO met the threshold for requesting a recovery period longer than the 12 months it initially petitioned. The amended interim storm surcharge falls below $4.00 per 1,000 kWh, but that is a function of spreading the remaining total costs, which increased from the initial petition, over an additional 9 months.

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review of the Company's total actual storm restoration costs reflected in its petition filed on September 29, 2023. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, will be considered by the Commission at a later date.

Based on a review of the information provided by TECO in its supplemental petition, the Commission should authorize TECO to implement an amended interim storm restoration recovery charge, subject to refund, and modified recovery period. This would enable the interim storm surcharge originally approved by Order No. PSC-2023-0116-PCO-EI to reflect the known and measurable changes identified by the Company and modify the recovery period to spread the cost recovery over a longer period. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination should be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, should be considered by the Commission at a later date.

***Issue 2:*** What is the appropriate security to guarantee the amount collected subject to refund through the amended interim storm restoration recovery charge?

***Recommendation:*** The appropriate security to guarantee the funds collected subject to refund is a corporate undertaking. (McGowan)

***Staff Analysis:*** Staff recommends that all funds collected subject to refund be secured by a corporate undertaking. The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. TECO requested a modified 12-month collection period from January 2024 through December 2024 for Interim Storm Cost Recovery Charges of $134,471,119 related to the Storms, including the ARCOS cost. Staff reviewed TECO's three most recent annual reports filed with the Commission (2022, 2021, and 2020) to determine if the Company can support a corporate undertaking to guarantee the funds collected for recovery of incremental storm restoration costs related to all the weather events. TECO's financial information demonstrates the Company has deficient levels of liquidity; that is, current assets are less than current liabilities. However, the Company has sufficient levels of ownership equity, profitability, and interest coverage to support a potential refund of $134.5 million. TECO's average net income for the three years 2022, 2021, and 2020 is almost three times the requested corporate undertaking amount ($399.6 million vs. $134.5 million). Moreover, it is improbable TECO will be required to refund the entire requested amount.

Staff believes TECO has adequate resources to support a corporate undertaking in the amount requested. Based on this analysis, staff recommends that a corporate undertaking of $134.5 million is acceptable. This brief financial analysis is only appropriate for deciding if the Company can support a corporate undertaking in the amount proposed and should not be considered a finding regarding staff's position on other issues in this proceeding.

***Issue 3:*** Should the Commission approve TECO's proposed amended interim storm restoration recovery charge tariff as shown in Attachment A to the recommendation?

***Recommendation:*** Yes. The Commission should approve TECO's proposal to revise the storm surcharge factors and associated tariff, as shown in Attachment A to this recommendation. The tariff should become effective the first billing cycle of January 2024 and conclude with the last billing cycle of December 2024. The proposed storm surcharge factors should be subject to final true-up once the final total actual storm-related costs are known and filed. (Hampson)

***Staff Analysis:*** TECO has proposed to decrease the currently effective storm surcharge factors, as discussed in Issue 1. In paragraph 15 of the petition, TECO stated that the updated surcharges were developed using the cost-of-service allocation methodology approved in the Company's most recent rate case. Staff has reviewed the allocation to rate classes and believes that the allocations provided on Exh 2, page 4 of 5, of the petition are consistent with those approved in TECO's most recent rate case. Furthermore, staff has reviewed the derivation of the surcharges provided on Exh 2, page 5 of 5, of the petition. Staff believes that the surcharges have been calculated correctly, using projected kilowatt hour (kWh) sales for January through December 2024.

The proposed storm surcharge factors are shown on First Revised Tariff Sheet No. 6.024. For residential customers the proposed surcharge would be 0.219 cents per kWh, which equates to a total surcharge of $2.19 for a 1,000 kWh monthly bill. The current surcharge is 1.022 cents per kWh, which equates to a total surcharge of $10.22 for a 1,000 kWh monthly bill. The proposed storm surcharge factors would be included in the non-fuel energy charge on customer bills.

Staff recommends that the Commission should approve TECO's proposal to revise the storm surcharge factors and associated tariff, as shown in Attachment A to this recommendation. The tariff should become effective the first billing cycle of January 2024 and conclude with the last billing cycle of December 2024. The interim storm restoration surcharge factors should be subject to final true-up once the final total actual storm-related costs are known and filed.

***Issue 4:*** Should this docket be closed?

***Recommendation:*** No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted. (M. Thompson)

***Staff Analysis:*** No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**FIRST REVISED SHEET NO. 6.024**
**CANCELS ORIGINAL SHEET NO. 6.024**

STORM SURCHARGE

**Storm Surcharge:** The following charges shall be applied to each kilowatt-hour ~~delivered and~~ billed on monthly bills from ~~April 2023~~January 2024 through ~~March~~ December 2024. The following factors by rate schedule were calculated using the approved formula and allocation method approved by the Florida Public Service Commission

| Rate Schedules | Energy Rate ¢/kWh |
|---|---|
| RS (all tiers), RSVP-1 (all pricing periods) | 0~~1.022~~.219 |
| GS, GST (all pricing periods), CS | ~~1.061~~0.225 |
| GSD, GSDO, SBD, GSDT and SBDT (all pricing periods) | ~~0.238~~0.052 |
| GSLDPR, GSLDTPR, SBLDPR and SBLDTPR (all pricing periods) | 0.~~127~~027 |
| GSLDSU, GSLDTSU, SBLDSU and SBLDTSU (all pricing periods) | 0.~~028~~006 |
| LS-1, LS-2 | 0.~~326~~074 |

**ISSUED BY**: A. D. Collins, President

**DATE EFFECTIVE:**

# Item 8

FILED 10/27/2023
DOCUMENT NO. 05849-2023
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-**

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**DATE:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Engineering (M. Watts, Ramos) TB
Division of Accounting and Finance (Sewards, Thurmond) ALM
Division of Economics (Bruce, Hudson) CJD
Office of the General Counsel (Watrous) JSC

**RE:** Docket No. 20230033-SU – Application for transfer of wastewater Certificate No. 562-S of TKCB, Inc. to CSWR-Florida Utility Operating Company, LLC, in Brevard County.

**AGENDA:** 11/09/23 – Regular Agenda – Proposed Agency Action for Issue 2 – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** La Rosa

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

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## Case Background

TKCB, Inc. (TKCB or Utility) is a Class C utility currently providing wastewater service to 295 mobile home lots in the Sun Lake Village Estates manufactured home community (formerly Sun Lake Estates) in Cocoa, Florida. The Utility is located in the St. Johns River Water Management District. Water service is provided by the City of Cocoa. In its 2022 Annual Report, TKCB reported a net operating loss of $17,868. The Utility's last rate case was in 2021.[1]

[1] Order No. PSC-2021-0435-PAA-SU, issued November 22, 2021, in Docket No. 20210120-SU, *In re: Application for a limited alternative rate increase proceeding, by TKCB, Inc.*

In 2011, the Florida Public Service Commission (Commission) granted TKCB an original wastewater certificate in Brevard County.[2] The certificated service territory has not been amended since that time.

On March 13, 2023, CSWR-Florida Utility Operating Company, LLC (CSWR-TKCB or Buyer) filed an application with the Commission for the transfer of Certificate No. 562-S from TKCB to CSWR-TKCB in Brevard County. The sale will close after the Commission votes to approve the transfer. The Office of Public Counsel's intervention was acknowledged by Order No. PSC-2023-0139-PCO-SU, issued April 21, 2023.

This recommendation addresses the transfer of the wastewater system and Certificate No. 562-S, and the appropriate net book value (NBV) of the wastewater system for transfer purposes. The Commission has jurisdiction pursuant to Sections 367.071 and 367.081, Florida Statutes (F.S.).

[2] Order No. PSC-2011-0522-FOF-SU, issued November 7, 2011, in Docket No. 20100442-SU, *In re: Application for certificate to provide wastewater service in Brevard County by TKCB.*

## Discussion of Issues

***Issue 1:*** Should the transfer of Certificate No. 562-S in Brevard County from TKCB, Inc. to CSWR-Florida Utility Operating Company, LLC be approved?

***Recommendation:*** Yes. The transfer of the wastewater system and Certificate No. 562-S 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 a copy of its signed and executed contract for sale to the Commission within 60 days of the Order approving the transfer, which is final agency action. If the sale is not finalized within 60 days of the transfer Order, the Buyer should file a status update in the docket file. The Utility's existing rates, as shown on Schedule No. 4, 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, 2022. The Buyer should be responsible for filing annual reports and paying RAFs for all future years. (M. Watts, Thurmond, Bruce)

***Staff Analysis:*** On March 13, 2023, CSWR-TKCB filed an application for the transfer of Certificate No. 562-S from TKCB to CSWR-TKCB in Brevard County. The application is in compliance with Section 367.071, F.S., and Commission rules concerning applications for transfer of certificates. The sale to CSWR-TKCB will become final after Commission approval of the transfer, pursuant to Section 367.071(1), F.S.

### Noticing, Territory, and Land Ownership

CSWR-TKCB 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 application, CSWR-TKCB provided a copy of an unrecorded warranty deed as evidence that the Buyer will have rights to 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-TKCB committed to providing the executed and recorded deed to the Commission within 60 days after the closing of the sale.

### Purchase Agreement and Financing

Pursuant to Rule 25-30.037(2)(i) and (j), 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 TKCB that must be disposed of with regard to the transfer. CSWR-TKCB 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 $425,000. 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 TKCB wastewater treatment plant (WWTP) is a 0.099 million gallon per day annual average daily flow (AADF) permitted capacity extended aeration domestic wastewater treatment plant consisting of flow equalization, influent screening, aeration, secondary clarification, filtration, chlorination, and aerobic digestion of bio solids. Chlorinated effluent is discharged to one of four percolation ponds. The collection system consists of gravity mains served by two lift stations.

Staff reviewed the most recent Florida Department of Environmental Protection (DEP) compliance evaluation inspection (CEI) for the WWTP. The DEP's October 31, 2019 CEI noted the following deficiencies. First, the Discharge Monitoring Reports (DMR) for the review period (September 1, 2018 to September 30, 2019) revealed one exceedance of the permitted allowable AADF in October 2018. Second, the CEI noted three deficiencies with respect to the Utility's wastewater permit compliance schedule. The Utility failed to remove grit from the surge tank, repair tank leaks, and register for and begin using the DEP's electronic system for filing its DMRs. On April 10, 2020, the DEP notified TKCB that it had corrected all of the deficiencies noted in the October 31, 2019 CEI.

## 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 representations of the Seller with regards to utility matters. CSWR-TKCB's application states that it owns and operates water and wastewater systems in Florida, Missouri, Arkansas, Kentucky, Louisiana, Texas, Mississippi, Arizona, North Carolina, South Carolina, and Tennessee that currently serve more than 136,000 water and 210,600 wastewater customers.

The Commission has also approved CSWR-Florida Utility Operating Company, LLC's purchase of nine Florida certificated utilities in prior dockets.[3]

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-TKCB and believes the Buyer has documented adequate resources to support the Utility's wastewater operations. Based on the above, the Buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

## Rates and Charges

TKCB's wastewater rates were last approved in a 2021 limited alternative rate increase proceeding. Subsequently, the rates were amended by a price index in June 2022. The Utility also had a rate decrease to remove expired rate case expense amortization in 2023. 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. Therefore, staff recommends that the Utility's existing rates shown on Schedule No. 4, 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.

[3] See Order No. PSC-2022-0115-PAA-WS, issued March 15, 2022, in Docket No. 20210093-WS, *In re: 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*; Order No. PSC-2022-0120-PAA-WU, issued March 18, 2022, in Docket No. 20210095-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-2022-0116-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-2022-0364-PAA-WU, issued October 25, 2022, in Docket No. 20220019-WU, *In re: 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;* Order No. PSC-2023-0216-PAA-SU, issued July 27, 2023, in Docket No. 20220149-SU, *In re: Application for transfer of wastewater Certificate No. 365-S of Sebring Ridge Utilities, Inc. to CSWR-Florida Utility Operating Company, LLC, in Highlands County*; Order No. PSC-2023-0245-PAA-WS, issued August 17, 2023, in Docket No. 20220063-WS, *In re: Application for transfer of water and wastewater facilities of Tradewinds Utilities, Inc., water Certificate No. 405-W, and wastewater Certificate No. 342-S to CSWR-Florida Utility Operating Company, LLC, in Marion County*; Order No. PSC-2023-0257-PAA-SU, issued August 21, 2023, in Docket No. 20220061-SU, *In re: Application for transfer of wastewater Certificate No. 318-S from BFF Corp to CSWR-Florida utility Operating Company, LLC, in Marion County*; Order No. PSC-2023-0266-PAA-WS, issued August 22, 2023, in Docket No. 20220062-WS, *In re: Application for transfer of water and wastewater facilities of C.F.A.T. H2O, Inc., water Certificate No. 552-W, and wastewater Certificate No. 481-S to CSWR-Florida Utility Operating Company, LLC, in Marion County*; Order No. PSC-2023-0305-PAA-WS, issued October 13, 2023, in Docket No. 20220064-WS, *In re: Application for transfer of water and wastewater facilities of Tymber Creek Utilities, Inc., water Certificate No. 303-W, and wastewater Certificate No. 252-S to CSWR-Florida Utility Operating Company, LLC, in Volusia County.*

## 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, 2022. The Buyer will be responsible for filing the Utility's annual reports and paying RAFs for all future years.

## Conclusion

Based on the foregoing, staff recommends that the transfer of the wastewater system and Certificate No. 562-S 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 a copy of its signed and executed contract for sale to the Commission within 60 days of the Order approving the transfer, which is final agency action. If the sale is not finalized within 60 days of the transfer Order, the Buyer should file a status update in the docket file. The Utility's existing rates, as shown on Schedule No. 4, 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, 2022. The Buyer should be responsible for filing annual reports and paying RAFs for all future years.

***Issue 2:*** What is the appropriate net book value for CSWR-Florida Utility Operating Company LLC's wastewater system for transfer purposes?

***Recommendation:*** For transfer purposes, the NBV of the wastewater system is $127,878 as of March 31, 2023. An acquisition adjustment should not be included in rate base. Within 90 days of the date of the Consummating Order, CSWR-TKCB 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 2023 Annual Report when filed. (Thurmond)

***Staff Analysis:*** Rate base was last established as of September 30, 2018, by Order No. PSC-2019-0362-PAA-SU.[4] 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 March 31, 2023.[5] 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 $96,163 as of March 31, 2023. Staff traced additions and retirements since the Utility's last order and found no adjustments were necessary. Accordingly, staff recommends a total UPIS balance of $96,163 as of March 31, 2023.

**Land**

The Utility's general ledger reflected a land balance of $36,203 as of March 31, 2023. There have been no additions to land since the Utility's last order. Accordingly, staff recommends a total land balance of $36,203 as of March 31, 2023.

**Accumulated Depreciation**

According to the Utility's general ledger, the total accumulated depreciation balance was $5,143 as of March 31, 2023. Staff auditors recalculated depreciation accruals using the depreciation rates established by Rule 25-30.140, F.A.C. As a result, staff recommends that the accumulated depreciation balance be decreased by $655 as of March 31, 2023. Accordingly, staff recommends a total accumulated depreciation balance of $4,488 as of March 31, 2023.

**Contributions-in-Aid-of-Construction (CIAC) and Accumulated Amortization of CIAC**

According to the Utility's general ledger, the CIAC and accumulated amortization of CIAC both had balances of $0 as of March 31, 2023. Staff reconciled both balances from the date of the Utility's last order to March 31, 2023, and found no adjustments necessary. Accordingly, staff

[4] Order No. PSC-2019-0362-PAA-SU, issued August 26, 2019, in Docket No. 20180218-SU, *In re: Application for a staff-assisted rate case in Brevard County by TKCB, Inc.*

[5] 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.

recommends total CIAC and Accumulated Amortization of CIAC balances of $0 and $0, respectively, as of March 31, 2023.

### Net Book Value

The Utility's general ledger reflected an NBV of $127,223 as of March 31, 2023. Based on the adjustments described above, staff recommends an NBV of $128,878 as of March 31, 2023. Staff's recommended NBV and the National Association of Regulatory Utility Commissioners, Uniform System of Accounts balances for UPIS and accumulated depreciation are shown on Schedule No. 1 as of March 31, 2023.

### 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 $425,000. As stated above, staff has determined the appropriate NBV total to be $127,878. 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. Under the original application, the Utility requested a positive acquisition adjustment be granted for the difference between the purchase price and the NBV. However, on September 1, 2023, the Utility withdrew its request for a positive acquisition adjustment. As such, staff recommends no acquisition adjustment is warranted.

### Conclusion

Based on the above, staff recommends an NBV of $127,878 as of March 31, 2023, for transfer purposes. An acquisition adjustment should not be included in rate base. 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 2023 Annual Report when filed.

***Issue 3:*** 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, that the Buyer has submitted the executed and recorded warranty deed, that the Buyer has submitted a copy of its application for permit transfer to the DEP, and that the Buyer has submitted a signed and executed copy of its contract for sale within 60 days of the Commission's Order approving the transfer. (Watrous)

***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, that the Buyer has submitted the executed and recorded warranty deed, that the Buyer has submitted a copy of its application for permit transfer to the DEP, and that the Buyer has submitted a signed and executed copy of its contract for sale within 60 days of the Commission's Order approving the transfer.

CSWR-Florida Utility Operating Company, LLC
Brevard County
Sun Lake Village Estates Wastewater Service Area

A parcel of land lying in the East ½ of Section 1, Township 24 South, Range 35 East, being a portion of Canaveral Groves Subdivision, Phases 1 and 2, being more particularly described as follows:

Commence at the North ¼ corner of said Section 1 and run South 01° 01′ 56″ W along the West line of the Northeast ¼, a distance of 50 feet to a point on the North right-of-way line of Canaveral Groves Boulevard, the Point of Beginning; Thence continue South 01° 01′ 56″ West along said West line, a distance of 1,362.29 feet; thence South 88° 45′ 34″ East, a distance of 320 feet more or less; thence South 1,650 feet more or less to a point 150 feet South of Emerald Lakes Drive; thence East 1,000 feet more or less to the West right-of-way line of Sharpes Lake Avenue; thence Northwesterly along said right-of-way line, a distance of 1,700 feet more or less to a point; thence North a distance of 450 feet more or less to a point on the South right-of-way line of Lake Erie Place; thence South 88° 45′ 34″ East a distance of 560 feet more or less to a point on the East right-of-way line of Lake Superior Drive; thence North 01° 14′ 26″ East a distance of 50 feet; thence South 88° 45′ 34″ East a distance of 70.25 feet; thence North 01° 14′ 48″ East a distance of 108.18 feet; thence South 88° 29′ 58″ East a distance of 25 feet; thence North 01° 14′ 48″ East a distance of 1,225.69 feet to the Southerly right-of-way line of Canaveral Groves Boulevard; thence North 88° 28′ 48″ West a distance of 1,338.84 feet to the Point of Beginning.

**FLORIDA PUBLIC SERVICE COMMISSION**
**Authorizes**
**CSWR-Florida Utility Operating Company, LLC**
**pursuant to**
**Certificate Number 562-S**

to provide wastewater service in Brevard 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, cancelled or revoked by Order of this Commission.

| Order Number | Date Issued | Docket Number | Filing Type |
|---|---|---|---|
| PSC-11-0522-FOF-SU | 11/7/ 2011 | 20100442-SU | Original Certificate |
| * | * | 20230033-SU | Transfer |

***Order Number and date to be provided at time of issuance.**

## CSWR-Florida Utility Operating Company, LLC
## TKCB, Inc.

## Schedule of Net Book Value as of March 31, 2023

| Description | Balance Per Utility | Adjustments | | Staff |
|---|---|---|---|---|
| Utility Plant in Service | $96,163 | $- | | $96,163 |
| Land & Land Rights | 36,203 | - | | 36,203 |
| Accumulated Depreciation | (5,143) | 655 | A | (4,488) |
| CIAC | - | - | | - |
| Amortization of CIAC | - | - | | - |
| Total | $127,223 | $655 | | $127,878 |

**CSWR-Florida Utility Operating Company, LLC**
**TKCB, Inc.**

**Explanation of Adjustments to Net Book Value as of March 31, 2023**

| Explanation | Amount |
|---|---|
| A. Accumulated Depreciation | |
| To reflect the appropriate balance. | $655 |
| | |
| Total Adjustments to Net Book Value as of March 31, 2023 | $655 |

**CSWR-Florida Utility Operating Company, LLC**
**TKCB, Inc.**

**Schedule of Staff's Recommended Account Balances as of March 31, 2023**

| Account No. | Description | UPIS | Accumulated Depreciation |
|---|---|---|---|
| 354 | Structures & Improvements | $6,203 | ($795) |
| 361 | Collection Sewers - Gravity | 2,000 | (244) |
| 370 | Receiving Wells | 42,158 | 1,292 |
| 380 | Treatment and Disposal Equipment | 45,802 | (4,742) |
| | Total | $96,163 | ($4,488) |

## CSWR – Florida Utility Operating Company, LLC.
## TKCB, Inc.

## Monthly Wastewater Rates

| | |
|---|---|
| **Residential Service** | |
| Base Facility Charge by Meter Size | |
| All Meter Sizes | $20.25 |
| | |
| Charge Per 1,000 gallons – Residential Service | |
| 6,000 gallon cap | $7.14 |
| | |
| **General Service** | |
| Base Facility Charge by Meter Size | |
| 5/8" x 3/4" | $20.25 |
| 3/4" | $30.38 |
| 1" | $50.63 |
| 1 1/2" | $101.25 |
| 2" | $162.00 |
| 3" | $324.00 |
| 4" | $506.25 |
| 6" | $1,012.50 |
| | |
| Charge Per 1,000 gallons | $8.55 |

# Item 9

FILED 10/27/2023
DOCUMENT NO. 05847-2023
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:** October 27, 2023

**TO:** Docket No. 20230068-EI

**FROM:** Adam J. Teitzman, Commission Clerk, Office of Commission Clerk

**RE:** Rescheduled Commission Conference Item

Commission staff's memorandum assigned DN 05321-2023 was filed on September 21, 2023, for the October 3, 2023 Commission Conference. As the vote sheet reflects, this item was deferred. This item has been placed on the November 9, 2023 Commission Conference Agenda.

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 21, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Ward, Hampson) EJD
Office of the General Counsel (Brownless) JSC

**RE:** Docket No. 20230068-EI – Petition for approval of smart outdoor lighting services pilot program by Duke Energy Florida, LLC.

**AGENDA:** 10/03/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 01/15/24 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On May 15, 2023, Duke Energy Florida, LLC (Duke or utility) filed a petition for approval of the smart outdoor lighting services pilot program (pilot program). Specifically, Duke is proposing to make modifications to Tariff Sheet Nos. 6.280 and 6.281 to allow certain customers who take service under the existing LS-1 lighting tariff to set their own personal lighting schedule and to dim the lights. Currently, all lights offered under the tariff operate from dusk to dawn.

In Order No. PSC-2023-0182-PCO-EI, the Commission suspended Duke's proposed modifications to Tariff Sheet Nos. 6.280 and 6.281 to allow staff time to gather additional data.[1] On June 26, 2023, staff issued its first data request, to which Duke responded on July 17, 2023. Staff issued a second data request on July 28, 2023, to which Duke responded on August 11, 2023. Staff noticed a scrivener's error in the tariff sheets filed with the petition, and Duke

[1] Order No. PSC-2023-0182-PCO-EI, issued June 26, 2023, in Docket No. 20230068-EI, *In re: Petition for approval of smart outdoor lighting services pilot program by Duke Energy Florida, LLC*.

included updated legislative and clean versions of the tariff sheets in response to staff's first data request. The proposed legislative tariffs are included in this recommendation as Attachment A. This recommendation addresses the proposed smart outdoor lighting services pilot program. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

## Discussion of Issues

***Issue 1:*** Should the Commission approve Duke's smart outdoor lighting services pilot program?

***Recommendation:*** Yes, the Commission should approve Duke's smart outdoor lighting services pilot program and the associated revised Tariff Sheet Nos. 6.280 and 6.281 effective on the date of the final Commission order approving the pilot. The pilot program would allow Duke to gather data on energy usage changes from participating customers so that it may develop a future program that is appropriately priced. Participating customers would be able to customize the operating and dimming schedule of their lights. (Ward)

***Staff Analysis:***

### Rate Schedule LS-1

Rate schedule LS-1, Lighting Service, is available to any customer for the sole purpose of lighting roadways or other land use areas. Currently, the energy rates for the LS-1 tariff are set for all customers based on the same lighting schedule (dusk to dawn), with no option to dim the lights. Customers taking service under the LS-1 tariff pay a fixed monthly customer charge, a non-fuel energy charge based on per kWh usage, cost recovery factors, as well as per unit fixture and maintenance charges. Service is available to both metered and unmetered customers.

### Proposed Pilot Program

Under the proposed pilot program, Duke would offer certain customers taking service under rate schedule LS-1 the option to set their own lighting schedules and dim the lights. The rates offered under the current tariff would remain the same. Customers would be able to schedule lighting service during the time period from 30 minutes prior to dusk until 30 minutes after dawn. The terms and conditions of the pilot program state that customers would be able to request brightness between 50 and 100 percent of the standard output of the fixture. Additionally, the terms and conditions state that participating customers would be able to request changes to their lighting schedules during the pilot program. The processing time for normal schedule changes would be five business days and the processing time for "emergent special events" would be three business days. Examples of these special events given by Duke in response to staff's first data request include turning off desired lights for a fireworks show, community concerts, or outdoor movie events.

If approved, the pilot would run for a period of 18 months beginning on the date of the final Commission order approving the petition. In response to staff's first data request, the utility stated that customers would be enrolled in the pilot program for a period of 12 consecutive months, with enrollment ending after the sixth month of the pilot program. In its petition, the utility stated that it would file an amendment to its LS-1 tariff to remove references to the pilot program no less than sixty days before its expiration.

### Pilot Program Participation and Availability

In its petition, Duke stated that customers would be able to participate if they take service for at least five light-emitting diode (LED) lights with company installed smart nodes. In response to staff's first data request, Duke stated that it has begun installing the smart nodes on all compatible LEDs through its typical installation and maintenance work. In response to staff's second data request, Duke stated that there are no incremental costs associated with the installation of a smart node. Additionally, the utility asserted that, as of July 2023, 250 customers have LED light fixtures with smart nodes installed. The utility estimates that approximately 25 to 50 customers would participate in the pilot program. Duke proposes to limit participation in the pilot program to 10,000 lights, while also reserving the right to allow additional participation.

The pilot program would be available to both metered and unmetered customers. In response to staff's first data request, Duke stated that pilot program participants on LS-1 with metered accounts would be charged based on their actual kWh usage, so their actual energy consumption would be charged based on their energy usage (which may be higher or lower). In response to staff's second data request, the utility stated that it would measure the impact of the program on unmetered customers by utilizing vendor provided software that tracks street light usage based on being on/off or dimmed and compare that to data from a normal streetlight that turns the light on from dusk to dawn.

In its petition, Duke stated that the purpose of the pilot program is to gather data on energy usage changes from participating customers so that it can develop a future permanent program that is appropriately priced. Examples of customers who might participate in the pilot include a sporting arena that may only need lights on until the late evening or a parking lot that may need to light the lot for slightly longer than dusk to dawn.

### Pilot Program Costs

In response to staff's second data request, the utility stated that the marketing cost of the pilot program is estimated to be between $3,320 and $5,320. These costs include the one time cost for the development of a customer website and the one time cost for 500 color printouts of a pilot program factsheet. Duke stated that these costs are not included in rate base and would be included in future rate cases if applicable.

### Conclusion

Having reviewed the petition and staff data request responses, staff recommends that the Commission approve Duke's proposed smart outdoor lighting services pilot program and associated revised Tariff Sheet Nos. 6.280 and 6.281 effective the date of the final Commission order approving the pilot. The proposed pilot program would allow Duke to gather data on energy usage changes from participating customers so that it may develop a permanent future program that is appropriately priced. Participating customers would be able to customize the operating and dimming schedules of their lights.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff should not go into effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Brownless)

***Staff Analysis:*** If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff should not go into effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

DUKE ENERGY.

**SECTION NO. VI**
**~~FORTIETH~~ FORTY-FIRST REVISED SHEET NO. 6.280**
**CANCELS ~~THIRTY-NINTH~~FORTIETH REVISED SHEET NO. ~~6.280~~**



**RATE SCHEDULE LS-1**
**LIGHTING SERVICE**

**Availability:**

Available throughout the entire territory served by the Company.

**Applicable:**

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or customer owned fixtures of the type available under this rate schedule. 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.

**Character of Service:**

Continuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available; provided, however, that Customers electing to participate in the Smart Outdoor Lighting Service Pilot Program may choose a different period of time.

**Smart Outdoor Lighting Services Pilot Program:**

Any customer, who is in good financial standing and takes service under LS-1 for certain LED fixtures with Company-installed smart nodes, may apply to participate in the Smart Outdoor Lighting Services Pilot Program ("Smart Pilot"). During the 18-month Smart Pilot period, customers~~,~~ can schedule lighting service during the time period from 30 minutes prior to dusk until 30 minutes after dawn. Participants in the Smart Pilot will agree to the Smart Pilot's Terms and Conditions and will continue to be billed through the LS-1 rates. Participation in the Smart Pilot is limited to 10,000 lights, but the Company reserves the right to allow additional participation.

**Limitation of Service:**

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

**Rate Per Month:**

**Customer Charge:**

| | |
|---|---|
| Unmetered: | $ 1.65 per line of billing |
| Metered: | $ 4.71 per line of billing |

**Energy and Demand Charge:**

| | |
|---|---|
| Non-Fuel Energy Charge: | 2.852¢ per kWh |
| Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: | See Sheet No. 6.105 and 6.106 |

**Per Unit Charges:**

I. **Fixtures:**

**(Continued on Page No. 2)**

**ISSUED BY:** **Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL**

**EFFECTIVE:** ~~January 1, 2023~~

DUKE ENERGY

SECTION NO. VI
~~FORTIETH~~ FORTY-FIRST REVISED SHEET NO. 6.280
CANCELS ~~THIRTY-NINTH~~FORTIETH REVISED SHEET NO. ~~6.280~~



| BILLING TYPE | DESCRIPTION | LAMP SIZE [2] INITIAL LUMENS OUTPUT | LAMP WATTAGE | kWh | CHARGES PER UNIT FIXTURE | MAINTENANCE | NON-FUEL ENERGY [3] |
|---|---|---|---|---|---|---|---|
| | **Incandescent:** [1] | | | | | | |
| 110 | Roadway | 1,000 | 105 | 32 | $1.02 | $4.70 | $0.91 |
| 115 | Roadway | 2,500 | 205 | 66 | 1.60 | 4.32 | 1.88 |
| 170 | Post Top | 2,500 | 205 | 72 | 20.01 | 4.32 | 2.05 |
| | **Mercury Vapor:** [1] | | | | | | |
| 205 | Open Bottom | 4,000 | 100 | 44 | $2.38 | $1.80 | $1.25 |
| 210 | Roadway | 4,000 | 100 | 44 | 3.06 | 1.80 | 1.25 |
| 215 | Post Top | 4,000 | 100 | 44 | 3.60 | 1.80 | 1.25 |
| 220 | Roadway | 8,000 | 175 | 71 | 3.10 | 1.77 | 2.02 |
| 225 | Open Bottom | 8,000 | 175 | 71 | 2.45 | 1.77 | 2.02 |
| ~~235~~ | ~~Roadway~~ | ~~21,000~~ | ~~400~~ | ~~158~~ | ~~3.75~~ | ~~1.79~~ | ~~4.51~~ |
| ~~240~~ | ~~Roadway~~ | ~~62,000~~ | ~~1,000~~ | ~~386~~ | ~~5.49~~ | ~~2.07~~ | ~~11.01~~ |
| ~~245~~ | ~~Flood~~ | ~~21,000~~ | ~~400~~ | ~~158~~ | ~~4.92~~ | ~~1.79~~ | ~~4.51~~ |
| ~~250~~ | ~~Flood~~ | ~~62,000~~ | ~~1,000~~ | ~~386~~ | ~~5.77~~ | ~~2.07~~ | ~~11.01~~ |

(Continued on Page No. 2)

**ISSUED BY:** Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

**EFFECTIVE:** ~~January 1, 2023~~

DUKE ENERGY.

**SECTION NO. VI**
**THIRTY-~~FIFTH~~ SIXTH REVISED SHEET NO. 6.281**
**CANCELS THIRTY-~~FOURTH~~ FIFTH REVISED SHEET NO. 6.281**



**RATE SCHEDULE LS-1**
**LIGHTING SERVICE**
(Continued from Page No. 1)

**I. Fixtures: (Continued)**

| | | LAMP SIZE [2] | | | CHARGES PER UNIT | | |
|---|---|---|---|---|---|---|---|
| **BILLING TYPE** | **DESCRIPTION** | **INITIAL LUMENS OUTPUT** | **LAMP WATTAGE** | **kWh** | **FIXTURE** | **MAINTENANCE** | **NON-FUEL ENERGY [3]** |
| | **Mercury Vapor: [1] Continued** | | | | | | |
| 235 | Roadway | 21,000 | 400 | 158 | 3.75 | 1.79 | 4.51 |
| 240 | Roadway | 62,000 | 1,000 | 386 | 5.49 | 2.07 | 11.01 |
| 245 | Flood | 21,000 | 400 | 158 | 4.92 | 1.79 | 4.51 |
| 250 | Flood | 62,000 | 1,000 | 386 | 5.77 | 2.07 | 11.01 |
| | **Sodium Vapor: [1]** | | | | | | |
| 300 | HPS Deco Rdwy White | 50,000 | 400 | 168 | $10.50 | $1.87 | $4.79 |
| 301 | Sandpiper HPS Deco Roadway | 27,500 | 250 | 104 | 13.61 | 1.85 | 2.97 |
| 302 | Sandpiper HPS Deco Rdwy Blk | 9,500 | 100 | 42 | 13.16 | 1.84 | 1.20 |
| 305 | Open Bottom | 4,000 | 50 | 21 | 2.49 | 1.86 | 0.60 |
| 306 | 100W HS Deco Rdwy Blk | 9,500 | 100 | 42 | 10.19 | 1.84 | 1.20 |
| 310 | Roadway | 4,000 | 50 | 21 | 3.06 | 1.86 | 0.60 |
| 313 | Open Bottom | 6,500 | 70 | 29 | 4.11 | 1.84 | 0.83 |
| 314 | Hometown II | 9,500 | 100 | 42 | 3.83 | 1.84 | 1.20 |
| 315 | Post Top - Colonial/Contemp | 4,000 | 50 | 21 | 4.95 | 1.86 | 0.60 |
| 316 | Colonial Post Top | 4,000 | 50 | 34 | 3.97 | 1.86 | 0.97 |
| 318 | Post Top | 9,500 | 100 | 42 | 2.45 | 1.84 | 1.20 |
| 320 | Roadway-Overhead Only | 9,500 | 100 | 42 | 4.04 | 1.84 | 1.20 |
| 321 | Deco Post Top - Monticello | 9,500 | 100 | 49 | 12.59 | 1.84 | 1.40 |
| 322 | Deco Post Top - Flagler | 9,500 | 100 | 49 | 15.53 | 1.84 | 1.40 |
| 323 | Roadway-Turtle OH Only | 9,500 | 100 | 42 | 4.84 | 1.84 | 1.20 |
| 325 | Roadway-Overhead Only | 16,000 | 150 | 65 | 4.57 | 1.85 | 1.85 |
| 326 | Deco Post Top – Sanibel | 9,500 | 100 | 49 | 18.69 | 1.84 | 1.40 |
| 330 | Roadway-Overhead Only | 22,000 | 200 | 87 | 3.40 | 1.85 | 2.48 |
| 335 | Roadway-Overhead Only | 27,500 | 250 | 104 | 5.68 | 1.85 | 2.97 |
| 336 | Roadway-Bridge | 27,500 | 250 | 104 | 6.28 | 1.85 | 2.97 |
| 337 | Roadway-DOT | 27,500 | 250 | 104 | 5.47 | 1.85 | 2.97 |
| 338 | Deco Roadway–Maitland | 27,500 | 250 | 104 | 9.65 | 1.85 | 2.97 |
| 340 | Roadway-Overhead Only | 50,000 | 400 | 169 | 5.79 | 1.87 | 4.82 |
| 341 | HPS Flood-City of Sebring only | 16,000 | 150 | 65 | 3.78 | 1.85 | 3.08 |
| 342 | Roadway-Turnpike | 50,000 | 400 | 168 | 8.33 | 1.87 | 4.79 |
| 343 | Roadway-Turnpike | 27,500 | 250 | 108 | 8.50 | 1.85 | 3.08 |
| 345 | Flood-Overhead Only | 27,500 | 250 | 103 | 5.18 | 1.85 | 2.94 |
| 347 | Clermont | 9,500 | 100 | 49 | 20.49 | 1.84 | 1.40 |
| 348 | Clermont | 27,500 | 250 | 104 | 21.51 | 1.85 | 2.97 |
| 350 | Flood-Overhead Only | 50,000 | 400 | 170 | 5.36 | 1.87 | 4.85 |
| 351 | Underground Roadway | 9,500 | 100 | 42 | 5.68 | 1.84 | 1.20 |
| 352 | Underground Roadway | 16,000 | 150 | 65 | 6.21 | 1.85 | 1.85 |
| 353 | Underground Roadway | 22,000 | 200 | 87 | 6.21 | 1.85 | 2.48 |
| 354 | Underground Roadway | 27,500 | 250 | 108 | 7.33 | 1.85 | 3.08 |
| 356 | Underground Roadway | 50,000 | 400 | 168 | 7.44 | 1.87 | 4.79 |
| 357 | Underground Flood | 27,500 | 250 | 108 | 8.83 | 1.85 | 3.05 |
| 358 | Underground Flood | 50,000 | 400 | 168 | 9.01 | 1.87 | 4.79 |
| 359 | Underground Turtle Roadway | 9,500 | 100 | 42 | 6.59 | 1.84 | 1.20 |
| 360 | Deco Roadway Rectangular | 9,500 | 100 | 47 | 11.93 | 1.84 | 1.34 |
| 365 | Deco Roadway Rectangular | 27,500 | 250 | 108 | 11.39 | 1.85 | 3.08 |
| 366 | Deco Roadway Rectangular | 50,000 | 400 | 168 | 11.39 | 1.87 | 4.79 |
| 370 | Deco Roadway Round | 27,500 | 250 | 108 | 16.48 | 1.85 | 3.08 |
| 375 | Deco Roadway Round | 50,000 | 400 | 168 | 16.48 | 1.87 | 4.79 |
| 380 | Deco Post Top – Ocala | 9,500 | 100 | 49 | 10.42 | 1.84 | 1.40 |
| 381 | Deco Post Top | 9,500 | 100 | 49 | 3.77 | 1.84 | 1.40 |
| 383 | Deco Post Top-Biscayne | 9,500 | 100 | 49 | 13.21 | 1.84 | 1.40 |
| 385 | Deco Post Top – Sebring | 9,500 | 100 | 49 | 6.67 | 1.84 | 1.40 |
| 393 | Deco Post Top | 4,000 | 50 | 21 | 8.13 | 1.86 | 0.60 |
| 394 | Deco Post Top | 9,500 | 100 | 49 | 16.92 | 1.84 | 1.40 |

(Continued on Page No. 3)

**ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL**

**EFFECTIVE: ~~January 1, 2023~~**

# Item 10

FILED 10/27/2023
DOCUMENT NO. 05844-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Barrett) GD
Division Of Engineering (Ellis) TB
Office of the General Counsel (Stiller) JSC

**RE:** Docket No. 20230072-EI – Petition for approval of shared solar tariff change, by Tampa Electric Company.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 1/31/2024 (8-month Effective Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On May 31, 2023, Tampa Electric Company (TECO or utility) filed a petition for approval of changes to its Shared Solar Rider Tariff (SSR-1 Tariff or Tariff). The SSR-1 Tariff pertains to an optional program that is marketed by TECO as its "Sun Select" program. The utility's current SSR-1 Tariff was approved by the Commission in Order No. PSC-2019-0215-TRF-EI (Tariff Approval Order) and offers residential and commercial customers the option to purchase all or a portion of their monthly energy consumption from an allocation of 17.5 megawatts (MWs) of dedicated capacity from the utility's Lake Hancock solar facility.[1] In its petition, the utility seeks

[1]Order No. PSC-2019-0215-TRF-EI, Order Approving Tampa Electric Company's Shared Solar Tariff, issued June 3, 2019, in Docket No. 20180204-EI, *In re: Petition for approval of shared solar tariff, by Tampa Electric Company.* In 2021, the Commission reaffirmed its approval of the SSR-1 Tariff when it approved a stipulation and settlement agreement that resolved TECO's last general rate case. *See* 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* (2021 Settlement).

approval of several modifications designed to attract more participants to subscribe to the optional Tariff. TECO also states that it hopes to learn more about customer adoption of community solar programs and engage with its customers to help them reach decarbonization goals.

In Order No. PSC-2023-0214-PCO-EI, the Commission suspended the proposed modified tariff in order to allow staff sufficient time to review the proposed modifications and gather pertinent information.[2] Subsequently, staff issued two data requests to the utility, and conducted two informal meetings with utility representatives on August 17, 2023, and September 7, 2023.

On September 15, 2023, TECO filed revisions to the proposed SSR-1 Tariff based on feedback provided by staff. TECO's proposed SSR-1 Tariff, as amended, is shown in Attachment A.

The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

[2]Order No. PSC-2023-0214-PCO-EI, issued July 26, 2023, in Docket No. 20230072-EI, *In re: Petition for approval of shared solar tariff change, by Tampa Electric Company.*

## Discussion of Issues

***Issue 1:*** Should the Commission approve the proposed changes to TECO's Shared Solar Rider Tariff?

***Recommendation:*** Yes, the Commission should approve the proposed changes to TECO's Shared Solar Rider Tariff, as shown in Attachment A, contingent upon TECO's compliance with certain program implementation provisions and reporting requirements described below.

First, incremental revenues from this program that exceed the Sun Select revenue credits approved in the 2021 Settlement should be recorded as a credit to the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause) to offset expenditures for fuel.

Second, TECO should manage its SSR-1 Tariff program subscriptions to ensure that the proportion of energy sales of residential and commercial customers in the RS and GS classes to total energy sales (all classes) is, in the aggregate, no lower than thirty percent.

Third, in its marketing of the revised program, TECO should not claim or imply that program revenues are earmarked for or contribute to the construction of new solar resources.

Finally, TECO should submit annual reports in March of 2024, 2025, 2026, and 2027 with data for the prior calendar year, detailing the following: 1) the number of revised SSR-1 Tariff program participants, amount of energy sales, waiting list levels, and revenues collected, by subscription level and by rate class; 2) the incremental revenue, above the Sun Select revenue currently included in base rates, credited to the Fuel Clause; 3) a summary of TECO's key findings regarding customer adoption of community solar programs and its customers' desire to reach decarbonization goals; and 4) a detailed description of whether and how the results of the program have impacted TECO's generation planning. (Barrett, Ellis)

***Staff Analysis:*** As set forth in the Tariff Approval Order, the utility's current SSR-1 Tariff offers customers an opportunity to support the construction of a 17.5 MW portion of the Lake Hancock solar project, a 49.5 MW solar facility constructed by TECO that came fully on-line in 2019. The remaining 32 MWs of the Lake Hancock solar project were included in base rate charges through a solar generation base rate adjustment (SoBRA) mechanism.[3]

Customers taking service under the current SSR-1 Tariff pay a levelized energy rate of 6.3 cents/kWh, which recovers the anticipated revenue requirement of the capital and operating and maintenance (O&M) costs of 17.5 MWs of this solar facility over the 30-year projected life, plus program administrative costs. Under the SSR-1 Tariff, residential customers can opt to purchase solar energy on the basis of 25, 50, or 100 percent of their monthly energy usage, and commercial/industrial customers are eligible to purchase in 1,000 kWh blocks. In exchange, such customers are exempted from having to pay fuel costs via the Fuel Clause for the portion of their bills under SSR-1 Tariff subscription. While this exemption decreased revenues in the Fuel Clause,

[3]Order No. PSC-2018-0571-FOF-EI, issued December 7, 2018, in Docket No. 20180133-EI, *In re: Petition for limited proceeding to approve second Solar Base Rate Adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.*

the general body of ratepayers received the benefit of an additional 17.5 MW of solar capacity that was not funded by the general body of ratepayers at the time the original proposal was approved.

The Tariff Approval Order provided that the 17.5 MW portion of the Lake Hancock unit would be included in TECO's revenue requirement as an addition to base rates in a future rate case proceeding. Accordingly, in the 2021 Settlement, TECO included the cost associated with the 17.5 MW portion of Lake Hancock in its base rates.[4] The projected SSR-1 Tariff revenues will continue to be included as a credit to the revenue requirement when calculating base rates. Staff confirmed that TECO included the SSR-1 Tariff revenues as an offset when calculating base rates in Docket No. 20210034-EI, thereby putting downward pressure on base rates and avoiding double recovery.

### Proposed Changes to SSR-1 Tariff and Sun Select Program

As shown in Attachment A, TECO proposes the following notable changes to its SSR-1 Tariff:

1. The Tariff rate decreases from 6.3 cents/kWh to 4.9 cents/kWh.
2. The program capacity increases from 17.5 MW of incremental capacity to 30 MW of existing capacity.
3. New customer enrollments and re-enrollments will not be allowed to exceed 10 million kWh per year for GSD, GSLDPR, and GSLDSU customers.
4. Re-enrollments are prohibited for 12 months after an account's cancellation from the program.
5. The SSR-1 Tariff's "Monthly Rate" is renamed "Rate."

The utility explained that it seeks approval of changes to the Sun Select program for the purpose of elevating participation levels. Participation in the program has been modest, with only 35 percent of the available capacity currently subscribed and a churn rate of 44 percent.[5] Additionally, the utility states it hopes to learn more about customer adoption of community solar programs and engage with its customers to help them reach decarbonization goals.

In order to achieve these objectives, TECO proposes two primary changes to the program. First, the utility proposes to reduce the monthly rate under the SSR-1 Tariff from 6.3 cents/kWh to 4.9 cents/kWh based on a revised pricing model. The reduction of 1.4 cents/kWh is intended for current and future program participants. Second, TECO proposes to expand the available capacity of the Sun Select program from 17.5 MWs to 30.0 MWs.

TECO's proposal to reduce the monthly SSR-1 Tariff rate is based on a complete change in its pricing model. Exhibit B to the petition, the "Waterfall Chart," proposes that increased incremental costs under the proposed program are offset by decreased incremental costs, resulting in the proposed SSR-1 Tariff rate of 4.9 cents/kWh.[6] TECO states it used a marginal cost of service analysis to arrive at its calculation of levelized costs, including energy and generation capacity.

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[4]Order No. PSC-2021-0423-S-EI, issued November 10, 2021, Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

[5]Exhibit A to the petition ("Sun Select De-enrollment Reasons") summarizes de-enrollment data reflecting that about 51 percent of customers that enrolled and later dropped out of the program cited high participation costs as their reason for exiting.

[6]Exhibit B to Petition, FPSC Document No. 03449-2023.

TECO then used various cost/credit assumptions that, when summed, equal the proposed SSR-1 rate. These cost considerations are more fully described below.

While TECO has historically based Sun Select program costs on the actual capital and O&M costs of the eligible 17.5 MW of the Lake Hancock facility, the proposed changes are based upon the capital and O&M expenses of TECO's entire solar fleet, plus added credits and expenses associated with the facility's energy and capacity. TECO proposes a program price in part based on the average installed costs of TECO's entire solar generation portfolio, which is lower than the installed cost of the Lake Hancock solar facility under which the Sun Select program price was originally established. In addition, the utility's pricing model adjusted the depreciable life of solar assets by five years (from 30 years to 35 years).[7] Unlike the original program, no new incremental capacity will be constructed as a result of this increase in amount of eligible solar capacity in the Sun Select participation from 17.5 MW to 30.0 MW,[8] or approximately 0.3 percent of TECO's net energy for load in 2023.[9] TECO states that the portfolio approach enables it to make available to customers the entire capacity limit of the program, rather than having a small portion reserved as a buffer.[10]

Regarding the proposed capacity credit, TECO specifies that it includes the capacity credit as an offset to ensure customers are not paying for capacity twice, using the next avoidable unit instead of the system's costs. TECO includes a 1.5 cents/kWh credit for capacity based on the installed cost information for the 2023 Standard Offer Contract avoided unit, a 2030 natural gas-fired internal combustion engine. However, no new generation will be constructed, and the existing capacity is solar, which TECO considers non-firm for its winter system peak and only partially firm for its summer system peak. As a result, the resulting 4.9 cents/kWh rate is not cost based. While the program is voluntary, the Commission should consider whether it has an undue impact on the general body of ratepayers.

In addition to the proposed rate change, a proposed wording change in the tariff renames the term "Monthly Rate" to "Rate" in reference to the SSR-1 rate, designed to avoid the appearance of a flat fee.

In response to staff concerns, TECO updated its original tariff filing to include two other proposed changes to its SSR-1 Tariff. First, the proposed tariff would limit new customer enrollments and re-enrollments to 10 million kWh per year for the customers in the GSD, GSLDPR, and GSLDSU rate classes, to address staff concerns that a small number of customers could prohibit more widespread adoption of the program. Second, TECO proposed tariff changes that would prohibit re-enrollments for 12 months after an account's cancellation from the program. TECO offered this change in response to staff's concern that some customers may seek to enter and exit the program

[7] The price support for the current (6.3 cents per kWh) rate used a depreciable life of 30 years for the Lake Hancock facility. In the 2021 Agreement, the utility agreed to extend the life of solar assets to 35 years for depreciation purposes. TECO proposes to use this Commission-approved 35-year life in calculating the SSR-1 rate. This change puts additional downward pressure on the rate.

[8] TECO's response to Staff Data Request 2, No. 16.a.

[9] Based on 30 MW operating at a 25.8% capacity factor, which produces approximately 67.8 gigawatt-hours (GWh) annually, versus TECO's net energy for load of 20,977 GWh.

[10] In its current form, the Sun Select program features a 5 percent buffer, which results in the program having a maximum expected annual energy output of 95 percent.

frequently, based on what they perceive is or will be a favorable relationship between TECO's fuel factor and the SSR-1 Tariff rate.

### *SSR-1 Tariff Customer Impacts*

TECO claims that the proposed program provides Sun Select participants a pricing option to facilitate their efforts to decarbonize their operations or homes by using renewable power. TECO also indicated that it provides participants with an opportunity to mitigate bill changes due to fuel price fluctuations (hedge).[11] Staff considered several customer impacts, as discussed below.

#### Pricing Impact

When a subscriber enrolls in this optional program, they continue to receive electric service from TECO's mix of fossil and renewable generating resources. The fixed Sun Select tariff rate effectively replaces a portion or all of the Fuel Clause charges that customer would ordinarily be assessed. Staff notes this is somewhat similar to a customer installing rooftop solar panels, in that such a customer voluntarily pays a premium (for their rooftop solar panels), with the expectation of having lower Fuel Clause charges as the result of paying the premium. Fuel Clause charges are ordinarily reset on an annual basis, or perhaps more often depending on actions the utility takes in responding to external (market) conditions or as required by the Commission. TECO's marketing materials for this program state:

> Sun Select participants lock in a solar rate. While this rate is slightly higher, your fuel charge is waived for that portion of your electricity use.[12]

Staff compared the proposed SSR-1 Tariff and TECO's Projected System Average Fuel Costs (for 2024 through 2030). As shown in Table 1-1, the proposed Tariff rate (4.9 cents per kWh) is higher than TECO's Projected System Average Fuel Costs (for 2024 through 2030).

**Table 1-1**
**Proposed Tariff Rate and Projected Fuel Cost Comparison (cents/kWh)**

| Year<br>(A) | Proposed SSR-1 Tariff Rate<br>(B) | Projected System Average Fuel Cost<br>(C)* | Difference between Proposed SSR-1 Tariff Rate and Projected Average System Fuel Costs<br>(B – C) |
|---|---|---|---|
| 2024 | 4.9 | 3.8 | 1.4 |
| 2025 | 4.9 | 3.3 | 1.6 |
| 2026 | 4.9 | 3.2 | 1.7 |
| 2027 | 4.9 | 3.2 | 1.7 |
| 2028 | 4.9 | 3.2 | 1.7 |
| 2029 | 4.9 | 3.2 | 1.7 |
| 2030 | 4.9 | 3.2 | 1.7 |

Source: *TECO's Response to Staff's 1st Data Request, No. 3.b and FPSC Document No. 04517-2023, and FPSC Document No. 05265-2023.

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[11] TECO's Response to Staff's First Data Request, Nos. 5 and 6, FPSC Document No. 04517-2023.

[12] The utility provided staff the website link promoting their optional Sun Select program. *See* https://www.tampaelectric.com/company/solar-energy/sun-select/

Based on 2024 through 2030 rate comparisons, Sun Select participants appear to continue the history of paying more for electric service than they otherwise would, assuming the nominal fuel price projections provided by TECO.[13] Staff further notes that fuel prices are inherently volatile, and believes it is plausible that in some future periods Sun Select participants may pay less than the fuel factor for the volume of energy they purchase under the program.

Additionally, as is the case under the existing tariff, the proposed SSR-Tariff rate serves as a hedge of fuel prices. By paying a flat rate for Sun Select rather than the variable fuel factor, participants may perceive a benefit of the program in more stable bills.

### Access and Marketing

Staff has identified two areas of concern regarding customer impacts that can be addressed by staff's recommendation, as discussed below. First, TECO's petition does not address the potential for one or more rate classes to be excluded for participation at the levels they have been able to in the past. If TECO's proposal to reduce the rate for this optional program is approved, and fuel prices rise, staff believes that the residential and general service rate classes should be in a position to participate in proportions somewhat similar to their level of participation to date.[14] In Table 1-2, staff presents the level of sales participation in numbers and percent for the applicable rate classes as of June 2023. The Residential Class has accounted for 43 percent of total sales (all classes), and the General Services Class has participated at a much lower rate, about 1 percent of total sales, for a total participation rate between the two classes of 44 percent. Staff believes TECO should manage its SSR-1 Tariff program subscriptions to ensure that the proportion of energy sales of the Residential class (RS) and General Services class (GS), in the aggregate, to total sales are no lower than thirty percent. This reservation threshold will ensure the RS and GS classes have the opportunity to subscribe to a minimum of 30 percent of sales. Staff notes that the current tariff language supports subscription management by the utility.

**Table 1-2**
**SSR-1 Tariff Participation by Rate Class (June 2023)**

| Usage | Residential | Small Commercial | Commercial and Industrial | Total |
|---|---|---|---|---|
| MW | 4.96 | 0.11 | 6.73 | 11.8 |
| kWh | 11,524,305 | 308,985 | 14,855,328 | 26,688,618 |
| Percent (%) | 43.18 | 0.93 | 55.66 | 100 |

Source: TECO's Response to Staff's 1st Data Request, FPSC Document No. 04715-2023.

Second, if the proposed SSR-1 Tariff is approved, staff believes TECO should carefully review all marketing efforts and materials to ensure that they contain no claim or implication that Sun Select program revenues are earmarked for constructing new solar resources. In corresponding with staff, the utility emphasized that no new solar construction is planned.

[13]TECO provided staff a projection of nominal System Average Fuel Costs to 2030, FPSC Document No. 05265-2023.
[14]TECO's Response to Staff's First Data Request, No. 4.a., FPSC Document No. 04517-2023.

### *SSR-1 Tariff Impacts, Non-Participant Customers*

TECO reports that increasing program participation in the SSR-1 program to 30 MW will have no effect on base rates, fuel, or other charges to non-participants in 2024.

Staff's primary concern related to non-participant impacts is the potential for Fuel Clause factor increases. If the utility's proposal is approved, staff believes participation and revenues derived from this program, based on the attractive lower rate and higher program capacity, will likely both increase. Concurrently, fuel clause collections would decrease as more customers avoid the fuel clause factor on their bills. Such decreases in fuel revenue could impose an added burden on the other customers that continue to pay fuel clause charges at a potentially higher rate. While previously the Sun Select program offered additional solar generation that offset fuel and capacity prices, the proposed program expansion to 30 MWs uses existing solar capacity, which offers no additional avoided system savings.

However, staff believes the Commission could address this concern by requiring TECO to record incremental revenue collected from this program (i.e., revenue exceeding the authorized Shared Solar Tariff revenue credits approved in the 2021 Agreement) as an offset to expenditures for fuel in the fuel cost recovery clause docket. Projected Shared Solar Tariff revenue amounts in 2021 Settlement Agreement were credited to base rates.[15] Staff believes excess revenues generated under the proposed revisions to TECO's Shared Solar Tariff can and should be used to reduce the potential of unfavorable impacts on TECO's fuel factor which would otherwise be borne by non-participants. The Commission approved a similar approach in Order No. PSC-2023-0191-TRF-EI, which addressed Duke Energy Florida, LLC's (Duke) optional Clean Energy Impact program and associated tariff.[16] The Commission required Duke to include program revenues, net of expenses, in Duke's Fuel Clause filings to ensure that program benefits for the general body of ratepayers are reflected in rates on a more timely basis.

### *Reporting Requirements*

The utility stated that it seeks to learn about customer adoption of community solar programs and its customers' desire to reach decarbonization goals. However, because the utility has not clearly expressed how additional generation now or in the future may or may not materialize as a result of this program, staff is uncertain as to what degree the proposed pricing option facilitates decarbonization. A utility representative indicated that TECO will be reviewing the ongoing results of the program to evaluate its options for accelerating decarbonization efforts in the future, but no specific plans are in place at this time. As such, staff believes a reporting requirement would give TECO the opportunity to share its key findings with the Commission.

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[15]*See* 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.* At Page 5 of that Order, the revenue requirement of the 17.5 MW portion of Lake Hancock Generating Station was required to be included in the revenue requirements of future rate proceedings, as an addition to base rates, and the revenues under the tariff were to be credited to the revenue requirement as an offset. This was implemented in the 2021 Settlement Agreement in revised MFR Schedule E-13c in Docket No. 20210034-EI (Document No. 03510-2021, Pages 2, 3, and 5. This credit to revenue amounted to $723,807 for the RS rate class, $6,691 for the GS class, and $15,120 for the GSD and GSDT.

[16]Oder No. PSC-2023-0191-TRF-EI, issued June 29, 2023, in Docket No. 20220202-EI, *In re: Petition for approval of new clean energy impact program, a new renewable certificates (REC) buying program, by Duke Energy Florida, LLC.* An appeal of this Order is currently pending before the Florida Supreme Court, Case No. SC21-303.

If the petition is approved, the utility should be required to submit an annual report on the progress of this program for the years 2024-2027. Specifically, staff believes the utility should submit an annual report in March of 2024, 2025, 2026, and 2027, for the prior year, detailing the following: 1) the number of revised SSR-1 Tariff program participants, amount of energy sales, waiting list levels, and revenues collected, by subscription level and by rate class; 2) the incremental revenue, above the Sun Select revenue currently included in base rates, credited to the fuel clause; 3) a summary of TECO's key findings regarding customer adoption of community solar programs and its customers' desire to reach decarbonization goals; and 4) a detailed description of whether and how the results of the program has impacted TECO's generation planning.

## Conclusion

Staff agrees with TECO that a lower price, if approved, should assist the utility in increasing subscriptions to this program. Additionally, staff notes that higher participation up to the proposed limit of 30 MWs would give TECO the opportunity to learn more about customer adoption of community solar program and their customer's desire to reach climate change oriented goals. Further, staff notes that the Commission has a history of generally being supportive of optional renewable energy programs by the investor-owned electric utilities operating in Florida when the pricing of such services are not expected to result in harm to the general body of ratepayers.

Staff believes the Commission should approve the proposed changes to TECO's Shared Solar Rider Tariff, as shown in Attachment A, contingent upon TECO's compliance with certain program implementation provisions and reporting requirements described below.

First, incremental revenues from this program that exceed the Sun Select revenue credits approved in the 2021 Settlement should be recorded as a credit to the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause) to offset expenditures for fuel. While TECO's proposed Shared Solar Rider Tariff charge of 4.9 cents/kWh is not cost based, this voluntary program is not expected to have an undue impact on the general body of ratepayers, assuming such incremental revenues are credited to the Fuel Clause.

Second, TECO should manage its SSR-1 Tariff program subscriptions to ensure that the proportion of energy sales of residential and commercial customers in the RS and GS classes to total energy sales (all classes) are, in the aggregate, no lower than thirty percent.

Third, in its marketing of the revised program, TECO should not claim or imply that program revenues are earmarked for or contribute to the construction of new solar resources.

Finally, TECO should submit annual reports in March of 2024, 2025, 2026, and 2027 with data for the prior calendar year, detailing the following: 1) the number of revised SSR-1 Tariff program participants, amount of energy sales, waiting list levels, and revenues collected, by subscription level and by rate class; 2) the incremental revenue, above the Sun Select revenue currently included in base rates, credited to the Fuel Clause; 3) a summary of TECO's key findings regarding customer adoption of community solar programs and its customers' desire to reach decarbonization goals; and 4) a detailed description of whether and how the results of the program has impacted TECO's generation planning.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff, in effect at that time, should remain in effect, with any revenue held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of the consummating order. (Stiller)

***Staff Analysis:*** If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff, in effect at that time, should remain in effect, with any revenue held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of the consummating order.

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**SECOND~~FIRST~~ REVISED SHEET NO. 3.300**
**CANCELS FIRST REVISED~~ORIGINAL~~ SHEET NO. 3.300**

## SHARED SOLAR RIDER

**SCHEDULE:** SSR – 1

**AVAILABLE:** At the option of the customer, available to residential, commercial and industrial customers per device (non-totalized or totalized electric meter) on rate schedules RS, GS, GSD, GSLDPR and GSLDSU on a first come, first served basis subject to subscription availability. Not available to customers who take service under NM-1, RSVP-1, any standby service or time of use rate schedule. Subscription availability will be dependent on availability of ~~the~~ Shared Solar capacity ~~facility~~. Customers who apply when availability is closed will be placed on a waiting list until Shared Solar capacity becomes available. The Shared Solar facility will be for 30~~17.5~~ MWac* capacity and full subscription will be when 100~~95~~% of expected annual energy output has been subscribed.

**APPLICABLE:** Applicable, upon request, to eligible customers in conjunction with their standard rates and availability of service subject to subscription availability.

**CHARACTER OF SERVICE:** Shared Solar - 1 (SSR-1) enables customers to purchase monthly energy produced from Company-owned solar facilities for a selected percentage of that month's billed kWh. For RS and GS, individual subscriptions will be measured as a percentage of the monthly energy consumption as selected by the customer: 25%, 50% or 100% rounded up to the next highest kWh. For GSD, GSLDPR and GSLDSU, a fixed kWh subscription in 1,000 kWh blocks will be identified by the customer not to exceed their average monthly kWh consumption for the previous 12-months at the time of subscription. ~~.~~ Additionally, no new customer enrollments, re-enrollments, or changes to existing subscription amounts shall exceed 10,000,000 kWh per year.

**~~MONTHLY~~ RATE:** $0.049~~63~~ per kWh for monthly energy consumption.

The ~~monthly~~ SSR-1 rate, multiplied by the monthly energy consumption selected by the customer, will be charged to the customer in addition to the customer's normal cost of electricity pursuant to their RS, GS, GSD, GSLDPR and GSLDSU tariff charges applied to their entire monthly billing determinants, with the exception of the Fuel Charge, which is normally billed under the applicable tariff. Tampa Electric will seek to maintain the SSR-1 energy rate at $0.063 per kWh or lower until January 1, 2048, however the SSR-1 energy rate will remain subject to change by order of the Florida Public Service Commission.

Under SSR-1, the Fuel Charge for the applicable RS, GS, GSD, GSLDPR and GSLDSU tariff, for the monthly energy percentage or blocks selected by the customer, will be billed at a rate of $0.00 per kWh provided under this rider. The Fuel Charge applies to the remainder of the monthly billing determinates.

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~January 1, 2022~~

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SECOND~~FIRST~~ REVISED SHEET NO. 3.300
CANCELS FIRST REVISED~~ORIGINAL~~ SHEET NO. 3.300

Continued to Sheet No. 3.305

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~January 1, 2022~~

TECO
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**~~FIRST~~ SECOND REVISED SHEET NO. 3.305**
**~~ORIGINAL~~ CANCELS FIRST REVISED SHEET NO. 3.305**

Continued from Sheet No. 3.300

**TERM OF SERVICE:** Subscription to the SSR-1 Rider will be for a period of one (1) month. The subscription will automatically renew on a month-to-month basis, until the customer provides notice of cancellation or the participant is terminated from the program by the company for delinquency on the customer's electric service account or failure to satisfy eligibility requirements. After cancellation request is received, subscription will be removed from account within two billing cycles. Upon cancellation whether by the customer or by the company, the account is prohibited from re-enrolling for a twelve (12) month period. Request to rejoin the SSR-1 Rider after previous cancellation may be subject to price changes and subscription availability.

~~Requests to rejoin the SSR-1 Rider after previous cancellation may be subject to price changes and subscription availability.~~ Participating customers who relocate to another Tampa Electric Company metered residence may transfer their subscription to the new premises. A participating customer cannot transfer their rights under this Rider to another customer.

State or Federal Legislation Opt-Out Clause: If State or Federal laws are instituted requiring Tampa Electric to provide renewable energy to all customers on some basis, the Company reserves the right to cancel all contracts and sales through this tariff without penalty.

**SPECIAL PROVISIONS:**

1. The bill calculated under this tariff is subject to change in such an amount as may be approved and/or amended by the Florida Public Service Commission.
2. Service hereunder is subject to the Rules and Regulations for Electric Service on file with the Florida Public Service Commission.
3. Billing will begin with the first billing cycle of the month following the month service under this Rider has been granted to the SSR-1 customer. Billing will cease should the Shared Solar facility utilized for service under this Rider cease operation for any reason or if the Opt-Out Clause listed above is enforced by Tampa Electric.
4. No charges made under this Rider in prior months will be refunded or adjusted if service under this Rider is discontinued for any reason.
5. The c~~C~~ompany will retain ownership of the Renewable Energy Credits (RECs) and retire on behalf of the customer. ~~all other environmental attributes including but not limited to carbon emission reduction credits, which will not be otherwise sold by the Company.~~ Customers may request to have RECs deposited into a designated account at their own expense.

**ISSUED BY:** ~~N. G. Tower~~A.D. Collins, President

**DATE EFFECTIVE:** ~~October 3, 2019~~

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~~ORIGINAL~~ CANCELS FIRST REVISED SHEET NO. 3.305

6. The company will retain ownership of all other environmental attributes including, but not limited to, carbon emission reduction credits, which will not be otherwise sold by the Company.

ISSUED BY: ~~N. G. Tower~~A.D. Collins, President

DATE EFFECTIVE: ~~October 3, 2019~~

# Item 11

FILED 10/27/2023
DOCUMENT NO. 05848-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Guffey, Lang) EJD
Division of Accounting and Finance (Mason, Norris) ALM
Office of the General Counsel (Dose) JSC

**RE:** Docket No. 20230090-EI – Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2021 stipulation and settlement agreement, by Tampa Electric Company.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 4/16/23 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On August 16, 2023, Tampa Electric Company (TECO or Company) filed a petition to implement the 2024 Generation Base Rate Adjustment (GBRA) provisions pursuant to 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] In Order No. PSC-2022-0434-TRF-EI, the Commission approved TECO's 2023 GBRA provision of the 2021 settlement agreement.[2]

[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.*
[2] Order No. PSC-2022-0434-TRF-EI, issued December 21, 2022, in Docket No. 20220148-EI, *In re: Petition to implement 2023 generation base rate adjustment provisions in 2021 agreement, by Tampa Electric Company.*

The GBRA provisions of the settlement order and agreement provide for an increase in base rates to reflect the 2024 GBRA amount of $21,376,909, effective with the first billing cycle of January 2024.[3] In this petition, TECO proposed to increase the GBRA amount to $21,689,323 to reflect the updated 10.20 percent mid-point return on equity (ROE) allowed by a trigger provision of the 2021 settlement agreement and approved by the Commission on August 16, 2022, in Docket No. 20220122-EI.[4] The Company also noted that it was evaluating the tax provisions of the Inflation Reduction Act (IRA) to address impacts of the IRA on the 2024 GBRA, consistent with paragraphs 4(c) and 11 of the settlement agreement. The IRA, which became effective August 16, 2022, does not contain a federal income tax rate change applicable to TECO, but it does allow for the substitution of the existing investment tax credit for solar generating facilities with a new production tax credit.

During the review process, staff issued a data request to TECO on September 7, 2023, for which the responses were received on September 14, 2023. On October 2, 2023, staff held an informal telephonic meeting with the parties to the 2021 settlement agreement to discuss TECO's filing in this docket. The legislative version of the proposed tariffs is Attachment A to this recommendation. This is staff's recommendation on the proposed tariffs. The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes (F.S.)

[3] See page 20 in 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.*

[4] 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 2024 GBRA amount of $21,689,323?

***Recommendation:*** Staff recommends approving TECO's updated 2024 GBRA amount of $21,689,323 with the requirement that the Company file updated 2023 and 2024 GBRAs, adjusted to reflect IRA impacts, by April 1, 2024. (Mason, 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 $21,376,909 effective with the first billing cycle in January 2024. 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 2024 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. 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 2024 GBRA, TECO provided a calculation updating the GBRA amount to $21,689,323 to reflect the Company's 10.20 percent authorized ROE mid-point. The updated amount is correct based on staff's review of the Company's calculations.

When the Commission approved TECO's 2023 GBRA last year, the Company said it was in discussions with the Office of Public Counsel (OPC) regarding the process for updating the 2023 GBRA to reflect the impact of the IRA. As reflected in Order No. PSC-2022-0434-TRF-EI, TECO agreed to collect the rate increase reflected in the 2023 GBRA subject to refund, so that the 2023 GBRA could go into effect with the first billing cycle of January 2023. The Company would refund the difference between the 2023 GBRA, as approved by the Commission, and the 2023 GBRA as adjusted for the IRA, once the 2023 GBRA adjusted for the IRA has been approved by the Commission.

Staff requested an update on this process, as there has not been a revised filing for the 2023 GBRA, and the impacts of the IRA would also adjust the 2024 GBRA. The Company indicated that it is still in the process of discussing the impacts of the IRA on the 2023 and 2024 GBRAs with OPC. As such, TECO is requesting the Commission consider staff's recommendation now so the 2024 GBRA can go into effect with the first billing cycle of January 2024. As was the case with the 2023 GBRA, the Company agrees to collect the rate increase reflected in the 2024 GBRA subject to refund. The Company will refund the difference between the 2024 GBRA as approved by the Commission, and the 2024 GBRA as adjusted for the IRA once the 2024 GBRA adjusted for the IRA has been approved by the Commission.

In light of the extended timeframe for addressing the impacts of the IRA, staff recommends approving TECO's updated 2024 GBRA amount of $21,689,323 with the requirement that the Company file updated 2023 and 2024 GBRAs, adjusted to reflect IRA impacts, by April 1, 2024.

***Issue 2:*** Should the Commission approve TECO's revised tariffs to implement the GBRA increase effective January 2024?

***Recommendation:*** Yes, the Commission should approve TECO's revised tariffs to implement the GBRA increase effective with the first billing cycle of January 2024 as approved in the settlement order. (Guffey, Lang)

***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 $1.58 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. 20230002-EG was filed on August 4, 2023.[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 are in compliance with the language of the settlement agreement.

Staff has also reviewed TECO's proposed 2024 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 $21,689,323 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 2024. TECO should notify its customers of the approved new rates by way of bill notification in the December 2023 billing cycle.

[5] Document No. 04531-2023, filed August 4, 2023, in Docket No. 20230002-EG, *In re: Energy Conservation Cost Recovery Clause.*

***Issue 3:*** Should this docket be closed?

***Recommendation:*** No. 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. This docket should remain open in order for TECO to file updated 2023 and 2024 GBRAs, adjusted to reflect IRA impacts, by April 1, 2024. (Dose)

***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. This docket should remain open in order for TECO to file updated 2023 and 2024 GBRAs, adjusted to reflect IRA impacts, by April 1, 2024.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.030
CANCELS ~~THIRTIETH~~ THIRTY-FIRST 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~~ 650 ¢ per kWh |
| All additional kWh | 7.~~617~~ 802 ¢ 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:** ~~January 1, 2023~~

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TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**THIRTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.050**
**CANCELS THIRTY-~~FIRST~~ SECOND 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~~ ~~863~~862 ¢ 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**THIRTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.080**
**CANCELS ~~THIRTIETH~~ THIRTY-FIRST 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~~ 20 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.140**
**CANCELS ~~ELEVENTH~~ TWELFTH 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~~ 88 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:** ~~January 1, 2023~~

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TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SECOND~~ THIRD REVISED SHEET NO. 6.160
CANCELS ~~FIRST~~SECOND 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~~ 29 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:** ~~January 1, 2023~~

THIRTY-~~EIGHTH~~ NINTH REVISED SHEET NO. 6.290
CANCELS THIRTY-~~SEVENTH~~ EIGHTH 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~~ ~~863~~ 862¢ 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.

**PAYMENT OF BILLS:** See Sheet No. 6.023.

**STORM SURCHARGE:** See Sheet No. 6.024.

**STORM PROTECTION PLAN RECOVERY CHARGE:** See Sheet Nos. 6.021 and 6.023.

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~April 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**THIRTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.320**
**CANCELS ~~THIRTIETH~~ THIRTY-FIRST 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~~~~12.318~~12.317¢ per kWh during peak hours
6.~~154~~~~332~~331¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~January 1, 2023~~

THIRTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.330
CANCELS THIRTY-~~FIRST~~ SECOND 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~~4.55 per kW of billing demand, plus
$9.~~24~~ 28 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.370**
**CANCELS ~~ELEVENTH~~ TWELFTH 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~~ 77 per kW of billing demand, plus
$8.~~04~~ 08 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.400
CANCELS ~~SEVENTH~~ EIGHTH 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~~ 95 per kW of billing demand, plus
$6.~~28~~ 31 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.565**
**CANCELS ~~SEVENTEENTH~~ EIGHTEENTH REVISED**
**SHEET NO. 6.565**

Continued from Sheet No. 6.560

**RATES:**
Basic Service Charge: $0.71per day

Energy and Demand Charges: ~~6.846~~7.012¢ 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 SURCHARGE**: See Sheet No. 6.024.

**STORM PROTECTION PLAN RECOVERY CHARGE:** See Sheet Nos. 6.021 and 6.023.

Continued to Sheet No. 6.570

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~April 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~NINTEENTH~~ TWENTY REVISED SHEET NO. 6.600
CANCELS ~~EIGHTEENTH~~ NINETEENTH 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~~75 | per kW/Month of Standby Demand (Local Facilities Reservation Charge) |
| plus the greater of: | | |
| $ | 1.~~69~~70 | per kW/Month of Standby Demand (Power Supply Reservation Charge) or |
| $ | 0.~~67~~68 | 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.601**
**CANCELS TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.601**

Continued from Sheet No. 6.600

**CHARGES FOR SUPPLEMENTAL SERVICE:**

Demand Charge:

| | |
|---|---|
| $ 14.~~13~~20 | 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SIXTEENTH~~ SEVENTEENTH REVISED SHEET NO. 6.605
CANCELS ~~FIFTEENTH~~ SIXTEENTH 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~~75 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$1.~~69~~ 70 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.~~67~~68 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:** ~~January 1, 2023~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

**~~NINTEENTH~~ TWENTIETH REVISED SHEET NO. 6.606**
**CANCELS ~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.606**

Continued from Sheet No. 6.605

**CHARGES FOR SUPPLEMENTAL SERVICE**

Demand Charge:

| | |
|---|---|
| $4.~~53~~55 | per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus |
| $9.~~24~~28 | 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:** ~~January 1, 2023~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.610
CANCELS ~~NINTH~~ TENTH 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~~ 43per 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:** ~~January 1, 2023~~

TECO
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AN EMERA COMPANY

**~~SECOND~~ THIRD REVISED SHEET NO. 6.615**
**CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 6.615**

Continued from Sheet No. 6.610

**CHARGES FOR SUPPLEMENTAL SERVICE:**

Demand Charge:
$ 11.~~83~~88 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:** ~~January 1, 2023~~

TECO
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~~SECOND~~ THIRD REVISED SHEET NO. 6.630
CANCELS ~~FIRST~~ SECOND 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~~12 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:** ~~January 1, 2023~~

TECO
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~~SECOND~~ THIRD REVISED SHEET NO. 6.635
CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 6.635

Continued from Sheet No. 6.630

**CHARGES FOR SUPPLEMENTAL SERVICE:**

Demand Charge:
$ 9.~~24~~29 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:** ~~January 1, 2023~~

TECO
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AN EMERA COMPANY

~~SECOND~~ THIRD REVISED SHEET NO. 6.650
CANCELS ~~FIRST~~ SECOND 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~~43 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:** ~~January 1, 2023~~

TECO
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~~SECOND~~ THIRD REVISED SHEET NO. 6.655
CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 6.655

Continued from Sheet No. 6.650

**CHARGES FOR SUPPLEMENTAL SERVICE**

Demand Charge:

| | |
|---|---|
| \$ 3.~~76~~77 | per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus |
| \$ 8.~~04~~08 | 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:** ~~January 1, 2023~~

TECO
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AN EMERA COMPANY

~~SECOND~~ THIRD REVISED SHEET NO. 6.670
CANCELS ~~FIRST~~ SECOND 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~~12 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:** ~~January 1, 2023~~

TECO
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~~SECOND~~ THIRD REVISED SHEET NO. 6.675
CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 6.675

Continued from Sheet No. 6.670

**CHARGES FOR SUPPLEMENTAL SERVICE**

Demand Charge:

| | |
|---|---|
| $2.~~94~~95 | per kW/Month of Supplemental Demand (Supplemental Billing Demand Charge), plus |
| $6.~~28~~31 | 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:** ~~January 1, 2023~~

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**~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.805**
**CANCELS ~~FOURTEENTH~~ FIFTEENTH 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 | 4.54~~4.45~~ | 2.48 | 0.65~~0~~ ~~.64~~ | 0.33~~0~~ ~~.32~~ |
| 802 | 862 | Cobra/Nema[1] | 6,300 | 70 | 29 | 14 | 4.61~~4.52~~ | 2.11 | 0.95~~0~~ ~~.93~~ | 0.46~~0~~ ~~.45~~ |
| 803 | 863 | Cobra/Nema[1] | 9,500 | 100 | 44 | 22 | 5.22~~5.12~~ | 2.33 | 1.43~~1~~ ~~.41~~ | 0.72~~0~~ ~~.70~~ |
| 804 | 864 | Cobra[1] | 16,000 | 150 | 66 | 33 | 6.01~~5.89~~ | 2.02 | 2.15~~2~~ ~~.11~~ | 1.08~~1~~ ~~.05~~ |
| 805 | 865 | Cobra[1] | 28,500 | 250 | 105 | 52 | 7.01~~6.87~~ | 2.60 | 3.42~~3~~ ~~.35~~ | 1.70~~1~~ ~~.66~~ |
| 806 | 866 | Cobra[1] | 50,000 | 400 | 163 | 81 | 7.32~~7.18~~ | 2.99 | 5.31~~5~~ ~~.21~~ | 2.64~~2~~ ~~.59~~ |
| 468 | 454 | Flood[1] | 28,500 | 250 | 105 | 52 | 7.72~~7.57~~ | 2.60 | 3.42~~3~~ ~~.35~~ | 1.70~~1~~ ~~.66~~ |
| 478 | 484 | Flood[1] | 50,000 | 400 | 163 | 81 | 8.22~~8.06~~ | 3.00 | 5.31~~5~~ ~~.21~~ | 2.64~~2~~ ~~.59~~ |
| 809 | 869 | Mongoose[1] | 50,000 | 400 | 163 | 81 | 9.35~~9.17~~ | 3.02 | 5.31~~5~~ ~~.21~~ | 2.64~~2~~ ~~.59~~ |
| 509 | 508 | Post Top (PT)[1] | 4,000 | 50 | 20 | 10 | 4.43~~4.34~~ | 2.48 | 0.65~~0~~ ~~.64~~ | 0.33~~0~~ ~~.32~~ |
| 570 | 530 | Classic PT[1] | 9,500 | 100 | 44 | 22 | 17.05~~16.72~~ | 1.89 | 1.43~~1~~ ~~.41~~ | 0.72~~0~~ ~~.70~~ |
| 810 | 870 | Coach PT[1] | 6,300 | 70 | 29 | 14 | 6.78~~6.65~~ | 2.11 | 0.95~~0~~ ~~.93~~ | 0.46~~0~~ ~~.45~~ |
| 572 | 532 | Colonial PT[1] | 9,500 | 100 | 44 | 22 | 13.08~~12.82~~ | 1.89 | 1.43~~1~~ ~~.41~~ | 0.72~~0~~ ~~.70~~ |
| 573 | 533 | Salem PT[1] | 9,500 | 100 | 44 | 22 | 12.99~~12.74~~ | 1.89 | 1.43~~1~~ ~~.41~~ | 0.72~~0~~ ~~.70~~ |
| 550 | 534 | Shoebox[1] | 9,500 | 100 | 44 | 22 | 11.53~~11.30~~ | 1.89 | 1.43~~1~~ ~~.41~~ | 0.72~~0~~ ~~.70~~ |
| 566 | 536 | Shoebox[1] | 28,500 | 250 | 105 | 52 | 12.50~~12.26~~ | 3.18 | 3.42~~3~~ ~~.35~~ | 1.70~~1~~ ~~.66~~ |
| 552 | 538 | Shoebox[1] | 50,000 | 400 | 163 | 81 | 10.60~~10.39~~ | 2.44 | 5.31~~5~~ ~~.21~~ | 2.64~~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~~260¢ per kWh for each fixture.

Continued to Sheet No. 6.806

**ISSUED BY:** A. D. Collins, President **DATE EFFECTIVE:** ~~January 1, 2023~~

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**~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.806**
**CANCELS ~~TWELFTH~~ THIRTEENTH 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 | 10.83 ~~10.62~~ | 4.99 | 4.50 ~~4.41~~ | 2.25 ~~2.20~~ |
| 520 | 522 | Cobra[1] | 32,000 | 400 | 159 | 79 | 8.67 ~~8.50~~ | 4.01 | 5.18 ~~5.08~~ | 2.58 ~~2.52~~ |
| 705 | 725 | Flood[1] | 29,700 | 350 | 138 | 69 | 12.30 ~~12.06~~ | 5.04 | 4.50 ~~4.41~~ | 2.25 ~~2.20~~ |
| 556 | 541 | Flood[1] | 32,000 | 400 | 159 | 79 | 12.04 ~~11.80~~ | 4.02 | 5.18 ~~5.08~~ | 2.58 ~~2.52~~ |
| 558 | 578 | Flood[1] | 107,800 | 1,000 | 383 | 191 | 15.11 ~~14.81~~ | 8.17 | 12.49 ~~12.24~~ | 6.23 ~~6.10~~ |
| 701 | 721 | General PT[1] | 12,000 | 150 | 67 | 34 | 15.25 ~~14.95~~ | 3.92 | 2.18 ~~2.14~~ | 1.11 ~~1.09~~ |
| 574 | 548 | General PT[1] | 14,400 | 175 | 74 | 37 | 15.68 ~~15.37~~ | 3.73 | 2.41 ~~2.36~~ | 1.21 ~~1.18~~ |
| 700 | 720 | Salem PT[1] | 12,000 | 150 | 67 | 34 | 13.42 ~~13.16~~ | 3.92 | 2.18 ~~2.14~~ | 1.11 ~~1.09~~ |
| 575 | 568 | Salem PT[1] | 14,400 | 175 | 74 | 37 | 13.49 ~~13.23~~ | 3.74 | 2.41 ~~2.36~~ | 1.21 ~~1.18~~ |
| 702 | 722 | Shoebox[1] | 12,000 | 150 | 67 | 34 | 10.38 ~~10.18~~ | 3.92 | 2.18 ~~2.14~~ | 1.11 ~~1.09~~ |
| 564 | 549 | Shoebox[1] | 12,800 | 175 | 74 | 37 | 11.44 ~~11.22~~ | 3.70 | 2.41 ~~2.36~~ | 1.21 ~~1.18~~ |
| 703 | 723 | Shoebox[1] | 29,700 | 350 | 138 | 69 | 13.74 ~~13.47~~ | 4.93 | 4.50 ~~4.41~~ | 2.25 ~~2.20~~ |
| 554 | 540 | Shoebox[1] | 32,000 | 400 | 159 | 79 | 14.41 ~~14.13~~ | 3.97 | 5.18 ~~5.08~~ | 2.58 ~~2.52~~ |
| 576 | 577 | Shoebox[1] | 107,800 | 1,000 | 383 | 191 | 23.74 ~~23.28~~ | 8.17 | 12.49 ~~12.24~~ | 6.23 ~~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~~260¢ per kWh for each fixture.

Continued to Sheet No. 6.808

**ISSUED BY:** A. D. Collins, President **DATE EFFECTIVE:** ~~January 1, 2023~~

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~~FOURTEENTH~~ FIFTEENTH REVISED SHEET NO. 6.808
CANCELS ~~THIRTEENTH~~ FOURTEENTH 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 | 11.03 ~~10.81~~ | 1.74 | 0.65 ~~0.64~~ | 0.33 ~~0.32~~ |
| 820 | 840 | Roadway (1) | 7,577 | 103 | 36 | 18 | 16.59 ~~16.27~~ | 1.19 | 1.17 ~~1.15~~ | 0.59 ~~0.58~~ |
| 821 | 841 | Roadway(1) | 8,300 | 106 | 37 | 19 | 16.59 ~~16.27~~ | 1.20 | 1.21 ~~1.18~~ | 0.62 ~~0.61~~ |
| 829 | 849 | Roadway(1) | 15,285 | 157 | 55 | 27 | 16.53 ~~16.21~~ | 2.26 | 1.79 ~~1.76~~ | 0.88 ~~0.86~~ |
| 822 | 842 | Roadway(1) | 15,300 | 196 | 69 | 34 | 20.97 ~~20.56~~ | 1.26 | 2.25 ~~2.20~~ | 1.11 ~~1.09~~ |
| 823 | 843 | Roadway(1) | 14,831 | 206 | 72 | 36 | 24.17 ~~23.70~~ | 1.38 | 2.35 ~~2.30~~ | 1.17 ~~1.15~~ |
| 835 | 855 | Post Top(1) | 5,176 | 60 | 21 | 11 | 23.77 ~~23.31~~ | 2.28 | 0.68 ~~0.67~~ | 0.36 ~~0.35~~ |
| 824 | 844 | Post Top(1) | 3,974 | 67 | 24 | 12 | 28.02 ~~27.47~~ | 1.54 | 0.78 ~~0.77~~ | 0.39 ~~0.38~~ |
| 825 | 845 | Post Top(1) | 6,030 | 99 | 35 | 17 | 29.51 ~~28.93~~ | 1.56 | 1.14 ~~1.12~~ | 0.55 ~~0.54~~ |
| 836 | 856 | Post Top(1) | 7,360 | 100 | 35 | 18 | 24.02 ~~23.55~~ | 2.28 | 1.14 ~~1.12~~ | 0.59 ~~0.58~~ |
| 830 | 850 | Area-Lighter(1) | 14,100 | 152 | 53 | 27 | 21.37 ~~20.95~~ | 2.51 | 1.73 ~~1.69~~ | 0.88 ~~0.86~~ |
| 826 | 846 | Area-Lighter(1) | 13,620 | 202 | 71 | 35 | 27.49 ~~26.95~~ | 1.41 | 2.31 ~~2.27~~ | 1.14 ~~1.12~~ |
| 827 | 847 | Area-Lighter(1) | 21,197 | 309 | 108 | 54 | 29.65 ~~29.07~~ | 1.55 | 3.52 ~~3.45~~ | 1.76 ~~1.73~~ |
| 831 | 851 | Flood(1) | 22,122 | 238 | 83 | 42 | 22.88 ~~22.43~~ | 3.45 | 2.71 ~~2.65~~ | 1.37 ~~1.34~~ |
| 832 | 852 | Flood(1) | 32,087 | 359 | 126 | 63 | 27.56 ~~27.02~~ | 4.10 | 4.11 ~~4.03~~ | 2.05 ~~2.01~~ |
| 833 | 853 | Mongoose(1) | 24,140 | 245 | 86 | 43 | 21.16 ~~20.75~~ | 3.04 | 2.80 ~~2.75~~ | 1.40 ~~1.37~~ |
| 834 | 854 | Mongoose(1) | 32,093 | 328 | 115 | 57 | 23.47 ~~23.01~~ | 3.60 | 3.75 ~~3.67~~ | 1.86 ~~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.~~105~~260¢ per kWh for each fixture.

Continued to Sheet No. 6.809

**ISSUED BY:** A. D. Collins, President **DATE EFFECTIVE:** ~~January 1, 2023~~

TECO
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~~NINTH~~ TENTH REVISED SHEET NO. 6.809
CANCELS ~~EIGHTH~~ NINTH 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 | 7.72~~7.67~~ | 1.74 | 0.29~~0.29~~ | 0.16~~0.16~~ |
| 914 | 901 | Roadway | 5,392 | 47 | 16 | 8 | 7.64~~7.49~~ | 1.74 | 0.52~~0.51~~ | 0.26~~0.26~~ |
| 921 | 902 | Roadway/Area | 8,500 | 88 | 31 | 15 | 11.82~~11.59~~ | 1.74 | 1.01~~0.99~~ | 0.49~~0.~~48 |
| 926 | 982 | Roadway | 12,414 | 105 | 37 | 18 | 10.85~~10.64~~ | 1.19 | 1.21~~1.18~~ | 0.59~~0.58~~ |
| 932 | 903 | Roadway/Area | 15,742 | 133 | 47 | 23 | 20.41~~20.01~~ | 1.38 | 1.53~~1.50~~ | 0.75~~0.73~~ |
| 935 | 904 | Area-Lighter | 16,113 | 143 | 50 | 25 | 15.21~~14.91~~ | 1.41 | 1.63~~1.60~~ | 0.82~~0.80~~ |
| 937 | 905 | Roadway | 16,251 | 145 | 51 | 26 | 11.57~~11.34~~ | 2.26 | 1.66~~1.63~~ | 0.85~~0.83~~ |
| 941 | 983 | Roadway | 22,233 | 182 | 64 | 32 | 14.74~~14.45~~ | 2.51 | 2.09~~2.04~~ | 1.04~~1.02~~ |
| 945 | 906 | Area-Lighter | 29,533 | 247 | 86 | 43 | 21.20~~20.79~~ | 2.51 | 2.80~~2.75~~ | 1.40~~1.37~~ |
| 947 | 984 | Area-Lighter | 33,600 | 330 | 116 | 58 | 26.60~~26.08~~ | 1.55 | 3.78~~3.71~~ | 1.89~~1.85~~ |
| 951 | 985 | Flood | 23,067 | 199 | 70 | 35 | 16.51~~16.19~~ | 3.45 | 2.28~~2.24~~ | 1.14~~1.12~~ |
| 953 | 986 | Flood | 33,113 | 255 | 89 | 45 | 27.78~~27.24~~ | 4.10 | 2.90~~2.84~~ | 1.47~~1.~~44 |
| 956 | 987 | Mongoose | 23,563 | 225 | 79 | 39 | 17.77~~17.42~~ | 3.04 | 2.58~~2.52~~ | 1.27~~1.25~~ |
| 958 | 907 | Mongoose | 34,937 | 333 | 117 | 58 | 22.22~~21.79~~ | 3.60 | 3.81~~3.74~~ | 1.89~~1.85~~ |
| 965 | 991 | Granville Post Top (PT) | 3,024 | 26 | 9 | 4 | 8.47~~8.30~~ | 2.28 | 0.29~~0.29~~ | 0.13~~0.13~~ |
| 967 | 988 | Granville PT | 4,990 | 39 | 14 | 7 | 18.50~~18.14~~ | 2.28 | 0.46~~0.45~~ | 0.23~~0.22~~ |
| 968 | 989 | Granville PT Enh[4] | 4,476 | 39 | 14 | 7 | 22.10~~21.67~~ | 2.28 | 0.46~~0.45~~ | 0.23~~0.22~~ |
| 971 | 992 | Salem PT | 5,240 | 55 | 19 | 9 | 15.07~~14.78~~ | 1.54 | 0.62~~0.61~~ | 0.29~~0.29~~ |

**ISSUED BY:** A. D. Collins, President

**DATE EFFECTIVE:** ~~January 1, 2023~~

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TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~NINTH~~ TENTH REVISED SHEET NO. 6.809
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 6.809

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 972 | 993 | Granville PT | 7,076 | 60 | 21 | 10 | 20.24~~1~~ ~~9.84~~ | 2.28 | 0.68~~0~~ ~~.67~~ | 0.33~~0.~~ ~~32~~ |
| 973 | 994 | Granville PT Enh[(4)] | 6,347 | 60 | 21 | 10 | 23.76~~2~~ ~~3.30~~ | 2.28 | 0.68~~0~~ ~~.67~~ | ~~0.32~~0. 33 |
| 975 | 990 | Salem PT | 7,188 | 76 | 27 | 13 | 19.57~~4~~ ~~9.10~~ | 1.54 | 0.88~~0~~ ~~.86~~ | 0.~~42~~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.~~105~~260¢ 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: ~~January 1, 2023~~

111

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.810**
**CANCELS ~~SIXTH~~ SEVENTH 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 | 7.83~~7.68~~ | 0.17 |
| 626 | Wood | 30 ft | OH | 3.87~~3.79~~ | 0.17 |
| 627 | Wood | 35 ft | OH | 4.58~~4.49~~ | 0.17 |
| 597 | Wood | 40/45 ft | OH | 9.78~~9.59~~ | 0.31 |
| 637 | Standard | 35 ft, Concrete | OH | 8.19~~8.03~~ | 0.17 |
| 594 | Standard | 40/45 ft, Concrete | OH | 15.68~~15.37~~ | 0.31 |
| 599 | Standard | 16 ft, DB Concrete | UG | 22.60~~22.16~~ | 0.14 |
| 595 | Standard | 25/30 ft, DB Concrete | UG | 31.03~~30.42~~ | 0.14 |
| 588 | Standard | 35 ft, DB Concrete | UG | 32.53~~31.89~~ | 0.34 |
| 607 | Standard (70 - 100 W or up to 100 ft span)(1) | 35 ft, DB Concrete | UG | 16.63~~16.31~~ | 0.34 |
| 612 | Standard (150 W or 100 -150 ft span)(1) | 35 ft, DB Concrete | UG | 22.29~~21.85~~ | 0.34 |
| 614 | Standard (250 -400W or above 150 ft span)(1) | 35 ft, DB Concrete | UG | 33.64~~32.98~~ | 0.34 |
| 596 | Standard | 40/45 ft, DB Concrete | UG | 37.90~~37.16~~ | 0.14 |
| 523 | Round | 23 ft, DB Concrete | UG | 30.45~~29.86~~ | 0.14 |
| 591 | Tall Waterford | 35 ft, DB Concrete | UG | 41.94~~41.12~~ | 0.14 |
| 592 | Victorian | PT, DB Concrete | UG | 36.01~~35.31~~ | 0.14 |
| 593 | Winston | PT, DB Aluminum | UG | 20.26~~19.86~~ | 1.10 |
| 583 | Waterford | PT, DB Concrete | UG | 30.44~~29.85~~ | 0.14 |
| 422 | Aluminum(1) | 10 ft, DB Aluminum | UG | 12.46~~12.22~~ | 1.30 |
| 616 | Aluminum | 27 ft, DB Aluminum | UG | 41.39~~40.58~~ | 0.34 |
| 615 | Aluminum | 28 ft, DB Aluminum | UG | 17.78~~17.43~~ | 0.34 |
| 622 | Aluminum | 37 ft, DB Aluminum | UG | 56.67~~55.56~~ | 0.34 |
| 623 | Waterside | 38 ft, DB Aluminum | UG | 48.78~~47.83~~ | 3.85 |
| 584 | Aluminum(1) | PT, DB Aluminum | UG | 23.38~~22.92~~ | 1.10 |
| 581 | Capitol(1) | PT, DB Aluminum | UG | 35.69~~34.99~~ | 1.10 |
| 586 | Charleston | PT, DB Aluminum | UG | 27.22~~26.69~~ | 1.10 |
| 585 | Charleston Banner | PT, DB Aluminum | UG | 35.63~~34.93~~ | 1.10 |
| 590 | Charleston HD | PT, DB Aluminum | UG | 30.80~~30.20~~ | 1.10 |
| 580 | Heritage(1) | PT, DB Aluminum | UG | 25.79~~25.29~~ | 1.10 |
| 587 | Riviera(1) | PT, DB Aluminum | UG | 27.23~~26.70~~ | 1.10 |
| 589 | Steel(1) | 30 ft, AB Steel | UG | 51.02~~50.02~~ | 1.68 |
| 624 | Fiber(1) | PT, DB Fiber | UG | 10.84~~10.63~~ | 1.30 |
| 582 | Winston (1) | PT, DB Fiber | UG | 19.72~~19.33~~ | 1.10 |
| 525 | Franklin Composite | PT, DB Composite | UG | 32.49~~31.86~~ | 1.10 |
| 641 | Existing Pole | | UG | 6.94~~6.80~~ | 0.34 |

(1) Closed to new business

Continued from Sheet No. 6.815

**ISSUED BY:** A. D. Collins, President **DATE EFFECTIVE:** ~~January 1, 2023~~

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**~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.815**
**CANCELS ~~FOURTEENTH~~ FIFTEENTH 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~~39 | $1.43 |
| 569 | PT Bracket (accommodates two post top fixtures) | $4.~~66~~75 | $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 SURCHARGE:** See Sheet No. 6.024.

**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~~260¢ 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:** ~~April 1, 2023~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.830
CANCELS ~~SIXTH~~ SEVENTH REVISED 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~~260¢ 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

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**DATE EFFECTIVE:** ~~January 1, 2023~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

**~~EIGHTH~~ NINTH REVISED SHEET NO. 6.835**
**CANCELS ~~SEVENTH~~ EIGHTH REVISED 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~~260¢ 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.

Continued to Sheet No. 6.840

**ISSUED BY:** A. D. Collins, President **115** **DATE EFFECTIVE:** ~~April 1, 2023~~

# Item 12

FILED 10/27/2023
DOCUMENT NO. 05854-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Ward, Hampson, P. Kelley) EJD
Office of the General Counsel (Brownless) JSC

**RE:** Docket No. 20230094-GU – Petition by Peoples Gas System, Inc. for approval of special contract with Tampa Port Authority.

**AGENDA:** 11/09/23 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Graham

**CRITICAL DATES:** None

**SPECIAL INSTRUCTIONS:** None

## Case Background

On August 25, 2023, Peoples Gas System, Inc. (Peoples or the utility) filed a petition for approval of a special contract with the Tampa Port Authority (the Port). The Port is the governing body and port authority of the Hillsborough County Port District, an independent special district of the State of Florida, created by Chapter 95-488, Laws of Florida (the Port's Enabling Act).

The Port is seeking gas service from Peoples in order to run a standby gas-fired electric generator that would add resiliency during a loss of electric power. The proposed special contract modifies Peoples' standard gas service agreement to correspond with the terms of the Port's Enabling Act. Specifically, the term of the grant of easement and the indemnification language are being modified. Peoples and the Port have executed an easement agreement which is separate from the special contract. The easement agreement itself does not require Commission approval and was signed by representatives of the Port on June 13, 2023.

The purpose of the special contract is to allow Peoples to construct a service line and provide natural gas service to the Port. The natural gas would power a gas-fired electric generator that would provide resiliency to the Port during times of electrical power outages. Under the special contract the Port would take service for 500 therms per year at a capacity of 3,000 cubic feet per hour. In response to staff's first data request, Peoples stated that the service line constructed in the easement will be 1¼" in diameter and approximately 258 linear feet. The utility also stated that it has constructed an approximate 450-feet long extension of the main pipeline within the right of way to provide service to the Port. The extension is not part of the special contract.

On October 6, 2023, staff issued a data request, to which responses were received on October 12, 2023. The proposed special contract is included in this recommendation as Attachment A. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

## Discussion of Issues

***Issue 1:*** Should the Commission approve the special contract between Peoples and Tampa Port Authority?

***Recommendation:*** Yes, the Commission should approve the special contract between Peoples and Tampa Port Authority. The changes addressed in the special contract are necessary to correspond with the terms of Tampa Port Authority's Enabling Act and allow it to receive gas service. Peoples should file a conformed copy of the signed special contract with the Commission before the special contract becomes effective. (Ward)

***Staff Analysis:*** Pursuant to Rule 25-9.034, Florida Administrative Code, Commission approval is required if a utility enters into a contract where its filed regulations and standard approved rate schedules are not specifically covered under the contract. The proposed special contract makes changes to Peoples' standard gas service agreement and requires Commission approval under this rule.

### Peoples Gas Service Agreement

Peoples' standard gas service agreement contained in Tariff Sheet Nos. 8.102 and 8.102-1 is completed by a customer in order to initiate natural gas service. The gas service agreement includes a wide range of customer information as well as terms and conditions. Included within the terms and conditions is a grant of "perpetual right of ingress and egress" to allow the utility to operate and maintain the gas pipe and gas meter installed on the customer's property. Additionally, the utility's standard indemnity provision specifies that the customer: "shall be responsible for marking and/or locating any underground facilities that may be on Customer's property that do not belong to local utilities (Power, Telephone, Water, Cable TV companies, etc.) and agrees to indemnify and hold [c]ompany harmless for any damages arising out of Customer's failure to do so."

### Port Enabling Act

The Port's Enabling Act establishes the powers necessary for the Port to carry out the provisions of its Enabling Act and has "the specific responsibility of planning and of carrying out plans for the long-range development of the facilities of and traffic through the port in the port district."[1] Additionally, the Enabling Act provides for certain conditions related to easements and rights of way. Specifically, the Enabling Act provides that:

> "[e]asements for rights of way for railroads, pipelines, gas pipes, and electric transmission, telephone, and telegraph lines may be granted by the port authority for a period not to exceed 40 years with an option of 40 years without the approval, of the electors, but no such easement shall be exclusive, and every easement shall be subject to the right of the port authority or its successors and assigns to use and occupy the lands over or under the pipe or other line for any legitimate purpose."

[1] Chapter 95-488, Section 7, Laws of Florida.

## Proposed Special Contract

The proposed special contract modifies the term of the grant of easement and the indemnification language of the standard gas service agreement form to correspond with the terms of the Port's Enabling Act. Specifically, the right of ingress and egress is limited to a period of 40 years with automatic one-year extensions at the expiration of the 40 year period. Additionally, the special contract modifies the standard gas service agreement to specify that the customer's indemnification of the utility is "to the extent permitted by law." The extent permitted by law is a $200,000 limit on damages. Section 768.28(5), F.S.

Staff has reviewed the proposed special contract and the provided easement agreement between Peoples and the Port and believes that the special contract would not negatively impact the general body of ratepayers. In response to staff's data request, Peoples explained that no other customer would connect to the service line constructed for the Port, because the facilities within the easement are fully located on the property owned and maintained by the Port.[2] Furthermore, Peoples explained that it would not connect potential future customers to the Port's service line, because this would be inconsistent with the utility's best practices. Instead, any future customers would be required to connect to the existing main pipeline located in the right of way outside of the Port's property.[3]

## Conclusion

Staff believes that the special contract between Peoples and Tampa Port Authority is reasonable and that the changes made to Peoples standard form gas service agreement are necessary to correspond with the terms of the Port's Enabling Act. Staff recommends approval of the special contract. Peoples should file a conformed copy of the signed special contract with the Commission before the special contract becomes effective.

[2] DN 05652-2023, response No. 7.
[3] DN 05652-2023, response No. 9.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. If no protest is filed by a person whose substantial interests 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 interests are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order.

TECO PEOPLES GAS
AN EMERA COMPANY

## Gas Service Agreement

No. Q6UJ9A03E2N9

| | | | |
|---|---|---|---|
| Business Partner Name (Customer): TAMPA PORT AUTHORITY | Phone: (813) 241-1701 | Cell Phone: (813) 955-5007 | E-mail: nsanchez@tampaport.com |
| Service Address: 6807 Lakeview Center Drive | City: Tampa | State: FL | Zip: 33619 |
| Doing Business As (DBA): Port Tampa Bay | City Limits (Enter Yes or No): | County Name: Hillsborough | |
| Mailing Address: 1101 Channelside Drive. | City: Tampa | State: FL | Zip: 33602 |
| Contact Name: Norberto Sanchez | Phone: (813) 241-1701 | E-mail: nsanchez@tampaport.com | |
| Federal ID: 59-6001256 | Tax Exempt (Yes or No): | Date Service Line Requested: 04/01/2023 | Date Gas Service Requested: 04/01/2023 |
| Field Contact Name: Eric Nash | Phone: (850) 417-0845 | E-mail: enash@blackwatercsllc.com | |

**SALES INSTRUCTIONS/REMARKS**

Commercial service to generator

**SERVICE TYPE**

| | |
|---|---|
| Main (Enter On or Off) | On |
| New (N), Added Load (AL), Conversion (Co) | N |
| Reactivate (RA) | Manifold (MA) |
| Residntl (R), Commrl (C) Industrial (I) | C |
| Rate Class | CS-SG |
| Map # | |

| QTY. | APPLIANCE TYPE | PEAK HR DEMAND CF/H | ANNUAL THERMS PRESENT | ANNUAL THERMS ADDITIONAL | PRESSURE AT EQPT. |
|---|---|---|---|---|---|
| 1 | GE | 3000 | | | 2 lb |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | TOTAL | 3000 | | 500 | |

**FINANCIAL INFORMATION**

| | |
|---|---|
| Gas Deposit | $125.92 |
| Turn-on Charge | $100.00 |
| Aid to Construction (Non-Refundable) | $0.00 |
| Construction Deposit | |
| Prepayment | |
| **Balance Due** | $225.92 |

**OTHER SERVICES**

| | |
|---|---|
| WH Billing Prog | |
| Conversion Bill | |
| Other | 600000001142 |
| Other | |
| Other | |
| Other | |

**DEALER INFORMATION (if applicable)**

| | |
|---|---|
| Dealer Name | |
| Dealer Phone | Alt Phone |
| Services to be provided by Dealer | |

**TO BE COMPLETED BY PGS ONLY**

| | | | |
|---|---|---|---|
| Meter Size | Regulator Size | BP# 1100876042 | CA# |
| System Pressure | Delivery Pressure | Premise# | Install# |
| Conversion Propane Company | | Meter# | Project# |

**REMARKS**

**I have read all of the terms and conditions on the second page and agree to them.**

Business Partner/Customer Signature

Sales Rep Signature

20426
Sales Rep ID #

Business Partner/Customer Printed Name

Date

Frank Hernandez
Sales Rep Printed Name

Date

**PGS CUSTOMER SERVICE CONTACT DURING INSTALLATION OF GAS SERVICE PHONE #: 1-877-832-6747**

**NATURAL GAS SERVICE TERMS AND CONDITIONS:**

The applicant named on the first page hereof ("Customer") makes application to Peoples Gas System, Inc. ("Company") for natural gas service under the rate classification indicated on the first page hereof according to the following terms and conditions in consideration of the Company's agreement to deliver natural gas to Customer pursuant to the applicable provisions of Company's tariff approved by the Florida Public Service Commission.
Gas is to be delivered to Customer at the outlet side of the Company's gas meter serving the premises indicated on the first page hereof, such meter and service line there to be installed and operated by the Company, and, if located on Customer's property, the site therefor to be furnished free of charge by Customer.

The Company and its representatives are hereby authorized to enter upon and install on Customer's property any required gas meter or meters and gas pipe for furnishing gas to said address, and to ditch, lay, or otherwise install pipe as is required outside the building(s). The gas pipe from the Company's gas system to and including said meter or meters shall be owned, operated, and maintained by the Company, with a ~~perpetual~~ right of ingress and egress thereto for a period of 40 years, hereby granted to the Company for such purposes. At the expiration of the 40-year period, such ingress and egress right granted to the Company shall automatically extend, in one year intervals, concurrent with the 12 month renewal term of this agreement. If Customer terminates this agreement, the ingress and egress rights granted to Company shall terminate, however, Company shall have ingress and egress rights, for a reasonable period of time, for the purpose of Company capping and abandoning the pipe that is the subject of this agreement. Installation of Company's facilities may require that Company be granted an easement. All gas pipe, from the outlet side of said meter or meters, shall be owned, operated, and maintained by Customer at its sole cost and risk.

Customer shall receive and pay for all gas delivered to Customer according to the applicable provisions of Company's Tariff and the applicable rules and regulations of the Florida Public Service Commission. Any gas delivered to Customer at any other delivery point is also subject to the terms and conditions hereof. No oral statement shall change the term of this obligation. A customer receiving gas service under the residential or commercial standby generator tariff rate shall be obligated to remain on that schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month period unless Customer terminates gas service at the end of any 12-month period.

If Customer fails or refuses to take gas service from the Company, Customer shall pay to the Company the actual cost incurred by the Company in constructing the facilities to have been used in providing service to the Customer. Any deposits currently held by the Company shall be forfeited by Customer in payment or partial payment of these costs.

**UNDERGROUND FACILITIES:**

Prior to construction of gas pipeline, it is extremely important that the Company be made aware of existing underground obstacles, sprinkler systems, septic tanks, sewer lines, or structures, etc., located on Customer's property which may be damaged as a result of installation of the gas pipeline. Customer shall be responsible for marking and/or locating any underground facilities that may be on Customer's property that do not belong to local utilities (Power, Telephone, Water, Cable TV companies, etc.)~~,~~. To the extent permitted by law, Customer ~~and~~ agrees to indemnify and hold Company harmless for any damages arising out of Customer's failure to do so.

**GENERAL TERMS AND CONDITIONS APPLICABLE TO NATURAL GAS SERVICE:**

This agreement is not assignable or transferable by Customer without prior written consent by the Company.

IN NO EVENT SHALL THE COMPANY OR ITS AFFILIATED COMPANIES, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS OR REPRESENTATIVES BE LIABLE FOR ANY INCIDENTAL, INDIRECT, SPECIAL, CONSEQUENTIAL, EXEMPLARY OR PUNITIVE DAMAGES, INCLUDING, BUT NOT LIMITED TO, LOSS OF USE OF ANY PROPERTY OR EQUIPMENT, LOSS OF PROFITS OR INCOME, LOSS OF PRODUCTION, RENTAL EXPENSES FOR REPLACEMENT PROPERTY OR EQUIPMENT, DIMINUTION IN VALUE OF REAL PROPERTY, EXPENSES TO RESTORE OPERATIONS, OR LOSS OF GOODS OR PRODUCTIONS, EVEN IF THE COMPANY HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

Customer understands and acknowledges that the dealer (if any) identified on the first page of this document ("Dealer") is not affiliated in any way with the Company and has not been engaged by the Company as a contractor or subcontractor. The Company assumes no responsibility whatsoever for any acts or omissions of, or any services or goods provided by, such Dealer.

This agreement may not be amended or modified except by an instrument in writing signed by the Company and Customer.

This agreement shall be governed by the laws of the State of Florida without regard to principles of conflicts of laws.

This agreement contains the entire understanding between the parties hereto and supersedes any written or oral, prior or contemporaneous agreement or understanding between the parties.

**NOTE: I acknowledge installation of the required gas line will not be scheduled until the required easement is signed by the landowner and received by Peoples Gas System, Inc. __________ (customer initials)**

______________________________
Customer – Authorized Signature

______________________________
Name

______________________________
Title

______________________________

# Item 13

FILED 10/27/2023
DOCUMENT NO. 05855-2023
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-**

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**DATE:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Ward, Hampson) EJD
Division of Accounting and Finance (Hinson) ALM
Office of the General Counsel (Sandy) JSC

**RE:** Docket No. 20230098-GU – Petition for approval of 2022 true-up, projected 2023 true-up, and 2024 revenue requirements and surcharges associated with cast iron/bare steel pipe replacement rider, by Peoples Gas System.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 05/01/24 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

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## Case Background

On September 1, 2023, Peoples Gas System, Inc. (Peoples or utility) filed a petition for approval of its final 2022 true-up, projected 2023 true-up, and 2024 revenue requirement and surcharges associated with the cast iron/bare steel replacement rider (CI/BSR Rider or rider). The rider was originally approved in Order No. PSC-12-0476-TRF-GU (2012 Order) to recover the cost of accelerating the replacement of cast iron and bare steel pipes through a surcharge on customers' bills.[1] In the 2012 Order, the Commission found that, "replacement of these types of pipelines is in the public interest to improve the safety of Florida's natural gas infrastructure, and reduce the

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[1] Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 20110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

possibility of loss of life and destruction of property should an incident occur." Peoples' current surcharges were approved in Order No. PSC-2022-0405-TRF-GU (2022 Order).[2]

In Order No. PSC-17-0066-AS-GU, the Commission approved a comprehensive settlement agreement between PGS and the Office of Public Counsel (OPC).[3] The settlement agreement, in part, added problematic plastic pipe (PPP) installed in the company's distribution system to eligible replacements under the rider beginning in 2017 and continuing through 2028. PPP was manufactured before 1983 and has significant safety concerns. In certain areas, the PPP is interspersed with, or connected to, the cast iron/bare steel pipe that is being replaced under the rider. As provided for in the settlement agreement, PPP replacements are included in the calculation of the 2024 rider surcharges.

On April 4, 2023, Peoples filed its petition for a rate increase in Docket No. 20230023-GU (rate case), which is pending a final decision by the Commission in December. As required in the original 2012 Order, Peoples has proposed to move CI/BSR investments into rate base that were made during January 1, 2021 through December 31, 2023. Accordingly, the CI/BSR tariff provided in the petition, and shown in Attachment B, has been calculated using the assumption that the Commission will approve Peoples' request to move CI/BSR investments into rate base. If the Commission has not made a decision in the rate case prior to the January 1, 2024 effective date of the proposed CI/BSR factors, then any CI/BSR revenue requirement not collected in 2024 would be trued-up in the next CI/BSR filing.

In Order No. PSC-2023-0301-PCO-GU, issued October 10, 2023, the Commission suspended Peoples' proposed modifications to Tariff Sheet No. 7.806 to allow staff time to gather additional data. On September 12, 2023, staff issued its first data request, to which Peoples responded on September 22, 2023. Staff issued a second data request on September 26, 2023, to which Peoples responded on October 5, 2023. Peoples filed a revised response to staff's first data request on October 23, 2023.

Attachment A to this recommendation contains tables which display the replacement progress and forecasts for CI/BSR Rider (Table 2) and for PPP (Table 3). Additionally, Peoples provided Table 1 which consolidates actual and projected CI/BSR and PPP miles replaced investment and revenue requirements for each year of the replacement program. Attachment B contains the proposed tariff. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

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[2] Order No. PSC-2022-0405-TRF-GU, issued November 21, 2021, in Docket No. 20220152-GU, *In re: Petition for approval of 2021 true-up, projected 2022 true-up, and 2023 revenue requirements and surcharges associated with cast iron/bare steel replacement rider, by Peoples Gas System.*

[3] Order No. PSC-17-0066-AS-GU, issued February 28, 2017, in Docket No. 20160159-GU, *In re: Petition for approval of settlement agreement pertaining to Peoples Gas System's 2016 depreciation study, environmental reserve account, problematic plastic pipe replacement, and authorized ROE.*

## Discussion of Issues

***Issue 1:*** Should the Commission approve Peoples' proposed CI/BSR Rider surcharges for the period January through December 2024?

***Recommendation:*** Yes, the Commission should approve Peoples' proposed CI/BSR Rider surcharges to be effective for the first billing cycle of January through the last billing cycle of December 2024. Staff has reviewed Peoples' filings and supporting documentation and believes that the calculations are consistent with the methodology approved in the 2012 Order and are reasonable and accurate. (Ward)

***Staff Analysis:*** The CI/BSR Rider charges have been in effect since January 2013 and were projected to be in effect for 10 years with replacement projects completed by the end of 2022. In response to staff's first data request, Peoples stated that it experienced delays in cast iron/bare steel replacement that prevented it from completing the cast iron/bare steel projects within the projected 10-year time period.[4] Peoples stated that it expects to have approximately 7.5 miles of cast iron/bare steel replacement remaining entering 2024.

In 2023, Peoples' cast iron/bare steel and PPP replacement activity focused in the areas of Miami, Tampa, St. Petersburg, Orlando, Eustis, Jacksonville, Lakeland, Daytona, Avon Park, Jupiter, and Ocala. In 2024, Peoples states it will focus on replacement projects in Miami, Orlando, Jacksonville, Eustis, Lakeland, Daytona, St. Petersburg, Avon Park, and any further identified cast iron/bare steel in the system. A detailed description of the projects, including their address, has been provided in response to staff's first data request.[5]

### True-ups by Year

Peoples' calculation for the 2024 revenue requirement and surcharges includes a final true-up for 2022, an actual/estimated true-up for 2023, and projected costs for 2024. Pursuant to the 2012 Order, the capital expenditures for 2023 and 2024 exclude the first $1 million of facility replacements each year because that amount is included in rate base. Peoples has included depreciation expense savings as discussed in the 2012 Order; however, the utility has not identified any operations and maintenance savings.

#### *Final True-up for 2022*

Exhibit A of the petition shows that the revenues collected for 2022 were $5,052,616 compared to a revenue requirement of $5,020,126, resulting in an over-recovery of $32,490. The final 2021 under-recovery of $563,794, 2022 over-recovery of $32,490, state tax rate change recovery adjustment of $253,079, and interest associated with any over- and under-recoveries, results in a final 2022 under-recovery of $787,888. In response to staff's data request, Peoples explained that the state tax rate change adjustment of $253,079 was previously approved by the Commission.[6] Furthermore, the description provided in Exhibit A to the petition, page 2, line 9a was incorrect

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[4] DN 05355-2023, response No. 3.
[5] DN 05355-2023, response No. 3.
[6] Order No. PSC-2022-0134-PAA-GU, issued April 11, 2022, in Docket No. 20220018-GU, *In re: Petition for limited proceeding to address the impact of changes to Florida state income tax rates by Peoples Gas System.*

and should instead read, "2021 & 2022 State Corporate Income Tax Rate Changes Adjustment (PSC-2022-0134-PAA-GU)."[7]

### *Actual/Estimated 2023 True-up*

In Exhibit B of the petition, Peoples provided actual revenues for January through July and forecast revenues for August through December of 2023, totaling $8,361,539, compared to an actual/estimated revenue requirement of $7,586,789, resulting in an over-recovery of $774,750. The final 2022 under-recovery of $787,888, 2023 over-recovery of $774,750, and interest associated with any over- and under-recoveries, results in a total 2023 under-recovery of $10,683.

### *Projected 2024 Costs*

Exhibit C of the petition shows Peoples projects investment or capital expenditures of $18,802,302 for the replacement of cast iron/bare steel infrastructure and PPP in 2024, excluding the $1 million adjustment to rate base. The return on investment, depreciation expense (less savings), and property tax expense associated with that investment are $905,720. After adding the total 2023 under-recovery of $10,683, the total 2024 revenue requirement is $916,404. Table 1-1 displays the 2024 revenue requirement calculation. In response to staff's first data request Peoples provided updated investment and revenue requirement projections for the CI/BSR and PPP which is contained in Table 1 of Attachment A. On a phone call with staff Peoples explained that the 2024 revenue requirement in the petition and the 2024 revenue requirement in Table 1 of Attachment A are different because they were forecast at different times.

**Table 1-1**
**2024 Revenue Requirement**

| 2024 Projected Expenditures | $18,802,302 |
|---|---|
| Return on Investment | $786,310 |
| Depreciation Expense (less savings) | $118,789 |
| Property Tax Expense | $622 |
| 2024 Revenue Requirement | $905,721 |
| Plus 2023 Under-recovery | $10,683 |
| Total 2024 Revenue Requirement | $916,404 |

Source: Page 1 of 2 in Exhibit C in petition (Docket No. 20230098-GU).

## Proposed Surcharges

As established in the 2012 Order, the total 2024 revenue requirement is allocated to rate classes using the same methodology that was used for the allocation of mains and services in the cost of service study used in Peoples' most recent approved rate case. After calculating the percentage of total plant costs attributed to each rate class, the respective percentages were multiplied by the 2024 revenue requirement resulting in the revenue requirement by rate class. Dividing each rate class's revenue requirement by projected therm sales provides the rider surcharge for each rate class.

[7] DN 05484-2023, response No. 1.

If the Commission approves this recommendation, the proposed 2024 rider surcharge for residential customers would be $0.00322 per therm (compared to the current surcharge of $0.03111). The 2024 monthly bill impact would be $0.06 for a residential customer who uses 20 therms. The proposed tariff sheet is provided in this recommendation as Attachment B.

## Conclusion

Staff has reviewed Peoples' filings and supporting documentation and believes that the calculations are consistent with the methodology approved in the 2012 Order and are reasonable and accurate. Therefore, Staff recommends that the Commission should approve Peoples' proposed CI/BSR Rider surcharges to be effective for the first billing cycle of January through the last billing cycle of December 2024.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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. (Sandy)

***Staff Analysis:*** Yes. If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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.

**Table 1**
**Peoples' CI/BSR Replacement Program Progress**

| Year | CI/BS Miles Replaced | PPP Miles Replaced | [a]CI/BS Investment[b] | [a]PPP Investment[c] | CI/BS [a]Revenue Requirement | PPP [a]Revenue Requirement |
|---|---|---|---|---|---|---|
| 2017 | 51 | - | $17,588,366 | $2,915,802 | $6,868,302 | $74,021 |
| 2018 | 62 | 56 | $27,035,678 | $15,890,424 | $8,510,823 | $848,201 |
| 2019 | 52 | 42 | $35,821,371 | $17,425,589 | $11,075,229 | $2,706,161 |
| 2020 | 55 | 43 | $32,317,184 | $11,115,571 | $14,817,804 | $4,358,010 |
| 2021 | 14 | 38 | $23,726,642 | $19,812,603 | $1,347,321[g] | $(160,452)[g] |
| 2022 | 10.4 | 29 | $13,079,280 | $15,486,397 | $3,120,580 | $1,899,547 |
| 2023* | 8 | 26 | $5,198,305 | $21,141,445 | $3,933,425 | $3,650,897 |
| 2024* | 7.5 | 60 | -[i] | $19,844,519 | -[h] | $874,072[h] |
| 2025* | - | 60 | - | $19,188,075 | - | $2,827,369 |
| 2026* | - | 60 | - | $17,696,366 | - | $4,845,241 |
| 2027* | 0.5[d] | 55 | [e] | $18,010,216 | - | $6,756,946 |
| 2028* | - | 34 | - | $18,734,211[f] | - | $8,697,320 |

*Projected

[a]Projected investment and revenue requirement dollars are updated periodically based on current estimates.

[b]CI/BS Investment excludes initial $1M investment for each year.

[c]PPP Investment excludes initial $1M investment for each year beginning in 2024.

[d]5-year construction moratoriums in effect in the City of Miami preventing completion before 2027.

[e]Costs for remaining CI/BS miles in 2027 expected to be less than $1M and thus excluded from the investment amount.

[f]2028 PPP investment includes rollover costs to occur in 2029.

[g]Accounts for roll-in to rate base subsequent to the 2020 rate case.

[h]Assumes roll-in to rate base subsequent to the 2023 rate case.

[i]Investment dollars have not yet been estimated for CIBS replacement that is expected to occur in 2024. The company expects to shift investment dollars from PPP to CIBS to stay within budgeted amounts for 2024.

**Table 2**
**Peoples' CI/BSR Replacement Progress**

| Year | Main Replacements | | | | | Service Line Replacements | |
|---|---|---|---|---|---|---|---|
| | Replaced Cast Iron (miles) | Replaced Bare Steel (miles) | Remaining Cast Iron at Year End (miles) | Remaining Bare Steel at Year End (miles) | Total Miles Remaining of CI/BS Mains | Number of Bare Steel Service Lines Replaced | Number of Remaining Bare Steel Service Lines |
| 2012 | - | - | 100 | 354 | 454 | - | 14,978 |
| 2013 | 13 | 38 | 87 | 316 | 403 | 907 | 14,071 |
| 2014 | 2 | 15 | 85 | 298 | 383 | 7,964 | 6,107 |
| 2015 | 26 | 60 | 59 | 238 | 297 | 1,019 | 5,088 |
| 2016 | 15 | 35 | 44 | 203 | 247 | 1,050 | 6,963 |
| 2017 | 15 | 36 | 29 | 178 | 207 | 1,135 | 4,279 |
| 2018 | 10 | 52 | 18 | 126 | 144 | 1,970 | 2,309 |
| 2019 | 8 | 44 | 10 | 83! | 93 | 649 | 1,660 |
| 2020 | 4 | 51 | 6 | 35! | 41 | 423 | 1,237 |
| 2021 | 3.5 | 10.5 | 2 | 24 | 26 | 191 | 998 |
| 2022 | 1.3 | 9.1 | 0.9† | 14.6†! | 15.5 | 74 | 941 |
| 2023 * | 0.4 | 7.6 | 0.5 | 7! | 7.5 | 25 | ≠ |

*Projected

†For an explanation regarding remaining CI/BS after 2022 see response to Staff's First Data Request, Request No. 3.

≠This will be determined during the replacement year.

!Additional miles of pipe added after reclassification of pipe type.

**Table 3**
**Peoples' PPP Replacement Program Progress**

| Year | Replaced PPP (Miles) | Total Remaining PPP Mains (Miles) | Replaced Number of PPP Service Lines | Total Number of Remaining PPP Service Lines |
|---|---|---|---|---|
| 2016 | - | 551 | - | 28,237 |
| 2017 | - | 509 | 1,396 | 26,841 |
| 2018 | 56 | 461 | 3,941 | 24,741 |
| 2019 | 42 | 418 | 2,349 | 20,420 |
| 2020 | 43 | 370 | 1,702 | 18,718 |
| 2021 | 38 | 337 | 882 | 17,683 |
| 2022 | 29 | 306 | 837 | 17,229! |
| 2023* | 56 | 269 | 500 | † |
| 2024* | 60 | 209 | † | † |
| 2025* | 60 | 149 | † | † |
| 2026* | 60 | 89 | † | † |
| 2027* | 55 | 34 | † | † |
| 2028* | 34 | - | † | † |

*Projected

†This will be determined during the replacement year.
!Additional service lines reclassified during the year.

**Peoples Gas System, Inc.**
**Original Volume No. 3**

**Fourteenth ~~Thirteenth~~ Revised Sheet No. 7.806**
**Cancels Thirteenth ~~Twelfth~~ Revised Sheet No. 7.806**

## CAST IRON/BARE STEEL REPLACEMENT RIDER
## RIDER CI/BSR

The monthly bill for Gas Service in any Billing Period shall be increased by the CI/BSR Surcharge determined in accordance with this Rider. CI/BSR Surcharges approved by the Commission for bills rendered for meter readings taken on or after January 1, ~~2023~~2024, are as follows with respect to Customers receiving Gas Service under the following rate schedules:

| Rate Schedule | CI/BSR Surcharge |
|---|---|
| Residential/Residential Standby Generator / Residential Gas Heat Pump Service | $ ~~0.03111~~0.00322 per therm |
| Small General Service | $ ~~0.01816~~0.00174 per therm |
| General Service – 1/ Commercial Standby Generator Service / Commercial Gas Heat Pump Service | $ ~~0.01236~~0.00114 per therm |
| General Service – 2 | $ ~~0.01183~~0.00118 per therm |
| General Service – 3 | $ ~~0.01171~~0.00119 per therm |
| General Service – 4 | $ ~~0.01166~~0.00129 per therm |
| General Service – 5 | $ ~~0.00503~~0.00050 per therm |
| Commercial Street Lighting | $ ~~0.01033~~0.00104 per therm |
| Wholesale | $ ~~0.00499~~0.00084 per therm |
| Small Interruptible Service | $ ~~0.00574~~0.00059 per therm |
| Interruptible Service | $ ~~0.00125~~0.00013 per therm |
| Interruptible Service – Large Volume | $ 0.00000 per therm |

The CI/BSR Surcharges set forth above shall remain in effect until changed pursuant to an order of the Commission.

CI/BSR Surcharges shall be determined in accordance with the provisions of this Rider set forth below.

**Definitions**

For purposes of this Rider:

"Eligible Replacements" means the following Company plant investments that (i) do not increase revenues by directly connecting new customers to the plant asset, (ii) are in service and used and useful in providing utility service and (iii) were not included in the Company's rate base for purposes of determining the Company's base rates in its most recent general base rate proceeding:

Mains and service lines, as replacements for existing materials recognized/identified by the Pipeline Safety and Hazardous Materials Administration as being obsolete and that present a potential safety threat to operations and the general public, including cast iron, wrought iron, bare steel, and specific polyethylene/plastic facilities, and regulators and other pipeline system components the installation of which is required as a consequence of the replacement of the aforesaid facilities.

"CI/BSR Revenues" means the revenues produced through CI/BSR Surcharges, exclusive of revenues from all other rates and charges.

**Issued By:** Helen J. Wesley, President & CEO **Effective Date:** ~~January 9, 2023~~

# Item 14

**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-**

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**DATE:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (P. Kelley, Hampson) EJD
Division of Accounting and Finance (Buys, Gatlin) ALM
Office of the General Counsel (Thompson) JSC

**RE:** Docket No. 20230097-GU – Petition for approval of safety, access, and facility enhancement program true-up and 2024 cost recovery factors, by Florida City Gas.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 04/30/24 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

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## Case Background

On August 31, 2023, Florida City Gas (FCG or utility) filed a petition for approval of its safety, access, and facility enhancement program (SAFE) true-up and 2024 cost recovery factors. The SAFE program was originally approved by the Commission in Order No. PSC-15-0390-TRF-GU (2015 Order) to recover the cost of relocating on an expedited basis certain existing gas mains and associated facilities from rear lot easements to the street front.[1] In the 2015 Order, the Commission found that the relocation of mains and services to the street front provides for more direct access to the facilities and will enhance the level of service provided to all customers through improved safety and reliability. The SAFE factor is a surcharge on customers' bills.

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[1] Order No. PSC-15-0390-TRF-GU, issued September 15, 2015, in Docket No. 20150116-GU, *In re: Petition for approval of safety, access, and facility enhancement program and associated cost recovery methodology, by Florida City Gas.*

In the 2015 Order, the Commission required the utility to file an annual petition, beginning in 2016, for review and resetting of the SAFE factors to true-up any prior over-or under-recovery and to set the surcharge for the coming year. The SAFE program was originally approved as a 10-year program and was planned to finish in 2025.

During the utility's 2022 rate case, the Commission approved a stipulation for the expansion of the SAFE program in Order No. PSC-2023-0177-FOF-GU (Rate Case Order).[2] The parties agreed and the Commission found that the continuation of the SAFE program beyond its original 2025 expiration date and the relocation of an additional approximately 150 miles of mains and 13,874 services was reasonable.[3]

In the Rate Case Order, the Commission further approved a stipulation for the replacement of approximately 160 miles and 8,059 associated services of "orange pipe," through the SAFE program.[4] All parties to the rate case agreed that orange pipe is a specific plastic material that was used in the 1970s and 1980s that has been studied by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration and shown through industry research to exhibit premature failure in the form of cracking.

In addition, as part of its rate case, FCG moved the SAFE investment and related expenses as of December 31, 2022, from clause recovery to base rates, in compliance with the 2015 Order.[5] Specifically, the 2015 Order stated that "…if FCG files a base rate case prior to 2025, the then-current SAFE surcharge program would be folded into any newly approved rate base, and the surcharge would begin anew."[6] The Commission approved FCG's proposal to move the SAFE surcharge into base rates in the Rate Case Order.[7] The rate case decision was effective May 1, 2023.

The current 2023 SAFE factors were approved by Order No. PSC-2022-0403-TRF-GU (2022 Order).[8] The SAFE factors effective January 2023 were calculated based on the assumption that the Commission would approve the request to roll SAFE investments into rate base in the rate case docket and therefore decreased compared to the 2022 SAFE factors. Since the rate case decision became effective May 1, 2023 (as opposed to January 2023), FCG did not collect the full SAFE revenue requirement in 2023, resulting in a 2023 under-recovery. The 2022 Order provided that if the Commission has not made a decision in the 2022 rate case prior to the January 1, 2023 effective date, then any SAFE revenue requirement not collected in 2023 would

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[2] Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas.*
[3] See page 72, Section X, B. of Order No. PSC-2023-0177-FOF-GU.
[4] See page 72, Section X, C. of Order No. PSC-2023-0177-FOF-GU.
[5] Docket No. 20220069-EI, *In re: Petition for approval of rate increase and request for approval of depreciation rates*, filed May 31, 2022.
[6] See page 4 of Order No. PSC-15-0390-TRF-GU.
[7] See page 18 of Order No. PSC-2023-0177-FOF-GU.
[8] Order No. PSC-2022-0403-TRF-GU, issued November 21, 2022, in Docket No. 20220153-GU, *In re: Petition for approval of safety, access, and facility enhancement program true-up and 2023 cost recovery factors, by Florida City Gas.*

be trued-up in the next SAFE filing. Accordingly, FCG has included the 2023 under-recovery with the proposed 2024 SAFE factors.

Finally, in the Rate Case Order, the Commission required FCG to propose a new investment/construction schedule and term for the SAFE program in its next applicable annual SAFE filing. Subsequently, FCG now proposes in this petition to extend the SAFE program for an additional 10-year period through 2035 for the replacement of orange pipe and relocation of rear lot mains and services to the street front. The utility proposes to begin the replacement of orange pipe in 2024 and continue through 2033. FCG also proposes to begin the relocation of mains and services in 2026 and continue through 2035.

In Order No. PSC-2023-0302-PCO-GU, the Commission suspended the proposed tariffs to allow staff sufficient time to analyze the utility's filing, pursuant to Section 366.06(3), Florida Statue (F.S.). Commission staff issued their first data request to FCG on September 13, 2023, for which FCG provided a response on September 19, 2023. Staff issued a second data request on September 22, 2023 for responses were received September 28, 2023.

FCG's annual progress in the SAFE program is shown in Attachment A to the recommendation. The proposed 2024 SAFE factors are shown in Attachment B to the recommendation on Tariff Sheet No. 79. The Commission has jurisdiction over the matter pursuant to Sections 366.04, 366.041, 366.05, and 366.06, F.S.

## Discussion of Issues

***Issue 1:*** Should the Commission approve FCG's proposed SAFE tariffs for the period January through December 2024?

***Recommendation:*** Yes. The Commission should approve FCG's proposed SAFE tariff for the period January through December 2024. After reviewing FCG's filings and supporting documentation, the calculations of the 2024 SAFE factors appear consistent with the methodology approved in the 2015 Order and are reasonable and accurate. Furthermore, staff recommends that the Commission approve FCG's proposed 10-year SAFE investment and construction schedule. The proposed tariffs, provided in Attachment B to this recommendation, should be effective for the first billing cycle in January 2024 through the last billing cycle of December 2024. (P. Kelley, Hampson)

***Staff Analysis:*** Under the SAFE program originally approved in 2015, FCG was ordered to relocate or replace 254.3 miles of mains and 11,443 associated service lines from rear property easements to the street over a 10- year period, ending in 2025. The utility began its mains and services replacements at the end of 2015. The surcharges have been in effect since January 2016. During 2023, the utility has replaced 26 miles of mains and 1,399 services, as shown in Attachment B to the recommendation.[9]

### Proposed SAFE Timeline

FCG proposes a 10-year investment and construction schedule for the continuation and expansion of the SAFE program projects, as approved in the Rate Case Order. FCG stated in response to staff's data request that the 10-year schedule aligns similarly with the original approval for the 2015 SAFE program, which had a 10-year period.[10] FCG also explained that delaying projects would prevent customers and communities from safe access to natural gas in the form of declining pipe integrity. FCG further stated that accelerating the respective 10-year timeline would have a negative impact on customers' billing and could potentially require FCG to engage additional outside resources.[11] Staff believes that the proposed 10-year investment and construction schedule for the SAFE program projects is reasonable, based on FCG's provided arguments and the Commission's previous approval of similar timelines for investments made through a surcharge.[12] Staff recommends that FCG should be required to file a final true-up of the actual SAFE program costs at the end of the 10-year period, once all program costs are known.

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[9] DN 05438-2023, data response No. 1.
[10] DN 05277-2023, data response No. 5.
[11] DN 05438-2023, data response No. 4.
[12] Order No. PSC-2023-0235-PAA-GU, issued August 15, 2023, in Docket No. 20230029-GU, *In re: Petition for approval of gas utility access and replacement directive, by Florida Public Utilities Company.* Order No. PSC-12-0490-TRF-GU, issued September 24, 2012, in Docket No. 120036-GU, *In re: Joint petition for approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation.* Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

### Prioritization of SAFE Relocation and Replacement Projects

The utility stated that prioritization of the SAFE relocation and replacement projects was determined by FCG's risk assessment model, the Distribution, Integrity, and Management Program (DIMP). Based on FCG's DIMP, the utility has prioritized future SAFE projects based on the location of the pipelines, material of the pipelines, leak incident rates, maintenance access complications, and customer encroachments.

## True-ups by Year

As required by the 2015 Order, the utility's calculations for the 2024 revenue requirement and SAFE factors include a final true-up for 2022, and an estimated/actual true-up for 2023, and projected costs for 2024.

### *Final True-up for 2022*

FCG stated that the revenues collected for 2022 were $4,562,635, compared to a revenue requirement of $4,305,208 resulting in an over-recovery of $257,427. Adding the 2021 final under-recovery of $326,212 and the $257,427 over-recovery of 2022, including interest, results in a final 2022 under-recovery of $35,929.[13]

### *Actual/Estimated 2023 True-up*

FCG provided actual revenues for January through June and forecasted revenues for July through December 2023, totaling $674,737 as compared to a projected revenue requirement of $2,506,526, resulting in an under-recovery of $1,831,789. Adding the 2022 under-recovery of $35,929 to the 2023 under-recovery of $1,831,789, the resulting total 2023 true-up, including interest, is an under-recovery of $1,935,339.[14]

### Projected 2024 Costs

The utility's projected investment for 2024 is $29,851,712 for its projects located in Miami-Dade and Brevard County. The revenue requirement, which includes a return on investment, depreciation, and taxes is $2,682,570. The return on investment calculation includes federal income taxes, regulatory assessment fees, and bad debt. After adding the 2023 under-recovery of $1,935,339, the total 2024 revenue requirement is $4,647,910. Table 1-1 displays the projected 2024 revenue requirement calculation.

[13] The calculation also includes a December 2021 true-up of $7,799 booked in January 2022. The petition shows $37,226 as the final 2022 true-up as a result of a cell error, the correct number is $35,929. The error does not impact the final rates.

[14] The calculation also includes a December 2022 true-up of $26,525 booked in January 2023.

**Table 1-1**
**2024 Revenue Requirements Calculation**

| | |
|---|---|
| 2024 Projected Investment | $29,851,712 |
| Return on Investment | $1,861,231 |
| Depreciation Expense | $441,201 |
| Property Tax Expense | $380,138 |
| 2024 Revenue Requirement | $2,682,570 |
| Plus 2023 Under-recovery | $1,965,339 |
| Total 2024 Revenue Requirement | $4,647,910 |

Source: Page 6 of Attachment D of the petition and Attachment 2 in response to Staff's First Data Request No. 1

## Proposed 2024 SAFE Factors

The SAFE factors are fixed monthly charges. FCG's cost allocation methodology was approved in the 2015 Order and was used in the instant filing. The approved methodology allocates the current cost of a 2-inch pipe to all customers on a per customer basis and allocates the incremental cost of replacing a 4-inch pipe to customers who use over 6,000 therms per year. For customers who require 4-inch pipes, the cost takes into account that the minimum pipe is insufficient to serve their demand, and therefore, allocates an incremental per foot cost in addition to the all-customer cost. The resulting allocation factors are applied to the 2024 total revenue requirement to develop the monthly SAFE factors.

The proposed fixed monthly SAFE factor is $3.17 for customers using less than 6,000 therms per year (current factor is $0.44). The proposed fixed monthly SAFE factor for customers using more than 6,000 therms per year is $5.44 (current factor is $0.98). Staff notes that the current 2023 SAFE factors decreased from 2022 since the Commission approved moving SAFE investments into rate base in the Rate Case Order, resulting in a lower SAFE factor.

## Conclusion

The Commission should approve FCG's proposed SAFE tariff for the period January through December 2024. After reviewing FCG's filings and supporting documentation, the calculations of the 2024 SAFE factors appear consistent with the methodology approved in the 2015 Order and are reasonable and accurate. Furthermore, staff recommends that the Commission approve FCG's proposed 10-year SAFE investment and construction schedule. The proposed tariffs, provided in Attachment B to this recommendation, should be effective for the first billing cycle in January 2024 through the last billing cycle of December 2024.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. If Issue 1 is 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. (Thompson)

***Staff Analysis:*** Yes. If Issue 1 is 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.

**Florida City Gas**
**Docket No. 20220097-GU**
**Staff's Second Set of Data Requests**
**Request No. 1**
**Attachment No. 1 of 1**
**Tab 1 of 1**

**ATTACHMENT B**
Florida City Gas
SAFE Program
Actual and Forecasted Replacements

| | SAFE Replacements | | | | | | Orange Pipe Replacements | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Replaced (miles) | Remaining at Year End (miles) | Total Miles Remaining | Replaced Services (No.) | Remaining Services at year end | Total Remaining Services | Replaced (miles) | Remaining at Year End (miles) | Total Miles Remaining | Replaced Services (No.) | Remaining Services at year end | Total Remaining Services |
| 2014 | - | 254.3 | 254.3 | - | 11,443 | 11,443 | - | - | - | - | - | - |
| 2015 | - | 254.3 | 254.3 | 49 | 11,394 | 11,394 | - | - | - | - | - | - |
| 2016 | 17.1 | 237.2 | 237.2 | 1,433 | 9,961 | 9,961 | - | - | - | - | - | - |
| 2017 | 37.5 | 199.7 | 199.7 | 1,551 | 8,410 | 8,410 | - | - | - | - | - | - |
| 2018 | 27.6 | 172.1 | 172.1 | 1,634 | 6,776 | 6,776 | - | - | - | - | - | - |
| 2019 | 37.8 | 134.3 | 134.3 | 1,183 | 5,593 | 5,593 | - | - | - | - | - | - |
| 2020 | 25.5 | 108.8 | 108.8 | 1,186 | 4,407 | 4,407 | - | - | - | - | - | - |
| 2021 | 26.0 | 82.8 | 82.8 | 1,105 | 3,302 | 3,302 | - | - | - | - | - | - |
| 2022 | 29.0 | 53.8 | 53.8 | 830 | 2,472 | 2,472 | - | - | - | - | - | - |
| 2023 | 26.0 | 27.8 | 27.8 | 1,399 | 1,073 | 1,073 | - | 160.0[a] | 160.0[a] | - | 8,059 | 8,059 |
| 2024 | 27.8 | 0.0 | 0.0 | 1,073 | - | - | 10.0 | 150.0 | 150.0 | 1,431 | 6,628 | 6,628 |
| 2025 | - | 150.0[b] | 150.0[b] | - | 13,874 | 13,874 | 25.0 | 125.0 | 125.0 | 1,105 | 5,523 | 5,523 |
| 2026 | 14.5 | 135.5 | 135.5 | 1,341 | 12,533 | 12,533 | 15.0 | 110.0 | 110.0 | 663 | 4,861 | 4,861 |
| 2027 | 14.5 | 121.0 | 121.0 | 1,341 | 11,192 | 11,192 | 15.0 | 95.0 | 95.0 | 663 | 4,198 | 4,198 |
| 2028 | 14.0 | 107.0 | 107.0 | 1,295 | 9,897 | 9,897 | 15.0 | 80.0 | 80.0 | 663 | 3,535 | 3,535 |
| 2029 | 12.5 | 94.5 | 94.5 | 1,156 | 8,741 | 8,741 | 16.0 | 64.0 | 64.0 | 707 | 2,828 | 2,828 |
| 2030 | 12.0 | 82.5 | 82.5 | 1,110 | 7,631 | 7,631 | 16.0 | 48.0 | 48.0 | 707 | 2,121 | 2,121 |
| 2031 | 11.5 | 71.0 | 71.0 | 1,064 | 6,567 | 6,567 | 16.0 | 32.0 | 32.0 | 707 | 1,414 | 1,414 |
| 2032 | 10.0 | 61.0 | 61.0 | 925 | 5,642 | 5,642 | 16.5 | 15.5 | 15.5 | 729 | 685 | 685 |
| 2033 | 10.5 | 50.5 | 50.5 | 971 | 4,671 | 4,671 | 15.5 | - | - | 685 | (0) | (0) |
| 2034 | 25.5 | 25.0 | 25.0 | 2,359 | 2,312 | 2,312 | - | - | - | - | - | - |
| 2035 | 25.0 | - | - | 2,312 | - | - | - | - | - | - | - | - |

Notes:

[a] The expansion of the SAFE program to include the capital investments necessary for the expedited replacement of approximately 160 miles of orange pipe installed before 1990 was approved by Commission Order No. PSC-2023-0177-FOF-GU.

[b] The continuation of the SAFE program beyond its 2025 expiration date and inclusion of an additional approximately 150 miles of mains and services was approved by Commission Order No. PSC-2023-0177-FOF-GU.

[c] The future-dated items herein are provided for estimation purposes only and do not constitute the actual allocation for the respective year. The actual figures shall be adjusted accordingly in accordance with applicable regulations and standards with each annual filing.

Florida City Gas
FPSC Natural Gas Tariff
Volume No. 10

~~Third~~ Fourth Revised Sheet No. 78
Cancels Third~~Second~~ Revised Sheet No. 78

RIDER "D"
SAFETY, ACCESS AND FACILITY ENHANCEMENT (SAFE) PROGRAM

Applicable to all Customers served under the Rate Schedules shown in the table below except for those Customers under RSG, CSG, NGV, KDS and special contract rates ~~receiving a discount under the AFD Rider~~.

Through its SAFE Program, the Company has identified the potential replacement projects focusing initially on area of limited access/pipe overbuilds, early vintage polymer pipeline and risk assessment for Rear Lot Mains and Services considering:

i. The pipe material;
ii. Leak incident rates;
iii. Age of pipeline;
iv. Pressure under which the pipeline is operating.

The Eligible Infrastructure Replacement includes the following:

Company investment in mains and service lines, as replacements for existing Rear Lot Facilities, early vintage polymer pipelines and regulatory station and other distribution system components, the installation of which is required as a consequence of the replacement of the aforesaid facilities that:

i. do not increase revenues by directly connecting new Customers to the plant asset;

ii. are in service and used and useful in providing utility service; and

iii. that were not included in the Company's rate base for purposes of determining the Company's base rates in its most recent general base rate proceeding.

The Company is recovering its revenue requirement on the actual investment amounts. The revenue requirements are inclusive of:

1. Return on investment as calculated using the following:

   a.) Equity balance from the most recent year-end surveillance report and the ROE and equity ratio cap from the most recent rate case:

   b.) Debt and customer deposit components from the Company's most recent year-end surveillance report; and

   c.) Accumulated deferred income tax balance from the Company's most recent year-end surveillance report as adjusted, if applicable, consistent with the normalization rules of the Internal Revenue Code.

2. Depreciation expense (calculated using the currently approved depreciation rates);

3. Customer and general public notification expenses associated with the SAFE Program incurred for:

Issued by: Kurt Howard
General Manager, Florida City Gas

Effective: ~~January 1, 2024~~

Florida City Gas
FPSC Natural Gas Tariff — ~~Fifth~~ Sixth Revised Sheet No. 79
Volume No. 10 — Cancels Fifth~~Fourth~~ Revised Sheet No. 79

RIDER "D"

SAFETY, ACCESS AND FACILITY ENHANCEMENT (SAFE) PROGRAM
(Continued)

i. all Customers regarding the implementation of the SAFE Program and the approved surcharge factors;

ii. the immediately affected Customers where the eligible infrastructure is being replaced; and

iii. the general public through publications (newspapers) covering the geographic areas of the eligible infrastructure replacement activities;

4. Ad valorem taxes; and

5. Federal and state income taxes.

The Company is utilizing a surcharge mechanism in order to recover the costs associated with the SAFE Program. The Company has developed the revenue requirement for the SAFE Program using the same methodology approved in its most recent rate case. The SAFE revenue requirement will be allocated to each Customer class (Rate Schedule) using allocation factors established by the Florida Public Service Commission for the SAFE Program. The per Customer SAFE surcharge is calculated by dividing the revenue requirement allocated to each Customer class by the number of Customers in the class.

The cost recovery factors including tax multiplier for the twelve-month period from January 1, ~~2023~~2024 through December 31, ~~2023~~2024are:

| Rate Class | Rates Per Customer |
|---|---|
| Rate Schedule RS-1 | $~~0.44~~3.17 |
| Rate Schedule RS-100 | $~~0.44~~3.17 |
| Rate Schedule RS-600 | $~~0.44~~3.17 |
| Rate Schedule GS-1 | $~~0.44~~3.17 |
| Rate Schedule GS-6K | $~~0.98~~5.44 |
| Rate Schedule GS-25K | $~~0.98~~5.44 |
| Rate Schedule GS-120K | $~~0.98~~5.44 |
| Rate Schedule GS-1,250K | $~~0.98~~5.44 |
| Rate Schedule GS-11M | $~~0.98~~5.44 |
| Rate Schedule GS-25M | $~~0.98~~5.44 |
| Rate Schedule GL | $~~0.44~~3.17 |

Issued by: Kurt Howard
General Manager, Florida City Gas

Effective: ~~January 1, 2023~~

Florida City Gas
FPSC Natural Gas Tariff
Volume No. 10

~~Fourth~~ Fifth Revised Sheet No. 81
Cancels Fourth ~~Third~~ Revised Sheet No. 81

RIDER "D"

SAFETY, ACCESS AND FACILITY ENHANCEMENT (SAFE) PROGRAM
(Continued)

Calculation of the SAFE Revenue Requirements and SAFE Surcharges

In determining the SAFE Revenue Requirements, the Commission shall consider only (a) the net original cost of Eligible Replacements (i.e., the original cost); (b) the applicable depreciation rates as determined and approved by the Commission based on the Company's most recent depreciation study; (c) the accumulated depreciation associated with the Eligible Replacements; (d) the current state and federal income and ad valorem taxes; and (e) the Company's weighted average cost of capital as calculated on Tariff Sheet No. 78.

The SAFE Revenue Requirements shall be calculated as follows:

| Line | Description | Value | Source |
|---|---|---|---|
| 1 | Revenue Expansion Factor | ~~1.36420~~ 1.35270 | As calculated in most recent base rate proceeding, using current tax rates |
| 2 | Ad Valorem Tax Rate | % | Effective Property Tax Rate for most recent 12 Months ended December 31 |
| 3 | Mains | $ | Eligible Replacement Mains |
| 4 | Services | $ | Eligible Replacement Services |
| 5 | Regulators | $ | Eligible Replacement Regulators |
| 6 | Other | $ | Eligible Replacement Other |
| 7 | Gross Plant | $ | L3+L4+L5+L6 |
| 8 | Accumulated Depreciation | $ | Previous Period Balance +L13 |
| 9 | Construction Work In Progress | $ | Non-interest Bearing |
| 10 | Net Book Value | $ | L7-L8+L9 |
| 11 | Average Net Book Value | $ | (L10 + Balance From Previous Period)/2 |
| 12 | Return on Average Net Book Value | $ | L 11 X Company's calculated weighted average cost of capital |
| 13 | Depreciation Expense | $ | Lines 3,4,5 & 6 X applicable approved Depreciation Rates |
| 14 | Property Tax | $ | (L7-L8) X L 2 |
| 15 | Customer and general public notification and other applicable expense | $ | O&M expense incurred as a result of eligible plant replacement |
| 16 | SAFE Revenue Requirement | $ | (L12+L13+L14+L15) X L 1 |

Issued by: Kurt Howard
General Manager, Florida City Gas

Effective: ~~January 1, 2023~~

# Item 15

**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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (McClelland, Hampson) EJD
Office of the General Counsel (Watrous) JSC

**RE:** Docket No. 20230110-GU – Petition for approval of tariff modifications to implement transportation balancing charge rider, by Florida City Gas.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Suspension – Participation is at the Commission's discretion

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 11/25/23 (60-Day Suspension Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On September 26, 2023, Florida City Gas (FCG or utility) filed a petition for approval of tariff modifications to implement a Transportation Balancing Charge (TBC) rider. FCG is an investor-owned natural gas utility that provides service to two different types of gas supply customers: sales customers and transportation customers. Sales customers purchase gas from the utility and are charged the Purchased Gas Adjustment (PGA) for the cost of natural gas, in addition to base rates. FCG explained that transportation customers are commercial and industrial customers that elect to purchase their natural gas supply from a gas marketer authorized as a third party supplier by FCG. Transportation customers negotiate directly with third party suppliers for the purchase of the natural gas commodity and are not charged the PGA by the utility.

FCG stated that the purpose of the proposed TBC rider is to recover the cost of transportation and storage fees incurred on behalf of transportation customers. In its petition, FCG explained that these costs of transportation and storage fees are a result of mitigating imbalances between the amount of gas nominated by the third party supplier on behalf of its transportation customers and the quantity actually consumed, also known as "swing gas service." Nominations specify the monthly quantity of natural gas a transportation customers desires to receive; the third party supplier is responsible for making arrangements for transporting and delivering the gas. Since the actual gas quantity consumed by the transportation customer may vary from the gas delivered, FCG is responsible for balancing the system.

FCG explained that sales customers are currently subsidizing transportation customers because a portion of the capacity and storage costs paid for by sales customers through the PGA are being used to balance the system on behalf of transportation customers. The proposed TBC rider would be a cents per therm charge applicable to transportation customers. The utility has also proposed that all revenues from the TBC rider be booked and reflected as a credit to the PGA.

This is staff's recommendation to suspend the proposed tariffs. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

## Discussion of Issues

***Issue 1:*** Should the Commission suspend FCG's proposed Transportation Balancing Charge rider and associated tariffs?

***Recommendation:*** Yes. Staff recommends that FCG's proposed Transportation Balancing Charge rider and associated tariffs be suspended to allow staff sufficient time to review the petition and gather all pertinent information in order to present the Commission with an informed recommendation on the tariff proposal. (McClelland)

***Staff Analysis:*** Staff recommends that FCG's proposed Transportation Balancing Charge Rider rate and associated tariffs be suspended to allow staff sufficient time to review the petition and gather all pertinent information in order to present the Commission with an informed recommendation on the tariff proposal.

Pursuant to Section 366.06(3), F.S., the Commission may withhold consent to the operation of all or any portion of a new rate schedule, delivering to the utility requesting such a change, a reason, or written statement of good cause for doing so within 60 days. Staff believes that the reason stated above is a good cause consistent with the requirement of Section 366.06(3), F.S.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** No. This docket should remain open pending the Commission decision on the proposed revised tariffs. (Watrous)

***Staff Analysis:*** This docket should remain open pending the Commission decision on the proposed revised tariffs.

# Item 16

FILED 10/27/2023
DOCUMENT NO. 05850-2023
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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (McClelland, Hampson) EJD
Office of the General Counsel (Watrous) JSC

**RE:** Docket No. 20230096-GU – Petition for approval of swing service rider rates for January through December 2024, by Florida Public Utilities Company.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 04/29/24 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On August 29, 2023, Florida Public Utilities Company (FPUC or utility) filed a petition for approval of revised swing service rider rates and associated tariffs for the period January through December 2024. The swing service rider is a cents per therm charge that is included in the monthly gas bill of transportation customers, who purchase gas from third party marketers, and therefore do not pay the Purchased Gas Adjustment (PGA) charge.[1] FPUC is a local natural gas distribution company (LDC) subject to the regulatory jurisdiction of the Commission pursuant to Chapter 366, Florida Statutes (F.S.).

The Commission first approved FPUC's swing service rider tariff in Order No. PSC-16-0422-TRF-GU (swing service order) and the initial swing service rider rates were in effect for the

[1] The PGA charge is set by the Commission in the annual PGA cost recovery clause proceeding.

period March through December 2017.[2] As required in the swing service order, FPUC submitted the instant petition with revised 2024 swing service rider rates for Commission approval by September 1, 2023. The January through December 2023 swing service rider rates were approved in Order No. PSC-2022-0378-TRF-GU, conditional on Commission approval of FPUC's pending rate increase.[3] Following the rate increase, which was approved in Order No. PSC-2023-0103-FOF-GU, the swing service rider tariffs were updated to reflect a change in the rate classes approved in the rate case. [4]

At the October 3, 2023 Agenda, the Commission suspended the proposed swing service rider tariffs for further review by staff. During its evaluation of the petition, staff issued a data request to the utility for which responses were received on September 21, 2023. Staff met with the utility via telephone on October 23, 2023, after which the utility filed a revised response to staff's first data request. The proposed swing service rider rates and associated tariff revisions are provided in Attachment A to the recommendation. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

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[2] Order No. PSC-16-0422-TRF-GU, issued October 3, 2016, in Docket No. 160085-GU, *In re: Joint petition for approval of swing service rider, by Florida Public Utilities Company, Florida Public Utilities Company-Indiantown Division, Florida Public Utilities Company-Fort Meade, and Florida Division of Chesapeake Utilities Corporation*.
[3] Order No. PSC-2022-0378-TRF-GU, issued November 7, 2022, Docket No. 20220154-GU, *In re: Joint petition for approval of swing service rider rates for January through December 2023, by Florida Public Utilities Company, Florida Public Utilities Company-Indiantown Division, Florida Public Utilities Company-Fort Meade, and Florida Division of Chesapeake Utilities Corporation*.
[4] Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.*

## Discussion of Issues

***Issue 1:*** Should the Commission approve the utility's proposed swing service rider rates and tariffs for the period January through December 2024?

***Recommendation:*** Yes. The Commission should approve the utility's proposed swing service rider rates for the period January through December 2024. The costs included are appropriate and the methodology for calculating the swing service rider rates is consistent with the initial Order approving the tariff. (McClelland, Hampson)

***Staff Analysis:*** The utility incurs intrastate capacity costs when they transport natural gas on intrastate pipelines (i.e., pipelines operating within Florida only). The utility has two types of natural gas customers: sales and transportation. Sales customers are primarily residential and small commercial customers that purchase natural gas from an LDC and receive allocations of intrastate capacity costs through the Purchased Gas Adjustment (PGA) charge. Transportation customers receive natural gas from third party marketers, known as shippers[5] and, therefore, do not pay the PGA charge to the LDC. The swing service rider allows FPUC to recover allocations of intrastate capacity costs from transportation customers.

### Updated 2024 Swing Service Rider Rates

The updated 2024 swing service rider rates were calculated based on the same methodology approved in the 2016 swing service order. As stated in paragraph 7 of the FPUC's instant petition, the total intrastate capacity costs for the period July 2022 through June 2023 are $31,941,095. The total intrastate capacity costs reflect payments by FPUC to intrastate pipelines for the transportation of natural gas, pursuant to Commission-approved transportation agreements.

The proposed intrastate capacity costs include the purchase of renewable natural gas (RNG) at market price, generated by the New River Solid Waste Association (New River or landfill). New River is a waste management company that owns a landfill that produces methane near Starke, Florida. FPUC purchased the RNG during the period April 2022 through February 2023. New River contracted for the construction of a direct connection pipeline with Florida Gas Transmission facilities; however, the RNG production facilities were completed before the pipeline could deliver RNG to market. Therefore, the landfill's RNG was undeliverable to market and would have resulted in loss of revenue and Renewable Energy Credits for the landfill. FPUC offered to purchase the gas without the Renewable Energy Credits, and in exchange, the landfill arranged to cover the cost of delivery of the gas via truck to FPUC's distribution system. New River mitigated potential losses and, as the landfill assumed the costs of delivery, FPUC received a savings of $149,538 on 365,159 dekatherms of gas, which is equivalent to a savings of about $0.05 per dekatherm compared to gas traditionally acquired at market.

In addition, the intrastate capacity costs include payments associated with a software tool to manage customer usage and assist in determining the gas supply and capacity needs for FPUC, legal and consulting fees, and subscription fees to obtain market data and gas daily pricing.

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[5] The Commission does not regulate the shippers or their charges for the gas commodity.

Of these costs, $7,367,169 will be billed directly to certain large special contract customers. The remaining costs of $24,573,927 will be recovered during the period January 1, 2024 through December 31, 2024.

The utility used actual therm usage data for the period July 2022 through June 2023 to allocate the intrastate capacity costs. Based on the usage data, staff agrees that the appropriate split for allocating the cost is 73.49 percent or $18,060,416 to transportation customers and 26.51 percent or $6,513,511 to sales customers. The transportation customers' share of $18,060,416 is further allocated to the various transportation rate schedules in proportion with each rate schedule's share of the utility's total throughput. The sales customers' share of the cost of $6,513,511 is embedded in the PGA.

To calculate the swing service rider rates, the transportation customers' share of the cost is allocated to each transportation customer class and then divided by the customer class' number of therms. The swing service revenues the utility is projected to receive in 2024 totals to $18,060,416.

### Credit to the PGA

The total intrastate capacity costs are embedded in the PGA with the projected 2024 swing service rider revenues incorporated as a credit in the calculation of the 2024 PGA. The amount credited to the 2024 PGA is $18,060,416 plus $7,367,169 received from special contract customers, for a total of $25,427,585.[6]

### Conclusion

After reviewing the information provided in the petition and in response to staff's data request, staff recommends that FPUC's proposed swing service rider reflects the updated cost of swing service for transportation customers. Staff reviewed the total projected intrastate capacity costs and verified that the costs included are appropriate. The Commission should approve the proposed swing service rider rates for the period January through December 2024. The costs included are appropriate and the methodology for calculating the swing service rider rates is consistent with the swing service order.

[6] See direct testimony of witness Robert Waruszewski on behalf of FPUC, filed on August 4, 2023, Document No. 04540-2023, in Docket No. 20230003-GU, Exhibit RCW-2, Schedule E-1, line 8 on page 1, and the direct testimony of Robert Waruszewski, page 4, lines 8-9, included in the instant petition.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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. (Watrous)

***Staff Analysis:*** If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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.

Florida Public Utilities Company
FPSC Tariff — First Revised Sheet No. 7.407
Original Volume No. 2 — Cancels Original Sheet No. 7.407

**SWING SERVICE RIDER**

Applicability:
The bill for Transportation Service supplied to a Customer in any Billing Period shall be adjusted as follows:

The Swing Service factors for the period from the first billing cycle for each Company Operating Unit for the period of ~~March 2023~~January 2024 through the last billing cycle for December 2024~~3~~ are as follows:

| Rate Schedule | Rates per Therm |
|---|---|
| REST-1 | $0.2041~~1907~~ |
| REST-2 | $0.2185~~1924~~ |
| REST-3 | $0.2328~~2124~~ |
| GTS-1 | $0.1371~~1397~~ |
| GTS-2 | $0.1804~~1645~~ |
| GTS-3 | $0.1796~~1586~~ |
| GTS-4 | $0.1801~~1602~~ |
| GTS-5 | $0.1749~~1607~~ |
| GTS-6 | $0.1714~~1521~~ |
| GTS-7 | $0.1695~~1488~~ |
| GTS-8A | $0.1693~~1368~~ |
| GTS-8B | $0.1714~~1487~~ |
| GTS-8C | $0.1648~~1484~~ |
| GTS-8D | $0.1656~~1460~~ |
| COM-INTT | $0.1662 |
| COM-NGVT | $0.1646 |

Definitions
This surcharge allocates a fair portion of Upstream Capacity Costs and expenses associated with the provision of Swing Service to transportation Customers in accordance with FPSC approval.

Issued by: Jeffrey Sylvester, Chief Operating Officer — Effective: ~~March 1, 2023~~January 1, 2024
Florida Public Utilities Company

# Item 17

**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:** October 27, 2023

**TO:** Office of Commission Clerk (Teitzman)

**FROM:** Division of Economics (Guffey) EJD
Division of Accounting and Finance (Mason) ALM
Office of the General Counsel (Dose) JSC

**RE:** Docket No. 20230101-GU – Petition for approval of gas utility access and replacement directive cost recovery factors for January 2024 through December 2024, by Florida Public Utilities Company.

**AGENDA:** 11/09/23 – Regular Agenda – Tariff Filing – Interested Persons May Participate

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Administrative

**CRITICAL DATES:** 05/01/24 (8-Month Effective Date)

**SPECIAL INSTRUCTIONS:** None

## Case Background

On September 1, 2023, Florida Public Utilities Company (FPUC or Company) filed a petition for approval of its Gas Utility Access and Replacement Directive (GUARD program) cost recovery factors for January through December 2024. The petition includes the direct testimony and Exhibits RCW-1 and RCW-2 of Robert Waruszewski providing the calculations of the proposed factors.

In Order No. PSC-2023-0235-PAA-GU (GUARD Order), the Commission approved FPUC's 10-year GUARD program consisting of two components: (1) replacement of problematic pipes and facilities and (2) relocation of mains and service lines located in rear easement and other difficult to access areas to the front lot easements.[1] As established in the GUARD Order, FPUC would be able to recover the revenue requirements of expedited programs to replace problematic pipes and facilities and to relocate certain facilities in rear easements and other difficult to access areas in order to enhance the safety of portions of FPUC's natural gas distribution system through a monthly surcharge on customers' bills. The GUARD Order further established the methodology for annually setting the GUARD surcharge to recover the costs of the program.

In 2012, the Commission approved FPUC's 10-year Gas Reliability and Infrastructure Program (GRIP).[2] The purpose of GRIP was to recover the cost of accelerated replacement of cast iron and bare steel distribution mains and services that are subject to corrosion through a separate surcharge on customers' bills. In the recently concluded FPUC rate case in Docket No. 20220067-GU, the Company moved $19.8 million of GRIP revenue requirement to rate base.[3] Any remaining GRIP amounts that were not moved into base rates are included in the instant petition in the beginning balance for the GUARD program. The GRIP program was completed in July 2023. The GRIP program was originally scheduled to conclude at the end of December 2022; however, due to some permit delays, approximately 0.5 miles of pipeline were replaced in 2023.

The methodology to calculate the GUARD program surcharges is the same that was approved for the GRIP. The GUARD cost recovery procedure requires an annual filing with three components, similar as those approved in the 2012 GRIP Order:

1. A final true-up showing the actual replacement costs, actual surcharge revenues, and over- or under-recovery amount for the 12-month historical period from January 1 through December 31 of the year prior to FPUC's annual GUARD petition.

2. An actual/estimated true-up showing seven months of actual and five months of projected replacement costs, surcharge revenues, and over- or under-recovery amount.

3. A revenue requirement projection showing 12 months of projected GUARD revenue requirement for the period beginning January 1 following FPUC's annual GUARD petition filing.

In the GUARD Order, the Commission directed FPUC to file its annual GUARD program petition to revise the surcharge on or before September 1 of each year, to implement the revised surcharge effective January 1 through December 31 of the following year, and to file its first GUARD cost recovery petition on September 1, 2023. FPUC, in its petition, included revised tariff sheets 7.000 through 7.002 (Index), 7.403, 7.404, and 7.405.

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[1] Order No. PSC-2023-0235-PAA-GU, issued August 15, 2023, amended by Order No. PSC-2023-0235A-PAA-GU, issued August 18, 2023, in Docket No. 20230029-GU, *In re: Petition for approval of gas utility access and replacement directive, by Florida Public Utilities Company.*

[2] Order No. PSC-2012-0490-TRF-GU, issued September 24, 2012, in Docket No. 20120036-GU, *In re: Joint petition for approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation*.

[3] Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.*

The Commission further ordered FPUC to (1) include all calculations to show a final true-up, actual-estimated true-up, projected year investments and associated revenue requirements, and the calculations of the GUARD factors by rate class, (2) provide a report including the location, date, description, and associated costs of all replacement projects completed and all projects scheduled for the following year, and (3) include any remaining GRIP over- or under-recovery in the 2024 GUARD cost recovery.

FPUC has complied with the GUARD Order directives stated above. Since the GUARD Order established that any remaining GRIP investments that were not included for recovery in base rates in the rate case Docket No. 20220067-GU shall be rolled into the GUARD program for cost recovery, there will be no GRIP surcharge on customers' bills starting January 1, 2024. Accordingly, the proposed GUARD surcharge would replace the GRIP surcharge. The current 2023 GRIP factors have been approved in Order No. PSC-2022-0401-TRF-GU.[4] Finally, the GUARD Order provided for FPUC to start GUARD program expenditures in April 2023 and request recovery of any 2023 expenditures starting on January 1, 2024.

During the review process, staff issued a data request to FPUC on September 11, 2023, for which the responses were received on September 18, 2023. In Order No. PSC-2023-0304-PCO-GU, the Commission suspended the proposed tariffs. The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

[4] Order No. PSC-2023-0304-PCO-GU, issued November 17, 2022 in Docket No. 20220155-GU, *In re: Joint petition for approval of GRIP cost recovery factors, by Florida Public Utilities Company, Florida Public Utilities Company-Fort Meade, and Florida Division of Chesapeake Utilities Corporation.*

## Discussion of Issues

***Issue 1:*** Should the Commission approve FPUC's 2024 Gas Utility Access and Replacement Directive (GUARD) cost recovery factors and associated revised tariff sheets (Nos. 7.000 through 7.002, 7.403, 7.404, and 7.405) for the period January to December 2024?

***Recommendation:*** Yes. The Commission should approve FPUC's 2024 GUARD cost recovery factors and associated revised tariff sheets (Nos. 7.000 through 7.002, 7.403, 7.404, and 7.405), included in Attachment B, to be effective for the first billing cycle of January through the last billing cycle of December 2024. The GUARD surcharge would allow FPUC to replace problematic pipes and facilities and relocate certain facilities located in rear easements, and recover the project costs on an expedited basis. (Guffey)

***Staff Analysis:*** The GRIP surcharges have been in place since 2013 and the GRIP program is complete. As discussed in the GUARD Order, the Company identified additional safety risks and reliability concerns. Specifically, the GUARD program is driven by risks identified under FPUC's Distribution Integrity Management Program (DIMP)[5] and risk assessments performed by an independent contractor. The prioritized projects for 2023 and 2024 are included in Attachment A to this recommendation. Attachment A indicates that FPUC will replace obsolete/Aldyl-A and certain span pipes, and relocate pipes from rear lot to the street front in Martin, Palm Beach and Seminole counties in 15 projects for an estimated investment of $33 million during 2023 and 2024. As indicated in FPUC's response to staff's data request, the selected project areas include existing distribution mains and services that are considered high risk due to, but not limited to, Aldyl-A and vintage plastic pipes, damage due to excavation in rear lots, corrosion, leaks, and inaccessible rear lot facilities.[6]

### Remaining GRIP Revenue Requirement

As authorized by the GUARD Order, FPUC included the remaining GRIP investment and the remaining GRIP over- or under-recoveries in the 2024 GUARD cost recovery. Exhibit RCW-1, page 5 of 9, of the petition reflects the GRIP investments from the rate case being removed from the calculations at the end of February 2023 and only reflect the GRIP investments above the amount approved in the rate case ($4,197,096). The GRIP investment approved to be moved into rate base represents the total investment projected at the time of the rate case filing in May 2022. FPUC explained that the actual final GRIP investment was higher than projected, resulting in a remaining GRIP investment of $4,197,096.

The Company has been collecting Commission-approved GRIP factors from its customers in 2022 and 2023. FPUC's calculations for the 2022 and January – July 2023 GRIP revenue requirement and surcharges include a final GRIP true-up amount for the period ending July 31, 2023 of $332,795 (over-recovery). That over-recovery amount is being applied to the GUARD program in July 2023 (termination date for the GRIP program).

### 2023 GUARD Revenue Requirement

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[5]Pursuant to Chapter 49, Section 192.1005 Code of Federal Regulations (2023), a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan.
[6] Response No. 6 in Staff's First Data Request, Document No. 05239-2023.

The Company initiated work on the GUARD program in April 2023. Specifically, the Company explained that in April and May of 2023 activities were related to project material procurement, engineering design, and permitting necessary to start construction activities in June of 2023.

The April through December 2023 GUARD investment and associated revenue requirement amounts are shown on Exhibit RCW-1, page 6 of 9. The forecasted GRIP revenues for the remainder of 2023 exceed the GUARD 2023 revenue requirement, resulting in an over-recovery of $227,566, inclusive of interest of $9,613, for the period April through December 2023. Therefore, the total GUARD true-up, which includes the final over-recovery for GRIP, is $560,361 ($332,795+$227,566), inclusive of interest. As shown in Table 1-1 below, that amount is being applied to the 2024 GUARD revenue requirement, resulting in a lower revenue requirement to be recovered from customers in 2024.

Exhibit RCW-1, page 6 of 9, shows the 2023 year end net book value investment of $16,965,008. This amount represents the final GRIP investment moved into the GUARD program as of July 2023 ($4,347,919) and the 2023 GUARD investment ($12,617,089). That amount is reflected as the beginning balance for the 2024 GUARD calculations discussed below.

### Projected 2024 GUARD Revenue Requirement

For 2024, FPUC projects to invest $20,371,485 ($12,415,872 for mains and $7,955,613 for services), resulting in a total projected 2024 investment of $36,783,862 (including the year-end 2023 investment). Similar to the GRIP, the GUARD program revenue requirement includes a return on investment, depreciation expense, customer notification expense, and property taxes; all expenses are dependent upon the level of investment costs. Pursuant to witness Waruszewski's testimony, the Company also included $49,416 for the 2024 projection period as operating and maintenance costs which are for extending customer-owned downstream fuel lines to connect to meters that are required to be relocated due to safety concerns.[7] After subtracting the $560,361 over-recovery true-up amount, the 2024 GUARD revenue requirement to be recovered through the proposed surcharges is $2,296,223.

**Table 1-1**
**2024 GUARD Revenue Requirement Calculation**

| **2024 Projected Investment** | **$36,783,862** |
|---|---|
| Return on Investment | $1,903,237 |
| Depreciation Expense | $552,631 |
| Operations & Maintenance Expense | $49,416 |
| Property Tax Expense | $339,300 |
| Customer Notification Expense | $12,000 |
| 2024 GUARD Revenue Requirement | $2,856,584 |
| Less 2023 Over-Recovery | -$560,361 |
| 2024 Total Revenue Requirement | $2,296,223 |

Source: Witness Waruszewski Testimony Exhibit RCW-1

[7] Exhibit RCW-1, Schedule C-1, page 6 of 9 and Schedule C-2, page 7 of 9.

### Proposed GUARD Surcharges

As approved in the GUARD Order, the total 2024 revenue requirement is allocated to the rate classes using the same methodology used for the allocation of mains and services in the cost of service study used in the Company's most recent rate case. The respective percentages were multiplied by the 2024 revenue requirements and divided by each rate class's projected therm sales to provide the GUARD surcharge for each rate class. This methodology was originally established by the 2012 Order approving the GRIP program.

The proposed 2024 GUARD surcharge for FPUC's residential customers who use 20 therms a month (240 therms annually) on the Residential Service tariff (RES-2) would pay \$0.03263 per therm compared to the 2023 GRIP surcharge of \$0.02166 per therm. The monthly bill impact is \$0.65 for a residential customer using 20 therms per month or \$7.83 per year. The proposed GUARD surcharges are shown in Attachment B, in Tariff Sheet No. 7.403.

### Conclusion

Staff believes the calculation of FPUC's GUARD revenue requirement and surcharges for each rate class are reasonable and accurate. Staff therefore recommends approval of FPUC's proposed GUARD surcharges, effective for January 1, 2024. The proposed GUARD surcharge factors should be applied to each rate class during the billing period January 1 through December 31, 2024.

***Issue 2:*** Should this docket be closed?

***Recommendation:*** Yes. If 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. (Dose)

***Staff Analysis:*** If 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.

# GUARD Projects for 2023 and 2024



| Project Name | Location City/Town | Location County | Program Category | Program Sub-Category | Construction Estimate Start Date | Construction Estimate Completed Date | 2023-2024 Estimated Investment | Footages | Miles |
|---|---|---|---|---|---|---|---|---|---|
| Indiantown - North Ph.1 | Indiantown | Martin | Problematic | Obsolete/Aldyl-A | Jul-23 | Dec-23 | $ 3,169,036 | 27,856 | 5.28 |
| Indiantown - North Ph.2 | Indiantown | Martin | Problematic | Obsolete/Aldyl-A | Jan-24 | May-24 | $ 1,560,912 | 16,531 | 3.13 |
| Indiantown - South Ph.1 | Indiantown | Martin | Problematic | Obsolete/Aldyl-A | Jun-24 | Dec-24 | $ 2,800,000 | 28,685 | 5.43 |
| | | **Martin Total** | | | | | | | **13.84** |
| | | | | | | | | | |
| Lake Park - North | Lake Park | Palm Beach | Accessiblity | Rear-to-Front | Jun-23 | Dec-23 | $ 4,109,604 | 44,345 | 8.40 |
| Turnpike and Jog | West Palm Beach | Palm Beach | Problematic | Span | Jul-23 | Oct-23 | $ 550,000 | 1,150 | 0.22 |
| Turnpike and Belvedere | West Palm Beach | Palm Beach | Problematic | Span | Sep-23 | Nov-23 | $ 850,000 | 2,457 | 0.47 |
| Lake Park - South | Lake Park | Palm Beach | Accessiblity | Rear-to-Front | Oct-23 | Jan-24 | $ 2,121,186 | 18,750 | 3.55 |
| Mercer Ave | West Palm Beach | Palm Beach | Problematic | Span | Oct-23 | Dec-23 | $ 341,538 | 678 | 0.13 |
| Forest Hill Villages | West Palm Beach | Palm Beach | Accessiblity | Rear-to-Front | Jan-24 | Jul-24 | $ 4,702,694 | 35,985 | 6.82 |
| Park Manor | Riviera Beach | Palm Beach | Accessiblity | Rear-to-Front | Jun-24 | Nov-24 | $ 3,410,244 | 36,941 | 7.00 |
| Grammercy Park | Riviera Beach | Palm Beach | Accessiblity | Rear-to-Front | Jul-24 | Dec-24 | $ 2,720,854 | 26,461 | 5.01 |
| Le Chalet | Boynton Beach | Palm Beach | Problematic | Obsolete/Aldyl-A | Oct-24 | Dec-24 | $ 1,245,568 | 11,800 | 2.23 |
| | | **Palm Beach Total** | | | | | | | **33.82** |
| | | | | | | | | | |
| Winter Springs Ph.1 | Winter Springs | Seminole | Accessiblity | Rear-to-Front | Jun-23 | Dec-23 | $ 1,894,849 | 19,890 | 3.77 |
| Sanford Ph.1 | Sanford | Seminole | Accessiblity | Rear-to-Front | Jan-24 | Apr-24 | $ 935,343 | 9,360 | 1.77 |
| Winter Springs Ph.2 | Winter Springs | Seminole | Accessiblity | Rear-to-Front | Jun-24 | Dec-24 | $ 2,684,684 | 22,360 | 4.23 |
| | | **Seminole Total** | | | | | | | **9.77** |
| | | | | | | | | | |
| | | **Grand Total** | | | | | | | **57.43** |
| | | | | | | | $ 33,096,512 | 303,249 | |

***INDEX OF RATE SCHEDULES***

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Issued by: Jeffrey Sylvester, Chief Operating Officer Effective: ~~March 1, 2023~~January 1, 2024
Florida Public Utilities Company

Florida Public Utilities Company
FPSC Tariff
Original Volume No. 2

First Revised Sheet No. 7.403
Replaces Original Sheet No. 7.403

**GAS ~~RELIABILITY INFRASTRUCTURE PROGRAM~~ UTILITY ACCESS AND REPLACEMENT DIRECTIVE (GUARD)**

Applicability:
The bill for Regulated Gas Sales Service or Transportation Service, as applicable, supplied to a Customer in any Billing Period shall be adjusted as follows:

The ~~GRIP~~GUARD factors for the period from the first billing cycle for January 2024~~March 2023~~ through the last billing cycle for December 2024~~3~~ are as follows:

| Rate Schedule | Rates per Therm |
|---|---|
| RES-1 and REST-1 | $~~0.11016~~0.05887 |
| RES-2 and REST-2 | $~~0.04443~~0.03263 |
| RES-3 and REST-3 | $~~0.01869~~0.01557 |
| RES-SG and SGT | $~~0.07555~~0.04523 |
| GS-1 and GTS-1 | $~~0.03653~~0.02654 |
| GS-2 and GTS-2 | $~~0.01449~~0.01824 |
| GS-3 and GTS-3 | $~~0.01264~~0.01686 |
| G4-4 and GTS4 | $~~0.01164~~0.01621 |
| GS-5 and GTS-5 | $~~0.01075~~0.01451 |
| GS-6 and GTS-6 | $~~0.01062~~0.01356 |
| GS-7 and GTS-7 | $~~0.01041~~0.01249 |
| GS-8A and GTS-8A | $~~0.01032~~0.01559 |
| GS-8B and GTS-8B | $~~0.01032~~0.01559 |
| GS-8C and GTS-8C | $~~0.01032~~0.01559 |
| GS-8D and GTS-8D | $~~0.01032~~0.01559 |
| COM-INT and COM-INTT | $~~0.00522~~0.00710 |
| COM-NGV and COM-NGVT | $~~0.00826~~0.01161 |
| COM-OL and COM-OLT | $~~0.01144~~0.02092 |
| COM-SG and COM-SGT | $~~0.05750~~0.05010 |

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities Company

Effective: January 1, 2024 ~~March 1, 2023~~

Florida Public Utilities Company
FPSC Tariff
Original Volume No. 2

First Revised Sheet No. 7.404
Replaces Original Sheet No. 7.404

**GAS ~~RELIABILITY INFRASTRUCTURE PROGRAM –~~ UTILITY ACCESS AND REPLACEMENT DIRECTIVE -CONTINUED**

Definitions:

~~The Company has prioritized the potential replacement projects focusing initially on areas of high consequence and areas more susceptible to corrosion. The GRIP~~ GUARD Program minimizes impact to Customers, but at the same time, allows the Company to accelerate its replacement

~~Definitions Continued~~program- for eligible infrastructure. Costs incurred to remove the existing eligible distribution Mains and Service Lines are not recoverable under the ~~GRIP~~GUARD Program~~.~~

The Eligible Infrastructure Replacement includes the following:

1. Company plant investment that
    a. Does not increase revenues by directly connecting new Customer to the plant asset,
    b. is in service and used and useful in providing utility service, and
    c. was not included in the Company's rate base for purposed of determining the Company's base rates in its most recent general base rate proceeding.

2. Mains and Service Lines, as replacements for existing ~~cast iron, wrought iron, and~~ Rear Lot ~~bare steel~~ facilities and other problematic facilities, and regulation station and other pipeline system components, the installation of which is required as a consequence of the replacement of the aforesaid facilities.

The Company is recovering its revenue requirement on the actual investment amounts. The revenue requirements are inclusive of:

1. Return on investment as calculated using the allowable equity and debt components of the Company's weighted cost of capital,

2. Depreciation expense (respectively calculated using the currently approved depreciation rates),

3. Customer and general public notification expenses associated with ~~GRIP~~GUARD for:

    a. All Customers regarding the implementation of the ~~GRIP~~ GUARD Program and the approved surcharge factors,

Issued by: Jeffrey Sylvester, Chief Operating Officer
~~March 1, 2023~~
Florida Public Utilities Company

Effective: January 1, 2024

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b. The immediately affected Customers where the eligible infrastructure is being replaced, and

~~GAS RELIABILITY INFRASTRUCTURE PROGRAM – CONTINUED~~

c. The general public through publications (newspapers) covering the geographic areas of the eligible infrastructure replacement activities.

4. Ad valorem taxes, grossed-up for federal and state income taxes.

**GAS UTILITY ACCESS AND REPLACEMENT DIRECTIVE - CONTINUED**

The Company is utilizing a surcharge mechanism in order to recoup the costs associated with the ~~GRIP~~GUARD Program. The Company has developed its ~~GRIP~~GUARD surcharge factors for each rate classification utilizing the same investment data developed and approved in its most recent rate case.

The ~~GRIP~~GUARD surcharge for each Customer class will be a per Therm rate per Month that is calculated by multiplying the ~~GRIP~~GUARD revenue requirements by the percentage representing a class share of such requirements and dividing the result by the projected therm sales~~surcharge~~.

Issued by: Jeffrey Sylvester, Chief Operating Officer
~~March 1, 2023~~
Florida Public Utilities Company

Effective: January 1, 2024