

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:** November 22, 2024

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

**FROM:** Division of Engineering (P. Buys, Ballinger, Davis, Ellis, King, Ramirez- *TB*  
Abundez, Ramos, Smith II, O. Wooten)  
Division of Accounting and Finance (D. Buys, Cicchetti, Ferrer, Folkman, *ALM*  
Higgins, Hinson, G. Kelley, Mason, McGowan, Norris, Souchik, Vogel, Zaslow)  
Division of Economics (Barrett, Draper, Hampson, Hudson, Galloway, Guffey, *GP*  
Kunkler, McClelland, McNulty, Panek, Prewett, J. Wu)  
Office of the General Counsel (Harper, Marquez, Sparks) *ACH*  
Office of Industry Development and Market Analysis (B. Crawford, Eichler) *CH*

**RE:** Docket No. 20240026-EI – Petition for rate increase by Tampa Electric Company.  
  
Docket No. 20230139-EI – Petition for approval of 2023 depreciation and  
dismantlement study, by Tampa Electric Company.  
  
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:** 12/03/24 – Special Agenda – Post-Hearing Decision – Participation is Limited to  
Commissioners and Staff

**COMMISSIONERS ASSIGNED:** All Commissioners

**PREHEARING OFFICER:** Clark (20240026-EI)  
Graham (20230139-EI)  
Administrative (20230090-EI)

**CRITICAL DATES:** 12/02/24 (8-Month Statutory Deadline)

**SPECIAL INSTRUCTIONS:** None

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## List of Acronyms

AFUDC	Allowance for Funds Used During Construction
ADIT	Accumulated Deferred Income Taxes
AMI	Advanced Metering Infrastructure
AMR	Advanced Meter Reading
AOM	Asset Optimization Mechanism
ARL	Average Remaining Life
ASL	Average Service Life
BB4	Big Bend Unit 4
BCA	Benefit-Cost Analysis
BEBR	Florida's Bureau of Economic and Business Research
BESE	Battery Energy Storage Equipment
BOC	Bearss Operations Center
BR	Brief
CAM	Cost Allocation Manual
CAPM	Capital Asset Pricing Model
CATS	Consumer Activity Tracking System
CC	Combined Cycle
CCS	Carbon Capture and Storage
CDD	Cooling Degree Days
CETM	Clean Energy Transition Mechanism
CIAC	Contributions in Aid of Construction
CIP	Critical Infrastructure Protection
Commission	Florida Public Service Commission
CP	Coincident Peak
CPI	Consumer Price Index
CPVRR	Cumulative Present Value of Revenue Requirements
CSP	Centralized Service Provider
CT	Combustion Turbine
CWIP	Construction Work in Progress
D&O	Directors and Officer
DAP	Data Analytics Platform
DC	Direct-Current
DCF	Discounted Cash Flow
DEF	Duke Energy Florida
DER	Distributed Energy Resources
DPS	Dividends per Share
ECAPM	Empirical Capital Asset Pricing Model
ECC	Energy Control Center
ECCR	Energy Conservation Cost Recovery
ECRC	Environmental Cost Recovery Clause
EDITs	Excess Deferred Income Taxes
EDR	Economic Development Rider
EMS	Energy Management System
EPS	Earnings per Share

ERP	Enterprise Resource Planning
EUSHI	Emera United States Holdings, Inc.
EXH	Exhibit
F.A.C.	Florida Administrative Code
F.S.	Florida Statute
FCTC	Florida Conservation and Technology Center
FEA	Federal Executive Agencies
FEECA	Florida Energy and Efficiency Conservation Act
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FL Rising	Florida Rising, Inc.
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FPUC	Florida Public Utilities Company
FRF	Florida Retail Federation
Fuel Retailers	Americans for Affordable Clean Energy, Inc.; Circle K Stores, Inc.; RaceTrac Inc.; and Wawa, Inc.
GAAP	Generally Accepted Accounting Principles
GBRA	Generation Base Rate Adjustment
GDP	Gross Domestic Product
GRR	Grid Reliability and Resilience
GS	General Service – Non-Demand
GSD	General Service - Demand
GSLDPR	General Service Large Demand – Primary
GSLDSU	General Service Large Demand - Subtransmission
HDD	Heating Degree Days
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-Owned Utilities
IRA	Inflation Reduction Act of 2022
IRC or Code	Internal Revenue Code
IRS	Internal Revenue Service
IT	Information Technology
ITC	Investment Tax Credits
kW	Kilowatt
kWh	Kilowatt Hour
LDES	Long Duration Energy Storage
LNG	Liquid Natural Gas
LS	Lightning Service
LTIP	Long Term Incentive Plan
LULAC	League of United Latin American Citizens of Florida
MFR	Minimum Filing Requirements
MMM	Modified Massachusetts Model
Moody's	Moody's Analytics
MPN	Master Page Number
MRP	Market Equity Risk Premium

MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Commissioners
NERC	North American Electric Reliability Corporation
NOI	Net Operating Income
NPVRR	Net Present Value Revenue Requirement
NS	Net Salvage Percentage
NSMR	Non-Standard Meter Rider
O&M	Operational and Maintenance
OEP	Order Establishing Procedure
OPC	Office of Public Counsel
OPEB	Other Post-Retirement Employee Benefit
PDA	Parent Debt Adjustment
PLTE	Private Cellular Network
PRPM	Predictive Risk Premium Model
PSC	Florida Public Service Commission
PTC	Production Tax Credits
R&D	Research and Development
RAP	Regulatory Assistance Project
REC	Renewable Energy Credit
RICE	Reciprocating Internal Combustion Engines
ROE	Return on Common Equity
RPM	Risk Premium Models
RS	Residential Service
SAE	Statistically Adjusted End-use
SERP	Supplemental Executive Retirement Plan
SoBRA	Solar Base Rate Adjustment
SPR	Simulated Plant Record
SPPCRC	Storm Protection Plan Cost Recovery Clause
SQ	Square
SSD	Sum of Squared Differences
ST	Steam Turbine
STR Project	South Tampa Resilience Project
SYA	Subsequent Year Adjustments
TECO or Company	Tampa Electric Company
TMARPM	Total Market Approach RPM
TOTI	Taxes Other than Income Taxes
TR	Transcript
WACC	Weighted Average Cost Of Capital
Walmart	Walmart, Inc.
WMS	Work Management System
Ybor	Ybor Data Center

## Case Background

On April 2, 2024, Tampa Electric Company (TECO or Company) filed its Petition for Rate Increase, minimum filing requirements (MFRs), and testimony.<sup>1</sup> TECO provides service to approximately 844,000 customers in a 2,000 square mile service territory in Hillsborough and portions of Polk, Pasco, and Pinellas counties, Florida.

TECO initially requested an increase of approximately \$296.6 million in base rates and charges effective January 1, 2025. In addition, the Company requested incremental rate increases of approximately \$100 million, effective January 1, 2026, and \$72 million, effective January 1, 2027. On August 22, 2024, the Company reduced its initial request for rates in 2025 to \$287.9 million, with the incremental rate increases also reduced to \$92.4 million and \$65.5 million, for 2026 and 2027, respectively.<sup>2</sup> TECO requested a return on common equity (ROE) of 11.5 percent.

TECO's last base rate hearing was in 2021. In that proceeding the Florida Public Service Commission (Commission or FPSC) approved a unanimous settlement agreement (2021 Settlement Agreement) which authorized a total base rate increase of \$123 million in 2022; a \$90 million generation base rate adjustment (GBRA) in 2023; and a \$21 million GBRA in 2024.<sup>3</sup> The GBRA's were designed to recover the costs associated with the completion of the Big Bend modernization project and additional solar facilities. TECO's authorized ROE was initially established at 9.95 percent. Due to the increase in interest rates, the ROE trigger provision of the 2021 Settlement Agreement reset TECO's ROE to the current level of 10.2 percent.

The Office of Public Counsel's (OPC) intervention was acknowledged by Order No. PSC-2024-0048-PCO-EI, issued February 26, 2024. On April 23, 2024, intervention was granted to Federal Executive Agencies (FEA); Sierra Club; Florida Rising, Inc. (FL Rising); League of United Latin American Citizens of Florida (LULAC); Florida Retail Federation (FRF); and Florida Industrial Power Users Group (FIPUG).<sup>4</sup> On June 3, 2024, intervention was granted to Americans for Affordable Clean Energy, Inc.; Circle K Stores, Inc.; RaceTrac Inc.; and Wawa, Inc. (Fuel Retailers).<sup>5</sup> Intervention was granted to Walmart, Inc. (Walmart) on August 8, 2024, by Order No. PSC-2024-0317-PCO-EI.

Two virtual customer service hearings were held on June 10 and 11, 2024, and one in-person service hearing was held in Tampa on June 13, 2024. A total of 53 customers testified. An administrative evidentiary hearing was held August 26-30, 2024.

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<sup>1</sup> By Order No. PSC-2024-0096-PCO-EI, Docket Nos. 20240026-EI, 20230139-EI, and 20230090-EI were consolidated.

<sup>2</sup> Document Number 08609-2024.

<sup>3</sup> 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*.

<sup>4</sup> Order Nos. PSC-2024-0121-PCO-EI, PSC-2024-0122-PCO-EI, PSC-2024-0123-PCO-EI, PSC-2024-0124-PCO-EI, and PSC-2024-0125-PCO-EI.

<sup>5</sup> Order No. PSC-2024-00182-PCO-EI.



Docket Nos. 20240026-EI, 20230139-EI, 20230090-EI

Date: November 22, 2024

This recommendation addresses the requested rate increases for 2025, 2026, and 2027. The Commission has jurisdiction over this matter pursuant to Chapter 366, including Sections 366.06 and 366.071, Florida Statutes (F.S.).

## Executive Summary

TECO's last base rate hearing was in 2021. In that proceeding the Commission approved a unanimous settlement agreement which authorized a total base rate increase of \$123 million in 2022; a \$90 million GBRA in 2023; and a \$21 million GBRA in 2024. The GBRAs were designed to recover the costs associated with the completion of the Big Bend modernization project and additional solar facilities. TECO's authorized ROE was initially established at 9.95 percent. Due to the increase in interest rates, the ROE trigger provision of the 2021 Settlement Agreement reset TECO's ROE to the current level of 10.2 percent.

### 2025 Test Year

On April 2, 2024, TECO filed the current petition requesting approval of a base rate increase with subsequent year adjustments (SYA). In the petition, TECO requested an increase of approximately \$296 million for the 2025 test year, an increase of \$100 million for 2026, and an increase of \$72 million for 2027. The 2025 requested increase was supported by MFRs, while the 2026 and 2027 increases were not. On July 24 and again on August 22, 2024, TECO reduced its requested increase for 2025 (\$288 million), 2026 (\$92 million), and 2027 (\$65 million), but did not file amended MFRs for 2025. Therefore, all adjustments contained in this recommendation are made from the originally filed values. The requested base revenue increase is driven primarily by plant investment and a requested mid-point ROE of 11.5 percent.

OPC, FEA, Sierra Club, FL Rising/LULAC, FRF, FIPUG, Fuel Retailers, and Walmart intervened in the docket. All intervenors except FRF, Fuel Retailers, and Walmart sponsored witness testimony. A summary of each party's position for the 2025 projected test year is shown below:

<b>Party</b>	<b>2025 Revenue Requirement Increase</b>	<b>ROE</b>
TECO	\$296.6 million (\$287.9 million revised)	11.5%
OPC	\$68.1 million	9.5%
FEA	No specific amount recommended	9.6%
Sierra Club	No position	Adopted OPC position
FL. Rising/LULAC	\$0	9.5%
FRF	\$36.7 million	9.5%
FIPUG	Adopted OPC's position	9.8%
Fuel Retailers	No position	No position
Walmart	Adopted FRF position	9.8%

Staff is recommending an incremental revenue increase of \$153.4 million effective January 1, 2025. Key components of staff's recommendation are an increase from the current authorized ROE of 10.2 percent to a more appropriate market-based ROE of 10.3 percent (Issue 39) and changes to depreciation rates and resulting expenses (Issue 7).

As discussed in Issue 39, there were multiple witnesses and model results that provided a wide range (8.85 to 11.91) of ROEs. Evidence in the record shows that since 2022, interest rates have increased and that TECO has been able to provide reliable service and make all necessary investments with an authorized ROE of 10.2 percent. On balance, staff is recommending that an ROE of 10.3 percent would continue to enable TECO to generate the cash flow to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events.

As discussed in Issue 7, staff is recommending changes to TECO's proposed average service lives for solar generation facilities, battery energy storage equipment, and underground conductors and devices. For solar generating facilities, staff is recommending retaining the currently approved service life of 35 years compared to TECO's proposed 30-year service life estimate. For battery storage, staff is recommending a 20-year service life compared to TECO's originally proposed 10-year service life. As previously stated, the recommended adjustment to revenue requirements is being made from the original filing. However, TECO's updated revenue requirement request dated August 22, 2024, agreed to the 20-year service life for battery storage projects. For underground conductors, staff is recommending a 40-year service life compared to TECO's requested 35-year service life. All three recommendations reflect the account's life characteristics and are within the industry range of estimates. Lengthening the service lives for these assets reduces the associated depreciation expense.

## **SYAs**

Companies have requested SYAs before, but those cases have been resolved by settlement agreements. This is notable because although the Commission evaluates all the issues in a settlement, it historically has done so looking at the agreement as a whole as opposed to considering each individual investment project separately. TECO requested a \$100 million SYA for 2026 and a \$72 million SYA for 2027. The largest component of the requested SYAs is the annualization of capital projects that go in-service in the year prior.

As discussed in Issue 94, a SYA is an incremental adjustment to a company's revenue requirement for a project(s) that lapses beyond the projected test year. TECO's proposed 2026 and 2027 SYAs reflect two types of requests: the annualization of projects placed into service in a period prior to the proposed SYA and projects placed into service subsequent to the 2025 projected test year. Regardless of the type of SYA request, the Company has the burden of proof to support the need and necessity for each proposed project. If the costs associated with significant and material plant additions (i.e., a generating facility) that occur later in a projected test year are not annualized, then, all other things being equal, there will be an under recovery of the costs associated with such investment in the subsequent year. This would hinder a company's opportunity to earn its authorized ROE and could result in another base rate proceeding. For projects with in-service dates beyond the projected test year, the Commission should also consider whether the reasons to approve cost-recovery for the project in the current rate case outweigh the inherent uncertainty in forecasting beyond a projected test year. If a company can demonstrate that a SYA will minimize the need for future rate cases or potentially reduce costs associated with future rate requests, staff believes that said reduction in costs is an important and relevant consideration. The projects which give rise to TECO's requests for SYAs in 2026 and 2027 are discussed in Issues 95 through 102.

Date: November 22, 2024

A summary of each party's position for the SYAs is shown below:

<b>Party</b>	<b>2026 SYA</b>	<b>2027 SYA</b>
TECO	\$100.0 million (\$92.4 revised)	\$72.0 million (\$65.5 revised)
OPC	\$54.7	\$20.9
FEA	No position	No position
Sierra Club	No position	No position
FL. Rising/LULAC	\$0.0	\$0.0
FRF	Adopted OPC position	Adopted OPC position
FIPUG	Adopted OPC position	Adopted OPC position
Fuel Retailers	No position	No position
Walmart	Adopted OPC position	Adopted OPC position

Staff is recommending an incremental increase of \$74.7 million for the 2026 SYA and \$0 for the 2027 SYA. The SYA recommended by staff is limited to annualized costs for projects being placed in-service during the 2025 projected test year. Projects with in-service dates beyond the 2025 projected test year were not supported by the evidence showing that the need for approving cost recovery of the projects in the current rate case outweigh the inherent uncertainty and risk in forecasting beyond a projected test year.

### **Cost of Service Methodology**

Once a revenue requirement is established, then the Commission must approve a methodology by which rates are set to collect the costs. As discussed in Issue 71, four parties, who were also signatories to the 2021 Settlement Agreement, filed testimony in support of the 4 Coincident Peak (CP) cost allocation methodology. The 4 CP method allocates costs based on a rate class' contribution to peak demand for the months of January, June, July, and August. Such a cost allocation method does not allocate any production plant costs to energy. TECO also filed a traditional 12 CP and 1/13 AD cost of service study per Rule 25-6.043(1)(a), F.A.C. The 12 CP and 1/13 AD method allocates costs to recognize a company's obligation to serve load throughout the year and that generation investment can also result in fuel savings.

The primary evidence in support of the 4 CP method is that it was approved in the 2021 Settlement Agreement, which also required TECO to file a 4 CP method in the current docket. Clearly, the Commission is not bound by a previous settlement agreement after considering all the evidence in the record. The four months selected for the proposed 4 CP method were agreed upon for the 2021 Settlement Agreement and could easily have been 2 or 7 months. If a generating plant produces lower fuel costs, (i.e. solar facilities), then staff recommends that a portion of the plant costs should be allocated on an energy basis. The 4 CP method would not do this. For these reasons, staff is recommending that TECO use the 12 CP and 1/13 AD cost of service methodology when it files its final rates and tariffs for approval.

### **Other Issues**

As discussed in Issue 112, staff is recommending that TECO be allowed to continue its Storm Cost Recovery process which allows for timely recovery of storm restoration costs subject to Commission review, party intervention, and a true-up process that protects customers.

As discussed in Issue 113, staff is recommending that TECO's current Asset Optimization Mechanism (AOM) remain in place, unchanged, and that the Commission open a generic proceeding to evaluate all investor-owned utilities' (IOU's) incentive mechanisms. If the Commission wants to expand TECO's mechanism to include the release of natural gas pipeline capacity and renewable energy credits (RECs), then staff would recommend adjusting the sharing thresholds from \$4.5 million to \$12.5 million and from \$8.0 million to \$25 million.

As discussed in Issue 119, if the Commission considers affordability of customer's bills, it must do so in the context of Chapter 366, F.S., which requires the Commission to set rates that are fair, just, and reasonable. Affordable rates are therefore rates that allow a Company to recover all of its necessary costs incurred to provide safe and reliable service and to earn a reasonable return on its investment. Affordability of individual electric utility bills relies on many factors beyond the control of a Company such as income levels, personal energy use choices, personal financial obligations, spending priorities, etc. While other states may have specific affordability considerations, Florida's enabling legislation does not.

### **Uncontested, Fall-out, and Final Rate Issues**

Based upon the parties' post-hearing positions, there appears to be several uncontested Issues. Staff recommends that Issues 1, 6, 9, 36, 48, 49, 50, 51, 52, 57, 61, 70, 77, 89, 90, 91, 109, and 110 are uncontested by the parties to this proceeding,

Issues 26, 32, 41, 42, 43, 46, 47, 59, 60, 66, 67, 69, 72, 103, 107, and 114 are fall-out Issues that depend on the Commission's vote in prior Issues. As such, these Issues will be subject to change if the Commission modifies staff's recommendations.

Final rate Issues rely on the Commission's final vote on revenue requirements and cost-of-service methodology. Issues that will be voted on at the December 19, 2024 Commission Conference are Issues 78, 79, 80, 81, 82, 93, and 117.

## Discussion of Issues

### 2025 TEST PERIOD AND FORECASTING

**Issue 1:** Is TECO's projected test period for the 12 months ending December 31, 2025, appropriate?

**Recommendation:** Yes. TECO's projected test period comprised of the 12 months ending December 31, 2025, is appropriate. (Kunkler)

#### **Position of the Parties:**

**TECO:** Yes. Tampa Electric's proposed test period of the twelve months ending December 31, 2025 is appropriate for use as a test year because (1) 2025 is the first year the company's proposed rates are proposed to be in effect and (2) the company's financial budget for that period reasonably represents Tampa Electric's projected revenues and costs of service, capital structure, and rate base needed to provide safe, reliable and cost-effective electric service.

**OPC:** Yes, the Tampa Electric projected test period for the twelve months ending December 31, 2025 is appropriate with OPC's adjustments.

#### **FL RISING/**

**LULAC:** Yes, with adjustments.

**FIPUG:** Yes. However, adjustments are recommended by the Office of Public Counsel ("OPC") should be made.

**FEA:** No position.

#### **SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Considered on a stand-alone basis, TECO's projected test year - the 12 months ending December 31, 2025 - is consistent with PSC practice. The PSC must recognize that using a projected test year reduces risks faced by the utility, TECO in this case, and this reduced risk must be reflected in the ROE used to set rates. Moreover, the Commission must ensure that forecasts for the test year are accurate and appropriate.

#### **FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

In general, a projected test year methodology uses forecasted data for a 12-month period to match average revenues and expenses with average rate base investment. TECO witness Chronister maintained the projected test period “reflects the Company’s projected revenues and expenses, capital structure, and rate base required to provide safe, reliable, and cost-effective service to customers when the Company’s proposed new rates for 2025 will be in effect. (TR 3366; TECO BR 5)

OPC, FL Rising/LULAC, and FIPUG appear to agree that the 2025 test year is appropriate with the caveat of “with adjustments.” (OPC BR 15; FL Rising/LULAC BR 7; FIPUG BR 5) FRF and Walmart stated that the use of a projected test year is consistent with Commission practice; however, they contend that the use of a projected test year reduces risk faced by the Company, and that reduced risk must be reflected in the ROE used to set rates. (FRF BR 27; Walmart BR 10) Sierra Club and Fuel Retailers took no position on this Issue. (Sierra Club BR 45; Fuel Retailers BR 3)

Considering no intervenors have cited any specific adjustments be made to the test year, staff agrees with the Company that this Issue appears uncontested. (TECO BR 5)

Staff believes that the 12 months ending December 31, 2025, provides a reasonable and forward-looking basis for assessing TECO’s financial and operational performance, allowing for a thorough evaluation of future revenues, expenses, and rate base investment. Further, staff believes this test period ensures that the projections reflect current trends, anticipated developments, and future conditions, making it a sound period for regulatory and financial planning.

TECO’s proposed 2025 test year will result in a matching of the Company’s projected revenues with average rate base investment and average expenses during the first 12 months in which the new rates would be in effect. No testimony was provided in this case to the contrary, therefore, staff agrees with the parties that the projected test period of the 12 months ending December 31, 2025, is appropriate.

**CONCLUSION**

Staff recommends that TECO’s projected test period comprised of the 12 months ending December 31, 2025, is appropriate.

**Issue 2:** Are TECO’s forecasts of customers, kilowatt-hour (kWh), and kilowatt (kW) by revenue and rate class, appropriate?

**Recommendation:** TECO’s forecast of customers for the 2025 test period is reasonable; however, TECO’s forecast of kWh (energy sales) and kW (demand) should be adjusted to reflect recent weather trends. TECO’s retail energy sales forecast for the 2025 test period should be increased by 204,301,725 kWh and TECO’s monthly peak demand forecast should be adjusted to reflect 10-year normal weather as shown in Table 2-4. For purposes of the rate setting phase of this proceeding, TECO should be directed to provide the associated adjusted revenue and rate class energy and demand forecasts for all impacted classes. (Kunkler)

**Position of the Parties:**

**TECO:** Yes. The company’s 2025 customer, demand, and energy forecast uses theoretically and statistically sound forecasting methods previously reviewed and approved by the Commission and reasonable and appropriate “out of model” adjustments for changes in energy efficiency, electric vehicle charging, and private rooftop solar. OPC’s proposed base revenue adjustments for 2025, 2026, and 2027 use a methodology that overlooks key facts, has severe shortcomings, is inaccurate, and therefore should be rejected.

**OPC:** No. Tampa Electric’s forecasting fails to conform to historic trends and is biased by Tampa Electric’s usage of out-of-model adjustments. As a result, Tampa Electric’s forecasts are consistently lower than actuals. For example, the average forecast variance in Tampa Electric’s prior two rate cases was 2.1%, which, if applied to this case, would result in higher forecasted achieved retail revenue of \$31 million in 2025, \$37 million in 2026, and \$39 million in 2027.

**FL RISING/**

**LULAC:** No. As discussed further below, TECO consistently over forecasts the month of January for kW sales (especially from the residential class) and under forecasts kWh sales for the summer months.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. TECO's forecasts understate customer growth and sales, which in turn understates the revenues that TECO can reasonably be expected to receive over the 2025-2027 period. TECO's forecasts consistently understate the utility's actual results and are further biased by inappropriate out-of-model adjustments.

**FUEL**

**RETAILERS:** No Position.



**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

An electric utility's load forecast is a projection of the quantity of customers, energy, and demand over a specified period in the future. The load forecast helps a utility plan its energy production and manage resources to ensure reliable service for customers. Typically, a utility's load forecast is the composite of revenue and rate class forecasts. The Company's customer, use-per-customer (energy), and demand forecasts in this proceeding were sponsored by TECO witness Cifuentes and utilized an integration of econometric models and Statistically Adjusted End-use (SAE) models to develop the Company's load forecast for the 2025 test year. (TR 1491, TECO BR 6)

**TECO's Customer Forecast**

TECO witness Cifuentes stated that the primary economic drivers for its customer forecast are "Hillsborough County population estimates, Hillsborough County Commercial and Manufacturing employment, building permits, and time-trend variables." (TR 1492) With this information, according to witness Cifuentes, TECO developed a forecasted annual customer growth rate of 1.7 percent for the 2025 test year, resulting in a forecast of 862,443 customers. (EXH 25, MPN C10-605)

OPC witness Dismukes remarked that TECO's forecasts of customers historically have been understated, ranging from -0.3 percent to -2.2 percent per year, however, OPC did not directly challenge TECO's customer forecast itself nor the inputs used to arrive at the Company's forecast. (OPC BR 16; TR 2180; EXH 40, MPN C20-1983) FRF also criticized TECO's customer forecast as being "understated," while FIPUG and Walmart adopted OPC's position. (FRF BR 28; FIPUG BR 5; Walmart BR 9)

Staff has reviewed TECO's customer models, assumptions, and inputs used to project the Company's number of customers for the 2025 test year. TECO's 0-3 year average error rate with respect to its customer forecast was -0.5 percent, while its projection of 1.7 percent growth is comparable to its historical customer growth average over the past 15 years (1.6 percent). (EXH 193, MPN E5462; EXH 25, MPN C10-605) Based on its review, staff believes the Company's customer forecast of 862,443 for the 2025 test year is reasonable.

**TECO's Energy Sales Forecast**

TECO's energy sales forecast is essentially the result of multiplying a utility's customer forecast by its use-per-customer consumption forecast. A use-per-customer forecast predicts how much energy each customer (such as a household, business, or factory) will likely use on average. Factors such as energy efficiency improvements, new technologies (electric vehicles, solar, etc.), and seasonal variations in demand can impact a utility's use-per-customer forecast.

TECO projects its total use-per-customer energy consumption to decline by approximately 3.9 percent from 24,925 kWh in 2023 to 23,949 kWh in 2024, and then decline by another 0.9 percent from 23,949 kWh in 2024 to 23,730 kWh for the 2025 test year. (EXH 25, MPN C10-610) To explain the forecasted reduction, TECO cited improvements in end-use efficiency resulting from appliance and equipment replacement; new end-use standards, such as the new lighting standards, economy-induced conservation; demand-side management (DSM) program activity; and the continued addition of rooftop solar panels. (TR 1501) In addition, specific to the 2023-2025 year, TECO witness Cifuentes cited the transition from years when actual weather was hotter than normal to years based on normal weather. (TR 1516)

After multiplying its use-per-customer forecast with its customer forecast for the 2024 historic base year + 1 and the 2025 test year, TECO projects its total retail energy sales to decline by approximately 2.3 percent, from 20,791 gigawatt hours (GWh) in 2023 to 20,315 GWh in 2024, and then increase by 0.7 percent from 20,315 GWh in 2024 to 20,466 GWh for the 2025 test year. (EXH 25, MPN C10-611)

TECO witness Cifuentes explained that the primary cause of the decline in its forecasted 2024 energy sales is due to “higher energy consumption in 2023 due to hotter weather versus a projection of energy consumption for 2024 under normal weather conditions.” (TR 1516, TECO BR 7) Witness Cifuentes further explained that TECO’s projected gradual increase in energy sales over the forecast horizon (2024-2033), including the 2025 test year, is due to customer growth, which is offset by its projected decline in energy use-per-customer. (TR 1501, EXH 25, MPN C10-606)

**Historical Energy Sales Forecast Error**

TECO has under-forecasted its Total Retail Sales in recent years, by an average of 2.3 percent as presented in Table 2-1. TECO explained that these under-forecasts, for the 2020 through 2023 period, were due to weather being “extreme with many record-breaking years of heat.” (EXH 193, MPN E5459-5460) OPC witness Dismukes contends that the Company’s consistent under-forecasts of energy sales over the past decade raises “serious questions about the reliability and integrity of the forecasts.” (TR 2180)

**Table 2-1  
 Accuracy of TECO Total Retail Sales Forecasts**

	Forecast Error Rate (%)				0-3 Year Error (%)	
	Years Prior				Average	Absolute Average
	3 years	2 years	1 year	0 years		
<b>2020</b>	-0.7%	-0.2%	-1.6%	-2.2%	-1.2%	1.2%
<b>2021</b>	0.1%	-1.2%	-2.0%	-2.5%	-1.4%	1.5%
<b>2022</b>	-2.3%	-2.8%	-3.3%	-3.2%	-2.9%	2.9%
<b>2023</b>	-3.3%	-3.9%	-4.0%	-3.9%	-3.8%	3.8%
<b>Average</b>	-1.5%	-2.0%	-2.7%	-2.9%	-2.3%	2.3%

Source: Exhibit 193, MPN 5462

### ***Out of Model Adjustments***

An out-of-model adjustment is a manual adjustment made to the results of a model to account for factors not captured within the model itself.

TECO's energy sales forecast incorporates three major out-of-model adjustments – energy efficiency, electric vehicle charging, and private rooftop solar. These three out-of-model adjustments collectively reduce the Company's energy sales forecast for the 2025 test year by approximately 168,429 megawatt-hour (MWh). (EXH 146, MPN D7-427-439)

OPC witness Dismukes argued that TECO's forecasting methodology "fails to conform to historic trends and is biased" due to TECO's usage of out-of-model adjustments. (TR 2177; OPC BR 16) Witness Dismukes insisted that TECO's out of model adjustment calculations lack supporting evidence and rely on assumptions not supported by the record. (TR 2172-2176, OPC BR 18) OPC argued that, due to TECO's history of under-forecasting energy sales, the Company should exclude the "subjective" out of-model adjustments made to its energy sales forecasts. (TR 2167) Witness Dismukes further argued the Company's out-of-model adjustments lack "supporting evidence and proper documentation" to prove their reasonableness and also lead to "biased" load forecasts. (TR 2176; TR 2180) OPC concluded that the Commission should address TECO's forecasting "deficiencies" by rejecting the Company's out-of-model adjustments, resulting in a 2025 sales projection of 20,635,457 MWh. (TR 2186; OPC BR 18)

In rebuttal, TECO witness Cifuentes argued against OPC's suggested removal of the Company's out of model adjustments to its future energy sales projections. (TR 1509-1521) The Company contended that its forecasting models do not contain explanatory variables that capture the effects of conservation, electric vehicle charging, and customer-owned rooftop solar, and the removal of such adjustments would "impair the [C]ompany's ability to provide reliable service to its customers and would impede [its] ability to plan appropriately for future generation and infrastructure needs." (TECO BR 6-7, TR 1512-1513)

While staff agrees with OPC that the Company's recent history of under-forecasting energy sales is problematic, staff is not persuaded by OPC witness Dismukes that TECO's out-of-model adjustments lack supporting evidence and proper documentation. Therefore, staff disagrees with OPC's proposed removal of the Company's out-of-model adjustments from its energy sales forecast. Staff believes the Company's out-of-model adjustments are substantiated and well-documented, as detailed in the rebuttal exhibits of witness Cifuentes. (EXH 146, MPN D7-429-444)

### ***Normal Weather Projections***

Weather plays a vital component in a utility's load forecasts due to its direct and sizable impact on how much energy customers use. When modeling use-per-customer, utilities rely on an assumption of "normal weather," which is a utility-calculated baseline used to estimate typical weather conditions over a specific period. This modelled weather is then used as the utility's projected weather in the test year used to create the Company's sales and demand forecasts.

TECO obtained its weather data from a National Oceanic and Atmospheric Administration (NOAA) weather station located at Tampa International Airport, which represents the weather

conditions in TECO's service area. (EXH 212, MPN E8208; TR 1633) TECO's normal weather projection acts as a baseline for its weather variables, measured in cooling degree days (CDD) and heating degree days (HDD), which are the leading drivers in TECO's energy sales.<sup>6</sup> (EXH 14, MPN J1336-J1337)

In this proceeding, TECO utilized Monte Carlo simulations over a 20-year historical base period to calculate normal weather conditions.<sup>7</sup> TECO witness Cifuentes explained that the Company utilized the 50th percentile in its Monte Carlo simulations when calculating normal weather, which results in CDD and HDD projections being very similar to a straight average over the past 20 years. (TR 1593) TECO witness Cifuentes maintained that a 20-year historical base period provides a "stable" transition year-to-year in normal weather assumptions, and is an important component for the Company's long-term planning. (TR 1598-1599; TECO BR 7-8)

OPC argued against TECO's reliance on a 20-year weather normalization period for forecasting normal weather, claiming it "biases" results. OPC insisted that the Company's energy sales forecasts "always understate results when compared to actuals but not always understate results when compared to weather normalized actuals," suggesting that the Company's weather normalization adjustment is "understating forecast results." (OPC BR 17) FL Rising/LULAC agree with OPC that TECO should not rely on 20-year normalized weather patterns, stating:

Energy sales growth assumptions must not rely on 20-year normalized weather patterns, but should assume that the increasing heat that the Tampa area is experiencing from climate change will continue to get worse.

(FL Rising/LULAC BR 7)

FIPUG and Walmart also adopted the position of OPC. (FIPUG BR 5; Walmart BR 9)

While TECO acknowledged that transitioning to a 10-year historic base period for calculating normal weather would increase projected sales for the test year, it also states that the transition would "accelerate the need to build new generating plant and increase projected expense levels." (TECO BR 8) TECO further argued that if it was forced to adopt a different period than 20-years, it would "impair the comparability" of Florida Reliability Coordinating Council (FRCC) data, which relies on a uniform period of 20-years for member utilities. (TR 1512, 1599) TECO contended that its 2025 customer, demand, and energy forecasts use "theoretically and statistically sound" methods previously approved by the Commission and should be approved in this case. (TECO BR 6)

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<sup>6</sup> CDDs and HDD's are calculated using a baseline of 65 degrees. In the instant docket, TECO calculates normal weather as the number of degrees deviation from that mark, as a Monte Carlo Simulation (that approximates a straight average by month over 20 years).

<sup>7</sup> Monte Carlo Simulations are a type of computational technique that uses random sampling to estimate complex systems' outcomes and assess uncertainty or variability in predictions.

Date: November 22, 2024

Using 20 or even 30 years as a historical base period has been standard practice for Florida utilities in the past.<sup>8</sup> However, staff is concerned that continued reliance on the historical methodology based on 20 to 30 year unweighted averaging/simulation of weather metrics for projecting future weather conditions may include a downward bias. Staff has reviewed the Company's weather data and it shows a trend of significantly warmer weather over the historical base period. (EXH 25, MPN C10-608) TECO has stated that Monte Carlo simulations do not account for trends in CDD/HDD data, even though the Company has acknowledged that trend exists in the data. (EXH 208, MPN E7781)

CDD data provided by the Company exhibit an increasing trend over the historical 20-year period, indicating warmer weather in more recent years. (EXH 25, MPN C10-608) For example, the past 9 years of TECO's weather data from 2015-2023 all depict higher annual CDDs than any of the previous 11 years from 2003-2014. (EXH 25, MPN C10-608) In fact, the past 9 years of the Company's weather data all show annual CDD counts higher than any of the previous 45 years going back to 1970. (EXH 216, MPN E8277) TECO witness Cifuentes acknowledged there was a "sharp increase" in CDDs in 2015 and the following years "have remained higher." (EXH 208, MPN E7781)

With higher temperatures, there is typically an increase in energy consumption for certain rate classes, particularly for cooling needs. As such, staff believes that if the Company's CDD and HDD baseline is understated, this will most likely result in understated energy sales and demand projections.

Assuming TECO's 50th percentile used for CDD projections is normal, one can infer that there is a 50 percent chance the actual CDDs for a given year will be lower than normal, and a 50 percent chance actual CDDs will be higher than normal, similar to a flip of a coin. Witness Cifuentes acknowledged at hearing that the likelihood of actual CDDs being higher than normal for 9 straight years was 0.2 percent.<sup>9</sup> (TR 1636) This extremely low probability leads staff to conclude that what TECO has proposed as a "normal" level of CDDs used to project sales for the test year is most likely understated.

At hearing, witness Cifuentes further contended "there is no utility [in Florida] using 10 years or anything lower than 20, and there is a reason for that." (TR 1598) However, later in the hearing, witness Cifuentes did not contest that on August 22, 2024, a date subsequent to her review on the matter, Florida Public Utilities Company filed testimony with the Commission in Docket No. 20240099-EI basing its energy use-per-customer forecast on 10-year weather normals for CDDs.<sup>10</sup> (TR 1634)

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<sup>8</sup> Order PSC-2021-0202-AS-EI, issued June 4, 2021, in Docket 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*

Order PSC-2021-0423-S-EI, issued November 10, 2021, in Docket 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

<sup>9</sup>  $\frac{1}{2}$  to the 9<sup>th</sup> power, or  $1/512 = 0.2$  percent.

<sup>10</sup> Document No. 08591-2024, filed on August 22, 2024, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company.*

Staff believes that utilizing a normal weather forecast based on a 20-year historical average fails to adequately account for the consistently hotter weather experienced during the past 9 years. Thus, staff believes that relying on such a weather forecast will likely result in understated energy sales/demand for the 2025 test year. Therefore, staff recommends the use of a 10-year normal weather methodology when projecting weather-related factors such as CDDs and HDDs. Staff believes based on record evidence that the more recent 10-year period better captures the weather trends experienced by TECO over the past decade.

**Energy Sales Impact**

In response to staff discovery, TECO provided 2025 test year energy sales and demand, using 5- and 10-year normal weather sensitivities. (EXH 216, MPN E8271-8273) In the 10-year sensitivity, TECO’s annual test year energy sales increased from 20,466,082,888 kWh to 20,670,384,613 kWh, an increase of 204,301,725 kWh (1.0 percent).

The impact to TECO’s 2025 test year energy sales utilizing a 10-year normal weather methodology versus the Company’s proposed 20-year normal weather methodology is summarized in Table 2-2.

**Table 2-2  
 TECO forecasted 2025 Test Year Energy Sales using 10-Year Normal Weather vs.  
 20-Year Normal Weather (kWh)**

Month	20-yr Normal	10-year Normal	Difference	Percent Difference
1	1,560,540,942	1,545,211,898	-15,329,045	-1.0
2	1,438,513,469	1,435,642,926	-2,870,543	-0.2
3	1,410,001,231	1,419,794,146	9,792,916	0.7
4	1,486,176,335	1,513,337,943	27,161,608	1.8
5	1,652,308,780	1,682,127,462	29,818,682	1.8
6	1,914,020,050	1,931,847,663	17,827,612	0.9
7	2,021,901,959	2,045,296,806	23,394,847	1.2
8	2,014,576,041	2,028,263,057	13,687,016	0.7
9	2,060,985,018	2,088,298,555	27,313,538	1.3
10	1,841,407,273	1,866,131,162	24,723,889	1.3
11	1,580,568,906	1,619,695,623	39,126,716	2.5
12	1,485,082,884	1,494,737,373	9,654,489	0.7
<b>TOTAL</b>	<b>20,466,082,888</b>	<b>20,670,384,613</b>	<b>204,301,725</b>	<b>1.0</b>

Source: EXH 216, MPN E8271

Staff believes that the aforementioned adjustment to TECO’s normal weather calculation will produce an energy sales forecast less likely to continue the trend in under-forecasting that has taken place over the last several years. A summary of TECO’s, OPC’s, and staff’s proposals, with regard to TECO’s 2025 test year energy sales, are summarized in Table 2-3.

**Table 2-3  
 TECO, OPC, and Staff’s Proposals – 2025 Test Year Energy Sales (GWh)**

	Retail Energy Sales excluding out of model adjustments	Out of model adjustments	Total Retail Energy Sales
TECO	20,635	(169)	20,466
OPC	20,635	0	20,635
STAFF	20,839	(169)	20,670

Source: EXH 25, C10-611; EXH 36, C20-1978; EXH 146, MPN D7-431, D7-435, D7-439

**TECO’s Demand Forecasts**

A demand forecast is a measure of the maximum amount of power consumers require at any given time (e.g. monthly, seasonal, etc.). Accurate demand forecasts are important for utilities in order to balance resources, plan for future capacity, and measure how much energy is needed to be produced, purchased, and/or stored to maintain a reliable and efficient power supply for customers.

TECO forecasts monthly peak demand on the per-customer basis, and multiplies that forecast by its customer forecast to arrive at its peak forecasts for the test year. TECO explained that, given the increase in customers is offset somewhat by the decrease in per customer demand, it projects a 1.2 percent increase in winter peak demand and a 0.8 percent increase in summer peak demand. This results in a winter peak projection of 4,566 MW and a summer peak projection of 4,421 megawatts (MW) for the 2025 test year. (TR 1502; EXH 216, MPN E8273; EXH 25, MPN C10-612-613)

No intervenors challenged TECO’s demand forecasts. However, to maintain consistency with the energy sales forecast methodology, staff believes a demand forecast based on 10-year weather normals, as provided by TECO, should be used. Thus, staff believes the 10-year normal adjustment to TECO’s 2025 forecasted demand, as shown below in Table 2-4, is appropriate. (EXH 216, MPN E8273)

**Table 2-4**  
**TECO's Forecasted 2025 Test Year Peak Demands using 10-Year Normal Weather vs 20-Year Normal Weather (MW)**

Month	20-year Normal	10-year Normal	Difference	Percent Difference
1	4,466	4,586	20	0.4
2	3,557	3,534	-23	-0.6
3	3,602	3,621	19	0.5
4	3,708	3,814	106	2.9
5	4,059	4,157	98	2.4
6	4,366	4,408	42	1.0
7	4,365	4,408	43	1.0
8	4,421	4,558	137	3.1
9	4,276	4,362	86	2.0
10	3,873	3,982	109	2.8
11	3,436	3,501	65	1.9
12	3,918	3,836	-82	-2.1

Source: EXH 216, MPN 8273

### CONCLUSION

TECO's forecast of customers for the 2025 test period is reasonable; however, TECO's forecast of kWh (energy sales) and kW (demand) should be adjusted to reflect recent weather trends. TECO's retail energy sales forecast for the 2025 test period should be increased by 204,301,725 kWh and TECO's monthly peak demand forecast should be adjusted to reflect 10-year normal weather as shown in Table 2-4. For purposes of the rate setting phase of this proceeding, TECO should be directed to provide the associated adjusted revenue and rate class energy and demand forecasts for all impacted classes.



Date: November 22, 2024

**Issue 3:** What are the inflation, customer growth, and other trend factors that should be approved for use in forecasting the test year budget?

**Recommendation:** The trend factors that should be used in forecasting the test year budget are: 2.1 percent for inflation, 1.7 percent for customer growth, 3.75 percent for non-union labor, and 3.5 percent for union labor. (Barrett, Kunkler)

**Position of the Parties:**

**TECO:** The company's 2025 forecast was prepared using a 2.1 percent inflation rate, a 1.7 percent increase in customer growth, a 3.75 percent increase for non-union labor, and a 3.5 percent increase for union labor.

**OPC:** A moderate sales/revenue adjustment which simply excludes several of Tampa Electric's proposed out-of-model adjustments is reasonable.

**FL RISING/**

**LULAC:** Assumptions used for forecasting customer growth should include Hillsborough County population estimates, among other variables. Inflation continues to come down and should be assumed to be approximately 2%. Energy sales growth assumptions must not rely on 20-year normalized weather patterns, but should assume that the increasing heat that the Tampa-area is experiencing from climate change will continue to get worse. Customer growth should be assumed to continue at approximately at least 1% per year.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The inflation, customer growth, sales growth, and other trend factors used in forecasting for TECO's test year budget are those recommended by OPC's witnesses.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

Trend factors are numeric escalators (or multipliers) that are applied to historic expenses as an operation and maintenance (O&M) benchmarking tool and for preparing the forward-looking test year O&M expense budget amounts. This Issue addresses TECO's application of inflation, customer growth, as well as labor and non-labor trend factors for the 2025 forecasted test year budget.

**Inflation Trend Factor**

TECO used the Consumer Price Index (CPI) - All Items (unadjusted) as its measure of inflation. (EXH 204, MPN E6574) The Company used CPI in its compound multiplier calculations as a comparative evaluation of its expense forecasts. (EXH 5, MPN J374) The source of the CPI values that TECO used was the May 2023 forecast delivery provided by Moody's Analytics (Moody's), which estimated inflation values of 2.6 percent for 2024, and 2.1 percent for 2025. TECO stated it did not consider any alternative sources of CPI other than Moody's, although it acknowledged that an internal work unit (Load Research & Forecasting) publishes an annual inflation forecast memo with CPI information for benchmarking purposes. (EXH 204, MPN 6575) For consistency across all schedules related to forecasting, the Company used the same source and forecasted values in all schedules in this proceeding that were related to CPI. (EXH 204, MPN E6573) TECO believes the forecasted inflation rate of 2.1 percent or the 2025 test year, which it obtained from Moody's, is reasonable and should be approved. (TECO BR 8)

No party offered testimony on the inflation trend factors that TECO used for forecasting its 2025 test year budget.

Although TECO did not consider any alternative sources of CPI other than Moody's, the Company monitors CPI on a continuous basis through internal sources. (EXH 204, MPN 6575) Staff notes the CPI values TECO sourced from Moody's May 2023 forecast delivery (inflation values of 2.6 percent for 2024, and 2.1 percent for 2025), which it used in this case, were conservative, when compared to Moody's May 2024 forecast, as shown in the table below.

Moody's Analytics	Date of Forecast Delivery	
	May 2023	May 2024
Forecast of CPI for 2024	2.6 percent	3.2 percent
Forecast of CPI for 2025	2.1 percent	2.5 percent

(EXH 204, MPN E6574)

Staff notes that the CPI inflation value TECO used for its 2025 test year budget (2.1 percent for 2025) is nearly the same as the value that FL Rising/LULAC believe is appropriate (approximately 2 percent). For preparing the 2025 test year budget, staff believes that TECO's forecasted inflation rates of 2.6 percent (for 2024) and 2.1 percent (for 2025) are reasonable.

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### **Customer Growth Trend Factor**

A customer growth trend factor is a composite of elements that influence the rate at which a customer base expands over time. MFR Schedule C-33 (page 1 of 1, line 17) reflects that TECO estimates customer growth at 1.69 percent for 2024, and 1.67 percent for 2025. (EXH 5, MPN J325) In its analysis, TECO utilized the Bureau of Economic and Business Research and Moody's as sources for its input variables. (EXH 14, MPN J1340) TECO witness Cifuentes stated:

The primary economic drivers for the customer forecast are Hillsborough County population estimates, Hillsborough County Commercial and Manufacturing employment, building permits, and time-trend variables. The population forecast is the starting point . . . [and it] is based upon the projections of the University of Florida's Bureau of Economic and Business Research (BEBR).

(TR 1492)

According to witness Cifuentes, TECO tests the reasonableness of its forecasts and assumptions by first comparing the projections to observed historical data. (TR 1495) TECO additionally evaluates state and federal government resources, and also data from the University of Central Florida, as alternative sources of information for comparative purposes. (TR 1495) The witness concedes that projections from the different sources vary slightly, but are consistent with regard to projecting the economic rebound forecasted for 2025. (TR 1495) TECO believes the forecast of customer growth (1.7 percent) it used for forecasting the 2025 test year budget is an appropriate value. (TECO BR 8)

OPC witness Dismukes did not offer alternatives to the inflation and customer growth trend factors TECO utilized for this proceeding. (TR 2177)

No other party offered testimony specific to the customer growth trend factors that TECO used for forecasting its 2025 test year budget. However, FL Rising/LULAC argued in its brief that TECO's 2025 test year customer growth forecasts should include the following Hillsborough County data: population estimates, commercial and manufacturing employment data, information on the number of building permits, and estimates on time-trend variables, such as customer growth values of about 1 percent per year, on a prospective basis. (FL Rising/LULAC BR 7)

Staff notes that the University of Florida's BEBR provides publicly available population data which TECO used as an input for its test year customer forecasting. (EXH 14, MPN J1326-1340) In addition, the forecast data the utility receives from Moody's, including economic growth data, is extracted from a customized database that provides county-specific (Hillsborough) data. (EXH 193, MPN 5463) The utility indicates that the customer forecast used in this proceeding has also been used in six other FPSC dockets since 2023. (EXH 193, MPN 5456)

Staff agrees with FL Rising/LULAC's advocacy that TECO should incorporate Hillsborough County-specific data to develop its customer forecasts. (FL Rising/LULAC BR 7) TECO did, in fact, incorporate Hillsborough County population and employment estimates, and supplemented

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that with other information from Moody's when developing its 2025 customer growth estimate of 1.7 percent. (TR 1496; EXH 14, MPN J1340) FL Rising/LULAC's analysis of Hillsborough County-specific data yielded a lower 2025 customer growth estimate of about 1 percent. (FL Rising/LULAC BR 7)

As mentioned in Issue 2, TECO's projection of 1.7 percent customer growth is comparable to its historical customer growth average over the past 15 years (which is 1.6 percent). (EXH 25, C-10-605) Therefore, for preparing the 2025 test year budget, staff believes it is reasonable that TECO forecasted a customer growth rates of 1.69 percent (for 2024) and 1.67 percent (for 2025).

### **Labor Trend Factors**

Labor trend factors are closely related to the compensation and payroll-related matters that are addressed in Issue 53. In its brief, TECO asserts that its 2025 budget forecast was prepared using a 3.75 percent increase for non-union labor, and a 3.5 percent increase for union labor. (TECO BR 8)

TECO compared historic and forecasted (2021-2025) payroll and fringe benefits growth rates to the CPI. (EXH 5, MPN J370) TECO witness Cacciatore stated:

Tampa Electric's 2025 budgeted gross average salary per active team member is \$116,217 as compared to \$108,017 in 2021. This represents an increase of 7.6 percent since 2021 and an average growth rate of 2 percent per year. The average annual growth rate is consistent with the average actual and forecasted CPI included in MFR Schedule C-35 for the period from 2021-2025.

(TR 1421)

TECO witness Cacciatore stated that approximately 840 of its employees are part of a collective bargaining unit affiliated with two unions. (TR 1383) The witness asserted TECO was engaged in negotiation activities for both agreements during 2024, although in 2023 the salary increases in their prior agreements were in the range of 3.0 to 3.5 percent. (TR 1425) Witness Cacciatore stated TECO's 2024 and 2025 forecasted labor costs are based on market survey data. (TR 1425)

Intervenors offered no testimony on the labor trend factors that TECO used for forecasting its 2025 test year budget.

Based on historical and projected gross average salary growth rates and CPI, as well as recently negotiated salary agreement increases, staff believes TECO's union and non-union labor trend factors are reasonable.

### **CONCLUSION**

The trend factors that should be used in forecasting the test year budget are: 2.1 percent for inflation, 1.7 percent for customer growth, 3.75 percent for non-union labor, and 3.5 percent for union labor.

## QUALITY OF SERVICE

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

**Recommendation:** Yes. Staff recommends that TECO's quality of service is adequate. (Ramirez-Abundez)

### **Position of the Parties:**

**TECO:** Yes. The company scored better than industry average for all six J.D. Power measures of customer satisfaction in 2023. Its FPSC complaint record and service hearings do not reveal systemic service problems. The company has improved its system heat rate, reduced the frequency of power outages and shortened the duration of those outages. Its "flickers" in 2023 were 30 percent less frequent than in 2017 and the company provides 99.98 percent service reliability.

**OPC:** The Commission held several customer service meetings in this matter in which the sworn testimony provided by Tampa Electric's customers was overwhelmingly negative. While Tampa Electric's electric service may be adequate for ratemaking purposes, the Commission should bear this testimony in mind.

### **FL RISING/**

**LULAC:** No. Per the customer service hearings and customer correspondence submitted in the docket, there is significant room for improvement in both the reliability of TECO's service for certain customers, and certainly in the cost of TECO's service for all of TECO's residential and small business customers.

**FIPUG:** Yes.

**FEA:** No position.

### **SIERRA**

**CLUB:** No, part of the adequacy of electric service is its affordability and TECO does not provide electric service at affordable rates.

**FRF:** TECO's quality of service as measured by standard reliability metrics satisfies minimum quality of service standards, and there is no evidence that TECO has violated the National Electrical Safety Code.

### **FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

Pursuant to Section 366.041, 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 one in-person service hearing on June 13, 2024, within TECO's service territory. Additionally, the Commission held two virtual service hearings on June 10, 2024, and June 11, 2024. The service hearings provide an opportunity for customers to raise concerns regarding the Company's quality of service and request for a rate increase. A total of 53 customers testified at the service hearings. Of those 53 customers, 44 customers expressed disapproval of a rate increase, and nine customers expressed concerns with quality of service and reliability. The nine customers raised concerns regarding difficulty reaching customer service, billing issues, meter difficulties, excess vegetation, switchgear problems, pole replacement difficulties, and momentary power interruptions. TECO serves approximately 844,000 customers. (SH1-TR; SH2-TR; SH3-TR)

Staff witness Calhoun testified that from April 1, 2020, through March 31, 2024, a total of 1,026 complaints were logged in the Commission's Consumer Activity Tracking System (CATS) and of those complaints, 615 were transferred directly to TECO via the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to TECO's customer service personnel for resolution. Of the 1,026 complaints, approximately 52 percent concerned billing issues and approximately 48 percent involved quality of service issues. (TR 2152) Additionally, witness Calhoun testified that of the total 1,026 logged complaints, two quality of service and two billing complaints appeared to demonstrate a Commission Rule violation. (TR 2154) For the two quality of service complaints, it appears that TECO did not provide a timely response to the Commission regarding the complaints. Whereas, for the two billing complaints, the rule violation was associated with improper bills. Given that only four potential rule violations were identified by staff witness Calhoun with respect to logged CATS complaints, staff believes TECO has demonstrated the ability to efficiently respond to customers.

TECO witness Sparkman argued that overall customer satisfaction has increased for both its residential and business customers, and exceeded the industry average in the utility benchmarking study conducted by J.D. Power. (TR 456) Witness Sparkman provided escalation totals, which consists of both customer complaints and inquiries, for the period of 2021 through 2023. Overall, it appears that the escalations received by TECO and the Commission have increased each year for this period. However, it appears the highest number of combined (TECO and Commission) escalations was 680 in 2023, which would represent approximately 0.08 percent of TECO's total customer base. (EXH 17, MPN C2-148; EXH 194, MPN E5497) Witness Sparkman further explained that TECO focuses on six pillars for customer satisfaction: power quality and reliability, billing and payment, price, corporate citizenship, communication, and customer care. (TR 431)

While OPC did not file testimony on quality of service, it did proffer two exhibits. The first exhibit contained copies of approximately 900 customer comments filed in this docket. An overwhelming majority of comments, 99 percent, expressed concerns over a potential rate

increase. (EXH 832) The second exhibit contained the customer complaints logged in CATS between January 1, 2022, and July 17, 2024. (EXH 833) As discussed above, witness Calhoun's testimony identified CATS complaints logged between April 1, 2020, and March 31, 2024. The second exhibit showed an additional 28 complaints filed between April 1 and July 17, 2024, all of which were billing complaints with no apparent rule violations.

None of the intervenors proffered testimony directly addressing quality of service. However, based on the intervenors' briefs, FL Rising/LULAC and Sierra Club do not believe TECO's quality of service is adequate. FEA and Fuel Retailers did not take a position on this Issue. Walmart adopted the same position as OPC. FIPUG stated TECO's quality of service is adequate. FRF stated that TECO satisfies minimum quality of service standards. Furthermore, in support of its position, OPC argued that the Commission should consider the customer testimony from the service hearings as well as Exhibits 832 and 833. As discussed above, staff included this evidence in its analysis. OPC also requested that the Commission consider affordability as part of this Issue; however, the topic of affordability is discussed in Issue 119.

TECO's quality of service appears to be adequate given only four potential rule violations were identified from April 1, 2020, to July 17, 2024, and the overwhelming majority of the customer testimony and comments addressed concerns with a potential rate increase rather than quality of service issues. For these reasons, staff recommends TECO's quality of service is adequate.

## **CONCLUSION**

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

**DEPRECIATION AND DISMANTLEMENT STUDY**

**Issue 5:** Should currently prescribed depreciation rates and provision for dismantlement of TECO be revised?

**Recommendation:** Yes. A review of TECO's 2023 depreciation and dismantlement studies indicate the need for revising the currently prescribed depreciation rates and provision for dismantlement. The specific revisions are discussed in Issues 7 and 11. (J. Wu)

**Position of the Parties:**

**TECO:** Yes. The 2023 Depreciation Study filed by Tampa Electric on December 27, 2023 shows that the company's currently prescribed depreciation rates and provision for dismantlement should be revised.

**OPC:** The present approved service life for solar assets is a 35-year service life and should be retained. The service life for battery energy storage assets should be increased to 20 years. Dismantlement expense related to solar and battery sites should remove environmental and site restoration costs.

**FL RISING/**

**LULAC:** Yes. The depreciation rates should be revised to reflect the presently approved service lives for solar assets. The provision for dismantlement should be reduced to remove post-test year escalations of estimated costs, reduce estimated solar site restoration costs, and reflect longer service lives for solar and battery assets.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes, in part. TECO's presently approved 35-year depreciation life of solar assets should be retained. The service life for battery energy storage assets should be increased to 20 years as proposed by the Company. Dismantlement of solar and battery facilities should not include environmental and site restoration costs.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

TECO's existing depreciation rates and dismantlement provision were approved effective January 1, 2022.<sup>11</sup> On December 27, 2023, the Company filed its 2023 depreciation study and its dismantlement study in Docket No. 20230139-EI. These studies were subsequently consolidated with the current rate case on April 16, 2024. TECO's 2023 depreciation study reflects changes in the Company's plant and reserve balances, and proposes revisions to its current estimates of the depreciation parameters and depreciation rates for various production, transmission, distribution and general accounts. (EXH 26) TECO's 2023 dismantlement study reflects updates to its current estimates of future dismantlement costs and dismantlement provision for the Company's generating facilities. (EXH 27)

In the current proceeding, OPC proposed different estimates of the depreciation parameters and the resulting depreciation rates for solar and battery energy storage equipment-related accounts. (TR 2303) FEA proposed different depreciation parameters and the resulting rates for certain other depreciable accounts. (EXH 112) OPC also proposed different dismantlement costs and the corresponding accruals. (TR 2282; TR 2310)

Taking into consideration the aforementioned changes in the Company's plant activities since its last depreciation study, the updated estimates of the future dismantlement costs, and various depreciation and dismantlement-related proposals proffered by the parties in the proceeding, staff believes that a revision of the existing depreciation rates and dismantlement provisions is necessary. The recommended revisions are discussed in detail in Issues 7 and 11.

**CONCLUSION**

A review of TECO's 2023 depreciation and dismantlement studies indicate the need for revising the currently prescribed depreciation rates and provision for dismantlement. The specific revisions are discussed in Issues 7 and 11.

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<sup>11</sup> PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20200264-EI, *In re: Petition for rate increase by Tampa Electric Company*.

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**Issue 6:** What should be the implementation date for new depreciation rates and the provision for dismantlement?

**Recommendation:** Staff recommends January 1, 2025, as the date of implementation for the new depreciation rates and dismantlement provision. (J. Wu)

**Position of the Parties:**

**TECO:** January 1, 2025. This effective date matches the proposed effective date of the company's proposed new 2025 customer rates.

**OPC:** The new depreciation and dismantlement rates should be implemented with the change in base rates upon approval of the Commission.

**FL RISING/**

**LULAC:** January 1, 2025.

**FIPUG:** The implementation date should be effective on the date that rate adjustments in this case are effective

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** New depreciation and dismantlement rates should be implemented at the same time as any new base rates approved by the Commission in the rate case.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO proposed a January 1, 2025, implementation date for the Company's proposed depreciation rates and its proposed dismantlement provision, because this date matches the Company's proposed effective date of its proposed new 2025 customer rates. All intervenors who took a position agreed with TECO's proposal; FEA and Sierra Club took no position on this Issue.

Rule 25-6.0436(4)(d), F.A.C., requires that data submitted in a depreciation study, including plant and reserve balances or company planning involving estimates, must coincide with the

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effective date of the proposed rates. TECO's supporting data, analyses, and calculations for its proposed depreciation rates, detailed in its 2023 Depreciation Study, are consistent with the Company's proposed implementation date of January 1, 2025. (EXH 26, MPN C11-717-726)

Rule 25-6.04364(3)(k), F.A.C., requires that in a dismantlement study, the proposed provision for dismantlement shall be identified as to the proposed effective date. In its 2023 Dismantlement Study, TECO used January 1, 2025, as the proposed effective date for its proposed accruals related to the dismantlement provision. (EXH 161, MPN E2072)

Staff therefore recommends January 1, 2025, as the practicable date for implementing the revised depreciation rates and provision of annual dismantlement accruals.

### **CONCLUSION**

Staff recommends January 1, 2025, as the implementation date for the new depreciation rates and dismantlement provision.

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**Issue 7:** What depreciation parameters and resulting depreciation rates for each depreciable plant account should be approved?

**Recommendation:** Staff recommends approval of the depreciation parameters and resulting depreciation rates for each depreciable plant account that are listed in Table 7-4. (J. Wu)

**Position of the Parties:**

**TECO:** The Commission should approve the parameters and depreciation rates in Document 4 of Exhibit NA-1, except the life for energy storage devices should be 20 years. The Commission should reject intervenor proposals to the contrary and approve the proposed 35- and 30-year lives for combined cycle and solar generation. It should also reject FEA's proposed interim survivor curves, its proposed survivor curve for account 367, and its net salvage estimates, and Sierra Club's proposed depreciation parameters.

**OPC:** The present approved service life for solar assets is a 35-year service life and should be retained. Battery energy storage systems should reflect a 20-year service life. The Commission should consider reasonable production plant life spans and parameters set forth by FEA Witness Andrews.

**FL RISING/**

**LULAC:** A 20-year service life should be used for Battery Energy Storage System (BESS) assets. A 35-year service life should be used for solar assets. For the depreciation rates for each depreciable plant account, adopt OPC position.

**FIPUG:** Adopt the position of OPC.

**FEA:** The depreciation parameters and depreciation rates presented in CEL Exhibit 111 and updated in CEL Exhibit 147, Document 2 should be approved.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC's position.

**FRF:** The appropriate depreciation life for solar assets is 35 years. The appropriate depreciation life for battery storage assets is 20 years, not 10 years as originally proposed by TECO. The appropriate depreciation lives for other depreciable plant accounts are those recommended by FEA witness Andrews.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue addresses the depreciation parameters and resulting depreciation rates for TECO's depreciable plant accounts that are categorized as production (further classified as steam, other, and solar), transmission, distribution, and general accounts. Staff's recommended depreciation parameters include the survivor curve, which is a pairing of average service life (ASL) with a specific curve shape, an average remaining life (ARL), and an average future net salvage percentage (NS) for each account.<sup>12</sup> The combination of these parameters can be used to provide an account-specific depreciation rate on a going-forward basis, which is the remaining life depreciation rate (depreciation rate). This depreciation rate is designed to recover the remaining unrecovered plant balance, or investment, over the remaining life of the associated investment in the account. The formula for the remaining life depreciation rate is prescribed in the Commission's depreciation rule.<sup>13</sup>

For each plant account, TECO proposed a survivor curve, an ARL, a NS and the resulting depreciation rate, all of which are detailed in TECO's 2023 Depreciation Study. (EXH 26, MPN C11-717-730) For certain accounts, the parties disagree with TECO's proposals. In the production plant category, compared with what TECO has proposed, OPC proposes a longer service life for solar and battery energy storage plants, respectively; and FEA proposes a longer service life for the combined cycle plant, as well as different interim survivor curves for four accounts. In the transmission, distribution, and general plant categories, compared with what TECO has proposed, FEA proposed a longer ASL for one account and larger NS for six accounts. (FEA BR 6-7)

The following sections present staff's analyses of the disparate positions taken by TECO and intervenors on depreciation parameters and resulting depreciation rates in this proceeding.

**Service Life of Solar Plant**

TECO's solar generation depreciation accounts have an existing survivor curve of 35-year ASL with SQ curve shape, denoted as 35-SQ.<sup>14</sup> TECO proposed changing the 35-SQ designation to 30-S3, i.e., using a 30-year ASL with a S3 curve to estimate the solar plant's retirement characteristics. OPC opposed that change, arguing that the currently approved 35-year ASL

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<sup>12</sup> For a depreciation account, the ASL is the average number of years that the assets in the account are expected to be in-service; the curve shape is a graphical representation of the retirement pattern for the plant assets in the account; the ARL is the average number of in-service years left for plant currently in service; and the NS is gross salvage minus cost of removal of the retired plant assets.

<sup>13</sup> See Rule 25-6.0436(1)(e), F.A.C., Remaining Life Rate =  $(100\% - \text{Reserve \%} - \text{Average Future Net Salvage \%}) \div \text{Average Remaining Life in Years}$

<sup>14</sup> In depreciation studies, Iowa Curves, published in Bulletin 125, Statistical Analysis of Industrial Reporting, published in 1935, by Robley E. Winfrey of the Iowa State College Engineering Experimental Station, are widely used to depict the retirement pattern of a plant asset. 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, an R curve implies that retirements tend to occur after the ASL, S represents a symmetric curve shape which implies that retirements tend to have equal chances of occurring prior or after the ASL, and SQ represents square curve shape which implies that retirements tend to occur at the ASL. The number portion of the Iowa Curve designation indicates how steep or flat the curve's shape is.

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should be retained, and OPC witness Kollen asserted that TECO has not provided any evidence that it will not operate the existing and new solar assets for 35 years. (TR 2303)

In refuting OPC's proposal, TECO witness Allis pointed out that the solar generation's existing 35-year service life is an outcome of its 2021 Settlement Agreement in the previous rate case and the Company had proposed a 30-year life originally in that rate case.<sup>15</sup> (TR 1716) He testified that "solar generation is still relatively new, and technology will likely continue to improve, both of which suggest that a shorter life for depreciation purposes would be better than a longer life." (TR 1716–1717)

Witness Allis further testified that:

[Federal Energy Regulatory Commission] FERC Order 898 [titled Reporting Treatment of Certain Renewable Energy Assets] modifies the Uniform System of Accounts for renewable and storage generation. This will include providing additional subaccounts for assets such as inverters and collector systems, at least some of which may have different life characteristics than the overall facilities. Mr. Kollen's proposal to use an average service life of 35 years rather than a life span of 35 years is to effectively increase the service life of solar assets. I do not believe it is reasonable to do so until, at a minimum, these accounting changes are implemented and the new subaccounts can be studied in a new depreciation study in the next rate case.

(TR 1717–1718)

Staff agrees with witness Allis that solar generation is still relatively new and its technology will likely continue to improve. However, due to the nature of new generation technology, TECO has not retired any of its solar facilities so far; hence, there is not much actual data/experience available to be used as a reference in determining the appropriate service life of this type of generation at the present time.

Witness Allis testified that FERC Order 898 will bring accounting changes to the solar generation and a new subaccount would be created. (TR 1717) Since the establishment of any accounts/subaccount involves a process of petition for approval,<sup>16</sup> staff believes that the future new account/subaccount establishment docket would provide for a more informed review of the solar plant accounts' life characteristics to set appropriate depreciation rates. Therefore, staff believes that retaining the currently approved 35-year service life for solar plant and implementing the 35-S3 survivor curve for the related depreciable accounts are appropriate.

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<sup>15</sup> TECO 2021 Settlement Agreement is outlined 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*.

<sup>16</sup> Rule 25-6.0436(3)(b), F.A.C., requires that "[u]pon establishing a new account or subaccount classification, each utility shall request Commission approval of a depreciation rate for the new plant category."

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### **Service Life of Battery Energy Storage Equipment**

TECO's battery energy storage equipment (BESE) accounts have an existing survivor curve of 10-SQ. As of December 2024, TECO has two BESE facilities that were placed in-service in 2020 and 2024. In 2025, the Company plans to bring another three BESE facilities in-service. (EXH 176, MPN E3198)

TECO proposes to use a 10-S3 survivor curve for the BESE plant account, i.e., modify the retirement dispersion for analysis but retain the estimate of a 10-year service life. OPC asserted that TECO's proposed service life estimate is "unduly short," and proposed an estimate of a 20-year service life instead. (TR 2300-2301)

On August 22, 2024, TECO filed an "Updated Revenue Requirements" document which noted that the Company agreed with OPC and proposed that the depreciation life of its energy storage assets be 20 years rather than its original proposal of 10 years. (EXH 835, P 2)

TECO has very limited historical data on the service lives and operations of the BESE assets. A 20-year service life is within the range of the life estimates for BESE assets that TECO's expert witness Allis and his consulting firm have provided for many other utilities across the nation.<sup>17</sup> Staff also notes that the service life of all of TECO's plant assets will be reviewed by the Commission every four years pursuant to Rule 25-6.0436(4)(a), F.A.C. Staff believes that a 20-year service life for TECO's BESE assets is appropriate at this time.

### **Service Life of Combined Cycle Plant**

In a depreciation study, assets such as steam or natural gas generation plants for which all assets at a facility are expected to retire concurrently are referred to as "life span property." (TR 1655) TECO witness Allis testified that life spans for combined cycle (CC) plants are generally consistent with a 35-year estimate, which is the same estimate as currently used for the Company's CC facilities. (TR 1708) He further testified that due to specifics of each facility, including the configuration of the plant, some estimates are longer than 35 years. (TR 1708)

FEA witness Andrews pointed out that TECO's 2023 Depreciation Study indicates that "the Big Bend combined cycle plant (Units 1, 5, & 6) have lifespans of either 35 or 36 years. The Bayside combined cycle plant (Units 1 & 2) have lifespans of 34 and 35 years." (TR 3036) He asserted that TECO witness Allis recommended the use of a 40-year life for CC plants in other Florida electric utilities' proceedings.<sup>18</sup> (TR 3036) He testified that "[i]n order to be consistent with the lifespan of the Polk combined cycle plant and the other major electric utilities in Florida, I recommend the use of a 40-year life for the Big Bend and Bayside combined cycle plants." (TR 3036)

TECO witness Allis disagreed with FEA's life proposal. He explained that his life proposal has taken into consideration the specifics of each generation unit. (TR 1708) Witness Allis also pointed out that FEA witness Andrews has not toured any CC facilities or met with TECO

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<sup>17</sup> EXH 176, MPN E3199-3201 shows ASL estimates for 34 BESE that witness Allis and his consulting firm recommended for various utilities. Among the 34 ASL estimates, 8 are 10-year, 22 are 15-year and 4 are 20-year.

<sup>18</sup> Docket Nos. 20240025-EI, *In re: Petition for rate increase by Duke Energy Florida, LLC.*; and 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

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subject matter experts on these plants, nor has he provided any discussion of factors that would influence the life span of CC facilities. (TR 1709–1710)

Witness Allis testified that:

Bayside Units 1 and 2 are a different construction from many other combined cycle units. While the combustion turbines, heat-recovery steam generators and other assets are relatively new (constructed in 2003 and 2004), the plant uses existing steam turbines that were originally placed in service in the 1960s. Because a portion of the plant is relatively old, this will impact the overall life span of the plant and mean that a 40-year life span, as measured from the installation of the combustion turbines, is likely not attainable from an operational standpoint.

(TR 1713–1714)

He pointed out that the CC units which have a similar configuration were retired much earlier than the 35-year life span.<sup>19</sup> Witness Allis further testified that the increased adoption of renewable generation can also reduce CC plants' life span due to more frequent cycling to follow electrical load:

[S]olar energy is not created consistently throughout the day and, as a result, other generation needs to come online – often quickly – to make up for the loss of solar generation when, for example, the sun goes down. Today, natural gas facilities most commonly follow these generation needs, with some also addressed with other technologies such as battery energy storage systems. As a result, it has become common for even newer base load facilities to follow load (or more precisely follow renewable generation) and cycle more frequently.

[I]ncreased cycling – particularly if there are more starts throughout the year – can limit or reduce the life span of the facility. At a minimum, it likely means more capital replacements and investments to continue operating the facility, impacting the overall economics of the facility.

(TR 1710–1711)

Witness Allis concluded that all of these factors mean that the operations of TECO's CC plants will likely favor a shorter life, all else equal. (TR 1712) Additionally, the witness testified that over the next three decades, there will be significant changes in the electric industry and it is unclear whether CCs could attain longer life spans, at least without major investments. (TR 1714) He argued that TECO's past experience shows that it has replaced aging generation when no longer economical, which also favors the 35-year life span. (TR 1715)

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<sup>19</sup> As an example, Florida Power & Light Company's Lauderdale Units 4 and 5 were CC plants that "had similar construction in that the Lauderdale units also reused the existing steam turbines that had been placed in service decades earlier. Lauderdale [Units] 4 and 5 were retired in 2018 with life spans of 25 years." (TR 1714)



A 35-year life span for TECO’s CC facilities, including the CCs at the Big Bend and Bayside plants, reflects the specific plant conditions of the Company’s CC assets and the current CC operating characteristics in general. Staff believes that retaining the currently approved 35-year life span is appropriate.

### Interim Retirement of Life Span Property Accounts

Interim retirements are the retirements related to assets of a generation facility that do not survive for the entirety of the plant’s life span but are replaced or retired during the life span of the facility.<sup>20</sup> (TR 1664, 1695-1696) For each production account, TECO witness Allis recommended an interim survivor curve to represent the life characteristic of the assets in that account. The only intervenor to propose different interim survivor curves from the Company’s recommendation was FEA witness Andrews, who proffered different proposals for four accounts as detailed below:

**Table 7-1**  
**Differences in Proposed Interim Survivor Curves**

Account No.	Account Description	TECO Proposed	FEA Proposed
312	Boiler Plant Equipment	40-L0	60-O3
341	Structures & Improvements	50-R3	74-R2
342	Fuel Holders	5-R0.5	55-R0.5
345	Prime Movers	50-O1	75-O1

Source: TR 3039

FEA witness Andrews testified that he conducted his own actuarial analysis based on the observed life tables created by TECO witness Allis to determine the interim survivor curve that best fits the significant points of witness Allis’ observed life table.<sup>21</sup> He claimed that the interim survivor curves he recommended are a better statistical fit (low SSD) than those curves that witness Allis recommended.<sup>22</sup> (TR 3037-3038)

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<sup>20</sup> Examples of interim retirements include the retirement of piping, boiler tubes, condensers, turbine blades, and rotors of a generating unit that occur prior to the unit’s final retirement date.

<sup>21</sup> Actuarial analysis is commonly used in evaluating the 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 the vintage and transaction year to develop an observed life table (OLT) to depict the percentage of the assets surviving at each age interval. 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 their end of life yet. 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.

<sup>22</sup> The SSD is the sum of the squared differences between the Iowa Curves and the significant data points from the observed life tables.

In his rebuttal testimony, TECO witness Allis asserted that:

Mr. Andrews “provides no support other than mathematical curve fitting results. However, his curve fitting results fail to properly consider the company’s historical data and, as a result, incorrectly project the experience of older, different technologies onto the company’s current generation fleet. Further, Mr. Andrews’s testimony gives no indication that he incorporated any information in addition to the statistical analysis.”

(TR 1722)

TECO witness Allis further argued this point by stating that FEA witness Andrews’ curve fitting “does not consider the relevance and importance of different data points from the historical analysis.” (TR 1723) He used an example to support the argument: witness Andrews’ analysis for Account 341.00 was based on data through approximately age 50, but TECO’s current power plants in the accounts being analyzed have all been constructed within the last 30 years. As a result, the data points beyond age 30 do not provide meaningful indications of the retirement experience for the plants currently in service, particularly the type of power plants included in the historical analysis that are much different today than 40 or 50 years ago. (TR 1723–1724)

TECO witness Allis concluded his argument by stating that “there are analytical issues with Mr. Andrews’ recommendations, which also lead to atypical results. Additionally, Mr. Andrews does not appear to have considered anything beyond the data.” (TR 1725-1726) Witness Allis claimed that his interim survivor curve recommendations are reasonably consistent with the available data, incorporated knowledge and understanding of the assets, and consistent with the operation of the types of plants as well; thus are better estimates than those of witness Andrews. (TR 1726)

Staff believes that TECO witness Allis’ arguments have merit. Based on the review of the record evidence, staff believes that TECO’s proposed interim survivor curves represent the plant assets’ characteristics more closely and, hence, are more reasonable.

### **Average Service Life and Net Salvage of Mass Property Accounts**

Plant assets such as meters, poles, and conductors that are continually added and replaced are referred to as “mass property.” (TR 1655) TECO’s depreciable transmission, distribution, and general plant assets were studied as mass property to generate its associated depreciation parameters. For those same mass property accounts, FEA proposed a different ASL for one account and different NS rates for six accounts.

#### ***ASL Proposal for Account 367.00 – Underground Conductors and Devices***

This account is the second largest among the mass property accounts, and the third largest of all of TECO’s depreciable accounts. The amount of plant investment booked in the account is \$742.4 million as of December 31, 2024. The assets in the account include cable, enclosed switchgears and potheads (insulated terminals for connecting overhead lines and high-voltage underground cables). Typical causes of retirement in the account include failure, dig-ins and relocations. The average age of retirement in the most recent 10-year period (2013 through 2022) is 21 years. (EXH 26, C11-1088)

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TECO witness Allis proposes a 35-year life estimate with an R1.5 curve shape for this account. In its 2023 Depreciation Study, the Company indicates that the results of the actuarial analysis and simulated plant record (SPR) analysis both support an ASL in the 35-year range.<sup>23</sup> TECO's study also notes that the 35-R1.5 life estimate is on the shorter end of the industry range, but its estimate is consistent with TECO's historic experience as well as the operating environment in Florida. (EXH 26, MPN C11-1088)

FEA witness Andrews disagreed with TECO's life proposal and recommended retaining the existing life estimate of 45-R1.5 which was adopted in TECO's 2021 Settlement Agreement. He asserted that:

In my experience, when companies rely on simulated data and the SPR procedure, the resulting ASLs are almost always understated. The simulations are very dependent on the survivor curves that are used to estimate the data, therefore, the results tend to be skewed to the downsides, resulting in higher depreciation rates.

(TR 3045)

TECO witness Allis responded by pointing out that:

[FEA witness] Andrews provides no support for this statement, and it is not generally consistent with my experience. [. . .] SPR analyses [do] produce results that are more difficult to interpret and require an experienced analyst to recognize the limitations of the analysis. For example, if mortality characteristics are dynamic over time, then the analysis may favor higher or lower mode curves. The selection of higher mode curves in these instances could produce[ ] shorter lives, although lower mode curves would have the opposite effect. [. . .] However, these limitations do not apply for this account to effectively ignore the available analysis, as [witness] Andrews proposes. My recommended survivor curve, supported by the statistical results, uses a mid-mode R1.5 survivor curve.

(TR 1730-1731)

Staff notes that TECO's 35-year ASL estimate was derived from an actuarial analysis that is based on the Company's actual retirement data, and the outcome of TECO's SPR analysis supports the

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<sup>23</sup> An actuarial analysis is a method of deriving survivor curves using the average rates at which property of each age group is retired. It is the preferred method when sufficient data are available. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts. TECO currently maintains aged data for all of its accounts. (TR 1657)

The SPR analysis is a method used for property groups for which the retirements of property by age are not known. However, it does require continuous records of annual plant activity and year-end plant balances. The method suggests probable survivor curves for a property group by successively applying a number of alternative survivor curves to the group's historical additions in order to simulate the group's surviving balance over a selected period of time. One of the several survivor curves which results in simulated balances that conform most closely to the book balance may be considered to be the survivor curve which the group under study is experiencing. (TR 1656)

life estimate resulting from the actuarial analysis. Staff is also aware that in its last depreciation study that was consolidated with the Company’s last rate case, TECO proposed a 40-R1.5 survivor curve for Account 367 based on an actuarial analysis. Further, staff has reviewed the potential impacts to the instant rate case, in terms of the adjustments to rate base, net operating income, and revenue requirement that would result from each witness’ ASL proposal. (EXH 26, MPN C11-721; EXH 112, MPN C30-3099; EXH 211, MPN E8089, E8132–8133; EXH 212, MPN E8202) Taking into consideration all of these matters, staff recommends a 40-R1.5 survivor curve for Account 367, because it reflects the account’s life characteristics, within the industry range of the account’s life estimates, and it is consistent with the Commission’s recognition of the generally accepted principle of gradualism.<sup>24</sup>

**NS Proposals**

Table 7-2 outlines the differences in the NS estimates proposed by TECO and FEA’s witnesses.

**Table 7-2  
 Differences in Proposed Net Salvage Percentage**

Account No.	Account Description	TECO Proposed	FEA Proposed
356	Overhead Conductors & Devices	(50)	(40)
362	Station Equipment	(20)	(15)
364	Poles, Towers and Fixtures	(75)	(70)
365	Overhead Conductors & Devices	(30)	(20)
367	Underground Conductors & Devices	(15)	(10)
392	Trucks	20	25

Source: (TR 1731)

For each disputed account listed above, TECO witness Allis reviewed the historical annual NS from 1982 to 2022, the three-year moving averages of the NS from 1982-1984 to 2020-2022, and the latest five-year average of the NS with Account 392 having fewer years of information due to data availability. (EXH 26, MPN C11-879–1032)

<sup>24</sup> The annual depreciation rates resulting from TECO, FEA, and the staff’s recommended ASLs (35-, 45-, and 40-years) are 2.3 percent, 3.6 percent, and 3.0 percent, respectively, for Account 367. (EXH 26, MPN C11-721; EXH 112, MPN C30-3099; EXH 211, MPN E8089) As it pertains to depreciation 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. 20090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc.*; 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-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System, Inc.*

Table 7-3 shows some experienced NS data related to the disputed accounts:

**Table 7-3  
 Experienced Net Salvage Percentage**

Account No.	Overall Experienced NS	Recent 10-year Experienced NS	Recent 5-year Experienced NS	TECO Proposed NS	FEA Proposed NS
356	(39)	(46)	(93)	(50)	(40)
362	(14)	(22)	(33)	(20)	(15)
364	(73)	(92)	(113)	(75)	(70)
365	(21)	(38)	(34)	(30)	(20)
367	(13)	(20)	(16)	(15)	(10)
392	(29)	25	45	20	25

Source: (TR 1732)

FEA witness Andrews focused on the overall net salvage, which is the average of the last 40 years' NS amount.<sup>25</sup> The witness claimed that:

As the net salvage analysis represents such a small sample size of each account and in order to establish a more reasonable recovery of net salvage costs, I have taken the following general approach to set net salvage rates: The net salvage rate for any account should not exceed (being more negative or less positive) than the overall net salvage rate by more than 1% and the net salvage rate should be a multiple of 5%.

(TR 3047)

TECO witness Allis disputed FEA's reliance on overall NS rates to estimate future NS because he maintained that it was not an appropriate approach. He contended that "[w]hile the overall average is a statistic I rely on, I also consider trends in the data as well as current estimates and estimates for other utilities." (TR 1733) Witness Allis claimed that "Tampa Electric's estimates are more reasonable than FEA's because they align more closely with recent trends in net salvage experience, and they more appropriately consider the trend towards increasing cost of removal in the utility industry." (TR 1732)

Witness Allis further testified that the removal costs, which is an important component of the NS,<sup>26</sup> have increased in the industry. He then expounded on the reasons behind the increase and pointed out many of them are outside of the Company's control: environmental rules have increased removal costs, permitting requirements have become more restrictive and burdensome, labor costs have increased because of wage increases and a shortage of skilled workers in the utility sector,

<sup>25</sup> Except Account 392 which has less years' available data.

<sup>26</sup> See Rule 25-6.0436(1)(e),(j), F.A.C.

material and equipment costs have increased due to overall inflation and increased demand across various industries.<sup>27</sup> (TR 1734–1735)

FEA’s general approach, which only focuses on overall net salvage, fails to consider certain factors. By accounting for the recent trends in the activities of cost of removal and the industry experience, TECO provides a more well-rounded analysis of the NS accounts. Staff believes this provides a more accurate picture of future NS. Therefore, staff recommends that TECO’s proposed estimates of the future NS are reasonable for this proceeding.

## **CONCLUSION**

Staff recommends approval of the depreciation parameters and resulting depreciation rates for each production, transmission, distribution and general plant account that are presented in Table 7-4.

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<sup>27</sup> Some examples are: disposal requirements for treated wood poles have increased over time; local governments may require work to only be performed at certain hours of the day which increases project costs; municipalities have required restoration of sidewalks or landscaping; increased requirements for traffic control. (TR 1734)

**Table 7-4  
 Depreciation Parameters and Resulting Depreciation Rates**

	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	SURVIVOR CURVE	EXISTING ESTIMATES			STAFF RECOMMENDED ESTIMATES				
				NET SALVAGE PERCENT	WRECK DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	NET SALVAGE PERCENT	WRECK DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE		
<b>STEAMPRODUCTION PLANT</b>											
<b>BIG BEND POWER PLANT</b>											
<i>50% COMMON</i>											
311.00	STRUCTURES AND IMPROVEMENTS	252,807,168	71,830,371	VARIOUS *	(2)	8,089,829	3.20	75-R1.5 *	(5)	8,365,095	2.52
312.00	BOILER PLANT EQUIPMENT	219,407,899	48,398,158	VARIOUS *	(5)	10,082,763	4.60	40-L0 *	(12)	8,358,267	3.81
314.00	TURBOGENERATOR UNITS	28,314,960	(956,157)	VARIOUS *	(8)	877,754	3.10	45-R1 *	(8)	1,104,579	3.90
315.00	ACCESSORY ELECTRIC EQUIPMENT	43,865,595	19,735,461	VARIOUS *	(5)	1,525,296	3.50	50-R1.5 *	(4)	946,090	2.16
318.00	MISCELLANEOUS POWER PLANT EQUIPMENT	26,452,683	11,830,648	VARIOUS *	(5)	822,156	3.30	50-R0.5 *	(3)	533,805	2.03
	<b>TOTAL BIG BEND COMMON</b>	<b>570,853,304</b>	<b>150,735,482</b>			<b>21,463,796</b>	<b>3.77</b>			<b>17,307,828</b>	<b>3.03</b>
<i>BIG BEND UNIT 4</i>											
311.00	STRUCTURES AND IMPROVEMENTS	104,828,976	54,187,413	VARIOUS *	(2)	1,987,951	1.90	75-R1.5 *	(5)	3,853,085	3.49
312.00	BOILER PLANT EQUIPMENT	952,262,872	218,119,144	VARIOUS *	(5)	16,224,678	3.30	40-L0 *	(12)	29,704,405	5.36
314.00	TURBOGENERATOR UNITS	123,877,662	52,223,800	VARIOUS *	(8)	3,967,285	3.20	45-R1 *	(8)	5,700,247	4.66
315.00	ACCESSORY ELECTRIC EQUIPMENT	97,538,411	61,793,800	VARIOUS *	(5)	2,826,814	2.80	60-R1.5 *	(4)	2,728,572	2.80
318.00	MISCELLANEOUS POWER PLANT EQUIPMENT	8,248,534	6,058,093	VARIOUS *	(2)	146,475	1.80	50-R0.5 *	(3)	158,757	1.92
	<b>TOTAL BIG BEND UNIT 4</b>	<b>1,286,652,655</b>	<b>597,382,250</b>			<b>27,352,200</b>	<b>3.06</b>			<b>27,624,866</b>	<b>4.74</b>
	<b>TOTAL BIG BEND POWER PLANT</b>	<b>1,457,505,959</b>	<b>548,117,732</b>			<b>48,815,996</b>	<b>3.34</b>			<b>58,332,792</b>	<b>4.67</b>
<b>TO THE B. PRODUCTION</b>											
<b>BIG BEND POWER PLANT</b>											
<i>BIG BEND UNIT 7</i>											
341.00	STRUCTURES AND IMPROVEMENTS	2,290,549	1,538,810	VARIOUS *	0	86,426	2.90	50-R3 *	(10)	78,624	3.43
342.00	FUEL HOLDERS	3,390,810	1,598,940	VARIOUS *	0	98,233	2.90	60-R0.5 *	(3)	76,258	2.22
343.00	PRIME MOVERS	458,001,278	18,810,395	VARIOUS *	0	13,211,027	2.90	50-O1 *	(4)	16,700,144	3.64
345.00	ACCESSORY ELECTRIC EQUIPMENT	548,961	95,858	VARIOUS *	0	15,862	2.90	55-S1 *	(4)	15,995	2.92
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	308,526	245,094	VARIOUS *	0	8,947	2.90	35-L2 *	(3)	8,195	2.66
	<b>TOTAL BIG BEND UNIT 7</b>	<b>495,538,124</b>	<b>23,887,198</b>			<b>13,500,606</b>	<b>2.90</b>			<b>16,878,276</b>	<b>3.63</b>
<i>BIG BEND UNIT 4</i>											
341.00	STRUCTURES AND IMPROVEMENTS	3,211,083	1,848,804	VARIOUS *	(2)	119,199	3.60	50-R3 *	(10)	112,235	3.38
342.00	FUEL HOLDERS	5,596,201	216,254	VARIOUS *	(5)	145,501	2.60	50-R0.5 *	(3)	248,206	4.45
343.00	PRIME MOVERS	23,963,084	10,732,429	VARIOUS *	(7)	730,456	3.10	50-O1 *	(4)	841,807	2.72
345.00	ACCESSORY ELECTRIC EQUIPMENT	15,256,508	7,575,498	VARIOUS *	(5)	427,182	2.80	55-S1 *	(4)	369,157	2.42
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	611,686	542,987	VARIOUS *	(2)	14,809	2.90	35-L2 *	(3)	14,865	3.13
	<b>TOTAL BIG BEND UNIT 4</b>	<b>45,237,561</b>	<b>19,626,472</b>			<b>1,637,147</b>	<b>2.90</b>			<b>1,588,160</b>	<b>2.98</b>
<i>BIG BEND UNIT 5</i>											
341.00	STRUCTURES AND IMPROVEMENTS	-	-	VARIOUS *	0	-	2.90	50-R3 *	(10)	-	2.20 **
342.00	FUEL HOLDERS	508,226	(21,322)	VARIOUS *	0	14,681	2.90	50-R0.5 *	(3)	19,224	3.78
343.00	PRIME MOVERS	178,878,891	14,301,530	VARIOUS *	0	5,123,682	2.90	50-O1 *	(4)	6,190,877	3.50
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	VARIOUS *	0	-	2.90	55-S1 *	(4)	-	1.89 **
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	0	-	2.90	35-L2 *	(3)	-	3.94 **
	<b>TOTAL BIG BEND UNIT 5</b>	<b>177,154,917</b>	<b>14,280,208</b>			<b>5,138,363</b>	<b>2.90</b>			<b>6,170,001</b>	<b>3.50</b>
<i>BIG BEND UNIT 6</i>											
341.00	STRUCTURES AND IMPROVEMENTS	-	-	VARIOUS *	0	-	2.90	50-R3 *	(10)	-	2.20 **
342.00	FUEL HOLDERS	528,138	(3,843)	VARIOUS *	0	15,316	2.90	60-R0.5 *	(3)	19,303	3.65
343.00	PRIME MOVERS	175,436,567	14,231,833	VARIOUS *	0	5,007,486	2.90	50-O1 *	(4)	6,145,998	3.50
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	VARIOUS *	0	-	2.90	55-S1 *	(4)	-	1.89 **
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	0	-	2.90	35-L2 *	(3)	-	3.94 **
	<b>TOTAL BIG BEND UNIT 6</b>	<b>175,965,105</b>	<b>14,227,990</b>			<b>5,022,802</b>	<b>2.90</b>			<b>6,165,301</b>	<b>3.50</b>
	<b>TOTAL BIG BEND POWER STATION</b>	<b>864,978,289</b>	<b>71,421,960</b>			<b>25,778,937</b>	<b>2.90</b>			<b>30,647,878</b>	<b>3.53</b>
<b>POLK POWER STATION</b>											
<i>POLK COMMON</i>											
341.00	STRUCTURES AND IMPROVEMENTS	192,917,190	67,373,353	VARIOUS *	(2)	5,990,433	3.10	50-R3 *	(10)	5,754,293	2.98
342.00	FUEL HOLDERS	12,700,608	3,274,311	VARIOUS *	(5)	391,168	3.80	60-R0.5 *	(3)	603,371	3.18
343.00	PRIME MOVERS	13,818,023	1,968,286	VARIOUS *	(7)	800,977	3.60	50-O1 *	(4)	526,458	3.78
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	-	-	VARIOUS *	(7)	-	3.60	8-L0 *	39	-	7.83 **
345.00	ACCESSORY ELECTRIC EQUIPMENT	14,519,008	4,521,861	VARIOUS *	(5)	522,684	3.60	55-S1 *	(4)	413,046	2.94
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	1,269,408	68,365	VARIOUS *	(2)	70,533	5.80	35-L2 *	(3)	59,892	4.67
	<b>TOTAL POLK COMMON</b>	<b>235,317,337</b>	<b>77,296,969</b>			<b>7,495,794</b>	<b>3.17</b>			<b>7,196,629</b>	<b>3.04</b>
<i>POLK UNIT 1 GASIFIER</i>											
341.00	STRUCTURES AND IMPROVEMENTS	53,947,915	28,573,732	VARIOUS *	(2)	1,962,773	3.70	50-R3 *	(10)	2,800,794	4.90
342.00	FUEL HOLDERS	248,878,996	152,814,023	VARIOUS *	(5)	10,298,057	4.10	50-R0.5 *	(3)	9,277,733	3.73
343.00	PRIME MOVERS	149,849,197	88,890,987	VARIOUS *	(7)	6,837,863	4.60	50-O1 *	(4)	5,824,903	3.99
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	15,598,216	3,898,254	VARIOUS *	(7)	884,428	4.60	8-L0 *	39	1,079,187	7.15
345.00	ACCESSORY ELECTRIC EQUIPMENT	60,548,847	45,710,331	VARIOUS *	(5)	1,998,112	3.80	55-S1 *	(4)	1,535,829	2.98
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	6,318,782	3,118,867	VARIOUS *	(2)	265,205	4.20	35-L2 *	(3)	333,786	5.28
	<b>TOTAL POLK UNIT 1 GASIFIER</b>	<b>532,636,013</b>	<b>322,884,325</b>			<b>27,968,538</b>	<b>4.12</b>			<b>20,751,632</b>	<b>3.90</b>
<i>POLK UNIT 2</i>											
341.00	STRUCTURES AND IMPROVEMENTS	2,342,155	1,331,857	VARIOUS *	(2)	80,896	2.60	50-R3 *	(10)	52,846	2.26
342.00	FUEL HOLDERS	2,365,828	690,828	VARIOUS *	(5)	91,722	4.30	50-R0.5 *	(3)	72,797	3.08
343.00	PRIME MOVERS	28,974,176	8,221,430	VARIOUS *	(7)	1,419,318	4.90	50-O1 *	(4)	894,045	3.09
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	7,888,119	1,558,312	VARIOUS *	(7)	347,318	4.90	8-L0 *	39	518,844	7.32
345.00	ACCESSORY ELECTRIC EQUIPMENT	19,207,796	11,228,600	VARIOUS *	(5)	653,065	3.40	55-S1 *	(4)	370,889	1.93
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	173,213	139,897	VARIOUS *	(2)	7,647	1.70	35-L2 *	(3)	7,804	1.50
	<b>TOTAL POLK UNIT 2</b>	<b>60,151,095</b>	<b>24,163,919</b>			<b>2,505,667</b>	<b>4.30</b>			<b>1,971,225</b>	<b>3.18</b>
<i>POLK UNIT 3</i>											
341.00	STRUCTURES AND IMPROVEMENTS	10,708,677	6,000,960	VARIOUS *	(2)	276,426	2.60	50-R3 *	(10)	243,411	2.27
342.00	FUEL HOLDERS	1,514,895	845,094	VARIOUS *	(5)	48,477	3.20	50-R0.5 *	(3)	38,749	2.56
343.00	PRIME MOVERS	32,248,524	21,819,630	VARIOUS *	(7)	1,190,953	3.60	50-O1 *	(4)	929,560	1.58
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	6,190,760	1,813,264	VARIOUS *	(7)	221,427	3.60	8-L0 *	39	357,045	5.60
345.00	ACCESSORY ELECTRIC EQUIPMENT	9,125,741	5,945,160	VARIOUS *	(5)	346,778	3.80	55-S1 *	(4)	155,791	1.66
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	632,810	283,897	VARIOUS *	(2)	9,524	2.20	35-L2 *	(3)	10,982	2.44
	<b>TOTAL POLK UNIT 3</b>	<b>60,182,587</b>	<b>36,307,895</b>			<b>2,085,675</b>	<b>3.43</b>			<b>1,971,198</b>	<b>2.18</b>
<i>POLK UNIT 4</i>											
341.00	STRUCTURES AND IMPROVEMENTS	5,818,841	2,412,947	VARIOUS *	(2)	157,108	2.70	50-R3 *	(10)	158,838	2.74
342.00	FUEL HOLDERS	2,369,199	1,298,813	VARIOUS *	(5)	86,328	2.80	50-R0.5 *	(3)	92,298	3.88
343.00	PRIME MOVERS	21,728,818	7,378,258	VARIOUS *	(7)	1,021,180	4.70	50-O1 *	(4)	851,719	3.00
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	6,888,260	1,933,396	VARIOUS *	(7)	314,348	4.70	8-L0 *	39	508,588	7.60
345.00	ACCESSORY ELECTRIC EQUIPMENT	5,886,747	3,437,915	VARIOUS *	(5)	139,689	2.50	55-S1 *	(4)	97,708	1.75
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42,188,985	14,562,125	VARIOUS *	(2)	1,668,824	4.60	35-L2 *	(3)	1,509,691	3.94 **
	<b>TOTAL POLK UNIT 4</b>	<b>104,080,840</b>	<b>41,325,558</b>			<b>3,256,101</b>	<b>3.64</b>			<b>3,088,120</b>	<b>3.59</b>
<i>POLK UNIT 5</i>											
341.00	STRUCTURES AND IMPROVEMENTS	5,748,795	2,423,708	VARIOUS *	(2)	195,217	2.70	50-R3 *	(10)	196,245	2.72
342.00	FUEL HOLDERS	2,759,831	767,540	VARIOUS *	(5)	102,114	3.70	50-R0.5 *	(3)	86,498	3.13
343.00	PRIME MOVERS	19,842,748	6,026,359	VARIOUS *	(7)	992,137	5.00	50-O1 *	(4)	826,237	3.16
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	5,388,812	1,823,354	VARIOUS *	(7)	299,031	5.00	8-L0 *	39	427,821	7.95
345.00	ACCESSORY ELECTRIC EQUIPMENT	5,471,817	3,427,254	VARIOUS *	(5)	142,262	2.60	55-S1 *	(4)	93,367	1.71
348.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	(2)	-	3.60	35-L2 *	(3)	-	3.94 **
	<b>TOTAL POLK UNIT 5</b>	<b>39,233,692</b>	<b>13,463,294</b>			<b>1,660,767</b>	<b>4.24</b>			<b>1,589,963</b>	<b>3.55</b>
<i>POLK UNIT 6</i>											
341.00	STRUCTURES AND IMPROVEMENTS	13,374,684	4,368,682	VARIOUS *	(2)	347,738	2.60	50-R3 *	(10)	391,802	2.93
342.00	FUEL HOLDERS	216,762,818	45,118,898	VARIOUS *	(5						

ORIGINAL COST AS OF DECEMBER 31, 2021	BOOK DEPRECIATION RESERVE	SERVICES COST	NET SALVAGE PERCENT	ESTIMATED		STAFF RECOMMENDED					
				ANNUAL DEPRECIATION ACCURALS	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCURALS	ANNUAL DEPRECIATION RATE				
				ESTIMATE	RECOMMENDATION	ESTIMATE	RECOMMENDATION				
341.00 ACCESSORY ELECTRIC EQUIPMENT	29,496,323	14,150,348	VARIOUS *	(5)	372,389	3.30	55-51 *	(4)	732,770	2.48	
342.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	11,380,833	4,400,845	VARIOUS *	(3)	852,145	4.30	35-12 *	(3)	380,984	3.26	
<b>TOTAL (BAYSIDE COMMON)</b>	<b>253,524,819</b>	<b>85,652,757</b>			<b>8,735,787</b>	<b>3.84</b>			<b>12,773,847</b>	<b>4.90</b>	
<b>BAYSIDE UNIT 1</b>											
341.00 STRUCTURES AND IMPROVEMENTS	31,251,205	9,810,255	VARIOUS *	(3)	765,046	3.80	50-R3 *	(70)	1,240,526	4.90	
342.00 FUEL HOLDERS	82,211,219	38,522,872	VARIOUS *	(5)	3,688,449	4.30	50-R3.5 *	(4)	4,339,322	4.71	
343.00 PRIME MOVERS	261,281,178	86,122,876	VARIOUS *	(7)	12,278,786	8.10	50-01 *	(4)	8,888,944	4.45	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	56,311,518	13,864,511	VARIOUS *	(7)	3,476,876	6.10	6-0 *	(3)	4,226,284	7.72	
345.00 ACCESSORY ELECTRIC EQUIPMENT	39,466,426	23,488,843	VARIOUS *	(5)	1,816,123	4.10	55-51 *	(4)	1,325,324	3.36	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	1,125,705	673,419	VARIOUS *	(3)	37,823	3.20	35-12 *	(3)	50,474	4.29	
<b>TOTAL (BAYSIDE UNIT 1)</b>	<b>471,436,363</b>	<b>181,361,139</b>			<b>27,604,871</b>	<b>5.30</b>			<b>37,041,244</b>	<b>4.87</b>	
<b>BAYSIDE UNIT 2</b>											
341.00 STRUCTURES AND IMPROVEMENTS	27,131,136	14,552,865	VARIOUS *	(3)	949,590	3.50	50-R3 *	(70)	1,151,475	4.24	
342.00 FUEL HOLDERS	142,487,135	42,389,029	VARIOUS *	(5)	5,557,388	3.90	50-R3.5 *	(4)	7,395,535	5.00	
343.00 PRIME MOVERS	282,839,409	113,313,487	VARIOUS *	(7)	18,882,243	6.25	50-01 *	(3)	11,882,286	4.85	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	71,741,582	16,880,514	VARIOUS *	(7)	4,445,351	6.25	6-0 *	(3)	5,575,906	8.10	
345.00 ACCESSORY ELECTRIC EQUIPMENT	49,254,446	25,820,125	VARIOUS *	(5)	1,853,362	4.10	55-51 *	(4)	1,819,192	3.88	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	1,468,582	850,728	VARIOUS *	(3)	49,823	3.30	35-12 *	(3)	60,212	4.14	
<b>TOTAL (BAYSIDE UNIT 2)</b>	<b>642,875,179</b>	<b>272,378,679</b>			<b>23,133,886</b>	<b>5.23</b>			<b>23,354,536</b>	<b>5.24</b>	
<b>BAYSIDE UNIT 3</b>											
341.00 STRUCTURES AND IMPROVEMENTS	858,349	35,171	VARIOUS *	(3)	22,872	3.50	50-R3 *	(70)	27,844	4.24	
342.00 FUEL HOLDERS	3,840,543	1,279,827	VARIOUS *	(5)	126,087	3.20	50-R3.5 *	(4)	127,294	3.23	
343.00 PRIME MOVERS	19,871,413	9,341,806	VARIOUS *	(7)	492,014	2.10	50-01 *	(3)	326,212	2.12	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	22,368	7,747	VARIOUS *	(7)	712	3.10	6-0 *	(3)	1,748	5.00	
345.00 ACCESSORY ELECTRIC EQUIPMENT	14,153,814	6,496,876	VARIOUS *	(5)	382,163	2.70	55-51 *	(4)	363,528	2.57	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	305	487	VARIOUS *	(3)	21	3.40	35-12 *	(3)	26	2.87	
<b>TOTAL (BAYSIDE UNIT 3)</b>	<b>34,488,369</b>	<b>17,397,883</b>			<b>7,621,879</b>	<b>2.94</b>			<b>896,952</b>	<b>2.47</b>	
<b>BAYSIDE UNIT 4</b>											
341.00 STRUCTURES AND IMPROVEMENTS	242,334	(73,138)	VARIOUS *	(3)	12,289	5.10	50-R3 *	(70)	14,861	6.06	
342.00 FUEL HOLDERS	3,372,331	1,418,335	VARIOUS *	(5)	187,915	3.20	50-R3.5 *	(3)	14,326	2.89	
343.00 PRIME MOVERS	19,890,871	9,587,763	VARIOUS *	(7)	507,231	3.20	50-01 *	(4)	323,330	2.84	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	42,590	13,833	VARIOUS *	(7)	1,363	3.20	6-0 *	(3)	2,177	5.11	
345.00 ACCESSORY ELECTRIC EQUIPMENT	4,160,899	2,059,325	VARIOUS *	(5)	116,732	2.80	55-51 *	(4)	101,265	2.43	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	905	487	VARIOUS *	(3)	31	3.40	35-12 *	(3)	35	2.87	
<b>TOTAL (BAYSIDE UNIT 4)</b>	<b>23,877,529</b>	<b>13,076,898</b>			<b>749,621</b>	<b>3.15</b>			<b>536,759</b>	<b>2.39</b>	
<b>BAYSIDE UNIT 5</b>											
341.00 STRUCTURES AND IMPROVEMENTS	789,114	(27,876)	VARIOUS *	(3)	34,887	4.40	50-R3 *	(70)	30,532	4.86	
342.00 FUEL HOLDERS	2,279,860	834,237	VARIOUS *	(5)	75,209	3.30	50-R3.5 *	(3)	89,477	3.05	
343.00 PRIME MOVERS	15,109,730	6,244,764	VARIOUS *	(7)	513,731	3.40	50-01 *	(4)	349,725	2.38	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	3,746,424	2,152,192	VARIOUS *	(7)	127,376	3.40	6-0 *	(3)	41,886	1.13	
345.00 ACCESSORY ELECTRIC EQUIPMENT	10,386,136	6,696,876	VARIOUS *	(5)	280,426	2.70	55-51 *	(4)	182,815	1.75	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	37,419	-	VARIOUS *	(3)	3	3.80	35-12 *	(3)	-	2.94 **	
<b>TOTAL (BAYSIDE UNIT 5)</b>	<b>37,374,659</b>	<b>17,822,463</b>			<b>1,020,647</b>	<b>3.19</b>			<b>601,767</b>	<b>2.11</b>	
<b>BAYSIDE UNIT 6</b>											
341.00 STRUCTURES AND IMPROVEMENTS	2,856,232	695,088	VARIOUS *	(3)	82,343	3.10	50-R3 *	(70)	96,189	3.62	
342.00 FUEL HOLDERS	1,545,420	646,223	VARIOUS *	(5)	57,181	3.70	50-R3.5 *	(3)	43,912	2.84	
343.00 PRIME MOVERS	17,213,969	11,503,969	VARIOUS *	(7)	472,853	2.70	50-01 *	(4)	323,789	2.88	
343.10 PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	11,862	4,307	VARIOUS *	(7)	312	2.70	6-0 *	(3)	509	4.43	
345.00 ACCESSORY ELECTRIC EQUIPMENT	14,326,608	7,179,279	VARIOUS *	(5)	401,145	2.80	55-51 *	(4)	344,701	2.41	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	11,726	6,890	VARIOUS *	(3)	208	2.20	35-12 *	(3)	268	3.13	
<b>TOTAL (BAYSIDE UNIT 6)</b>	<b>36,984,428</b>	<b>20,221,506</b>			<b>1,074,952</b>	<b>2.81</b>			<b>800,993</b>	<b>2.12</b>	
<b>TOTAL (BAYVIEW POWER STATION)</b>	<b>6,330,498,719</b>	<b>3,027,420,142</b>			<b>42,885,736</b>	<b>4.78</b>			<b>48,552,387</b>	<b>4.62</b>	
<b>TOTAL OTHER PRODUCTION PLANT</b>	<b>3,644,984,892</b>	<b>1,198,732,492</b>			<b>148,835,732</b>	<b>3.87</b>			<b>162,897,532</b>	<b>3.89</b>	
<b>SOLAR SITES</b>											
341.00 STRUCTURES AND IMPROVEMENTS	389,830,579	51,744,519	35-50	8	11,296,287	2.90	35-53	0	11,809,847	2.83	
343.00 PRIME MOVERS	1,110,462,450	97,471,891	35-50	8	32,283,899	2.90	35-53	0	31,790,194	2.86	
345.00 ACCESSORY ELECTRIC EQUIPMENT	387,296,825	5,281,270	35-50	8	7,791,560	2.90	35-53	0	7,570,791	2.83	
346.00 ENERGY STORAGE EQUIPMENT	30,513,911	4,475,510	10-50	0	2,951,391	10.00	20-53	0	1,372,864	4.65	
<b>TOTAL SOLAR SITES</b>	<b>2,794,925,569</b>	<b>160,976,138</b>			<b>52,324,136</b>	<b>2.89</b>			<b>52,743,796</b>	<b>2.89</b>	
<b>DC MICRO GRID</b>											
341.00 STRUCTURES AND IMPROVEMENTS	-	-	30-50	0	-	3.33	35-53	0	-	2.86 **	
343.00 PRIME MOVERS	829,495	58,825	30-50	0	30,982	3.23	35-53	0	28,284	2.89	
345.00 ACCESSORY ELECTRIC EQUIPMENT	-	-	30-50	0	-	3.33	35-53	0	-	2.86 **	
346.00 ENERGY STORAGE EQUIPMENT	9,125	1,773	10-50	0	813	10.00	20-53	0	420	4.63	
<b>TOTAL DC MICRO GRID</b>	<b>838,620</b>	<b>60,798</b>			<b>32,863</b>	<b>3.89</b>			<b>29,184</b>	<b>3.89</b>	
<b>MICRO AIR FORCE BASE</b>											
341.00 STRUCTURES AND IMPROVEMENTS	-	-	N/A	N/A	-	N/A	50-R3 *	(70)	-	2.20 **	
343.00 PRIME MOVERS	-	-	N/A	N/A	-	N/A	50-R3.5 *	(4)	-	2.88 **	
345.00 ACCESSORY ELECTRIC EQUIPMENT	-	-	N/A	N/A	-	N/A	55-51 *	(3)	-	1.85 **	
346.00 MISCELLANEOUS POWER PLANT & EQUIPMENT	-	-	N/A	N/A	-	N/A	35-12 *	(3)	-	2.94 **	
346.00 ENERGY STORAGE EQUIPMENT	-	-	N/A	N/A	-	N/A	20-53 *	(3)	-	5.80 **	
<b>TOTAL MICRO AIR FORCE BASE</b>	<b>-</b>	<b>-</b>			<b>-</b>	<b>-</b>			<b>-</b>	<b>-</b>	
<b>TOTAL PROTECTION PLANT</b>	<b>6,899,886,899</b>	<b>3,526,931,399</b>			<b>243,779,495</b>	<b>3.59</b>			<b>253,946,914</b>	<b>3.47</b>	
<b>TRANSMISSION</b>											
350.01 LAND RIGHTS	12,162,254	5,888,800	75-50	0	158,100	1.30	75-54	(70)	187,882	1.54	
351.00 ENERGY STORAGE EQUIPMENT	-	-	10-50	0	-	10.00	10-53	0	-	10.00 **	
352.00 STRUCTURES AND IMPROVEMENTS	76,137,281	16,885,842	60-R3	(5)	1,371,187	1.80	60-R3	(28)	1,880,724	2.17	
353.00 STATION EQUIPMENT	494,834,881	97,479,849	45-50	(5)	10,911,237	2.40	45-50	(1)	10,713,107	2.36	
354.00 TOWERS AND FIXTURES	5,992,281	5,281,270	55-R3	(15)	142,576	2.80	55-R4	(75)	165,444	1.29	
355.00 POLES AND FIXTURES	554,890,587	132,890,187	55-R2	(40)	14,139,737	2.80	55-R1	(50)	14,815,875	2.89	
356.00 OVERHEAD CONDUCTORS AND DEVICES	187,387,466	30,104,135	55-R2	(40)	5,431,917	2.90	55-R2	(50)	5,800,736	2.99	
356.01 CLEARING RIGHTS-OF-WAY	2,170,810	1,787,333	55-R4	0	33,770	1.80	55-R4	0	21,442	1.02	
357.00 UNDERGROUND CONDUIT	4,322,881	1,844,886	60-R5	0	73,489	1.70	60-R4	0	78,822	1.82	
358.00 UNDERGROUND CONDUCTORS AND DEVICES	13,246,787	3,959,270	55-R5	0	333,361	2.70	55-R4	(25)	346,982	2.80	
359.00 ROADS AND TRAILS	19,868,792	3,263,800	60-50	0	759,651	1.60	60-R4	(70)	784,736	1.77	
<b>TOTAL TRANSMISSION</b>	<b>6,379,119,117</b>	<b>297,844,428</b>			<b>32,974,838</b>	<b>2.57</b>			<b>33,493,772</b>	<b>2.49</b>	
<b>DISTRIBUTION</b>											
361.00 STRUCTURES AND IMPROVEMENTS	33,864,616	9,867,222	60-R3	(5)	811,363	1.80	60-R3	(40)	875,136	2.58	
362.00 STATION EQUIPMENT	325,868,732	79,868,419	45-R1	(70)	6,090,210	2.50	45-R1	(20)	6,915,715	2.76	
363.00 ENERGY STORAGE EQUIPMENT	-	-	10-50	0	-	10.00	10-53	0	-	10.00 **	
364.00 POLES, TOWERS AND FIXTURES	475,405,746	180,542,711	45-R3	(50)	17,590,913	3.70	35-R2.5	(4)	25,268,548	5.26	
365.00 OVERHEAD CONDUCTORS AND DEVICES	280,431,372	103,487,226	45-R1	(20)	6,389,122	2.20	60-R1.5	(20)	6,794,399	2.33	
366.00 UNDERGROUND CONDUIT	641,888,280	96,115,888	60-R3	(5)	7,513,288	1.70	60-R4	(5)	7,800,302	1.78	
367.00 UNDERGROUND CONDUCTORS AND DEVICES	742,409,241	36,871,823	45-R1.5	(5)	17,075,473	2.30	40-R1.5	(15)	21,823,702	2.94	
368.00 LINE TRANSFORMERS	863,730,376	267,079,061	30-35	(20)	44,781,272	4.50	30-32	(20)	38,885,292	3.92	
369.00 SERVICES - OVERHEAD	84,774,891	66,824,198	45-R3	(20)	1,670,723	1.30	45-R3	(3)	1,880,142	2.34	
369.02 SERVICES - UNDERGROUND	162,884,831	74,859,129	45-R3	(20)	3,511,891	2.30	45-R3	(20)	4,036,419	2.84	
370.00 METERS - ANALOG AND AMR	18,761,382	5,346,434	20-R2	(30)	1,482,126	7.80	20-R				



**Issue 8:** Based on the application of the depreciation parameters and resulting depreciation rates that the Commission approves, and a comparison of the theoretical reserves to the book reserves, what are the resulting imbalances?

**Recommendation:** If staff's recommendation on Issue 7 is approved, based on the application of that recommendation and a comparison of the theoretical reserves to the book reserves, the resulting theoretical reserve imbalances for each category of TECO's plant accounts are shown in Table 8-2. (J. Wu)

**Position of the Parties:**

**TECO:** As of December 31, 2024, the company's book reserve is approximately \$167 million lower than the theoretical reserve shown in the 2023 Depreciation Study, so the reserve imbalance is approximately negative \$167 million.

**OPC:** This is a fallout based on the resolution of Issue 7.

**FL RISING/**

**LULAC:** The Commission has not deemed any specific depreciation rates as appropriate yet, and therefore we cannot calculate the resulting imbalance. That being said, a 35-year depreciation life for solar assets should be used, and a 20-year depreciation life for battery assets.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC's position.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

The Commission's electric utility depreciation Rule 25-6.0436(1)(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 depreciation accruals and future net salvage. The reserve imbalance of an account is the difference between the account's book reserve and its calculated theoretical reserve. If the book reserve amount is larger than the theoretical reserve amount for a particular account, then this

account presents a reserve surplus at a specific point in time. If the book reserve amount is less than the theoretical reserve amount, the account presents a deficit.

Based on his proposed depreciation parameters and depreciation rate for each depreciable account, TECO witness Allis calculated the Company’s theoretical depreciation reserve imbalance to be a deficiency (or deficit) of \$166.9 million, as of December 31, 2024. (EXH 26, MPN C11-727–730) On August 22, 2024, TECO filed documents supporting an updated revenue requirement, which noted that “the Company agrees and proposes that the depreciation life of its energy storage assets be 20 years rather than its original proposal of 10 years.” (EXH 835, P 2) This revision of the depreciation life for the energy storage assets changes the calculated theoretical reserve and the reserve imbalance of the energy storage account. (TR 1745–1746; EXH 211, MPN E8185–8186)

Staff has reviewed TECO’s proposed theoretical depreciation reserve imbalance for each depreciable account. Staff believes that the theoretical reserve imbalance should reflect the impact of the aforementioned change in the depreciation life of TECO’s energy storage assets. Further, in Issue 7, staff recommends a respective longer service life than TECO’s proposed for the solar plant assets and the underground conductors and devices plant assets in Account 367. If approved, this recommendation will also have an impact on the theoretical reserve and the reserve imbalance of the affected accounts. (TR 1746) Consequently, staff has calculated the corresponding adjustments to TECO’s proposed theoretical reserve imbalances, and the results are presented in Table 8-1.

**Table 8-1  
 Staff’s Recommended Adjustment to  
 TECO’s Proposed Theoretical Reserve Imbalance**

	TECO Proposed (\$)	Staff Recommended (\$)	Staff Adjustment (\$)
Solar Sites	(24,586,766)	5,292,480	29,879,249
Energy Storage	(678,593)	1,873,012	2,551,605
Account 367 – UG Conductors/Devices	(66,102,061)	(54,255,569)	11,846,492
Total	(91,367,423)	(47,090,077)	44,277,346

Table 8-2 shows staff’s recommended theoretical reserve imbalances for each category of TECO’s plant accounts, with a total amount of the imbalance being a deficiency of \$122.6 million. It is the result of applying the formula prescribed in Rule 25-6.0436(1)(k), F.A.C., to the depreciation parameters and resulting depreciation rates that staff is recommending in Issue 7.

**Table 8-2**  
**Staff Recommended Theoretical Reserve Imbalance (as of 12/31/2024)**

Account Category	TECO Proposed (\$)	Staff Recommended (\$)	Staff Adjustment (\$)
Production	(130,187,005)	(101,756,150)	32,430,855
Transmission	586,441	586,441	-
Distribution	(62,067,348)	(50,220,855)	11,846,492
General	28,747,422	28,747,422	-
Total Depreciable Plant	(166,920,489)	(122,643,143)	44,277,347

**CONCLUSION**

If staff's recommendation on Issue 7 is approved, based on the application of the recommendation and a comparison of the theoretical reserves to the book reserves, the resulting theoretical reserve imbalances for TECO's depreciable plant accounts are shown in Table 8-2.

**Issue 9:** What, if any, corrective reserve measures should be taken with respect to the imbalances identified in Issue 8?

**Recommendation:** Staff recommends using the remaining life technique to correct the depreciation reserve imbalances identified in Issue 8. (J. Wu)

**Position of the Parties:**

**TECO:** The theoretical reserve balance identified in Issue 8 should be addressed through remaining life depreciation rates. There is no need for reserve balance transfers.

**OPC:** All reserve imbalances should be corrected using the remaining life technique in this case.

**FL RISING/**

**LULAC:** Remaining life technique.

**FIPUG:** Imbalances should be via the remaining life approach.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Any reserve imbalances should be corrected using the remaining life method.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO proposed to address the imbalances through remaining life depreciation rates. The Company's witness Allis testified that:

In most jurisdictions an explicit adjustment to the book reserve is not made. Instead, the remaining life technique is used. When using remaining life technique, there is an automatic adjustment, or self-correcting mechanism, that will increase or decrease depreciation expense to account for any imbalances between the book and theoretical reserves. The 2023 Depreciation Study uses the remaining life technique. The depreciation rates presented in the study therefore

already include an adjustment for the theoretical reserve imbalance. No further adjustment is needed.

(TR 1688)

All the intervenors who took a position also proposed to use the remaining life technique as the corrective measure.

Staff agrees with TECO and the intervenors' proposal, because the remaining life approach is the most often-used method to correct the reserve imbalances. Because, all of the depreciation rates that staff is recommending in Issue 7 are remaining life depreciation rates, these rates will automatically correct the reserve imbalance over the remaining life of the plant assets. Further, the total amount of reserve imbalances identified, in the amount of negative \$122.6 million (a deficit), is approximately three percent of either the book reserve or the theoretical reserve. With this level of reserve imbalance percentage, the Commission typically approves using the remaining life technique to correct the imbalance, instead of taking other measures such as amortizing the imbalance over a shorter period of time.<sup>28</sup> Staff believes that using the remaining life technique to address all the reserve imbalances is appropriate.

## CONCLUSION

Based on the record, staff recommends using the remaining life technique to correct the depreciation reserve imbalances identified in Issue 8.

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<sup>28</sup> In a prior Peoples Gas System, Inc. case, a reserve imbalance of \$160.4 million (a surplus) was identified which was 18 percent of the book reserve, or 22 percent of the theoretical reserve. By Order No. PSC-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System Inc.*, the Commission approved the use of the remaining life technique for correcting the theoretical reserve imbalance.

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**Issue 10:** Should the current amortization of investment tax credits (ITCs) and flow back of excess deferred income taxes (EDITs) be revised to reflect the approved depreciation rates?

**Recommendation:** Yes. The current amortization of ITCs and any flow back of EDITs should be revised to match the actual recovery periods for the related property, except for the ITCs related to TECO's battery storage assets. The Company should file detailed calculations of the revised ITC amortization and flow back of EDITs at the same time it files its earnings surveillance report as specified in Rule 25-6.1352, F.A.C. (Souchik, D. Buys)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** The amortization of ITCs and EDITs should reflect OPC's recommendations on the production tax credit treatment of solar assets with the 35-year service life as discussed in Issues 63 and 64 and ITC treatment for batteries as addressed in detail in Issue 65. The Commission should direct Tampa Electric to defer the ITCs pursuant to the Inflation Reduction Act earned each year, but to amortize the deferred ITCs over a three-year amortization period.

**FL RISING/  
LULAC:**

Yes, although the flowback of ITCs should be accelerated.

**FIPUG:** Yes.

**FEA:** No position.

**SIERRA  
CLUB:**

Sierra Club adopts FL Rising/LULAC's position.

**FRF:** Yes. Additionally, amortization of ITCs and EDITs should reflect the tax treatment of solar assets with a 35-year depreciation life and ITC treatment for battery storage assets with a 20-year depreciation life. The ITCs earned each year should be deferred pursuant to the Inflation Reduction Act, but the deferred ITCs should be amortized over three years.

**FUEL  
RETAILERS:**

No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

All the parties who took a position agree that the current amortization of ITCs and flow back of EDITs should be revised to reflect the approved depreciation rates. OPC also argued that the ITCs should reflect OPC's position in Issues 63, 64, and 65 regarding the proper treatment of ITCs related to TECO's battery storage assets. (TECO BR 17; OPC BR 23-25) Staff addressed OPC's arguments regarding the amortization of the Production Tax Credits (PTC) in Issues 63 and 64. Issue 10 is primarily concerned with setting the ITC amortization period and flow back of EDITs to match the book depreciation lives that are approved in Issues 7, 65, and 106.

Revising a utility's book depreciation lives generally results in a change in its rate of ITC amortization and flow back of EDITs in order to comply with the normalization requirements of the Internal Revenue Code (IRC or Code) set forth in Federal Tax Regulations,<sup>29</sup> U.S. Code Sections 168(f)(2) and (i)(9),<sup>30</sup> former IRC Sections 167(l), and 46(f),<sup>31</sup> and Section 203(e) of the Tax Reform Act of 1986 (the Act).<sup>32</sup>

Former IRC Section 46(f)(6), indicated that the amortization of ITC should be determined by the period of time actually used in computing depreciation expense for ratemaking purposes and on the regulated books of the utility.<sup>33</sup> While Section 46(f)(6) was repealed, under IRC Section 50(d)(2), the terms of former IRC Section 46(f)(6) remain applicable to public utility property for which a regulated utility previously claimed ITCs. Because staff is recommending changes to the Company's remaining lives, it is also important to change the amortization of ITCs and EDITs to avoid violation of the provisions of IRC Section 50(d)(2) for ITCs, and IRC Section 168(i)(9), former Section 167(l), and Section 13001(d) of the Tax Change and Jobs Act for EDITs, and their underlying Treasury Regulations. The consequence of an ITC or EDIT normalization violation is a repayment of unamortized ITC balances to the IRS and the inability to utilize accelerated depreciation. Therefore, staff recommends the current amortization of ITCs and any flow back of EDITs be revised to match the actual recovery periods for the related property. The Company should file detailed calculations of the revised ITC amortization and flow back of EDITs at the same time it files its earnings surveillance report as specified in Rule 25-6.1352, F.A.C.

The Inflation Reduction Act of 2022 (IRA) was signed into law on August 16, 2022, and changed Section 48 of the IRC.<sup>34</sup> As discussed above, prior to the IRA, IRC Section 50(d)(2) required that ITCs had to be normalized, that is, the benefit of the ITC could not be flowed back to the customers at a rate greater than the depreciation rates established by the regulating authority. Under the revised Code, a utility can choose to opt out of the normalization rules for

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<sup>29</sup> 26 C.F.R. §§ 1.168 *et seq.*; 26 C.F.R. §§ 1.167 *et seq.*; 26 C.F.R. §§ 1.46 *et seq.*

<sup>30</sup> 26 U.S.C. § 168(f)(2), (i)(9).

<sup>31</sup> Under IRC Section 50(d)(2), the terms of former 26 U.S.C. § 167(l) and § 46(f), which were repealed by the Revenue Reconciliation Act of 1990 (Pub. L. No. 101-508, § 11812(a)(1-2)(1990)), remain applicable to public utility property for which a regulated utility previously claimed ITCs, which is the case here. (I.R.S. Priv. Ltr. Rul. 200933023, In.1 (May 7, 2009)).

<sup>32</sup> Tax Reform Act of 1986, Pub. L. No. 99-514 (100 Stat. 2085, 2146) (1986).

<sup>33</sup> Former 26 U.S.C. § 46(f)(6) (establishing proper determination of ratable portion).

<sup>34</sup> H.R. 5376; Inflation Reduction Act of 2022; 26 U.S.C. § 48.

ITCs created by investment in energy storage.<sup>35</sup> Therefore, the amortization of ITCs related to TECO's battery storage investment do not have to be adjusted to match the depreciation rates approved by the Commission if TECO chooses to opt out of the normalization requirements required by Section 50(d)(2) of the IRC. In Issue 65, staff recommends that the ITCs related to TECO's battery storage investment be amortized over five years, but in Issue 7, staff recommends the Commission approve a 20-year depreciation life for the same battery storage assets. Therefore, by the Commission's approval to set the battery storage life at a different period as the depreciation life, TECO will be required to opt out of the normalization requirements in Section 50(d)(2), only for the Company's battery storage assets, to avoid a normalization violation.

### **CONCLUSION**

The current amortization of ITCs and any flow back of EDITs should be revised to match the actual recovery periods for the related property, except for the ITCs related to TECO's battery storage assets. The Company should file detailed calculations of the revised ITC amortization and flow back of EDITs at the same time it files its earnings surveillance report as specified in Rule 25-6.1352, F.A.C.

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<sup>35</sup> 26 U.S.C. §§ 48, 168.



**Issue 11:** What annual accrual for dismantlement should be approved?

**Recommendation:** Staff recommends approval of a total annual accrual of \$15,770,488 for TECO's dismantlement of its generating facilities, as shown in Table 11-2. (J. Wu, Higgins)

**Position of the Parties:**

**TECO:** The annual accrual for dismantlement should be \$17,442,392 effective January 1, 2025. This amount was calculated in accordance with Rule 25-6.04364, F.A.C., and properly considers escalation of costs, environmental remediation costs, and contingencies.

**OPC:** The annual accrual for dismantlement should exclude the cost and expense escalations after the end of the test year for dismantlement which reduces revenue requirement by \$7.110 million. The dismantlement expense also should be reduced by \$2.614 million to remove the solar site restoration environmental costs. Further, the dismantlement cost should be reduced by \$0.955 million with the continuation of the currently approved 35-year service life for solar as recommend by OPC.

**FL RISING/**

**LULAC:** \$10,325,056, adjusted to reflect removal of projects that should be disallowed as per the other issues.

**FIPUG:** Adopts the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Approximately \$10.325 million. The annual accrual for dismantlement should exclude post-test-year cost and expense escalations for dismantlement, which reduces revenue requirements by \$7.110 million. Dismantlement expense should also be reduced by \$2.614 million to remove solar site restoration environmental costs. Further, the dismantlement cost should be reduced by \$0.955 million to reflect continuation of the currently approved 35-year service life for solar facilities.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

The methodology for performing an electric utility's dismantlement study and determining the annual dismantlement accrual are codified in Rule 25-6.04364, F.A.C. The rule outlines three elements as the dependent factors in calculating the dismantlement accrual: estimated base costs for dismantlement, a contingency factor, and projected escalations. The fixed accrual amount is based on a four-year average of the accruals related to the years between depreciation study reviews. Utilities are required to provide updated dismantlement studies at least once every four years in conjunction with their depreciation study.<sup>36</sup> The purpose of these studies is to reflect changes in dismantlement cost estimates, inflation, regulatory or environmental requirements, and any newly discovered public health and safety issues since its last dismantlement study. TECO filed its 2023 dismantlement study, pursuant to Rule 25-6.04364(3), F.A.C.<sup>37</sup>

TECO retained the 1898 & Co. consulting firm to conduct the 2023 Dismantlement Study (Study).<sup>38</sup> The Study results in a recommendation regarding the base costs, in 2023 dollars, with consideration of dismantlement for all generation units and common facilities at the end of their corresponding useful lives.<sup>39</sup> The Study updates the costs presented in the 2020 dismantlement study, which was also conducted by 1898 & Co., with consideration of changes to market conditions, physical changes that have occurred at the plants, and incorporating new facilities that have been constructed or acquired since 2020. (TR 1659)

Using the base costs provided in the Study, TECO calculated its proposed annual accrual for dismantlement. (EXH 151, MPN D13-881-995) The Company applied a contingency factor and the projected inflation escalators to derive the future costs as of the estimated date of dismantlement. The future costs, less the amount recovered to date, are discounted over the remaining life of each generation unit/plant site to determine the fixed dismantlement accrual amounts based on a four-year average of the accruals related to the years between the dismantlement study reviews. Staff has reviewed TECO's "Generation Dismantling Model for FPSC" (EXH 161, MPN E2072) in detail, and confirms that the method TECO used in determining its proposed annual dismantlement accrual is consistent with Rule 25-6.04364(4) and (7), F.A.C.

**Environmental component of the dismantlement costs for the solar facilities**

The estimated base costs for dismantlement generally consist of four components: labor, material and equipment, disposal, and environmental costs. OPC witness Kollen recommended the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets.

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<sup>36</sup> These policies were codified in Rule 25-6.04364(3), (4), (7), F.A.C.

<sup>37</sup> TECO's 2020 depreciation and dismantlement studies were approved by Order No. PSC-2021-0423-S-EI. The Company's 2023 depreciation and dismantlement studies were filed on December 27, 2023, in Docket. No. 20230139-EI, which were subsequently consolidated with the instant proceeding.

<sup>38</sup> The Study is also referred to as "TECO Decommissioning Cost Estimate Study, Tampa Electric Company 2023 Fleet Decommissioning Study" by 1898 & Co. (EXH 27, MPN C12-1139).

<sup>39</sup> The base cost is net of salvage value for scrap materials at each plant.

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OPC Witness Kollen argued:

The costs that may be incurred are extremely speculative and are not known and measurable, and are based on Witness Kopp's unsupported assumptions regarding the abandonment of the sites and that the Company will be responsible for the site restoration, further compounded by the Company's unsourced and undescribed potential contingencies assumption, all of which are extremely speculative and not known and measurable.

(TR 2310)

TECO witness Kopp refuted this argument:

We don't assume that a site will be abandoned, retained, or reused. [. . .] As stated in my direct testimony, the basis of our estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use, sold, or returned to the lessor.

(TR 1777)

Witness Kopp quoted Rule 25-6.04364(2)(c), F.A.C., which defines "Dismantlement Costs" as "the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service." He then argued that OPC witness Kollen's suggestion to exclude the environmental component of the dismantlement costs on the solar generating assets, which includes site restoration costs, "is not only arbitrary, but in direct conflict" with this rule. (TR 1778) Staff believes that TECO witness Kopp's statement has merit.

OPC witness Kollen further argued that not all of the costs witness Kopp included in TECO's current dismantlement study are reasonably known and measurable. He provided four points to back up his argument:

First, for most of the solar facilities, Witness Kopp did not review the terms of the ground leases to assess whether the Company or the owner of the site is responsible for site restoration and environmental remediation or the scope of any activities required by the Company, if any. [. . .] Second, neither Witness Kopp nor the Commission know at this time whether the solar sites will be abandoned or remain in use with new equipment installed after the original equipment is retired and removed some 35 years in the future. [. . .] Third, neither Witness Kopp nor the Commission know at this time the scope of the site restoration, even assuming that it is the responsibility of the Company, including the extent of environmental remediation. [. . .] Fourth, other utilities intentionally exclude dismantlement costs because of the uncertainties as to costs that may be incurred and whether the salvage income will exceed any such costs.

(TR 2308–2309)

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TECO Witness Kopp contested witness OPC Kollen's assumption that the solar facility land leases may not require the Company to be responsible for site restoration or environmental remediation; and averred that witness Kollen provided no basis for his statement. (TR 1778) TECO witness Kopp also claimed that he had not seen a lease that placed the liability for removal of improvements and site restoration on anyone other than the solar facility owner. (TR 1778) Additionally, TECO witness Kopp testified as to why he and his team reviewed the land leases of the solar facilities, as part of the preparation of the instant dismantlement studies for the solar facilities:

We review the land leases to see if any additional requirements to site restoration are included in the leases than our standard assumptions to restore the site to a level of industrial use. This would potentially include additional foundation depth of removal or other activities to restore the land to a condition suitable for something other than industrial use, such as agricultural use.

(TR 1779)

During cross examination, counsel for OPC pointed out that TECO witness Kopp did not review certain solar sites' land leases, so he did not know the environmental remediation requirements for those sites. (TR 1792-1792) Witness Kopp admitted that some of the leases were not available for review. He testified:

I don't know if there were any requirements specifically stated in those leases, but typically those requirements are above and beyond our standard assumptions for site restoration. We typically include a minimum level of site restoration that's appropriate. And we review those leases to see if there is additional requirements beyond those minimum requirements.

(TR 1793)

Witness Kopp further asserted that the absence of a land lease being available for review gives him no concern that he overestimated environmental or site restoration costs or included speculative costs. He explained:

A land lease will likely only increase the need for environmental and site restoration costs beyond what is stated in the Florida Administrative Code and included in our estimates. This typically comes in the form of language that specifically requires the lessee to remove equipment and restore the sites to a defined condition, which simply reinforces the definition of "Dismantlement Costs" in the Florida Administrative Code as including site restoration.

(TR 1779)

As mentioned earlier, TECO witness Kopp testified that he has never seen a lease place the liability for removal of improvements and site restoration on anyone other than the solar facility

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owner. Staff is persuaded by witness Kopp's testimony, and believes that the Company will likely always incur some level of environmental-related cost to restore the solar site when the generation facility is dismantled. Witness Kopp also testified that site restoration requirements included in the leases are typically more stringent than the standard restoration requirement assumptions he and his team use in conducting a dismantlement study. Based on witness Kopp's testimony, staff believes that TECO's assumptions of site restoration/environmental remediation for dismantling the solar facilities are reasonable.

Counsel for FIPUG questioned whether TECO witness Kopp would make an adjustment to the estimate of the dismantlement cost in the scenario that the landowner does not want to remove the solar facility from the leasing land at the end of the lease. (TR 1794–1795) Witness Kopp testified that:

I've heard of it being an option in the lease but our studies are all looking at the liability at the end of useful life of the facilities. So this is what is the cost for restoring the sites. And that obligation is still typically on the utility at the end of life to take it out.

(TR 1795)

Furthermore, witness Kopp disagreed with witness Kollen's statement that other utilities intentionally exclude dismantlement costs because of the uncertainties as to costs that may be incurred and whether the salvage income will exceed any such costs. He testified that:

This is not an accurate representation of what is typical, based on my experience preparing dismantlement studies throughout the country and in particular in the state of Florida. First, every dismantlement study I have prepared, [ . . . ] have included site restoration costs. Second, utilities don't simply exclude these costs because of the uncertainties as to costs that may be incurred whether the salvage income will exceed any such costs. Instead, utilities typically hire an engineering firm to estimate the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service, consistent with Florida Administrative Code. This allows a site specific cost estimate to be used to make a determination of how much salvage income will offset the costs, rather than simply speculating that they might exceed restoration costs. Lastly, even if some utilities in other parts of the country have gone with the speculative approach of intentionally excluding these costs because salvage income may exclude the costs, that is not consistent with Florida Administrative Code Rule 25-6.04364, and therefore not relevant.

(TR 178–1782)

Staff has reviewed TECO's 2023 dismantlement study in detail. The study does include the specifications of the assumed cost elements for dismantling each generating unit, including solar. For example, the tasks assumed for dismantling the Agrivoltaics Solar site include "removal depth of 3 feet below grade;" and the tasks assumed for dismantling the Alafia Solar site include "removal depth of 3 feet below grade" and "grading and reseeding the area inside the perimeter fencing." (EXH 27, MPN C12-1159) All of these are the environmental restoration activities.

Based on the foregoing, staff believes that TECO witness Kopp's inclusion of the environmental component in his assumptions for estimating the dismantlement costs of solar sites is appropriate and consistent with Rule 25-6.04364, F.A.C.

### **Application of contingency**

Rule 25-6.04364(2)(a), F.A.C., defines "Contingency Costs" as "[a] specific provision for unforeseeable elements of cost within the defined project scope." As in its prior dismantlement study filings, TECO controlled the application of contingency factors for calculating the dismantlement accrual. This allows the Company "easier study cost estimate comparisons and quicker scenario calculations." (EXH 195, MPN E5577)

OPC witness Kollen considered the contingency costs TECO used to be "unsupported and unjustified." (TR 2307) However, staff disagrees with that conclusion.

A 15 percent contingency was utilized in TECO's 2023 dismantlement study. This contingency factor has three components: Engineering Scope, Cost Estimation, and Management Costs (indirect costs incurred to support vendor or non-vendor decommissioning work efforts), and each of these components was assigned a five percent contingency. (EXH 195, MPN E5577) TECO applied this 15 percent contingency factor to the cost estimates for Labor, Materials & Equipment and Environmental & Disposal, but this 15 percent contingency factor is not applied to the Salvage credits, that resulted from the 2023 dismantlement study. (EXH 195, MPN E5577)

TECO witness Kopp stated that the application of contingency is not only appropriate, but also standard industry practice; and provided very detailed reasons to support his statement. (TR 1782-1786) He further testified that for all of those reasons specified, 1898 & Co. personnel "typically recommend and include a percent contingency be added to the direct costs as reasonable and warranted based on the level of risk associated with the dismantlement projects. Therefore, the 15 percent contingency applied by the Company is less than our typical recommendation." (TR 1787)

Based on the record of the proceeding, staff believes that the application of a 15 percent contingency is appropriate because it is consistent with the provisions of Rule 25-6.04364, F.A.C., and in line with prior Commission orders.<sup>40</sup>

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<sup>40</sup> Order Nos. PSC-08-0014-PAA-EI, issued January 4, 2008, in Docket No. 20070284-EI, *In re: Petition for approval of 2007 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company*; PSC-12-0175-PAA-EI, issued April 3, 2012, in Docket No. 201101312-EI, *In re: Petition for approval of 2011 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company*.

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### **Application of escalations to the current estimates of dismantlement costs**

OPC witness Kollen proposed to “limit the dismantlement expense to costs escalated only through the test year and exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year.” (TR 2307)

TECO witness Chronister disagreed with OPC’s proposal. He argued that “the purpose of a dismantlement study is to estimate the future costs of retiring plant assets, so reasonable estimates of future cost increases should be considered.” (TR 3450) TECO witness Kopp further expounds that:

The dismantlement costs should include “escalation rates” used in converting the current estimated dismantlement costs to future estimated dismantlement costs” as outlined in Rule 25-6.04364, [F.A.C.], Electric Utilities Dismantlement Studies. It is reasonable and appropriate that the 2023 costs I provided in my Dismantlement Study should be escalated to future years, to account for the impact of inflation, to put them in the year dollars in which they will be expended, and to most accurately reflect the actual costs to be incurred, consistent with Rule 25-6.04364, [F.A.C.]

(TR 1774)

TECO confirmed that the methodology and escalation rates it used in this study are the same as in prior filings:

Escalation rates are calculated using Moody’s Analytics (Economy.com) forecasts. Historical information is provided for the years 2022 and prior. The needed forecast information is provided for the years 2023 to 2053. For the years 2054 and beyond, the same annual change percentage for year 2053 is carried forward. Since the cost estimates are provided in 2023 dollars, the dismantlement model initially escalates each unit’s cost estimate into 2025 dollars to align with the study, which projects each unit’s ending balance of reserve through December 31, 2024. Next, each unit’s cost estimates are escalated to the projected retirement date to perform the present value calculations and averaging of the next four years’ accrual results.

(EXH 195, MPN E5575–5576)

Staff believes that forecast growth in the dismantlement cost and expense beyond the end of the test year should be appropriately included in the calculation of the dismantlement accrual pursuant to Rule 25-6.04364(4), F.A.C., which specified that the dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement.

**Dismantlement cost resulting from TECO’s 2023 dismantlement study**

The dismantlement cost estimates in the current study are based on site-specific analysis. These cost estimates reflect an increase of approximately 86 percent from the cost estimates resulting from TECO’s last dismantlement study as shown in Table 11-1.

The key driver for the increase in cost is the plant additions of new solar sites since TECO’s last dismantlement study. (EXH 151, MPN D13-883) The Company also explained that the other major drivers for the cost increase are the addition of traveling screens and an organism return system at the Bayside Power Station site, and the increase of the Polk Power Station Site Cost Index. (EXH 195, MPN E5590)

**Table 11-1  
 Comparison of TECO’s Estimates of Generation Plant Dismantlement Cost\***

Account	2020 Study**	2023 Study***	Change (\$)	Change (%)
Bayside Power Station	\$14,575,850	\$21,418,750	\$6,842,900	46.9
Big Bend Power Station	\$80,772,550	\$86,859,500	\$6,086,950	7.5
Polk Power Station	\$15,229,450	\$20,115,800	\$4,886,350	32.1
MacDill Station		1,061,750	\$1,061,750	-
Solar Sites	81,786,195	\$228,872,135	\$147,085,940	179.8
Total Surviving Assets	\$192,364,045	\$358,327,935	\$165,963,890	86.3

\* Including 15 percent contingency.

\*\* In 2020 dollar.

\*\*\* In 2023 dollar.

Source: (EXH 195, MPN E5590)

**TECO’s annual accruals for dismantlement**

TECO’s currently approved annual accrual for dismantlement is \$8,014,743. Its proposed annual accrual is \$17,442,392 which represents an increase of approximately 117 percent. (EXH 151, MPN D13-883; EXH 195, MPN E5591) Apart from the aforementioned increased base costs, high escalation factors are also the major contributor to the large dismantlement annual accrual proposed. (EXH 195, MPN E5591) The Company explained:

In a comparison of the instant 2023 study to the prior 2020 study inflation indices, the resulting compound multipliers (escalation factors) starting from year 2019, the year 2020 has minimal percentage differences between the actual and forecast. However, due to global inflationary impacts resulting from the pandemic and post pandemic economic environments, the annual projections for year 2021 and beyond are vastly higher in the instant 2023 study index. Increases in these compound multipliers (escalation factors) applied to the vendor cost estimates will yield increases in the dismantlement accruals.

(EXH 195, MPN E5578)

As discussed in Issue 7, staff is recommending a 35-year service life, instead of TECO’s proposed 30-year service life, for solar plant. In responding to staff’s discovery request, the



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Company provided a calculation of the annual dismantlement accrual using a 35-year service life for solar facilities. The result indicates a reduction of approximately \$1.3 million in the accrual, compared to TECO's originally proposed amount. (EXH 151, EXH 203, MPN E6564; EXH 206, MPN E6649–6650) Staff recommends approval of the reduced annual accrual for dismantling solar facilities so as to coincide with its recommendation for a 35-year service life for solar plant that staff is recommending in Issue 7.

In Issue 24, staff is recommending to retire the gasification equipment (Gasifier), heat recovery steam generator (HRSG), and steam turbine (ST) at Polk Unit 1 in 2025. The associated cost recovery of the unrecovered investment and the un-accrued dismantlement cost are also addressed in that issue. As a result, staff recommends that the 2025 annual dismantlement accrual pertaining to the Gasifier, HRSG and ST at Polk Unit 1, in the amount of approximately \$0.2 million, should be removed from the provision for dismantlement accrual. (EXH 151, MPN D13-921; EXH 161, MPN E2072)

The escalation factors TECO used for deriving its proposed annual dismantlement accrual are based on Moody's Analytics' September 2023 publications. In responding to staff's request, the Company provided, in July 2024, an update of the escalation factors based on the latest available Moody's inflation forecast. It also provided an updated annual accrual resulting from the utilization of the latest escalation factors, which reflect a reduction of approximately \$0.1 million from TECO's originally proposed accrual. (EXH 211, MPN E8135–8139; EXH 212, MPN E8203–8204) Staff recommends approval of using the updated escalation factors for deriving the annual dismantlement accrual.

Taking into consideration all of the matters discussed above, staff's recommended annual dismantlement accrual for each of TECO's generation unit/facility are listed in Table 11-2.

## **CONCLUSION**

Staff recommends approval of a total annual accrual of \$15,770,488 for TECO's dismantlement of its generating facilities, as presented in Table 11-2.

**Table 11-2  
 Dismantlement Accruals**

GENERATION PLANT	CURRENT	COMPANY	COMPANY	STAFF	STAFF
	ACCRUAL	PROPOSED	PROPOSED	RCOMMENDED	RCOMMENDED
	(01/01/2022)	ACCRUAL	CHANGE IN	ACCRUAL*	CHANGE IN
	(01/01/2025)	ACCRUAL	ACCRUAL	(01/01/2025)	ACCRUAL
	\$	\$	\$	\$	\$
Bayside Common	270,547	399,464	128,917	383,764	113,217
Bayside Unit #1 (3xGT - HSRG - ST)	67,969	242,668	174,699	253,565	185,596
Bayside Unit #2 (4xGT - HSRG - ST)	107,666	340,207	232,541	353,001	245,335
<u>Bayside GTs 3-6</u>	<u>(290)</u>	<u>9,288</u>	<u>9,578</u>	<u>16,619</u>	<u>16,909</u>
Total Bayside Power Station	445,892	991,627	545,735	1,006,949	561,057
Big Bend Common (Handling)	1,756,377	1,578,811	(177,566)	1,588,579	(167,798)
Big Bend Unit #4	377,928	722,412	344,484	719,346	341,418
Big Bend GT 4	3,201	7,186	3,985	8,141	4,940
<u>Big Bend GTs 5-6 (and Unit 1 CCST)</u>	<u>174,385</u>	<u>414,543</u>	<u>240,158</u>	<u>406,963</u>	<u>232,578</u>
Total Big Bend Power Station	2,311,891	2,722,952	411,061	2,723,029	411,138
Polk Common (Handling)	430,877	535,436	104,559	515,762	84,885
Polk Unit #1 (Gasifier - GT - HRSG - ST)**	149,968	232,963	82,995	33,369	(116,599)
<u>Polk 2-5 (4xGT - HRSG - ST)</u>	<u>99,409</u>	<u>202,186</u>	<u>102,777</u>	<u>218,655</u>	<u>119,246</u>
Total Polk Power Station	680,254	970,585	290,331	767,786	87,532
MacDill Common	0	3,348	3,348	5,333	5,333
MacDill Unit 1 and 2	0	17,653	17,653	17,304	17,304
MacDill Unit 3 and 4	0	17,653	17,653	17,304	17,304
<u>MacDill BESS</u>	<u>0</u>	<u>18,428</u>	<u>18,428</u>	<u>19,179</u>	<u>19,179</u>
Total MacDill Station	0	57,082	57,082	59,120	59,120
Tampa International Solar	36,807	40,893	4,086	34,750	(2,057)
Big Bend Solar	213,003	236,966	23,963	202,213	(10,790)
Legoland Solar	8,161	10,303	2,142	8,644	483
Balm Solar	725,322	783,385	58,063	690,245	(35,077)
Bonnie Mine Solar	289,424	345,622	56,198	304,408	14,984
Grange Hall Solar	431,870	518,692	86,822	454,561	22,691
Lake Hancock Solar	337,632	408,257	70,625	358,422	20,790
Lithia Solar	524,578	638,608	114,030	561,722	37,144
Little Manatee River Solar	536,440	645,580	109,140	571,438	34,998
Payne Creek Solar	535,696	653,202	117,506	570,497	34,801
Peace Creek Solar	373,933	446,832	72,899	393,079	19,146
Wimauma Solar	563,840	743,515	179,675	655,051	91,211
Agrivoltaics Solar	0	6,020	6,020	5,328	5,328
Alafia Solar	0	432,587	432,587	383,577	383,577
Big Bend Floating Solar	0	2,220	2,220	2,291	2,291
Big Bend Solar Phase 2	0	75,106	75,106	65,836	65,836
Brewster Solar	0	259,621	259,621	231,529	231,529
Bull Frog Creek Solar	0	483,898	483,898	429,000	429,000
Cotton Mouth Ranch Solar	0	504,338	504,338	447,000	447,000
Durrance Solar	0	563,300	563,300	497,053	497,053
Eastern PVS+ES Solar	0	4,723	4,723	4,277	4,277
English Creek Solar	0	447,934	447,934	395,952	395,952
Florida Aquarium Pavilion Solar	0	565	565	507	507
Future Property 1 Solar	0	505,775	505,775	450,602	450,602
Future Property 2 Solar	0	505,775	505,775	450,602	450,602
Jamison Solar	0	521,734	521,734	466,316	466,316
Juniper Solar	0	537,349	537,349	477,107	477,107
Lake Mabel Solar	0	524,568	524,568	469,631	469,631
Laurel Oaks Solar	0	411,730	411,730	362,966	362,966
Magnolia Solar	0	629,160	629,160	555,444	555,444
Mountain View Solar	0	364,511	364,511	320,158	320,158
<u>Riverside Solar</u>	<u>0</u>	<u>447,377</u>	<u>447,377</u>	<u>393,398</u>	<u>393,398</u>
Total Solar Sites***	4,576,706	12,700,146	8,123,440	11,213,604	6,636,898
Total Dismantlement Accrual	8,014,743	17,442,392	9,427,649	15,770,488	7,755,745

\*Staff's recommended accrual is based on TECO's proposed updated escalation factors to reflect the latest inflation forecast.

\*\*The accrual amount reflects staff's recommendation detailed in Issue 24. It was calculated by using "TECO's 2023 Generation Dismantlement Model for FPSC."

\*\*\*The accrual for each solar site reflects a 35-year service life detailed in Issue 7. It was calculated by using "TECO's 2023 Generation Dismantlement Model for FPSC."

**Issue 12:** What, if any, corrective dismantlement reserve measures should be approved?

**Recommendation:** Staff recommends that all the dismantlement reserve imbalances should be resolved over the remaining service lives of the related assets, and no other corrective dismantlement reserve measures should be approved. (J. Wu, Higgins)

**Position of the Parties:**

**TECO:** All dismantlement reserve surpluses and deficiencies, if any, should be resolved over the remaining life of the related assets.

**OPC:** All imbalances should be flowed back over the useful lives of the assets in this case.

**FL RISING/**

**LULAC:** The Commission should limit the dismantlement expense to costs escalated only through the test year and exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Any imbalances in dismantlement reserves should be amortized or flowed back over the useful lives of the assets to which the reserves apply.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its brief, the Company stated that “Tampa Electric’s revised position on this Issue is consistent with the positions of the other parties; therefore, this Issue appears to be uncontested. Document No. 2 of Mr. Chronister’s rebuttal exhibit reflects a remaining life approach to dismantlement reserve deficiencies. [Ex. 151, MPN D13-881 to D13-995]” (TECO BR 18)

Staff notes that TECO’s estimate of the total amount of dismantlement cost is approximately \$358.3 million, while its total amount of dismantlement reserve, as of December 31, 2024, is

\$113.6 million. (EXH 151, MPN D13-887–890) This represents a total reserve imbalance of approximately negative \$244.7 million (deficit) in the dismantlement reserve.

TECO proposed that all of the dismantlement reserve imbalances (surpluses and deficiencies), if any, should be resolved over the remaining life of the related assets. This is consistent with OPC's position that all imbalances should be flowed back over the useful lives of the assets. Other intervenors who took a position, adopted OPC's position, except FL Rising/LULAC whose position does not address the corrective measure for the reserve imbalances. Further, neither the Company nor any of the intervenors have proposed other measures to correct the reserve imbalances. Staff agrees with TECO and the intervenors that all of the reserve imbalances should be resolved over the remaining life of the related assets.

### **CONCLUSION**

Staff recommends that all the dismantlement reserve imbalances should be resolved over the remaining service lives of the related assets, and no other corrective dismantlement reserve measures should be approved.

**2025 RATE BASE**

**Issue 13:** Has TECO made the appropriate adjustments to remove all non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. TECO has made the appropriate adjustments to remove all non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital in the 2025 projected test year. Therefore no additional adjustments are necessary. (Hinson)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No position.

**FL RISING/**

**LULAC:** No. Plant in Service, Accumulated Depreciation, and Working Capital should be adjusted to reflect the removal of at least the following projects from TECO's proposed rate base: Future Environmental Compliance; Research and Development; Customer Experience Enhancement; Information Technology Capital; Grid Reliability and Resilience; Corporate Headquarters; South Tampa Resilience; Bearss Operation Center; and Polk 1 Flexibility.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO has made the appropriate adjustments to remove all non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital. As pointed out in TECO's brief, the only party opposing this Issue is FL Rising/LULAC. However, they do not specifically address non-utility activities, but rather state an opposition to the removal of certain projects within Plant in Service, Accumulated Depreciation, and Working Capital. (FR Rising/LULAC BR 9) Because TECO has provided proof of the removal of non-utility activities from Plant in Service,

Accumulated Depreciation, and Working Capital in TECO witness Chronister's direct testimony and MFR Schedules B-1, B-2, B-6, and B-7, staff does not recommend any further adjustments. (TR 3382-3384; EXH 4; TECO BR 19)

### **CONCLUSION**

TECO has made the appropriate adjustments to remove all non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital. Therefore, no additional adjustments are necessary.

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**Issue 14:** Should TECO's proposed Future Environmental Compliance Project be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Future Environmental Compliance Project, with a capital cost of \$18.2 million, should be included in the 2025 projected test year with no adjustments as it allows TECO to evaluate the feasibility of Carbon Capture and Storage. With federal dollars paying for the vast majority of costs, and TECO being proactive in pursuing this evaluation, staff recommends this project is in the customers' interest. (P. Buys)

**Position of the Parties:**

**TECO:** Yes. This Project is a prudent step to protect the long-term viability of gas-fired generation at Polk at a significantly reduced cost to customers. After accounting for \$98.4 million in Department of Energy grants, the total cost of the project is estimated to be \$126.5 million, of which only \$28.1 million will be paid by Tampa Electric and only \$18.2 million of which the company proposes to be recovered through customer rates in this case.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show this project is in the customer interest and is reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** No, TECO has not justified its request to sink \$18.2 million into studying carbon storage, an experimental and relatively untested technology, at Polk Units 1 and 2.

**FRF:** No. TECO has not met its burden to show that this project is necessary to provide safe and reliable service.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO requested to recover certain costs associated with its Carbon Capture and Storage (CCS) evaluation as part of its Future Environmental Compliance project. TECO witness Stryker explained that CCS is a process where carbon dioxide is absorbed from the exhaust gas of a power plant and then concentrated and compressed for storage deep in the earth. TECO believes CCS technology can remove approximately 90 percent of carbon emissions from a power plant. (TR 845) The Company is evaluating CCS technology now because of a proposed rule by the United States (U.S.) Environmental Protection Agency (EPA) and availability of federal financial support. The EPA Rule would impose standards for greenhouse gas emissions for certain fossil fuel-fired electric generating units. However, this year the EPA announced that natural gas-based units would not be covered by the proposed rule and a separate rule limiting emissions from natural gas-fired units would be issued. (TR 845-847; TECO BR 19-20)

TECO received approximately \$98.4 million from the U.S. Department of Energy (DOE) in the form of three separate funding grants for the following items: (1) front-end engineering study; (2) evaluation of storage and transportation component; (3) and the Carbon Safe Program, which is a detailed geological characterization of the potential storage facility. The funds can only be used for TECO's CCS evaluation project. (TR 951) Witness Stryker testified that the total cost of the CCS evaluation is estimated to be \$126.5 million with TECO's portion totaling approximately \$28.1 million. Of the \$28.1 million, \$18.2 million is capital expense and is included in the 2025 test year. However, TECO is not seeking recovery of the estimated \$9.9 million of O&M expense in this proceeding. The CCS evaluation should be completed by the end of 2025. (TR 847-848; TR 885-886; TR 951-952; TECO BR 19-21)

While not specifically addressing this project, FL Rising/LULACs witness Rábago recommended that the Commission disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented benefit-cost analysis (BCA). He further argued that TECO's current approach to developing major capital projects relies solely on management discretion and a cumulative present value of revenue requirements (CPVRR) approach that lacks transparency and objectivity, and that ignores cost effective alternatives that may offer better, more affordable outcomes. FL Rising/LULAC believe that without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO's spending proposals will result in rates that are fair, just, and reasonable. (TR 2610-2611) In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project. (FL Rising/LULAC BR 1-6)

Sierra Club witness Glick testified that TECO has not performed an analysis comparing the costs of CCS at Polk 1 with the cost of simply retiring the unit. Moreover, witness Glick argued that TECO has not clearly stated what its CCS plans are, nor has it evaluated the costs of CCS in detail. Witness Glick further testified that CCS does not justify the cost and risks it imposes on ratepayers. TECO would be better off retiring the unused equipment and using its capital to build out commercially available options, such as solar photovoltaic (PV) and battery energy storage systems. (BESS). (TR 2521-2523)



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In response to Sierra Club witness Glick's above assertions, TECO witness Stryker testified that TECO is not seeking cost recovery for installation of CCS at Polk Unit 1 in this rate case, it is only seeking recovery of costs to perform a feasibility assessment. (TR 858-860; TR 859; TR 951-952; TECO BR 19-21) The remaining intervenors did not specifically address or take a position on this Issue.

If the EPA Rule becomes effective and requires CCS, then the remaining costs of the evaluation, which are not recovered in this rate proceeding, will be combined with the cost of the project and will be evaluated for recovery through the Environmental Cost Recovery Clause (ECRC). If the EPA Rule does not become effective, TECO may still choose to pursue the project, outside the ECRC, based on the project's potential savings to customers driven by tax credits within the Inflation Reduction Act and other federal funding provided by the Infrastructure Investment and Jobs Act. (EXH 194, MPN E5503)

TECO witness Stryker testified that the federal funding was available to cover approximately 80 percent of the costs for the CCS evaluation and staff believes this directly benefits customers. TECO is only requesting to recover a portion of the cost to evaluate the feasibility of CCS technology. As such, staff believes Sierra Club witness Glick's arguments are premature. If TECO determines, based on this feasibility assessment to implement CCS, parties will have an opportunity via the ECRC to challenge or support the project and its costs. Staff believes TECO is being proactive in pursuing an evaluation at this time with federal dollars paying for the vast majority of costs. Staff recommends that TECO has met its burden of proof that the Future Environmental Project is in the customers' interest. Therefore, staff recommends that the CCS project should be included in the 2025 projected test year with no adjustments.

### **CONCLUSION**

The proposed Future Environmental Compliance Project, with a capital cost of \$18.2 million, should be included in the 2025 projected test year with no adjustments as it allows TECO to evaluate the feasibility of CCS. With federal dollars paying for the vast majority of costs, and TECO being proactive in pursuing this evaluation, staff recommends this project is in the customers' interest.

Date: November 22, 2024

**Issue 15:** Should TECO's proposed Research and Development Projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. TECO's proposed Long Duration Energy Storage project, with a capital cost of \$4.2 million, should be included in the 2025 projected test year as it allows TECO to explore alternative battery technologies. The Florida Conservation and Technology Center Microgrid project, with a capital cost of \$2.8 million, should be removed from the 2025 projected test year as it will not be in-service until 2026. Therefore, an adjustment should be made to remove \$2,846,972. (O. Wooten)

**Position of the Parties:**

**TECO:** Yes. The company is exploring a long duration energy storage project and a microgrid project, both of which will likely be used in the future. The approximately \$7.1 million of costs associated with these projects are prudent because they will help the company better understand their possibilities and limitations before it is necessary to implement them on a larger scale; therefore, they should be included in test year rate base.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that these projects are in the customer interest and are reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. The Company has not met its burden to show that these projects are necessary to provide safe and reliable service.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO witness Striker testified that the Company is currently pursuing two research and development (R&D) projects to be included in the 2025 projected test year. These projects are the Long Duration Energy Storage (LDES) project and the Florida Conservation and Technology Center (FCTC) Microgrid project. Witness Striker asserted that both projects use emerging technologies that will be used in the future. TECO is requesting recovery of \$7.1 million in capital costs for both R&D projects in the projected test year. (TR 849)

**The Long Duration Energy Storage Project**

The LDES project is a pilot program intended to explore alternative flow battery technology that will be capable of storing energy at a longer duration than the lithium-ion battery technology typically utilized. Witness Striker affirmed that the cost-effectiveness of lithium-ion batteries diminishes at longer storage durations and the LDES will allow TECO to evaluate flow battery technology as a suitable lithium-ion battery alternative. (EXH 199, MPN E6024-6025) The witness further affirmed that the smaller R&D project will allow TECO to gain a better understanding of the flow batteries longer-term storage capabilities, challenges, and costs that would be applied to future projects. (EXH 199, MPN E6025) TECO also claimed that it evaluated alternative long duration battery technologies, such as liquid air energy storage, but the promptness of implementing the chosen battery technology and the suitability of the battery technology for smaller scale construction guided the Company towards the chosen flow battery. The LDES project will be interconnected at the Big Bend II Solar substation and will be capable of providing 0.78 MW of energy on TECO's system. The LDES project is anticipated to be operational in mid-2025. (EXH 199, MPN E6025) TECO is requesting \$4,227,020 of capital costs in base rates for the project through 2025. (EXH 199, MPN E6026)

**The Florida Conservation and Technology Center Microgrid Project**

The FCTC Microgrid project is a pilot program that would adapt both existing FCTC electric load and nearby existing solar facilities on TECO property into a microgrid with the capability of operating independently from TECO's electrical grid. This would be accomplished with the addition of an energy storage system, microgrid control system, power conversion systems, and other equipment to enable the existing solar facilities to be interconnected and operated in a local microgrid system. Witness Striker affirmed that the microgrid project would allow TECO to evaluate the costs and benefits associated with enabling customers to construct and operate customer-owned distributed energy resources. (EXH 199, MPN E6025) Staff noted that the proposed pilot program shares some similarities with TECO's previously approved direct-current (DC) Microgrid pilot. However, while the DC Microgrid pilot's objective was to demonstrate the ability of TECO to manage high-level renewable energy at residential homes, the FCTC Microgrid would demonstrate the ability of TECO to serve the microgrid load exclusively from existing renewable energy and develop a repeatable process for implementing microgrid projects at other locations. (EXH 199, MPN E6025) Witness Stryker further distinguished the two projects when he indicated that the DC Microgrid Pilot project was comprised of integrating a large number of smaller distributed renewable resources at individual residences, in comparison to the proposed FCTC Microgrid project that consists of integrating a smaller number of centralized renewable resources interconnected at the distribution level. According to the

Company, these distinctions led to the DC Microgrid concept being more suitable for concurrent installation during construction of new residential communities and the FCTC Microgrid concept being more suitable for being retrofitted to existing renewable systems.

The FCTC Microgrid is anticipated to be operational by the end of 2026. (EXH 199, MPN E6025) As part of the 2025 projected test year, TECO is requesting including \$2,846,972 of capital costs in base rates for the project through 2026. (EXH 199, MPN E6026) Staff notes that though the project's in-service date is in 2026, the Company has only provided costs through 2025. As discussed in Issue 94, staff recommends allowing a SYA for the incremental costs associated with the annualization of projects that are in-service during the projected test year. As noted above, the project has a 2026 in-service date, outside the projected test year. Staff notes that in traditional ratemaking, TECO would still be able to construct the facilities if existing rates were sufficient or request a limited proceeding closer to the in-service date of the project. Staff recommends that as it is outside the projected test year and TECO has not demonstrated a definitive reliability need associated with the project, the project should not be included in the projected test year.

None of the intervenors provided testimony regarding this Issue. However, in their briefs, FL Rising/LULAC and FRF disagreed with the inclusion of the R&D projects in the 2025 projected test year, both stating that TECO had not met its burden to show the necessity of the projects. (FL Rising/LULAC BR 75, FRF BR 30) All other intervenors took no position on this Issue.

Regarding the LDES project, staff recognizes the benefits provided from exploring alternative battery technology that has potential to be useful for establishing longer duration utility scale battery energy storage. Staff also recognizes the benefits to customer that are provided by cost-effective alternatives that bolster TECO's renewable resource portfolio. Staff recommends inclusion of the LDES project in the 2025 projected test year, with no adjustments.

Regarding the FCTC Microgrid pilot program, staff acknowledges the useful information provided by the project for TECO's further exploration of microgrid technologies. While the project appears reasonable, staff notes that the in-service date of the project is outside of the 2025 projected test year and TECO has not demonstrated a reliability need associated with the project. Therefore, staff recommends the cost of the FCTC Microgrid pilot program should be removed from the projected 2025 test year.

## **CONCLUSION**

TECO's proposed Long Duration Energy Storage project, with a capital cost of \$4.2 million, should be included in the 2025 projected test year as it allows TECO to explore alternative battery technologies. The Florida Conservation and Technology Center Microgrid project, with a capital cost of \$2.8 million, should be removed from the 2025 projected test year as it will not be in-service until 2026. Therefore, an adjustment should be made to remove \$2,846,972.

Date: November 22, 2024

**Issue 16:** Should TECO’s proposed Customer Experience Enhancement Projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** No. The proposed Customer Experience Enhancement projects should not be included in the 2025 projected test year because the projects are not needed for reliability and the customers indicated that they are unwilling to pay for the enhancements. Therefore, an adjustment should be made to remove \$13.4 million. (P. Buys, Vogel)

**Position of the Parties:**

**TECO:** Yes. The company’s proposed Customer Digitalization, Operational Efficiency, and Other Customer Programs are prudent and should be included in test year rate base. They will improve customer access to services, information, and support; allow the company to present energy management solutions to customers; and give customers more choice and flexibility in how they use electric services.

**OPC:** No, the Commission should deny the \$4.4 million in new capital costs for the “customer digitalization” enhancements and the \$4.9 million in new capital costs for the “optional customer programs” enhancements. These investments are unwanted, unnecessary, and will only provide benefits to some customers. Tampa Electric has failed to meet its burden of proof for these investments.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that these projects are in the customer interest and are reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. The Commission should deny TECO recovery of its proposed revenue requirements for what it styles its “customer digitalization” ‘enhancements’ (\$4.4 million) and its “optional customer programs” ‘enhancements’ (\$4.9 million). These proposed activities are unnecessary to provide safe and reliable service and are unwanted by TECO’s customers.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO's proposed Customer Experience Enhancement Projects cover a broad range of capital investments that focus on three main areas: Customer Digitalization, Operational Efficiency, and Optional Customer Programs. The purpose of these projects is to streamline processes for greater efficiency and responsiveness and invest in staff training to better understand and anticipate customer needs. In support of these projects, TECO witness Sparkman testified that the Company intends to adopt a more personalized approach to service, using data analytics to gain insights into customer preferences, and using technology to enhance interaction and service delivery. (TR 463-465; TECO BR 22)

The Customer Digitalization projects are intended to enhance TECO's digital platforms to provide customers with a convenient and efficient way to access services, information, and support. An example project is the customer's Interactive Bill, which will have more granular usage data, personalized insights based on usage and patterns, additional weather details, and comparisons to other customers with similar sized homes. TECO projected that the Customer Digitalization projects will include \$4.4 million of capital costs and \$0.174 million of annual O&M expenses. (TR 464; EXH 194, MPN E5499; TECO BR 22-23)

The Operational Efficiency projects are intended to enhance the operational efficiency of TECO's organization with the potential use of artificial intelligence and machine learning, advanced data analytics, and customer segmentation. These projects are aimed to help TECO proactively recognize specific customer needs and ensure a more efficient and responsive service experience. For example, through the use of artificial intelligence, TECO would be able to detect customer consumption patterns and proactively present energy management solutions. TECO projected that the Operational Efficiency projects will include \$4.1 million in capital costs and \$1.4 million of annual O&M expenses. (TR 464-465; EXH 194, MPN E5500; TECO BR 23)

The Optional Customer Programs provide customers more choice and flexibility in how they use TECO's services. The programs are intended to cater to the diverse needs and preferences of the customer base, and therefore, enhance the customer's overall experience and satisfaction with TECO's services. The Optional Customer Programs include TECO's Drive Smart electric vehicle charging pilot, investments to improve the administration of existing customer programs such as net metering, and investments in the design of additional customer programs and/or pilots to service customers who have renewable energy goals such as rooftop solar. TECO projected that the Optional Customer Programs will include \$4.9 million in capital costs with no O&M expenses. (TR 466; EXH 166, MPN E2227; EXH 194, MPN E5501; TECO BR 23)

TECO witness Sparkman asserted that a primary driver for these projects is customer demand. (TR 482-483) Through discovery, staff inquired as to how TECO became aware that its customers are demanding these services and if customers would be harmed if these projects were delayed to a later date. In response, TECO indicated that, based on research, customers have high expectations and expect the same level of service and offerings that they receive from other companies, including how they view and pay their bills, receive communications, access their accounts, answer questions, and resolve problems. Furthermore, TECO explained that delaying

the Customer Experience Enhancement Projects would prohibit TECO from providing customer enhancements that may result in customer dissatisfaction. (EXH 194, MPN E5498; TECO BR 23)

During the hearing, OPC questioned TECO witness Sparkman on its customer surveys. She testified that TECO conducts monthly surveys regarding customer experience on a volunteer group of residential customers, known as the Power Panel. The Power Panel survey results indicated that 86 percent of customers were not willing to pay additional money for digital service options and that digital offerings had the lowest percentage of importance to customers out of a list of several options. In addition, OPC argued in its brief that the “Optional Customer Programs” is unsupported. OPC asserted that all of TECO’s customers would be charged for these programs; however, not all customers would benefit from all these programs. (TR 490-491; OPC BR 26-27)

While not specifically addressing these projects, FL Rising/LULAC witness Rábago recommends that the Commission disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO’s spending proposals will result in rates that are fair, just, and reasonable. (TR 2610-2611) In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project. (FL Rising/LULAC BR 1-6)

Through discovery, TECO explained that the cost benefit analysis for these projects includes a capital and O&M costs assessment, a benefit assessment, a determination of the IRR and payback period, and a thorough risk analysis. The benefit assessment includes financial, strategic, alignment, customer value, best practices, and other organizational benefits. (EXH 194, MPN E5499-E5501) Staff found TECO’s response sufficient for explaining the Company’s benefits and costs, but not the impact to customers. However, FL Rising/LULAC maintained in its brief that this project should be disapproved due to the lack of a BCA. In addition, while OPC cross-examined witness Sparkman at the hearing, OPC did not provide testimony to address this Issue nor did any other intervenor. The remaining intervenors did not specifically address or take a position on this Issue.

Staff does not believe TECO demonstrated a need for these projects. While denying these projects at this time could potentially result in customer dissatisfaction, according to TECO witness Sparkman, the customer surveys indicate customers are unwilling to pay for these enhancements. Staff notes, that none of the customers that spoke at the service hearings indicated a need or want for these enhancements. In addition, there were no customer comments that indicated a need for these projects. Rather, as discussed in Issue 4, the overwhelming majority of customer’s comments addressed the potential rate increase. Last, these projects are not needed in order for TECO to provide reliable service to its customers. Therefore, staff recommends that the capital costs of approximately \$13.4 million and the O&M costs of approximately \$1.6 million for the Customer Experience Enhancement projects should not be included in the 2025 projected test year.

## **CONCLUSION**

The proposed Customer Experience Enhancement projects should not be included in the 2025 projected test year because the projects are not needed for reliability and the customers indicated that they are unwilling to pay for the enhancements. Therefore, an adjustment should be made to remove \$13.4 million.



Date: November 22, 2024

**Issue 17:** Should TECO’s proposed Information Technology Capital Projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Information Technology Capital Projects, with a capital \$22.9 million, should be included in the 2025 projected test year without any adjustments. Staff recommends that these projects are needed to replace hardware and software that are at the end of their life and unsupportable, and will improve cybersecurity to protect TECO’s system and customer information. (P. Buys, Vogel)

**Position of the Parties:**

**TECO:** Yes. The company’s proposed expenditures for Information Technology (“IT”) capital projects are prudent and should be included in test year rate base. They will help create a modern, cloud-based IT Service platform, replace/upgrade end of life data center hardware and software, enhance cybersecurity, comply with NERC/CIP requirements, maintain the company’s Enterprise Resource Planning and Customer Systems platform, and improve other IT applications.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that these projects are in the customer interest and are reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. The Company has not met its burden to show that these projects are necessary to provide safe and reliable service to Tampa Electric’s customers.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO witness Heck testified that the Company plans to invest \$22.9 million in 2025 on six different Information Technology (IT) projects. The projects are described below. (TR 1327-1329)

First, witness Heck described the ServiceNow project as a cloud-based IT Service Management and IT Operations Management platform. It allows the IT department to automate many of its processes, such as inventory management, routing of service requests, commissioning and decommissioning of assets and compliance and reporting functions. This platform will enable the IT department to handle increasing workloads without increasing staff, improve IT system reliability, and improve cybersecurity and regulatory controls. This project is a multi-year project schedule for 2024 and 2025. The cost will include \$0.4 million in capital costs and approximately \$0.6 million in O&M costs for 2025. (TR 1323; TR 1327; EXH 194, MPN E5486; TECO BR 23)

Second, the IT Infrastructure Upgrades project is for replacing/upgrading end of life data center hardware and software including servers, network equipment, data storage equipment, databases, and operating systems. The IT department will make purchases throughout each year to support new applications. These investments ensure that TECO's IT infrastructure is reliable and is supported by the providing vendors. The cost will include \$9.5 million in capital costs in 2025. (TR 1323-1324; TR 1327; EXH 194, MPN E5487; TECO BR 23)

Third, the Cybersecurity project implements new technologies and processes to strengthen the Company's security and compliance position. The projects are based on the National Institute of Standards and Technology, Cybersecurity Framework 2.0, and Control Objectives for Information and related Technology Framework's corporate policies and standards. The cost will include \$7.2 million in capital costs and approximately \$0.6 million in O&M costs for 2025. (TR 1324; TR 1328; EXH 194, MPN E5488; EXH 206, MPN E6641-E6642; TECO BR 23)

Fourth, the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Enhancements and Upgrades project protects TECO's critical generation, transmission, distribution, and technology assets from cyber criminals. It includes the upgrade of software used for management of intelligent devices located in the transmission and distribution substations, which is required by NERC. This project will ensure that TECO remains in compliance with current NERC CIP standards and effectively protects the Company's electric grid critical infrastructure. The cost will include \$1.1 million in capital costs for 2025. (TR 1324; TR 1329; EXH 194, MPN E5489; TECO BR 23)

Fifth, the SAP Enterprise Resource Planning (ERP) and Customer Systems are integrated applications that provide corporate and customer functionality including accounting, financial consolidation and reporting, financial analytics and planning, accounts payable/receivable, payroll, employee information database, recruiting, supply chain and inventory management, customer information database, customer billing, and customer service. The upgrades and enhancements will keep TECO's SAP ERP and Customer System up to date, secure, and ensure

Date: November 22, 2024

that it retains support. The cost will include \$3.3 million in capital costs for 2025. (TR 1325; TR 1329; EXH 194, MPN E5490; TECO BR 23)

Sixth, the Non-ERP Corporate applications are for corporate functions and processes that include contract management, document/records management, employee websites, employee collaboration and productivity, process automation, project management, process controls, compliance, legal, real estate, and safety. Upgrading and enhancing these applications will ensure that TECO's team members in those areas have the tools necessary to work effectively, efficiently, and securely. The cost will include \$1.4 million in capital costs for 2025. (TR 1325-1326; TR 1329; EXH 194, MPN E5491; TECO BR 23)

No intervening party specifically addressed this Issue in testimony. However, FL Rising/LULAC witness Rábago recommends that the Commission should disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable. (TR 2610-2611) In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for the Information Technology Capital Projects. (FL Rising/LULAC BR 1-6)

Through discovery, TECO explained that the analysis for these projects includes cost effectiveness, lifecycle analysis of the current solution, a market analysis of available solutions, cybersecurity health assessments, as well as the reliability, resiliency, and supportability of the existing solution. In addition, projects are evaluated during the annual budgeting process and determined to be necessary to improve the customer experience, providing a more modern intuitive interface, increase functionality, replace aging application software, reduce cybersecurity risks, and improve the quality of data. The IT Department follows a formal bidding process to ensure that goods and services are unbiased, consistent, and objective procurement process that leads to the lowest reasonable cost while maintaining necessary quality of product and effectiveness of the project. (EXH 194, MPN E5486-5488, E5490-5491)

Staff inquired if any of the project could be delayed. TECO responded that if the projects were delayed the IT systems would no longer be supported by the vendor. In addition, the systems would cause customer service/transactions, such as billing, outage reporting, answering customer calls and critical business operations, such as financial reporting, payroll, accounts payable, crew work-order for customer support, crew work-orders for asset management, grid balancing to be delayed, unavailable and creating a need to rely on manual processes. The IT systems will not receive normal support and enhancement upgrades, causing business process improvements to be delayed, driving up manual work and O&M costs. This would also cause cybersecurity vulnerabilities to TECO's customer data, business operations, and critical infrastructure at risk. (EXH 194, MPN E5484-5485)

When asked about Cybersecurity Insurance, TECO witness Heck confirmed that TECO does have Cybersecurity Insurance. He explained that the insurance would cover a portion of cybersecurity criminals getting into TECO's network and causing harm to the Company. The

insurance also covers a portion of ransomware payments. TECO's cyber risks are audited by the insurer to verify TECO is mitigating the risks. (TR 1362-1363)

TECO has provided detailed descriptions of its proposed projects and why they are needed. Staff was persuaded that replacing hardware and software that is at the end of its life and no longer supportable is prudent. Moreover, improving cybersecurity of its systems and protecting customer information is required. No party specifically contradicted these statements or offered an alternative. Therefore, staff recommends that the Information Technology Capital Projects should be included in the 2025 projected test year without any adjustments.

### **CONCLUSION**

The proposed Information Technology Capital Projects, with a capital \$22.9 million, should be included in the 2025 projected test year without any adjustments. Staff recommends that these projects are needed to replace hardware and software that are at the end of their life and unsupportable, and will improve cybersecurity to protect TECO's system and customer information.

Date: November 22, 2024

**Issue 18:** Should TECO's proposed Solar Projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed 2024 and 2025 Solar projects, with a combined capital costs of approximately \$359.1 million, should be included in the 2025 projected test year with no adjustments. While providing a minimal reliability benefit, the projects do provide cost-effective renewable energy for TECO's system that will provide savings for customers in the form of fuel savings. (O. Wooten, Vogel)

**Position of the Parties:**

**TECO:** Yes. The company's 488.7 MW of Future Solar Projects are prudent and should be included in 2025 rate base. The company's cost-effectiveness analyses for the projects are based on a reasonable fuel forecast and include reasonable sensitivities. The analyses show that the projects are cost-effective, will moderate fuel costs, and will benefit customers. FIPUG's proposed conditions are not reasonable or needed and should not be imposed by the Commission.

**OPC:** OPC takes no position at this time on the prudence or cost-effectiveness or need of the Solar Projects, but to the extent they are included in rates, the depreciable lives should be increased from 30 to 35 years to maintain the current 35-year service lives.

**FL RISING/**

**LULAC:** Yes, as long as TECO can show the projects are cost-effective. Any costs associated with these projects that TECO cannot demonstrate are prudent and reasonable should be removed from rate base thus adjusting rate base downward.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** No position.

**SIERRA**

**CLUB:** Yes, TECO's new solar projects are cost-effective for ratepayers and increase the fuel diversity of TECO's system.

**FRF:** The FRF supports the addition of solar generating resources to Florida's power supply grid, provided that such resources satisfy the normal standards of cost-effectiveness, reasonableness, and prudence of the utility's investment. These principles require that TECO's solar assets be depreciated over 35 years, and fair ratemaking policy requires that TECO only be allowed to recover costs associated with its solar facilities beginning when each facility achieves commercial service status.

**FUEL**

**RETAILERS:** No Position.

Date: November 22, 2024

**WALMART:** In accordance with Walmart's significant and company-wide renewable energy goals set forth in the Direct Testimony of Steve W. Chriss in Docket No. 20240014-EG, Walmart supports renewable energy projects to the extent those projects are prudent, cost-effective and are relevant to meet TECO's and TECO's customers' renewable energy goals and needs.<sup>41</sup>

**Staff Analysis:**

**ANALYSIS**

TECO has proposed adding 246.6 MW of solar capacity by the end of 2025. (TR 987) The 2024 solar projects consist of the English Creek and Bullfrog Creek solar projects that represent a total of 97.5 MW of solar capacity, both with in-service dates of December 2024. The 2025 solar projects consist of the Duette and Cottonmouth solar projects that represent a total of 149 MW of solar capacity, both with in-service dates in December 2025. (TR 819; EXH 20, MPN C5-337) Witness Aponte testified that the 2024 and 2025 solar projects have projected installed costs of approximately \$144.9 million and \$214.4 million, respectively. (EXH 19 MPN C4-272–C4-295, EXH 201, MPN E6133) During the hearing, TECO witness Stryker clarified that the Duette project had been renamed to Long Beach. (TR 879)

Witness Stryker explained that the proposed solar facilities are needed to provide TECO customers with cost-effective renewable energy that would circumvent fuel price volatility. The witness further explained that the projects were not immediately necessary on the basis of TECO's capacity reserve margin; but would provide economic value that would be decreased if the projects were delayed. (EXH 199, MPN E6030) The witness clarified that TECO has assembled a team of employees and contractors experienced with construction of solar projects that would be lost if the projects were delayed and would result in increased costs in order to be regained later. Additionally, the witness explained that the passage of the IRA is providing PTCs for the proposed solar facilities that would be deferred if the solar projects were delayed. (TR 819-820)

Witness Aponte testified that the 2024 and 2025 Solar projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the solar facilities and the omission of the solar facilities. This comparison was used to determine the system CPVRR. (TR 988) The conclusion of the analyses determined that the addition of the 2024 and 2025 solar projects would result in a CPVRR savings for customers of \$34 million and \$52.6 million, respectively. (EXH 20, MPN C5-346–C5-347) Staff notes that the majority of the CPVRR savings associated with the 2024 and 2025 solar projects are from fuel and PTC savings that the projects would provide. Staff also notes that there are no savings associated with system capacity from the installation of these projects. On a CPVRR basis, the 2024 and 2025 Solar projects are projected to be cost-effective in 2033 and 2035, respectively. (EXH 159, MPN E1966-E2007)

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<sup>41</sup> See Ex. Walmart-3 (Comprehensive Exhibit List Ex. 818); Walmart also incorporates by reference evidence and testimony on these Issues by OPC and/or FRF.

FIPUG witness Ly testified that the cost-effectiveness tests performed by the Company did not provide a robust evaluation of the projects under various capital cost and fuel cost assumptions. (TR 2763-2764) TECO witness Aponte rebutted that the Company had performed sensitivity analysis for both fuel cost assumption and capital cost assumptions. (TR 1005) The witness testified that CPVRR analysis was performed using low and high fuel price forecasts for the solar projects which resulted in CPVRR savings under both fuel price scenarios. (TR 1005-1006; EXH 144, MPN D3-316–D3-317) The witness further testified that TECO performed sensitivity analysis for capital cost assumptions during the initial planning of the project, which resulted in savings even with a 10 percent increase in capital cost assumptions. (TR 1005) Staff agrees with TECO that a comprehensive evaluation of the cost-effectiveness of the solar projects was conducted.

Witness Ly also testified the PTCs associated with the solar facilities are reliant on the solar facilities maintaining a 26 percent annual capacity factor over the first ten years of operation and should be subject to a minimum capacity factor. (TR 2773) Witness Aponte rebutted that initial cost-effectiveness analysis of the solar projects included conservative assumptions of a 0.4 percent projected capacity degradation factor per year and a lower capacity factor during the first full year of operation that would increase by 1 percent annually, until reaching the designed capacity factor by year five. (TR 1007) The witness further rebutted that a sensitivity analysis of the base fuel price scenario that excluded the annually increased capacity factor resulted in increased CPVRR savings of \$36.3 million for customers. (TR 1007; EXH 144, MPN D3-318) Additionally, TECO witness Stryker testified that it was inappropriate to apply a performance standard to a subset of one utility's generating assets. (TR 857) The witness further testified that if a performance standard were to be applied to TECO's proposed solar units, that it would be more appropriate for the Commission to develop a universal performance standard that would be applicable to all Florida public electric utilities solar units. (TR 857-858) Staff notes that the Company's conservative assumptions provide additional data in the evaluation of the proposed solar units' PTC benefits and ability to reliably meet the projected capacity factor. Furthermore, staff agrees it to be inappropriate to apply additional performance standards only to TECO's solar units.

FIPUG was the only intervenor to file testimony specific to this Issue. However, in their briefs, Sierra Club, FL Rising/LULAC, FRF, and Walmart agreed with the proposed solar projects. In its brief, OPC recommended that if the projects were implemented, the depreciable service lives of the units should be increased from 30 to 35 years, which was echoed by FRF. (OPC BR 28, FRF BR 31). Staff's recommendation on depreciation service lives is reflected in Issue 7.

Staff believes that the proposed 2024 and 2025 Solar projects provide cost-effective energy for TECO's system that will provide savings for ratepayers and bolster TECO's renewable energy portfolio. Based on the evidence in the record, staff recommends approval of the proposed energy storage projects in the 2025 projected test year.

## **CONCLUSION**

The proposed 2024 and 2025 Solar projects, with a combined capital costs of approximately \$359.1 million, should be included in the 2025 projected test year with no adjustments. While providing a minimal reliability benefit, the projects do provide cost-effective renewable energy for TECO's system that will provide savings for customers in the form of fuel savings.



**Issue 19:** Should TECO’s proposed Grid Reliability and Resilience Projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Grid Reliability and Resilience Projects, with capital costs of \$128.9 million, should be included in the 2025 projected test year without any adjustments. Staff recommends that these projects are in the customers’ interest as the projects will evolve the electric grid to meet customer demands while also providing reliability and safety benefits. (P. Buys, Vogel)

**Position of the Parties:**

**TECO:** Yes. These projects are prudent and should be included in test year rate base. Adding a dedicated grid communication network, intelligent field devices, and associated back-office control systems will enhance reliability by reducing the frequency, duration, and impact of outages; improve operational performance by enabling “self-healing” features to mitigate adverse grid events; provide more and better data for billing and planning purposes; and facilitate/manage the addition of more customer-owned, distributed generation on the company’s system.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that these projects are in the customer interest and are reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO’s requested Grid Reliability and Resilience (GRR) Projects consist of over 40 interdependent projects that include telecommunications, control center operational technology, back-office information technology, distributed energy resources and substations. When complete, these projects will create a “system of systems” to benefit customers. TECO’s goal is to complete all component projects by the end of 2030. These projects are aggregated, which TECO witness Whitworth believes would result in more efficient capital spending and unlocks enhanced functionality as the system elements are deployed. Witness Whitworth argued that these projects are necessary to replace obsolete systems and equipment that have reached end of life as well as meeting customer demands for greater reliability, greater access to data, and to adapt to changes in how customers consume energy. In addition, these projects will result in quantifiable benefits in terms of reliability and avoided capital and O&M expense. Witness Whitworth testified that TECO’s System Average Interruption Duration Index will reduce 30 minutes per year, Momentary Average Interruption Event Frequency Index will reduce to near zero, 30 million customer minutes of interruption will be avoided, and Customers Experiencing More Than Five Interruptions will reduce to near zero by 2031. (TR 1110; TR 1118-1120; TR 1122; TR 233; TR 240; TECO BR 27-28)

TECO witness Lukcic testified that TECO is proposing to include 12 projects in rate base for 2025 and three projects to be included in the subsequent year adjustments. The three SYA projects are discussed in Issue 96. Table 19.1 lists the 12 projects for 2025 with the associated capital amounts. In addition, there are no O&M costs for these projects. (TR 1240; TR 1245; EXH 194, MPN E5492) Each of these projects, excluding Data Analytics Platform (DAP), are a continuation of work that TECO performed in 2022 through 2024.

**Table 19-1  
 2025 GRR Projects**

<b>Projects</b>	<b>Capital Cost</b>
1. Significant GRR Projects	\$65,871,743
2. DAP	\$18,075,079
3. Blanket - Lighting	\$16,069,585
4. OT Application	\$11,312,970
5. Other	\$4,188,739
6. Blanket – Meter	\$3,867,678
7. ED Capital Maintenance/Improvement	\$2,900,685
8. Meter Operations	\$2,815,381
9. AMI	\$2,038,651
10. ES Capital Maintenance/Improvement	\$665,000
11. Lighting – Growth	\$550,000
12. Light – Operations	\$500,000
<b>Total Cost in 2025</b>	<b>\$128,855,509</b>

Source: (TR 1240)

### **1. Significant GRR Projects**

Witness Lukcic explained that the GRR Projects address changes to the grid, including digitalization, decentralization, and decarbonization, along with increases in distributed generation (e.g., rooftop solar), use of electric vehicles, and growth in other distributed technologies such as battery storage. These projects will enable TECO to meet rising customer demand and enhance reliability by reducing the frequency, duration, and impact of outages. The GRR Projects are comprised of the following projects:

- Control Systems Operations Technology (OT), which monitors and controls assets in the field; (TR 1215-1216; TR 1241)
- Back Office IT, which includes system implementation, software licensing, interfaces, data migration, and new configurations for back-office systems such as Geographic Information System and Work Management System (WMS); (TR 1216-1217)
- Field Devices, which involves deploying a variety of detection and operational devices to provide greater monitoring and control; (TR 1217-1218)
- Substation, which modernizes and replaces obsolete and end-of-life equipment to prepare for bi-directional power flows, including system protection and optimization of circuit level action; (TR 1218)
- Distributed Energy Resources (DER) Infrastructure, which implements monitoring and controls that will coordinate DER and electric vehicles on the system; (TR 1218-1219)
- Grid Communication Network Project, which addresses the need for data transmission and communication through construction of a Private Cellular Network (PLTE). (TR 1215; TECO BR 28)

### **2. DAP**

DAP is a software operating system that allows TECO to collect and analyze data including transformer loading, events, and alarms as testified by witness Lukcic. DAP also identifies proactive substation transformer maintenance and replacements. Witness Lukcic explained that TECO uses the data to proactively reduce outages. DAP provides real-time customer data to the call center to help Customer Service Professionals respond to customers' calls. This is a new project. (TR 1199)

### **3. Blanket – Lighting**

The Blanket - Lighting project includes purchase and replacement of streetlights. Witness Lukcic testified that the purchases are needed to accommodate growth, respond to customer requests, and ensure continued support of the lighting network. The benefits of this project include meeting customer demand, public safety, reliability, and integration with smart city technology. (TR 1212-1213; TR 1241)

#### **4. Operations Technology (OT) Application**

Witness Lukcic testified that the OT Application project enables operational control of TECO's power plants and grid systems, network communication and management of operational data, and collection and analysis of sensor data, which helps TECO understand the condition and performance of the grid. The project also facilitates the maintenance and operation of the grid assets. (TR 1227; TR 1241)

#### **5. Other**

The Other projects include various telecom and analytics projects. Included in these projects are LED Lightning Conversion Initiative, 15 Telecom growth projects, eleven Telecom projects, six Telecom Operations projects, and nine upgrade and enhance back-office system projects. Witness Lukcic explained the projects are needed to support routine customer growth and operations. The benefits include the ability to support continued reliability and standard field operations. (TR 1214; TR 1241; EXH 164, MPN E2129-2130)

#### **6. Blanket – Meter**

The Blanket - Meter projects include the purchase and replacement of failed electric meters as explained by witness Lukcic. The purchases are necessary to accommodate growth and provide continued support for the communication network. The meters will improve networking capabilities to provide faster and more reliable responses to customers for switching and data analysis. (TR 1228-1229; TR 1241)

#### **7. Electric Delivery (ED) Capital Maintenance/Improvement**

Witness Lukcic testified that the ED Capital Maintenance/Improvement project proactively addresses TECO's identified risk assets from TECO's asset class mitigation plan. When TECO identifies a common risk of failure in many similar or identical assets, the Company develops a mitigation plan. This will allow work for a group of assets by bundling and bidding of work, which will obtain a low reasonable cost. The project will improve reliability by mitigating failures and provide reduced costs associated with equipment replacement. Proactively replacing equipment reduces costs compared to reactively replacing equipment. (TR 1235-1236; TR 1241)

#### **8. Meter Operations**

The Meter Operations project is a meter firmware upgrade. Witness Lukcic explained that the firmware is a set of embedded software instructions that govern the operation of a metering device. This includes managing the collection, processing, and transmission of data such as electricity consumption. The firmware will enhance the customers' remote monitoring and management and TECO's ability to swiftly address issues and minimize downtime without physically accessing the meters. (TR 1233-1234; TR 1241)

#### **9. Advanced Metering Infrastructure (AMI)**

The AMI project includes advanced smart meter system, communication infrastructure, and data management systems upgrades. TECO completed the conversion of the Advanced Meter Reading (AMR) in 2021 and has continued to enhance the AMI system since that time. The AMI system includes advanced smart meters, communications infrastructure, and data management systems. The smart meters collect near real-time data that allows the customers to manage their electric use through daily and monthly usage graphs. The meters also provide the customer with information regarding how the weather will affect their bills. (TR 1199; TR 1212; TR 1241)

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### **10. Energy Supply (ES) Capital Maintenance/Improvement**

Witness Lukcic explained that the ES Capital Maintenance/Improvement project facilitates monitoring the condition and performance of TECO's generation assets and allows TECO to proactively replace components before failure, identify opportunities to improve unit efficiency and performance, and improve safety. The project will ensure proactive mitigation of failures, which will improve reliability, and proactive procurement and planning of capital work, which will reduce cost. (TR 1236-1237; TR 1241)

### **11. Lighting – Growth**

TECO's requested Lighting - Growth project is designed to satisfy customer lighting service requests such as solar powered or decorative lightning. The Lightning - Growth project seeks to acquire existing lighting systems, special projects, and new lighting products as the Blanket - Lighting projects fulfill inbound lighting service requests and addresses the long-term maintenance needs of regulated business. (TR 1229-1230; TR 1241; EXH 179, MPN E3508)

### **12. Lighting – Operation**

The Lighting - Operation project is the installation of intelligent lighting systems to fulfill customer requests, as explained by witness Lukcic. The smart lighting fixtures enhance safety and security, provides data insights and analytics, and offers customization and flexibility to meet community needs. (TR 1238; TR 1241)

OPC witness Mara argued that the type of programs in the GRR Projects are planned replacements of existing and obsolete facilities. Further, these types of programs are normally included in the annual budget and would be accounted for in a representative test year. However, increases in the test year costs for these routine types of activities unnecessarily increases costs for customers and should be scrutinized for imprudent spending. (TR 2376) As a result, OPC does not believe the GRR Projects should be approved for inclusion in the 2025 test year.

While not specifically addressing these projects, FL Rising/LULAC witness Rábago recommended that the Commission should disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable. Additionally, witness Rábago recommended that the Commission should disapprove most, if not all, of the requested rate recovery for the GRR projects, as he believes it is additional spending by TECO that is unjustified and unreasonable. (TR 2609-2612) In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project. (FL Rising/LULAC BR 1-6) The remaining intervenors did not specifically address or take a position on this Issue.

TECO witness Lukcic rebutted OPC witness Mara by testifying that the GRR Projects build on TECO's existing grid modernization strategy and will provide new and enhanced functionality across each of the investments. He further argued that none of the projects are considered routine maintenance or equipment replacements. Instead, each project provides new or enhanced functionality to meet customer expectations and provide smart grid benefits. Further, the GRR Projects are necessary to replace obsolete systems and equipment, as well as meet customer

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demands for greater reliability, greater access to data, and to adapt to changes in how customers consume energy. (TR 1262-1263; TR 1271-1274; EXH 194, MPN E5505; TECO BR 29)

Staff agrees with TECO witness Lukcic's arguments that the GRR projects should not be considered routine maintenance. TECO's witness Whitworth testified that in certain circumstances, replacing obsolete equipment would be normal activities; however, he further explained that some assets are replaced because they are not compatible with the communication technology. Staff also agrees with TECO's argument that technology is evolving and its grid needs to also adapt in order to best serve its customers. For example, with the GRR projects, TECO will have the technology to be able to pinpoint precisely where the outage is and dispatch troubleshooters and repair workers to a very specific location. Witness Whitworth testified the technology will be able to detect grid outages and automatically restore as many customers as possible prior to human intervention. Staff recognized the benefits that the GRR projects will bring to customers such as reliability, but also the benefits for TECO employees, such as safety. For example, TECO employees will be able to isolate the system and safely remove any hazards. (TR 1165-1166; TR 1170-1173; TR 1178; TR 1180-1182; TR 1185-1186)

Witness Lukcic also argues that by aggregating these projects under a common heading, the overall approach is better coordinated and results in a more efficient spending of capital. This also results in considerably more allowance for funds used during construction (AFUDC). Witness Lukcic explained that TECO found the most cost-effective way to deploy the projects, along with providing the maximum value to customers. By aggregating the projects, TECO can optimize capital spending, maximize functionally, and achieve efficiency in resource deployment. Witness Lukcic testified that this approach enables a centralized project management, reduces redundancy, and enhances resource efficiency. (TR 1219; TR 1279-1281) Staff believes TECO appropriately evaluated the costs of the GRR projects in its request by grouping like projects together for efficient spending.

Staff agrees with TECO that customer demand and activities are changing and that the electric grid needs to be updated to meet those demands. Based on the above, TECO's GRR Projects will evolve its electric grid to meet the demands noted above while also providing inherent reliability, and safety benefits. Staff recommends that TECO has met its burden of proof and that these projects are in the customers' interest. Therefore, staff recommends the GRR projects should be included in the 2025 protected test year with no adjustments.

## **CONCLUSION**

The proposed Grid Reliability and Resilience Projects, with capital costs of \$128.9 million, should be included in the 2025 projected test year without any adjustments. Staff recommends that these projects are in the customers' interest as the projects will evolve the electric grid to meet customer demands while also providing reliability and safety benefits.

**Issue 20:** Should TECO's proposed Energy Storage projects be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The four energy storage projects, with an estimated total capital cost of \$156.1 million, should be included in the 2025 projected test year with no adjustments. The projects provide cost-effective energy storage for TECO's system that will provide savings for customers. (O. Wooten, Vogel)

**Position of the Parties:**

**TECO:** Yes. The company's 115 MW of Future Energy Storage Capacity projects are prudent and should be included in test year rate base. They are cost-effective plant additions needed to maintain the company's required winter capacity reserve margin and to avoid the costs of certain transmission upgrades.

**OPC:** OPC takes no position at this time on the prudence or cost-effectiveness or need of the Energy Storage projects, but to the extent the projects are included in rates, the depreciable lives should be increased from 10 to 20 years. Based on the evidence adduced at the hearing, OPC has no other specific adjustments related to this issue.

**FL RISING/**

**LULAC:** Yes, as long as TECO can show the projects are cost effective. Any costs associated with these projects that TECO cannot demonstrate are prudent and reasonable should be removed from rate base thus adjusting rate base downward.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Yes, TECO's new energy storage projects are cost-effective for ratepayers and increase the fuel diversity of TECO's system.

**FRF:** The FRF supports the addition of battery energy storage resources to Florida's power supply grid, provided that such resources satisfy the normal standards of cost-effectiveness, reasonableness, and prudence of the utility's investment. These principles require that battery storage assets be depreciated over 20 years, not 10 years as originally proposed by TECO, and fair ratemaking policy requires that TECO only be allowed to begin recovery when each facility achieves commercial service status.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** In accordance with Walmart's significant and company-wide renewable energy goals set forth in the Direct Testimony of Steve W. Chriss in Docket No. 20240014-EG, Walmart supports renewable energy projects to the extent those projects are prudent, cost-

effective and are relevant to meet TECO's and TECO's customers' renewable energy goals and needs.<sup>42</sup>

**Staff Analysis:**

**ANALYSIS**

TECO requested to add four energy storage projects: Dover Energy Storage Project (Dover), Lake Mabel Energy Storage Project (Lake Mabel), Wimuuama Energy Storage Project (Wimuuama) and South Tampa Energy Storage Project (South Tampa) in the 2025 projected test year. (TR 840) Witness Stryker stated that the energy storage projects had initial projected in-service dates of September 2024, April 2025, February 2025, and April 2025, respectively. (TR 842) The storage capacity of the four energy storage projects is 15 MW, 40 MW, 40 MW and 20 MW. The projects would utilize lithium-ion battery technology and would represent a total addition of 115 MW of energy storage capacity to TECO's system. (EXH 19, MPN C4-288–C4-295) TECO witness Stryker asserted that the capital investment for the energy storage capacity projects would total \$156.1 million, consisting of \$136.8 million in construction costs and \$19.3 million in contingency. (TR 841) In response to a staff interrogatory, TECO indicated that the in-service date for two of the proposed energy storage projects and location of one of the energy storage projects would be revised from its initial petition. Lake Mabel's in-service date was accelerated from April 2025 to January 2025 and South Tampa's in-service date was delayed from April 2025 to December 2025. (EXH 208, MPN E7811–E7817) Witness Stryker testified that the South Tampa Energy Storage Project construction location was relocated to TECO's Bayside Power Station which delayed the in-service date and lead to the South Tampa Energy Storage project being renamed the Bayside Energy Storage Project (Bayside). (TR 811)

TECO witness Aponte testified that the four proposed energy storage projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the energy storage facilities and omitting the energy storage facilities. (TR 980) This comparison was used to determine the system CPVRR. (TR 981) The analyses showed that the addition of the four energy storage facilities would result in a CPVRR savings of \$151.2 million, for customers. (EXH 20, MPN C5-346–C5-347, EXH 159, MPN E1966-E2007) Staff notes that the majority of the CPVRR savings associated with the energy storage projects are from fuel and PTC savings that the projects would provide. The witness asserted that the next-best alternative to the construction of the proposed energy storage projects the Company explored was combustion turbine (CT) technology, which was ultimately rejected. This decision was influenced by the fact that the resource plan that included the four energy storage projects produced a lower CPVRR in comparison to the CT alternative resource plan. Additional non-economic benefits of the energy storage facilities include: smaller operational footprints, a more rapid location siting process, and deployment in smaller capacity increments to better fit TECO's winter capacity needs. (EXH 199, MPN E6031–E6033)

No intervenor provided testimony regarding this Issue. In its brief, OPC provided no comment on the cost-effectiveness of the projects; but recommended the depreciable service lives of the

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<sup>42</sup> *Id.* [See Ex. Walmart-3 (Comprehensive Exhibit List Ex. 818); Walmart also incorporates by reference evidence and testimony on these Issues by OPC and/or FRF].



units be increased from 10 to 20 years (OPC BR 29). Both FIPUG and FRF echoed OPC's position regarding depreciable service lives. (FIPUG BR 7, FRF BR 31) Staff's recommendation on depreciation life is reflected in Issue 7. Sierra Club, FL Rising/LULAC, FRF, and Walmart agreed with TECO's proposed energy storage projects. All other intervenors took no position on this Issue.

Staff believes that the proposed energy storage projects provide cost-effective energy for TECO's system that will provide savings for customers and bolster TECO's renewable energy portfolio. Based on the evidence in the record, staff recommends approval of the proposed energy storage projects in the 2025 projected test year.

### **CONCLUSION**

The four energy storage projects, with an estimated total capital cost of \$156.1 million, should be included in the 2025 projected test year with no adjustments. The projects provide cost-effective energy storage for TECO's system that will provide savings for customers.

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**Issue 21:** Should TECO’s proposed Corporate Headquarters project be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Corporate Headquarters, with a capital cost of \$188.7 million, should be included in the 2025 projected test year without any adjustments. Relocating TECO employees to the new Corporate Headquarters will provide additional space for expansion, and the structure will be more storm resilient and built to current building codes. (P. Buys, Hinson)

**Position of the Parties:**

**TECO:** Yes. This project is prudent and should be included in test year rate base. The company's lease for TECO Plaza is expiring and the cumulative net present value revenue requirement (“NPVRR”) of moving to the new building was about the same as other options. The new building location is not subject to flooding, has better parking, is safer for employees and the public, and has space to grow that is not available in TECO Plaza.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that this project is in the customer interest and is reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC’s position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Aldazabal testified that TECO is relocating its headquarters from TECO Plaza in Downtown Tampa to a new 18-story tower in Midtown Tampa. A portion of the tower will be purchased by TECO, with rights to approximately 740 parking spaces. This new headquarters will house TECO and its affiliate Peoples Gas System, Inc. TECO will occupy six floors and

Peoples Gas will occupy three floors. Each company will own its share of the tower. The anticipated in-service date is June 1, 2025, with a cost of \$188.7 million. (TR 669-670; TR 673)

As explained by witness Aldazabal, TECO has been leasing TECO Plaza, for 40 years and the lease expires in 2025. TECO evaluated multiple options prior to selecting the Midtown Tampa location. As part of the evaluation, TECO developed ten scoring criteria for each option that included resilience, security, connection to community, walkability, parking, nearby amenities, talent recruitment, dedicated elevators, dedicated lobby, building signage, and sustainability. In addition, TECO evaluated three scenarios: (1) leasing TECO Plaza; (2) purchasing TECO Plaza; and (3) purchasing the Midtown location. The 30-year CPVRR for continuing to lease the Plaza is \$209.5 million, for purchasing the Plaza is \$203.4 million, and for purchasing Midtown is \$210.2 million. This analysis showed that there is less than a \$1 million NPV differential between continuing to lease the existing corporate headquarters and purchasing the Midtown location. (TR 670; TR 672; TR 675; EXH 18, MPN C3-2030-2031; TECO BR 31)

Witness Aldazabal explained that continuing to lease an aging building that was designed over 40 years ago, without parking infrastructure and with outdated systems and susceptible to low levels of flood waters, was not in TECO's best interest. In addition, witness Aldazabal testified that customers will benefit from TECO owning the building from the equity accumulation and the Midtown location provides greater resilience in harsh weather conditions because it is inland and built to modern code standards. Furthermore, the Midtown location offers modern facilities, dedicated parking, more efficient floor layouts that will accommodate more team members, reduce space needs in the future, and improve employee satisfaction, which should result in lower employee turnover and costs. The new headquarters will provide TECO with the flexibility of right of first refusal to lease vacant space on other floors in the building and the right to sublease portions of the floors it will own. (TR 689; TR 672; TECO BR 31)

No intervenor specifically testified on this Issue. However, FL Rising/LULAC witness Rábago recommends that the Commission disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommends that the Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction. (TR 2610; TR 2612) In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project. (FL Rising/LULAC BR 1-6) The remaining intervenors did not specifically address or take a position on this Issue.

TECO witness Aldazabal rebutted FL Rising/LULAC witness Rábago's testimony stating that TECO performed a CPVRR calculation for the new Corporate Headquarters and compared it to two alternatives. The Company then compared this quantitative assessment against the resilience and qualitative benefits that the new Midtown location provides. In addition, the witness testified that TECO created an internal team of 18 director-level employees to evaluate several criteria and also identified several qualitative drawbacks to remaining in TECO Plaza, including flooding and storm surge risk, available capacity limits, and lack of dedicated parking. TECO determined that the Midtown location was the best alternative from a value, resilience, and employee retention and satisfaction perspective as explained by witness Aldazabal. Furthermore, as the analysis proceeded, the need to locate the Company's headquarters away from potential

flooding became a more important priority, especially since the economics of the options being considered were about the same. The Company weighed the identified qualitative benefits of the Midtown location against the approximately \$1 million difference in CPVRR cost and concluded that the benefits outweighed the \$1 million difference in cost. (TR 688-690) (EXH 194, MPN E5481; TECO BR 31-32)

Staff recommends that TECO has met its burden of proof by providing both a CPVRR analysis and detailed the qualitative benefits that the new Midtown location provides. Therefore, staff recommends that the Corporate Headquarters be included in TECO's 2025 projected test year without any adjustments.

### **CONCLUSION**

The proposed Corporate Headquarters, with a capital cost of \$188.7 million, should be included in the 2025 projected test year without any adjustments. Relocating TECO employees to the new Corporate Headquarters will provide additional space for expansion, and the structure will be more storm resilient and built to current building codes.

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**Issue 22:** Should TECO’s proposed South Tampa Resilience project be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** No. The South Tampa Resilience Project is not needed for reliability purposes in 2025 and its fuel savings are not projected to offset the early in-service date absent a reliability need. Therefore, an adjustment should be made to remove \$167.245 million. (G. Davis, Hinson)

**Position of the Parties:**

**TECO:** Yes. This project consists of four reciprocating internal combustion engines located on land leased at no cost to Tampa Electric from MacDill Air Force Base and is prudent. The project will be a system asset during normal operations, provides quick start capability, supports the company’s winter reserve margin, is cost-effective, and is expected to generate fuel savings of \$137.9 million. The generators will only be isolated to serve MacDill during rare national emergencies.

**OPC:** OPC does not propose a specific adjustment on this issue. The Commission should, however, give critical recognition to the circumstances surrounding the reprofiling of capital into the test year and the lack of federal government support for the product in light of the affordability issues enveloping this case.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that this project is in the customer interest and is reasonable and prudent, and should be rejected for the reasons explained in the brief, including that this is a project to provide back-up power to the Air Force at the expense of TECO’s ratepayers and that TECO did not use a proper base case in its cost-effectiveness analysis.

**FIPUG:** No, not at this time as the project has materially changed.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC’s position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

The South Tampa Resilience Project (STR Project) is a two-phase project consisting of two pairs of 18.5 MW reciprocating internal combustion engines (RICE) with in-service dates of December 2024 for Phase I and October 2025 for Phase II. (TR 654-655; EXH 208, MPN F2.2-6217). The STR Project is located on MacDill Air Force Base (MAFB), which agreed to lease the land at no cost to TECO in exchange for the provision of electrical service due to a validated threat against MAFB. (TR 6954, TR 745-748) Under normal operations, the STR Project will be a system asset that serves all customers. The future installed project cost is approximately \$167 million (including AFUDC). (EXH 20, MPN C5-337)

TECO witness Aldazabal described the project as needed to provide flexibility to its resources and resilience based on its location. (TR 655) Also, by providing quick-start capability, the units will improve the Company's utilization of its existing fleet of generating assets due to the increased flexibility, reduced maintenance intervals, improved heat rates, faster ramp rates, and lower turndowns of the STR Project. (TR 994) TECO witness Aponte asserted that the STR Project is cost-effective based on a CPVRR analysis that projects net benefit to customers of approximately \$10 million, excluding emission reductions. (TR 978) This net benefit includes a projected fuel savings to customers of \$137.9 million from the RICE generating units. The remaining savings are primarily associated with the delay or avoidance of other generating assets, and their related transmission components. (EXH 20, MPN C5-339) In cross-examination, witness Aponte agreed that TECO did not include any government funding for the project, despite the provision of emergency backup generation, and noted that such funding would have improved the cost-effectiveness of the project. (TR 1024-1025)

OPC has not proposed eliminating the STR project, but notes that TECO should be aware that an increase in rates will create an affordability challenge for many ratepayers. (TR 216-218; OPC BR 29). OPC was also concerned about the lack of sufficient federal government funding that recognizes the benefits being provided to MAFB. (TR 2611) OPC states that TECO moved capital cost for the STR project into the test year to maximize revenue requirements without seeking any federal funding, and therefore, has not proved that this project is prudent and customer rates are fair, just, and reasonable. (TR 266-267; TR 2611)

FL Rising/LULAC witness Rábago recommended the Commission deny any rate recovery for the STR Project due to several concerns, including a lack of support of a benefit-cost analysis, addition of polluting fossil generation, and a lack of direct financial support from MAFB for the benefits provided. (TR 2611-2612) In his rebuttal testimony, witness Aponte disputed the claim that a cost-benefit analysis was not conducted, highlighting the \$10 million CPVRR as well as operational benefits, including strengthening near-term reserve margins, improving reliability, enhancing dispatch flexibility, and further insulating customers from disruptions during extreme weather events. (TR 1010-1011) No intervenor, other than OPC, and FL Rising/LULAC filed testimony on this Issue. In their briefs, FIPUG, FEA, FRF, and Fuel Retailers have taken no position. OPC does not propose a specific adjustment to this Issue, but does recommend to consider this project cost along with other items that accelerate capital recovery when determining the ROE. (BR 30) Walmart adopted OPC's position. FL Rising/LULAC's position is

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no because TECO has not met its burden to show this project is in their customers' best interest, is reasonable and prudent. (BR 11) Last, Sierra Club adopted FL Rising/LULAC's position.

In his rebuttal testimony, TECO witness Aponte asserted that the value of the STR Project is its operational flexibility. (TR 1011) Witness Aponte attributed the increasing amount of solar generation and its operating characteristics with the need for faster start and ramp times, as rapid changes in solar output can lead to traditional generation being forced offline or operating inefficiently to maintain reliability. (TR 1014) To the extent that increased solar generation creates an operational need, it should be represented in the economic analysis of the solar generation as a cost associated with new generation or storage facilities. TECO witness Allis further testified that the increased adoption of renewable generations can also reduce CC plants' life span due to more frequent cycling to follow electrical load. While staff agrees that the STR Project would improve TECO's ability to operate its generating fleet, TECO has not demonstrated that the project is needed at this time for reliability, and has not demonstrated that the project is economical when considering the other solar or storage additions planned by TECO.

In determining whether to recommend approval of the project, staff considered whether TECO had a reliability need for the generation during or near the projected test year. In cross-examination, TECO witness Aponte admitted that there is no reserve margin need for the unit, but an economic one. (TR 1039) Based on a reserve margin requirement of 20 percent for winter peak, TECO would not require the firm capacity contribution of the STR Project until 2029, and even then the need is for a single year's winter peak, with the next need for capacity occurring in 2033. (TR 1043-44; EXH 120, MPN C32-3577) The economic need for the STR Project relied upon by witness Aponte is a CPVRR analysis that shows a \$10 million net benefit. (EXH 197, MPN D3-307) However, this net benefit is itself based on a \$74 million benefit from deferring or avoiding other generating facilities, beginning with the deferral of a hypothetical 200 MW CT unit in 2027. (TR 1040; EXH 197, MPN F3.2-3901) The disconnect between the reliability analysis showing no need for the unit and the economic analysis being based on a reliability need is due to the order in which TECO evaluated its generating units. When TECO performed the CPVRR analysis for the STR Project, it only included the system capacity impacts of the Dover Energy Storage and the Polk Flexibility projects. (EXH 197, MPN E5899) The remaining three energy storage projects and all of its proposed solar facilities, including those with in-service dates before the in-service date of STR Project Phase II, were not included in the analysis. As a result, TECO has not adequately demonstrated an economic need for the unit.

## **CONCLUSION**

The South Tampa Resilience Project is not needed for reliability purposes in 2025 and its fuel savings are not projected to offset the early in-service date absent a reliability need. Therefore, an adjustment should be made remove \$167.245 million.

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**Issue 23:** Should TECO’s proposed Bearss Operations Center project be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Bearss Operations Center project, with a total cost of \$335.0 million, should be included in the 2025 projected test year without any adjustments. The Bearss Operations Center was chosen by TECO for its storm resilience, office space, and strategic objectives. (P. Buys, Hinson)

**Position of the Parties:**

**TECO:** Yes. The Bearss Operations Center is a modern, storm hardened, secure operations center that will replace the company’s current energy control center (“ECC”) and IT functions at the Ybor Data Center. Unlike these existing structures, the new facility is designed to withstand major hurricanes, protect the company’s cyber assets, and operate utility command and control functions for the next 40 years. The project is prudent and should be included in test year rate base.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that this project is in the customer interest and is reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC’s position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO requested its Bearss Operations Center (BOC) project be included in the 2025 projected test year. This project consists of replacing TECO’s existing Energy Control Center (ECC) and Ybor Data Center (Ybor) with the BOC. This project also includes Energy Management System (EMS) upgrades, which are new map boards and dispatching consoles to match the operating



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assets within the facility. The anticipated in-service date for the BOC is June 2025 with a total cost of \$307.4 million. The EMS upgrades are projected to be completed by October 1, 2025, with a total cost of \$27.6 million. (TR 658-659; TR 665; TR 668; TECO BR 34)

TECO will continue to utilize the two buildings which housed the Ybor Data Center and the ECC. Ybor will become the Customer Experience Center for both TECO and Peoples Gas, and the existing ECC will be repurposed into an Engineering Center for Electric Delivery. It was explained that several Customer Experience departments and employees will relocate from their current home at TECO Plaza to the Ybor location instead of relocating to the BOC or the Corporate Headquarters. According to TECO, this change will more efficiently and effectively consolidate Customer Experience functions and departments into a single location. (EXH 206, MPN E6637-E6639; EXH 212, MPN E8211; TR 802-803)

In addition, TECO explained that it has a continuing lease of \$181,687.81 per year, with a scheduled CPI adjustment every five years for the Ybor Data Center. As explained above, the Ybor Data Center will continue to be used for employee work offices, so the Ybor Data Center lease costs are included as part of the Company's revenue requirement calculation. TECO witness Aldazabal testified that the Ybor lease is below market and it is a very economical lease for TECO. He indicated that is one of the reasons TECO wanted to maintain the Ybor Data Center. As TECO owns the ECC, there is no lease. (TR 804; EXH 194, MPN E5478)

Through discovery, TECO explained that the ECC has been TECO's primary control center since June 1989, serving customers for 35 years. The ECC operates 24/7/365 and was constructed under 1980 building codes and in a Level B evacuation zone. TECO's customer base has doubled since the ECC was first used and there is no room for growth within the ECC; as such, TECO considers the ECC to be at its "End of Life." The Ybor Data Center was also designed using 1980 technology and building codes. In addition, the Ybor Data Center is not hardened to withstand a major hurricane and is located within a storm evacuation zone. As stated above, TECO owns the ECC and the lease for the Ybor Data Center is below market value. While these two buildings are older and in flood prone areas, the buildings will house non-essential employees, like the Customer Experience Center and the Engineering Center for Electric Delivery unlike the BOC which will house all of TECO's cyber assets and operate TECO's command and control capabilities. The BOC will also house all for TECO's mission critical assets and departments. (TR 659-660; EXH 164, MPN E2126-2127; EXH 206, MNP E6638-6639; TECO BR 34)

TECO based its decision to replace the ECC and Ybor Data Center on three factors: (1) storm resilience; (2) space needs; and (3) strategic objectives. Both existing facilities are subject to high winds and storm surge in the event of a major hurricane tracking into Tampa Bay. The BOC will be located in a safer, higher, and more inland location, and will be designed to withstand winds up to 171 mph. TECO argued the importance of security and storm resilience for BOC, as it will house imperative functions. The Ybor Data Center will become the prime, full service, Customer Experience Center for both TECO and Peoples Gas, and the existing ECC will be repurposed into an Engineering Center for Electric Delivery. (TR 660-661; EXH 206, MPN E6637-6639; EXH 212, MPN E8211; TECO BR 34)

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TECO witness Aldazabal explained that TECO evaluated its existing facilities and future space plans, potential new site locations, and conceptual site layouts to replace the ECC and Ybor Data Center. The site location criteria included size, security risk, flood zone, topography, environmental conditions, employee commute, and relay service capability. TECO determined that the Bearss location was the best option because a modern, storm hardened facility will allow TECO to respond faster to customer outages without having to recover its own control of the grid first. The new facility is also better suited to withstand other potential threats such as physical, biological, and chemical. (TR 663-664)

TECO's current EMS went in-service in 2017. TECO upgrades its EMS every seven years to stay current; however, the current EMS software does not have the capabilities to support the grid's overall performance and will no longer be supported. The new BOC facility will have new situational awareness features such as visual displays, alarming features, operator consoles, and training simulators. In addition, the latest release of the EMS platform offers new functionalities that will be able to support the grid and growth. (TR 666-667)

No intervenor specially testified on this Issue. However, FL Rising/LULAC witness Rábago recommends that the Commission should disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommended that the Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction. (TR 2610; TR 2612) Additionally, witness Rábago did not specifically identify issues with this project aside from its generic position regarding a BCA. In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project. (FL Rising/LULAC BR 1-6) TECO did not address witness Rábago regarding this Issue in its rebuttal testimony. The remaining intervenors did not specifically address or take a position on this Issue. Staff believes that TECO adequately evaluated its decision to replace the ECC and Ybor Data Center. TECO's decision was based on storm resilience, space needs, and strategic objectives, which led TECO to choose BOC. (TR 660)

Staff believes TECO has met its burden of proof by providing how the BOC was chosen based on storm resilience, space needed, and strategic objectives. The BOC will be located inland and will be designed to withstand 171 mph sustained hurricane winds. The BOC will provide more space for employees and equipment and will have room to grow. In addition, the BOC will be designed to accommodate the EMS upgrades. Therefore, staff recommends that the BOC project be included in TECO's 2025 projected test year without any adjustments.

## **CONCLUSION**

The proposed Bearss Operations Center project, with a total cost of \$335.0 million, should be included in the 2025 projected test year without any adjustments. The Bearss Operations Center was chosen by TECP for its storm resilience, office space, and strategic objectives.

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**Issue 24:** Should TECO's proposed Polk 1 Flexibility project be included in the 2025 projected test year? What, if any, adjustments should be made?

**Recommendation:** Yes. The proposed Polk 1 Flexibility project, with a total cost of \$90.1 million, should be included in the 2025 projected test year. The conversion of Polk Unit 1 to a natural gas-fired simple cycle unit is projected to be more economic for customers than continuing as a combined cycle unit and incurring major capital expenses. However, as the remaining portions of Polk Unit 1 integrated gasification combined cycle system, including the gasification equipment, heat recovery steam generator, and steam turbine do not appear likely to return to service, they should be retired. Therefore, an adjustment should be made to remove \$142,251,955. Staff recommends establishing a capital recovery schedule with an 11-year amortization period to address recovery of the remaining balance in rate base. (G. Davis, Vogel)

**Position of the Parties:**

**TECO:** Yes. This Project will convert Polk Unit 1 into a highly efficient simple cycle unit, is prudent, and should be included in test year rate base. The Project will increase the unit's flexibility, allow faster start times, increase ramp rates, and reduce turndowns; and will generate an estimated \$40 million of fuel cost benefits and a CPVRR benefit of \$166.9 million. Sierra Club's proposal to retire Polk Unit 1 early should be rejected.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, TECO has not met its burden to show that this project is in the customer interest and is reasonable and prudent, and should be rejected for the reasons explained in the brief.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** No, as TECO has not met its burden of showing this project is fair, just, and reasonable for its ratepayers, who are already burdened with above-average electricity rates. The Commission should disallow recovery unless TECO provides an analysis demonstrating that converting its combined cycle unit to a simple cycle is necessary for reliability resources *and* lower cost than retiring the unit and replacing it with alternative resources by 2030 or earlier.

**FRF:** No. The Company has not met its burden of demonstrating that this project is necessary to provide safe and reliable service.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Polk Unit 1 is a 220 MW Integrated Gasification Combined Cycle (IGCC) plant that entered commercial service in 1996 with a 1x1 configuration consisting of a single CT with an attached HRSG, connected to a single ST. (TR 618; EXH 117, MPN C32-3445-C32-3446) Polk Unit 1 is a one-of-a-kind installation because it is supplied fuel via an integrated gasification facility that converted its coal or petcoke feedstock into syngas which was then fired in the combustion turbine. The unit can also operate on natural gas as needed, and has been fueled by natural gas and not the syngas from the gasifier since 2018. (TR 653). TECO witness Aldazabal stated that due to its age and operating history, it is in need of a major maintenance overhaul, and the existing combustion turbine system is no longer supported by its original equipment manufacturer, GE. (TR 653)

In lieu of maintaining the current configuration, TECO is proposing the Polk 1 Flexibility Project (Flexibility Project), which consists of the conversion of Polk Unit 1 to a simple cycle configuration using natural gas as its primary fuel while keeping the gasification, HRSG, and ST in reserve for a possible future conversion back to an IGCC. (TR 652-653) Witness Aldazabal asserted that by designing and operating the unit as a CT that TECO would avoid significant capital expenses associated with upgrades to the existing combined cycle system, and that operations would benefit from the unit's flexibility, including faster start times, higher ramp rates, and lower turndowns. (TR 654) In cross-examination, TECO witness Aponte agreed that the Flexibility Project does not add capacity to the system. (TR 1040-1041) In fact, the converted output of the unit is about 20 MW less than the current combined-cycle unit with 220 MW. (TR 1045-1046)

**Cost-Effectiveness**

The Flexibility Project is projected to have an overnight construction cost of \$90.1 million. (TR 1059) TECO witness Aponte asserted that TECO's economic analysis shows the proposed project is cost-effective and estimates a CPVRR benefit of \$166.9 million excluding emissions. (TR 973) The witness' net-benefit evaluation is based on the comparison of retaining the unit in its current IGCC configuration versus the simple cycle CT conversion proposal. (TR 971)

In their briefs, FL Rising/LULAC states that the Flexibility Project does not add capacity to TECO's service territory, and should be rejected. (FL Rising/LULAC BR 66-67) Witness Aldazabal admits that TECO is planning to use Polk Unit 1 at less than 5 percent of its capacity factor. (TR 769) Sierra Club witness Glick argued that even with the CT conversion, Polk Unit 1 is non-economical. (TR 2528) The witness further asserted that the Company failed to consider retirement as an option, excluding a study conducted in 2022 that assumed a 2028 retirement date. (TR 2531-2532) According to TECO witness Aldazabal's rebuttal testimony, TECO evaluated three alternatives: the retirement of Polk Unit 1, an "in-kind" upgrade that would maintain the unit as-is, and the Flexibility Project. (TR 699-700) Witness Aldazabal asserted that TECO has selected the most beneficial scenario for customers by opting to convert the unit to

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simple cycle mode, and that even when compared to the 2028 retirement scenario produces an additional \$24.6 million in savings. (TR 700) In redirect, TECO witness Aponte stated that the Polk Unit 1 retirement analysis revealed that no change to the unit is the most expensive option, followed by the retirement option, and the conversion to simple cycle being the most cost-effective option (TR 1083)

### **Remaining Non-Simple Cycle Assets**

TECO witness Aldazabal stated the Company plans to retain the Polk Unit 1 gasifier, HRSG, and steam turbine in the event petcoke became economically viable in the future and provide a fuel diversity option. (TR 653, 787) In his rebuttal testimony, witness Aldazabal stated that these components can be returned to service within a year period. (TR 698) In cross-examination, witness Aldazabal stated the Company has not estimated the cost of returning Polk Unit 1 to service as an IGCC. (TR 774) He further stated that for the return to service of those components to be feasible, the reduction in price from natural gas to coal or petcoke would need to occur for an extended period of time greater than a year and the price differential would need to cover the cost of conversion. (TR 775-776)

Sierra Club witness Glick argued TECO is not likely to return these components to service and they should be retired. (TR 2507) Witness Glick asserted that the time required for conversion back to operating on alternate fuels such as petcoke makes it unlikely that the unit would return to combined cycle service, and could not do so during a short-term fuel disruption or price spike. (TR 2518-2519) In cross-examination, TECO witness Aldazabal confirmed that TECO has operated the unit on natural gas since 2018, even when gas supply and price concerns occurred historically due to the short-term duration of the price or supply shocks. (TR 788) Staff agrees with Sierra Club witness Glick's recommendation to retire the gasifier, HRSG, and steam turbine units. No intervenor, other than Sierra Club, filed testimony on this Issue. In their briefs, OPC, FIPUG, FEA, Fuel Retailers, and Walmart have taken no position. FRF's position is that TECO has not met its burden to prove this project is necessary for safe and reliable service. (BR 32)

Due to the length of time necessary to convert back to syngas fuel sources, staff believes it is unlikely that these components will be able to provide fuel diversity benefits in the event of fuel supply shocks in a reasonable duration of time. Staff notes that the 2025 retirement of the gasifier, CT, and ST at Polk Unit 1 would result in an unrecovered capital investment, in the amount of \$142,251,955. Staff also notes that the 2025 retirement would result in an un-accrued dismantlement cost of \$1,692,786. (EXH 161, MPN E2072) Staff recommends establishing a capital recovery schedule with an 11-year amortization period to address recovery of the remaining balance in rate base.

## **CONCLUSION**

The proposed Polk 1 Flexibility project, with a total cost of \$90.1 million, should be included in the 2025 projected test year. The conversion of Polk Unit 1 to a natural gas-fired simple cycle unit is projected to be more economic for ratepayers than continuing as a combined cycle unit and incurring major capital expenses. However, as the remaining portions of Polk Unit 1 integrated gasification combined cycle system, including the gasification equipment, heat recovery steam generator, and steam turbine do not appear likely to return to service, they should be retired. Therefore, an adjustment should be made to remove \$142,251,955. Staff recommends establishing a capital recovery schedule with an 11-year amortization period to address recovery of the remaining balance in rate base.

**Issue 25:** What amount of Plant in Service for the 2025 projected test year should be approved?

**Recommendation:** The amount of Plant in Service that should be approved for the 2025 projected test year is \$12,868,236,740. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Plant in Service totaling \$13.4 billion as shown on MFR Schedule B-1, adjusted by the company's July and August Filings. OPC's proposed adjustment for distribution feeders should be rejected.

**OPC:** The Distribution Feeder Hardening costs should be disallowed and considered in the SPP and SPPCRC. This would require a reduction of \$0.356 million in revenue requirement. Plant in Service for the 2025 projected test year should reflect OPC's recommended adjustments. The appropriate amount of Plant in Service for the 2025 projected test year will fallout from the resolution of other issues.

**FL RISING/**

**LULAC:** The appropriate amount of Plant in Service for the 2025 projected test year will fallout from the resolution of other issues, but no more than \$12,774,719.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Agree with OPC.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

OPC stated in its brief, that the Distribution Feeder Hardening costs should be disallowed from Plant in Service and considered in the Storm Protection Plan and Storm Protection Plan Cost Recovery Clause (SPPCRC). (OPC BR 30) TECO argued in its brief, that the Distribution Feeder Hardening costs have been recovered this way in prior years and this approach recognizes that the depreciation expense for the removed assets incorporated the recovery of the cost of

removal in rate base. (TECO BR 36) Staff recommends allowing the Distribution Feeder Hardening costs to be included in Plant in Service, as it has been in prior years.

Staff has, however, made adjustments in other issues that affect Plant in Service. Based on adjustments made in Issues 15, 16, 22, and 24, Plant in Service should be reduced by \$549,841,260. Plant in Service for the 2025 projected test year should be \$12,868,236,740.

### **CONCLUSION**

The amount of Plant in Service that should be approved for the 2025 projected test year is \$12,868,236,740.



**Issue 26:** What amount of Accumulated Depreciation for the 2025 projected test year should be approved?

**Recommendation:** The amount of Accumulated Depreciation that should be approved for the 2025 projected test year is \$3,679,106,305. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Accumulated Depreciation and Amortization totaling approximately \$4.0 billion as shown on MFR Schedule B-1, adjusted for the company's July and August filings.

**OPC:** Accumulated depreciation should be adjusted to reflect the current 35-year service life of the solar plants and adjusting the Battery Storage lives from 10 to 20 years. This requires an adjustment to reduce Accumulated Depreciation of \$0.440 million and \$0.275 million respectively.

**FL RISING/**

**LULAC:** TECO's requested accumulated depreciation amount should be adjusted to reflect removal of the projects that should be disallowed.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts the position of OPC and FL Rising/LULAC on this issue.

**FRF:** Agree with OPC.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its original filing, TECO stated the amount of Accumulated Depreciation that should be approved for the 2025 test year is \$4,004,807,000. Based on adjustments made in Issues 7, 11, 15, 16, 20, 22, and 24, Accumulated Depreciation should be decreased by \$325,700,695. Accumulated Depreciation for the projected 2025 test year should be \$3,679,106,305.

### **CONCLUSION**

The amount of Accumulated Depreciation that should be approved for the 2025 projected test year is \$3,679,106,305.

**Issue 27:** What amount of Construction Work in Progress for the 2025 projected test year should be approved?

**Recommendation:** The amount of Construction Work in Progress (CWIP) that should be approved for the 2025 projected test year is \$230,175,000. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Construction Work In Progress (“CWIP”) totaling \$230.2 million as shown on MFR Schedule B-1.

**OPC:** CWIP should be adjusted for any disallowance of the Grid Reliability and Resilience Projects.

**FL RISING/**

**LULAC:** \$0.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Agree with OPC.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its original filing, TECO reflected \$230,175,000 of CWIP in the 2025 projected test year. (EXH 4) No parties introduced any testimony disputing this amount. In its brief, FL Rising/LULAC stated that no CWIP should be included in the projected 2025 test year. (FL Rising/LULAC BR 12) Additionally, OPC argued for the removal of CWIP associated with GRR projects in its brief, but did not cite any specific amount. (OPC BR 31) Although staff is recommending the removal of the 2026 GRR projects in the 2026 SYA, as addressed in Issue 96, staff does not believe an adjustment to 2025 CWIP is appropriate. As such, staff believes the amount of CWIP for the projected 2025 test year should be \$230,175,000.

### **CONCLUSION**

The amount of CWIP that should be approved for the 2025 projected test year is \$230,175,000.

**Issue 28:** What amount of Property Held for Future Use for the 2025 projected test year should be approved?

**Recommendation:** The amount of Property Held for Future Use that should be approved for the 2025 projected test year is \$68,034,000. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Property Held for Future Use totaling \$68.0 million as shown on MFR Schedule B-1.

**OPC:** No position.

**FL RISING/  
LULAC:** \$0.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

In its filing, TECO stated the amount of Property Held for Future Use that should be approved for the 2025 projected test year is \$68 million. (TECO BR 38; EXH 4) FL Rising/LULAC stated that no Property Held for Future Use should be included in the projected 2025 test year. (FL Rising/LULAC BR 12) No other parties have given arguments against the inclusion of Property Held for Future Use. Staff recommends that the amount of Property Held for Future Use for the projected 2025 test year should be \$68,034,000, because TECO has provided information to support this amount.

**CONCLUSION**

Based on the record in this case, the amount of Property Held for Future Use that should be approved for the 2025 projected test year is \$68,034,000.

**Issue 29:** What amount of unfunded Other Post-Retirement Employee Benefit (OPEB) liability and any associated expense should be included in rate base?

**Recommendation:** The amount of unfunded Other Post-retirement Employee Benefit (OPEB) that should be included in rate base is \$70,740,641. (Hinson)

**Position of the Parties:**

**TECO:** The amount of unfunded OPEB liability that should be included in rate base is the 13-month average of \$70,740,641. This equals the credit amount in account 228.3232, FAS 106 Liability – Retired – Non-Current. The sum of the balances in accounts 228.3231 and 242.0131 (FAS 158 credits), when added to debit balances in account 182.3200 (Regulatory Asset) offsetting the FAS 158 balances, equal zero. There are no associated expenses included in rate base.

**OPC:** The Commission should reduce the pension and OPEB expense in the filing to reflect the credit that should be recognized in the filing for the portions of the costs that will be capitalized for the reasons discussed in Issue 54. Once that adjustment is made it would be appropriate to recognize a corresponding debit to rate base.

**FL RISING/**

**LULAC:** \$0, as it should not be included in rate base where a return on equity is earned.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Agree with OPC.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its filing, TECO stated that the amount of unfunded OPEB liability that should be included in rate base is \$70,740,641. (TECO BR 38; EXH 4) TECO argued in its brief that it did not undercapitalize OPEB expense and the appropriate amount is reflected in Issue 54. (TECO BR 38) OPC argued in its brief that an adjustment to unfunded OPEB liability should be made in

correlation to adjustments it recommended in Issue 54. (OPC BR 31) FL Rising/LULAC stated that no OPEB should be included in the projected 2025 test year where a return on equity is earned. (FL Rising/LULAC BR 12) No other parties have given arguments against the inclusion of OPEB. Staff does not recommend an adjustment to unfunded OPEB liability, based on staff's recommendation in Issue 54. The amount of OPEB that should be included in rate base is \$70,740,641. There are no associated expenses included in rate base.

### **CONCLUSION**

The amount of unfunded OPEB that should be included in rate base is \$70,740,641.

**Issue 30:** What level of TECO's fuel inventories should be approved?

**Recommendation:** Staff recommends that the Commission approve \$36,509,000 as the jurisdictional fuel inventory value for the projected 2025 test year. (Zaslow)

**Position of the Parties:**

**TECO:** The Commission should approve fuel inventory for the projected 2025 test year totaling \$36.6 million as shown on MFR Schedule B-17. FR/L's position that the company should not be using coal or be allowed to recover fuel inventory ignores the important reliability and other benefits of coal-fired generation at Big Bend Unit 4 and should be rejected.

**OPC:** No position.

**FL RISING/**

**LULAC:** \$0. TECO should not be using coal or other fuels that require inventory given the higher cost of solid fuels.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** \$0, TECO has not demonstrated the reliability benefits of coal-fired generation at Big Bend 4 nor the utility of coal inventory.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

Fuel inventories are included in working capital, which is a component of rate base. The maximum value for fuel inventory to be included in working capital is defined as the 60-day burn rate for each type of fuel (i.e., coal and fuel oil). Staff discusses the specific projected inventory values and the necessary adjustments below.

Staff notes that the 13-month average fuel inventory value was \$36,824,000 (system). (EXH 4, MPN J35) TECO witness Chronister stated in his direct testimony that the Company subsequently made a downward adjustment of approximately \$189,000 to reflect the 60-day burn



level for its fuel oil inventory. Additionally, according to witness Chronister, the projected 2025 coal inventory was already below the 60-day burn rate level and warranted no adjustment. (TR 3385) The fuel oil adjustment resulted in TECO's requested fuel inventory value of \$36,635,000. (EXH 4, MPN J185) The jurisdictional amount, calculated using a separation factor of 0.996559, is approximately \$36,509,000. (EXH 4, MPN J185) Concerning Intervenor positions on this Issue, staff notes that FL Rising/LULAC and Sierra Club did not submit any specific prefiled testimony in support of the suggested fuel inventory value of \$0.

Based on the record evidence in this case, staff believes that TECO's proposed 2025 jurisdictional fuel inventory amount of \$36,509,000 is reasonable.

### **CONCLUSION**

Staff recommends that the Commission approve \$36,509,000 as the jurisdictional fuel inventory value for the projected 2025 test year.

**Issue 31:** What amount of Working Capital for the 2025 projected test year should be approved?

**Recommendation:** The amount of Working Capital that should be approved for the 2025 projected test year is \$223,971,393. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve a Jurisdictional Working Capital Allowance totaling \$83.3 million as shown on MFR Schedule B-1 as adjusted by its August 22, 2024 filing. OPC's proposed adjustment to remove four MVA transformers from inventory should be rejected, because those transformers are needed for reliability and resilience.

**OPC:** Based on general principles of ratemaking, the Commission would normally consider removing four MVA transformers from inventory as they are excessive. If the OPC proposal is adopted, an adjustment to Inventories of \$0.362 million would be required and a corresponding adjustment to Working Capital for the 2025 projected test year would be required.

**FL RISING/**

**LULAC:** The Working Capital should be adjusted to remove the Unamortized Rate Case Expense and should be adjusted to reflect other adjustments that have been made.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

OPC witness Mara argued that TECO has historically maintained and budgeted for an excessive number of spare transformers, which have a capital cost of approximately \$1 million each. (TR 2383-2384) Witness Mara argued that four 37 megavolt-ampere (MVA) transformers be removed from rate base, which would allow the Company four remaining spares in the 2024-2025 time period. (TR 2384-2385) TECO witnesses Whitworth and Chronister both

recommended the Commission reject witness Mara's arguments by noting that this equipment is needed for system reliability and the lead-time to obtain this class of transformers is approximately 2 or 3 years. (TR 1152; TR 3455) Witness Whitworth argued that the Company has experienced approximately 4.2 transformer failures annually for the period 2012 through 2023, whereas the Company projects purchasing transformer replacements of 4.8 annually for the period 2021 through 2027 to adjust for customer growth and allow for proactive replacements before failure. (TR1149) Witness Whitworth also argued that maintaining its proposed inventory avoids the need for emergency replacements, which would have higher costs. (TR 1152-1153) Staff recommends that TECO's proposed transformer acquisitions should be approved, as they allow the Company to maintain system reliability and avoid expensive emergency replacements.

Based on adjustments in Issue 24, 31, 45, and 64 and the recommendation to approve the transformer acquisitions, Working Capital should be increased by \$137,300,393. Therefore, staff recommends a Working Capital allowance for the projected 2025 test year amount of \$223,971,393.

### **CONCLUSION**

The amount of Working Capital that should be approved for the 2025 projected test year is \$223,971,393.

**Issue 32:** What amount of rate base for the 2025 projected test year should be approved?

**Recommendation:** The amount of rate base that should be approved for the 2025 projected test year is \$9,711,309,827. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve projected 13-month average rate base for 2025 of \$9.8 billion as shown on MFR Schedule B-1, less \$6,889,111 per the company's July and August Filings for a total of \$9,791,261,229.

**OPC:** This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in rate base. Rate base for the 2025 projected test year should reflect OPC's recommended adjustments and should be no more than \$9,800,670,000.

**FL RISING/**

**LULAC:** Approximately \$8,041,526. The rate base should be reduced to reflect the removal of the following projects from 2025 rate base: Future Environmental Compliance; Research and Development; Customer Experience Enhancement; Information Technology Capital; Grid Reliability and Resilience; Corporate Headquarters; South Tampa Resilience; Bearss Operation Center; and Polk 1 Flexibility.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** This is a fallout issue. The Polk 1 Flexibility Project and Fuel Diversity Projects should be removed from rate base. For the projects described in Issues 14, 16, 17, 19, 21, 22, and 23, Sierra Club also supports removal from rate base based on arguments put forth by intervenors. TECO's customers experience higher energy burdens than the national average, and their electricity rates can be reduced by removing unjustified spending.

**FRF:** Rate base for the 2025 test year should be no more than \$9.8 billion.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. Based on the adjustments made in Issues 7, 11, 15, 16, 22, 24, 31, and 64, rate base for the projected test year 2025 should be decreased by \$86,840,173. Therefore, staff recommends a projected 2025 test year rate base of \$9,711,309,827.

**CONCLUSION**

The amount of rate base that should be approved for the 2025 projected test year is \$9,711,309,827.

### **2025 COST OF CAPITAL**

**Issue 33:** What amount of accumulated deferred taxes should be approved for inclusion in the capital structure for the 2025 projected test year?

**Recommendation:** The amount of accumulated deferred income taxes to include in the 2025 projected test year capital structure is \$972.094 million. (Ferrer)

#### **Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Accumulated Deferred Income Taxes of \$980.2 million as shown on MFR Schedule D-1a.

**OPC:** The amount of accumulated deferred taxes that should be included in the capital structure for the 2025 projected test year is \$980.855 million.

#### **FL RISING/**

**LULAC:** Adopt OPC position.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate deferred income taxes that should be approved for inclusion in the capital structure should be \$980,855, or 10.01%, for the 2025 projected test year.

#### **SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The amount of accumulated deferred taxes that should be included in the capital structure for the 2025 projected test year is \$980.855 million.

#### **FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

#### **Staff Analysis:**

### **ANALYSIS**

TECO requested a total accumulated deferred income tax (ADITs) balance of \$980.855 million, to include in the 2025 projected test year capital structure, which is presented on MFR Schedule D-1a, page 2. (TECO BR 40; EXH 6, MPN J378) TECO later revised its amount after filing its letter of August 22, 2024, to \$980.2 million to reflect adjustments to rate base during the proceeding. (TECO BR 40; EXH 835) None of the parties made a specific objection to TECO's adjusted amount of ADITs. TECO witness Strickland explained that the ADITs for the 2025

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forecasted period have been computed based on the projected book/tax temporary differences and in accordance with Generally Accepted Accounting Principles (GAAP), the requirements of the Commission, and IRC rules, including special provisions applicable to utilities. (TR 3198) TECO calculates the deferred taxes and the related accumulated deferred income tax based on the projected book/tax temporary differences for the 2025 forecasted period. Under Treasury Regulations § 1.167(1)-1, when a projected test period is used to set rates and the newly determined rates are expected to be in effect for all or a portion of that test period, the utility plant ADIT additions in the portion of the test period in which the new rates are expected to be in effect must be pro-rated over the period for which the new rates are expected to be in effect. (TR 3199-3200; EXH 30, MPN C15-1429) None of the parties objected to TECO's proration adjustment. In Issue 32, staff is recommending a total rate base amount of \$9,711.310 million. When this amount is reconciled pro rata over all capital sources to staff's recommended capital structure, the corresponding amount of ADITs is \$972.094 million.

### **CONCLUSION**

Based on the record evidence, staff recommends the Commission approve the amount of \$972.094 million for ADITs to include in the 2025 projected test year capital structure.

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**Issue 34:** What amount and cost rate of the unamortized investment tax credits should be approved for inclusion in the capital structure for the 2025 projected test year?

**Recommendation:** The Commission should approve an ITC amount of \$208.205 million at a cost rate of 7.90 percent for inclusion in the capital structure for the 2025 projected test year. (Souchik)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Tax Credits in the amount of \$211.5 million and a cost rate of 8.26 percent as shown on MFR Schedule D-1a. The company acknowledges the fact that the unamortized investment tax credit would have been adjusted as a result of the July and August Filings. However, this change would not materially impact the overall weighted average cost of capital (“WACC”) rate and thus the investment tax credit cost rate.

**OPC:** The amount and cost rate of the unamortized investment tax credits that should be included in the capital structure for the 2025 projected test year is \$178.098 million at a cost rate of 7.18%.

**FL RISING/**

**LULAC:** The ITCs should be flowed back to customers over a ten-year period. The appropriate cost rate is zero, as TECO already receives a return on investment for the capital expenditures associated with the battery assets.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate deferred income taxes that should be approved for inclusion in the capital structure should be \$211,669, or 2.16%, for the 2025 projected test year.

**SIERRA**

**CLUB:** Sierra Club adopts OPC’s position on this issue.

**FRF:** The amount and cost rate of the unamortized investment tax credits that should be included in the capital structure for the 2025 projected test year is \$178.098 million at a cost rate of 7.18%.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

In its initial filing, TECO presented its 2025 projected test year capital structure based on a 13-month average consisting of unamortized ITCs in the jurisdictional adjusted amount of \$211.7 million at a cost rate of 8.26 percent as shown on MFR Schedule D-1a, page 1 of 3. (EXH 6, MPN J378; TECO BR 40) TECO later revised the amount after filing its letter of August 22, 2024, to \$211.5 million to reflect adjustments to rate base during the proceeding. (TECO BR 40; EXH 835) TECO stated that the change would not materially impact the overall weighted average cost of capital, and thus, its requested investment tax credit cost rate. (TECO BR 40) OPC argued that the cost rate for ITCs, in the projected capital structure, should be 7.18 percent with an amount of \$178.098 million. (OPC BR 32) FL Rising/LULAC stated the ITCs should be flowed back to customers over a 10-year period with a zero-cost rate, stating TECO already receives a return on investment for the capital expenditures associated with battery assets. (FL Rising/LULAC BR 13) FIPUG, FRF, Sierra Club, and Walmart adopted the position of OPC, while Fuel Retailers took no position on this Issue. FEA's position on this Issue cites deferred income taxes, not ITCs. (FEA BR 12)

TECO witness Strickland explained the ITC balance for the 2025 forecasted period has been calculated in accordance with GAAP, the requirements of the Commission, and the IRC rules, including special provisions applicable to utilities. (TR 3198) Witness Strickland's forecasted amount of ITCs reflect an amortization of 30 years for the Solar ITCs as proposed in the Company's recently filed depreciation study. (TR 3197) While the majority of the ITC balance was generated during the 2017-2021 period as a result of the Company's investment in solar facilities, the ITC balance in 2024 and 2025 is also projected to increase due to new ITCs generated by TECO's investment in energy storage facilities. (TR 3201) TECO initially established the energy storage facilities in this rate case at a 10-year service life. However, the Company amended the service life to reflect a 20-year service life in an updated revenue requirement document submitted on August 22, 2024. (OPC BR 58; EXH 835)

The unamortized ITC balance is a regulatory tax liability which is a component of the capital structure which earns the weighted average cost rate of investor sources of capital, which is consistent with the methodology used in prior rate case proceedings. (TR 3201) TECO witness Chronister asserted the cost rate of 8.26 percent is reasonable because it reflects the weighted cost of investor sources of capital, which has been the Commission-approved method for calculating the cost rate for ITCs. (TR 3350) TECO's calculation for the ITC cost rate is summarized in Table 34-1.

**Table 34-1**  
**TECO ITC Cost Rate Calculation (000s)**

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	\$3,505,671	41.57%	4.53%	1.88%
Short Term Debt	\$376,625	4.43%	3.90%	0.17%
Common Equity	\$4,593,473	54.00%	11.50%	6.21%
	\$8,059,316			8.26%

Source: (EXH 155, MPN E1308)

OPC witness Kollen applied OPC witness Woolridge’s recommended ROE of 9.50 percent to his proposed capital structure and obtained an ITC cost rate of 7.18 percent. (EXH 155, MPN E 1308) OPC’s recommended ITC cost rate is summarized in Table 34-2.

**Table 34-2**  
**OPC ITC Cost Rate Calculation (000s)**

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	\$3,536,333	41.57%	4.53%	1.88%
Short Term Debt	\$376,625	4.43%	3.90%	0.17%
Common Equity	\$4,593,473	54.00%	9.50%	5.13%
	\$8,506,431			7.18%

Source: (EXH 155, MPN 1308)

The IRC regarding the flow back of ITCs per the normalization rules discussed in Issue 10, require that the ITC cost rate should not have an impact on the overall investor sourced cost of capital. Pursuant to 26 C.F.R. §1.46-6, the unamortized (deferred) investment tax credits are assigned a cost of capital rate equal to the composite cost of capital for all other capital investments based on common equity, preferred stock, and long-term debt.<sup>43</sup> The appropriate investor sources to use in the calculation of the ITC cost rate include long-term debt and common equity, excluding short-term debt, as required by the IRC regulations. In Issue 39, staff recommends an ROE of 10.30 percent. The lower ROE reduces the Company’s requested ITC cost rate from 8.26 percent to 7.90 percent as shown in Table 34-3.

<sup>43</sup> 26 Code of Federal Regulations §1.46-6(b)(3)(ii)(B) requires that for purposes of determining the cost of capital rate assigned to the tax credit and the amount of additional interest that the taxpayer would pay or accrue, the composition of the capital that would have been provided if the credit were unavailable may be determined, (1) On the basis of all the relevant facts and circumstances; or (2) By assuming for both such purposes that such capital would be provided solely by common shareholders, preferred shareholders, and long-term creditors in the same proportions and at the same rates of return as the capital actually provided to the taxpayer by such shareholders and creditors.

**Table 34-3  
 Staff ITC Cost Rate Calculation**

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	\$3,505,671	43.498%	4.53%	1.97%
Common Equity	\$4,553,645	56.502%	10.30%	5.93%
	\$8,059,316			7.90%

Source: Staff Analysis

In Issue 7, staff recommends the pre-2022 solar service lives be adjusted from 30 to 35 years. In OPC witness Kollen’s work papers he calculated an ITC balance difference of \$1,240,667 between establishing a 35-year versus a 30-year service life. (EXH 155, MPN E1325) The corresponding adjustment is an increase to the ITC balance of \$1,240,667. Based on the increase in service life, the ITC balance would be reduced at a slower rate due to the additional 5 years of amortization.

In Issue 65, staff recommends to amortize the ITCs related to the battery storage projects over 5 years as opposed to TECO’s proposed 10 years. As a result, the annual ITC amortization amount should be increased by \$2,883,352 from the Company’s amount in its filing of \$3,743,460. This adjustment results in a decrease to the unamortized balance of \$2,883,352, since the balance is being reduced at a faster annual rate. This is a corresponding adjustment as a result of staff’s recommendation in Issue 65.

The net effect of staff’s recommended adjustments on the ITC unamortized balance is a decrease of \$1,340,644. The 13-month ITC balance in MFR Schedule D-1a is \$259,351,150 (per Company books). The new per books balance would be  $\$259,351,150 + \$1,240,667 - \$2,883,352 = \$257,708,465$ , for a decrease of \$1,642,685. The jurisdictional amount is lower due to TECO’s pro rata and jurisdictional adjustments;  $\$1,642,685 \times 0.821 \times .994068 = \$1,340,644$ . In Issue 32, staff is recommending a total rate base amount of \$9,711.310 million. After staff’s pro rata adjustments to reconcile the capital structure to rate base, the staff recommended ITC balance is \$208.205 million.

### **CONCLUSION**

The Commission should approve an ITC amount of \$208.205 million at a cost rate of 7.90 percent for inclusion in the capital structure of the 2025 projected test year.

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**Issue 35:** What amount and cost rate for customer deposits should be approved for inclusion in the capital structure for the 2025 projected test year?

**Recommendation:** The amount and cost rate for customer deposits that should be approved for inclusion in the capital structure for the 2025 projected test year is \$98.335 million at a cost rate of 2.41 percent. (McGowan)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Customer Deposits of \$99.1 million and a cost rate of 2.41 percent as shown on MFR Schedule D-1a.

**OPC:** The amount and cost rate for customer deposits that should be included in the capital structure for the 2025 projected test year is \$99.195 million at a cost rate of 2.41%.

**FL RISING/**

**LULAC:** \$99.195 million.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate deferred income taxes that should be approved for inclusion in the capital structure should be \$99,195 or 1.01%, for the 2025 projected test year.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The amount and cost rate for customer deposits that should be included in the capital structure for the 2025 projected test year is \$99.195 million at a cost rate of 2.41%.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue is uncontested by the intervening parties. (TECO BR 41) In its initial filing, TECO presented its 2025 projected test year capital structure based on a 13-month average reflecting a customer deposit balance in the jurisdictional adjusted amount of \$99.195 million at a cost rate of 2.41 percent as shown on MFR Schedule D-1a, page 1 of 3, line 6. (EXH 6, MPN J378; TECO BR 41) TECO later revised its as-filed amount in testimony and the Company's prehearing position of \$99.2 to \$99.1 million after filing its letter in August 2024, to reflect adjustments to rate base during the proceeding. (TECO BR 41; EXH 835, MPN 38091-38093)

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None of the intervenors made a specific objection to TECO's adjusted amount of customer deposits. TECO witness Chronister testified how the forecasted amount and cost rate for customer deposits are calculated as well as the reasonableness for inclusion in the projected 2025 test year capital structure. Witness Chronister explained the budgeted balances for customer deposits are calculated by using an assumed average percent for expected new deposits and released deposits associated with forecasted customers and accounts receivable. (TR 3348) Witness Chronister affirmed this is reasonable as it reflects a consistent application of long-standing budget process steps and asserted that the cost rate for customer deposits reflects rates approved by the Commission and is reasonable to forecast based on the infrequent number of changes made to these rates by the Commission over time. (TR 3348)

Furthermore, staff has reviewed MFR Schedule D-6, page 1 of 3, and confirmed the calculation of interest on customer deposits complies with the requirements set forth in Rule 25-6.097(5)(a), F.A.C. (EXH 6, MPN J391) Staff notes customer deposits is a component of the capital structure that was not disputed by the intervenors. In addition, no argument was proffered on behalf of the parties contesting the amount or cost rate that should be included in the 2025 projected test year capital structure. (TECO BR 41) OPC agreed with TECO's as-filed position concerning both amount and cost rate while FIPUG, FRF, and Walmart adopted or agreed with OPC's position. (OPC BR 32; FIPUG BR 10; FRF BR 34; Walmart BR 9) In addition, FL Rising/LULAC agreed with the amount but did not specify a cost rate. (FL Rising/LULAC BR 13) In Issue 32, staff is recommending a total rate base amount of \$9,711.310 million. When this amount is reconciled pro rata over all capital sources to staff's recommended capital structure, the corresponding amount of customer deposits is \$98.335 million.

### **CONCLUSION**

The amount and cost rate for customer deposits that should be approved for inclusion in the capital structure for the 2025 projected test year is \$98.335 million at a cost rate of 2.41 percent.

**Issue 36:** What amount and cost rate for short-term debt should be approved for inclusion in the capital structure for the 2025 projected test year?

**Recommendation:** The amount and cost rate for short-term debt that should be approved for inclusion in the capital structure for the 2025 projected test year is \$373.359 million and 3.90 percent, respectively. (Ferrer)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Short-Term Debt of \$376.4 million and a cost rate of 3.90 percent as shown on MFR Schedule D-1a.

**OPC:** The correct amount of short-term debt is \$376.625 million with a cost rate of 3.90%.

**FL RISING/**

**LULAC:** The Commission should approve a short-term debt amount adjusted downwards to account for a reduced rate base and adjusted upwards for the adjusted 50-50 equity-to-debt ratio. A cost rate of 3.90% should be approved.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate short-term debt balance that should be approved for inclusion in the capital structure should be \$376,625, or 3.84%, for the 2025 projected test year.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The correct amount of short-term debt is \$376.625 million with a cost rate of 3.90%.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO included the amount of \$376.625 million for short-term debt at a cost rate of 3.90 percent in its projected test year capital structure on MFR Schedule D-1a. (TECO BR 41 TR 3345; EXH 6, MPN J378) TECO later revised its amount after filing its letter of August 22, 2024, to \$376.6 million to reflect adjustments to rate base during proceeding. (TECO BR 41; EXH 835) None of the parties made a specific objection to TECO's adjusted amount of short-term debt or cost rate.

TECO witness Chronister explained how the Company forecasts for short-term debt and why its request is reasonable. The Company's forecasted borrowing needs are based on the combination of budgeted capital expenditures net of forecasted cash from operations and the Company's adherence to the capital structure (46 percent debt, 54 percent equity) which is needed to maintain financial integrity. (TR 3345) Witness Chronister asserted the amounts are determined using prudent forecasting of capital expenditures and cash from operations, and the application of TECO's commitment to capital structure ratios that are needed to keep the overall cost of capital low. (TR 3345) According to witness Chronister, the cost rates for long term and short-term debt are forecasted based on the combination of: (a) the actual cost rates for long term debt instruments actually in place, together with the forecasted rate for any budgeted long-term borrowing at the interest rate estimated for that point in time; and (b) the forecasted rate for budgeted short-term borrowing at the interest rates estimated for each month in the budget period. (TR 3345-3346) The cost rates are reasonable estimates based on TECO's financial integrity, credit ratings and forecasts for future market rates. (TR 3346)

Witness Chronister explained why the forecasted market rates are higher than market rates at the time of the last rate proceeding. In 2021, the Federal Reserve rate was 0.08 percent at year-end and increased to 5.33 percent by the end of 2023. (TR 3346) This increase was reflected in an average short-term debt interest rate for the Company of 0.58 percent in 2021, which increased to 5.70 percent in 2023. (TR 3346) The Company's actual short-term cost rate in 2022 was 2.30 percent; the forecasted short-term cost rate for 2025 is 3.90 percent. (TR 3346) The Company's actual long-term cost rate in 2022 was 4.36 percent and the forecasted long-term cost rate for 2025 is 4.53 percent. (9TR 3347) The 17-basis point increase in the long-term debt interest rate is less than the increase in the short-term debt interest rate because most of the Company's 2022 long-term debt will still be outstanding in 2025. (TR 3347)

The forecasted 2025 short-term debt cost rate of 3.90 percent is lower than the 5.70 percent in 2023. It is reasonable to use a lower interest rate forecast because the rise in interest rates has begun to subside, and TECO predicts that short-term rates will be lower in 2025. OPC and other intervening parties did not provide any specific arguments opposing the reasonableness of TECO's forecasted short-term debt amount and cost rate. Based on the current market rates for short-term debt, staff believes the forecasted rate of 3.90 percent is reasonable. In Issue 32, staff is recommending a total rate base amount of \$9,711.310 million. When this amount is reconciled pro rata over all capital sources to staff's recommended capital structure, the corresponding amount of short-term debt is \$373.359 million.

## **CONCLUSION**

Based on record evidence, staff recommends the amount and cost rate for short-term debt that should be approved for inclusion in the capital structure for the 2025 projected test year is \$373.359 million and 3.90 percent, respectively.

**Issue 37:** What amount and cost rate for long-term debt should be approved for inclusion in the capital structure for the 2025 projected test year?

**Recommendation:** The amount and cost rate for long-term debt that should be approved for inclusion in the capital structure for the 2025 projected test year is \$3,505.671 million at a cost rate of 4.53 percent. (McGowan)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Long-Term Debt of \$3.534 billion and a cost rate of 4.53 percent as shown on MFR Schedule D-1a.

**OPC:** The correct amount of long-term debt is \$3,536,333,000 with a cost rate of 4.53%.

**FL RISING/**

**LULAC:** The Commission should approve a long-term debt amount adjusted downwards to account for a reduced rate base and adjusted upwards to account for a 50-50 equity-to-debt ratio. A cost rate of 4.53% should be approved.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate long-term debt balance that should be approved for inclusion in the capital structure should be \$3,706,461.830, or 37.83%, for the 2025 projected test year.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The correct amount of long-term debt is \$3,536.333 million with a cost rate of 4.53%.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its initial filing, TECO presented its 2025 projected test year capital structure based on a 13-month average consisting of long-term debt in the jurisdictional adjusted amount of \$3.536 billion at a cost rate of 4.53 percent as shown on MFR Schedule D-1a, page 1 of 3, and D-4a. (EXH 6, MPN J378, MPN J386; TECO BR 42) TECO later revised the amount after filing its letter in August 2024, to \$3.534 billion to reflect adjustments to rate base during the proceeding. (TECO BR 42) Only FL Rising/LULAC and FEA took an opposing position on the amount of



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long-term debt to reflect their respective positions on the equity ratio in Issue 38. (TECO BR 42; FL Rising/LULAC BR 13-14)

TECO witness Chronister testified the cost rates for long-term and short-term debt are forecasted based on the combination of: (a) the actual cost rates for long-term debt instruments actually in place, together with the forecasted rate for any budgeted long-term borrowing at the interest rate estimated for that point in time; and (b) the forecasted rate for budgeted short-term borrowings at the interest rates estimated for each month in the budget period. (TR 3346) Witness Chronister affirmed the cost rates are reasonable estimates based on TECO's financial integrity, credit ratings and forecasts for future market rates. (TR 3346)

Witness Chronister explained the Company's actual long-term cost rate in 2022 was 4.36 percent and the forecasted long-term cost rate for the 2025 projected test year is 4.53 percent. Witness Chronister detailed how the 17-basis point increase in the long-term debt interest rate is less than the increase in the short-term debt interest rate because most of the Company's 2022 long-term debt will still be outstanding in 2025. (TR 3347) Witness Chronister emphasized and staff agrees the forecasted 2025 long-term debt cost rate is reasonable because it reflects: (a) embedded existing cost rates; (b) cost rates for the long-term debt assumed by TECO previously assigned to PGS; and (c) the 4.90 percent cost rate on the actual long-term debt issuance made in January 2024 for \$500 million. (TR 3347)

Staff notes the cost rate of 4.53 percent was not disputed throughout the proceeding. (OPC BR 32; FIPUG BR 10; FL Rising/LULAC BR 13-14; FRF BR 34; Walmart BR 9) None of the intervenors filed testimony contesting the long-term debt cost rate of 4.53 percent and no argument was proffered by the parties pertaining to the cost rate of long-term debt for the 2025 projected test year capital structure. OPC witness Woolridge testified that he is not contesting the Company's short-term and long-term debt cost rates. (TR 2797-2798) Additionally, FEA did not contest the long-term debt cost rate of 4.53 percent throughout the proceeding; however, FEA witness Walters recommended a 52.00 percent equity ratio and suggested that the Company has not reasonably demonstrated the need to be awarded a common equity ratio in excess of 52.00 percent. (TR 2952)

Furthermore, staff notes the primary driver for any adjustment in regards to the amount of long-term debt to include in the 2025 projected test year capital structure is due to a lower equity ratio recommended by FEA and FL Rising/LULAC witnesses as discussed further in Issue 38. (TECO BR 42; FL Rising/LULAC BR 13-14) In addition, staff acknowledges the fact FL Rising/LULAC did not contest the cost rate of 4.53 percent; however, FL Rising/LULAC argued the long-term debt amount should be adjusted downwards to account for a reduction to rate base and adjusted upwards to account for a 50-50 equity-to-debt ratio. (TECO BR 42; FL Rising/LULAC BR 13-14) Staff addressed the lower equity ratios recommended by the parties in Issue 38. In Issue 32, staff is recommending a total rate base amount of \$9,711.310 million. When this amount is reconciled pro rata over all capital sources to staff's recommended capital structure, the corresponding amount of long-term debt is \$3,505.671 million.

## **CONCLUSION**

Staff recommends the amount and cost rate for long-term debt that should be approved for inclusion in the capital structure for the 2025 projected test year is \$3,505.671 million at a cost rate of 4.53 percent.

Date: November 22, 2024

**Issue 38:** What equity ratio should be approved for use in the capital structure for ratemaking purposes for the 2025 projected test year?

**Recommendation:** The Commission should approve an equity ratio of 54.00 percent based on investor-supplied capital for ratemaking purposes for the 2025 projected test year. The amount of common equity in the capital structure should be \$4,553.645 million. (D. Buys)

**Position of the Parties:**

**TECO:** The Commission should approve the company's proposed 54 percent equity ratio (investor sources), which will allow the company to maintain its financial integrity, attract capital on reasonable terms and conditions, and ensure uninterrupted access to capital markets to finance infrastructure improvements and manage unforeseen events. The equity ratios advocated by FEA and FR/L are too low, would be perceived by credit-rating agencies as credit-negative, and should be rejected.

**OPC:** Tampa Electric's requested equity ratio of 54% should only be accepted if the ROE is accordingly established taking into consideration the high level of the equity ratio; otherwise, the proposed equity ratio is excessive.

**FL RISING/**

**LULAC:** 43.41% to reflect a 50-50 equity-to-debt ratio.

**FIPUG:** Adopt the position of OPC.

**FEA:** The appropriate equity ratio that should be approved for use in the capital structure for ratemaking purposes for the 2025 projected test year is 45.15%, or 52.0% on an investor-supplied basis.

**SIERRA**

**CLUB:** Sierra Club adopts OPC's position on this issue.

**FRF:** TECO's equity ratio of 54.0 percent is above the national average. The FRF does not oppose this equity ratio if the Commission takes account of the Company's above-average equity ratio by setting rates using an ROE no greater than 9.72 percent, which is the recent national average ROE approved for vertically integrated electric utilities.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

In its filing, TECO requested a projected test year capital structure consisting of an equity ratio of 54.00 percent based on investor-supplied capital for rate setting purposes. (TR 3341; EXH 6, MPN J378) TECO's current equity ratio of 54.00 percent was approved by the Commission as part of the 2021 Settlement Agreement in TECO's last rate case by Order No. PSC PSC-2021-0423-S-EI.<sup>44</sup> (TR 84; TR 101; TR 3341-3342; EXH 31, MPN C16-1492) TECO argued that its equity ratio of 54.00 percent is reasonable and prudent, and needed to support the Company's financial integrity as measured by cash flows and financial leverage. (TECO BR 42; TR 3342) TECO witness Chronister testified that continuing to maintain a strong financial position will allow the Company to attract capital on reasonable terms and continue to provide a safe and reliable electric system for its customers. (TR 3343) Witness Chronister explained that financial integrity helps ensure uninterrupted access to capital markets to finance required infrastructure investments as well as to manage unforeseen events. (TECO BR 42; TR 3343) TECO argued that its requested rate increase which includes an ROE of 11.50 percent, and a common equity ratio of 54.00 percent, will maintain the Company's financial integrity and place TECO in the appropriate financial position to fund capital costs for assets and continue providing the high level of reliable service to its customers. (TR 3343-3344)

TECO witness D'Ascendis testified that TECO's requested equity ratio of 54.00 percent is reasonable and consistent with the range of common equity ratios maintained by the electric utilities in his proxy group. (TR 1813) For 2022, the range of the equity ratios of the 14 electric utilities in the proxy group was 28.90 percent to 56.13 percent with an average equity ratio of 41.49 percent. (TR 1829; EXH 28, MPN C13-1325) Witness D'Ascendis also compared the equity ratios of the subsidiary operating electric utility companies of the proxy group companies and determined the range of equity ratios was 38.14 percent to 55.90 percent with an average of 49.05 percent. (TR 1829-1830; EXH 28, MPN C13-1328) Witness D'Ascendis reasoned that TECO's equity ratio of 54.00 percent is appropriate for ratemaking purposes because it is within the range of the common equity ratios of the companies in his electric utility proxy group. (TR 1830)

OPC witness Woolridge testified that he is not contesting TECO's equity ratio of 54 percent, but also recognized that the Company's proposed capital structure has more equity and less financial risk than the average current capitalizations of the electric companies in TECO witness D'Ascendis' proxy group. (OPC BR 33; TR 2797) OPC explained that witness Woolridge did not offer testimony contesting TECO's proposed capital structure because the 54.00 percent equity ratio was adopted in the 2021 Settlement Agreement and is consistent with how the Company financed its capital needs. (OPC BR 33) Consequently, witness Woolridge recommended an ROE of 9.50 percent that recognized and accounted for TECO's relatively high equity ratio and lower financial risk. (TR 2799) Witness Woolridge explained that a high equity component can amplify the overall impact of a relatively low ROE while a low equity component can mitigate the overall impact of a relatively high ROE. (OPC BR 32-33; TR 2823)

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<sup>44</sup> 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*.

Witness Woolridge explained that an electric utility that has an authorized ROE of 10.00 percent and common equity ratio of 50.00 percent would have a weighted cost of equity of 5.00 percent. This is financially the same as an authorized ROE of 9.00 percent but with a common equity ratio of 55.00 percent (4.95 percent). (TR 2823) Witness Woolridge explained that when a regulated utility's actual capital structure contains a high equity ratio, the Commission has two options. The first option is to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements. (TR 2824) The Commission's second option is to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group. (TR 2824) In its brief, OPC contended that witness Woolridge opted to account for TECO's high common equity ratio and lower financial risk in his ROE recommendation as discussed in Issue 39, instead of recommending a lower equity ratio for TECO. (OPC BR 33; TR 2826). OPC argued that should the Commission reject witness Woolridge's ROE recommendation of 9.50 percent, then the Commission should exercise the affordability levers at its disposal and choose an ROE that accounts for TECO's high equity ratio to avoid rates that will be higher than they need to be. (OPC BR 33; TR 2823-2824)

FEA recommends the Commission approve a capital structure with a common equity ratio no higher than 52.00 percent. (FEA BR 14; TR 2952) FEA argued that TECO has not reasonably demonstrated a need for an equity ratio greater than 52.00 percent and that an equity ratio of 52.00 percent strikes a balance between financial stability and the cost of equity that provides a buffer against financial risks without excessively increasing the cost of capital. (FEA BR 12-13) FEA witness Walters testified that TECO witness D'Ascendis' proxy group of electric companies has an average common equity ratio of 40.50 percent (including short-term debt) and 43.80 percent (excluding short-term debt) as calculated by S&P Global Market Intelligence and Value Line, respectively. (FEA BR 13; TR 2952) TECO's proposed equity ratio of 54.00 percent (including short-term debt) exceeds that of the proxy group's comparable equity ratio of 40.50 percent by almost 14 percentage points. (FEA BR 13; TR 2951) Witness Walters testified that the average authorized equity ratio for electric utilities from 2016 through 2024 was 50.84 percent. (TR 2932) Further, witness Walters testified that TECO has a slightly higher credit rating than that of the proxy group of companies, and although the companies in the proxy group have lower equity ratios, they still are attracting both debt and equity capital investment to fund their elevated capital investments. (TR 2934-2935, 2949-2950; EXH 96) FEA argued that TECO's credit rating is being hindered two notches as a result of its affiliation with Emera, Inc. (FEA BR 13) Witness Walters explained that TECO's "negative" outlook for its credit rating is driven by the "negative" credit rating outlook for Emera, Inc., and not the cash flow or credit metrics of TECO. (FEA BR 13; TR 2950) FEA argued the utility industries' capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that increases the value of utility stocks. (FEA BR 14; TR 2935) Therefore, FEA concluded, the increase in stock value is evidence that utilities have access to equity capital under reasonable terms at lower cost. (FEA BR 14; TR 2935)

In rebuttal, TECO witness Chronister testified that reducing the Company's requested equity ratio would result in a reduction to the revenue requirement and would have a negative effect on credit metrics and financial integrity. (TECO BR 42-43; TR 3481) TECO's obligation to serve

its customers and the significant capital expenditure requirements needed to maintain, modernize and grow its system is better served by stronger financial integrity. (TR 3481) In addition, witness Chronister contended that rating agencies will react negatively to a 52 percent equity ratio because it: (a) would be a deviation from the equity ratios approved by the Commission for utilities in the state of Florida; and (b) would be a downward movement from the equity ratio approved by the Commission for TECO for the last 11 years. (TR 3481) FEA's recommendation to reduce the equity ratio to 52.00 percent and the ROE to 9.60 percent at the same time would result in a reduction to TECO's requested revenue requirement of approximately \$134.7 million.

Staff recognizes that it has been Commission practice to allow electric utilities to maintain an equity ratio that approximates the Company's actual sources of capital so long as the equity ratio is within the range of 40 percent to 60 percent. TECO has maintained an equity ratio consistent with 54.00 percent for the past 11 years and reflects how the Company is actually financed. (TECO BR 43; TR 1813) The record evidence demonstrates that an investor-source based equity ratio of 54.00 percent will provide TECO with a strong balance sheet that will allow the Company an opportunity to maintain access to capital under reasonable terms in times of financial crisis and weather-related events. (TR 3342-3343) TECO's equity ratio of 54.00 percent is also reasonable and prudent because it offsets the Company's higher business risks as compared to the proxy group. They are: (1) a smaller geographic location that gives rise to greater risk from weather events; and (2) high customer growth that gives rise to increased capital expenditures to grow and maintain the Company's infrastructure in order to adhere to its obligation to serve its customers. (TR 1880-1896) These business risks are discussed in more detail in Issue 39 as the risks also relate to the determination of ROE.

Staff agrees with TECO witness Chronister that reducing the Company's equity ratio will potentially have a negative effect on its credit metrics, and that TECO's obligation to serve its customers by modernizing and growing its system is better served by stronger financial integrity. Staff did not make any specific adjustments to the amount of common equity in the capital structure. After reconciliation to the staff adjusted rate base amount of \$9,711.310 million, the amount of common equity in the capital structure is \$4,553.645 million.

## **CONCLUSION**

The Commission should approve an equity ratio of 54.00 percent based on investor-supplied capital for ratemaking purposes for the 2025 projected test year. The amount of common equity in the capital structure should be \$4,553.645 million.

Date: November 22, 2024

**Issue 39:** What authorized return on equity (ROE) should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year?

**Recommendation:** An authorized ROE of 10.30 percent, with a range of 9.30 percent to 11.30 percent, should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year. (D. Buys)

**Position of the Parties:**

**TECO:** The Commission should approve a mid-point return on equity of 11.5 percent with an allowed range of earnings of plus or minus 100 basis points. The ROEs proposed by the intervenors are too low, do not reflect a reasonable return, are not prudent, and should be rejected.

**OPC:** The Commission should approve a 9.50% ROE.

**FL RISING/**

**LULAC:** 9.50%.

**FIPUG:** The authorized ROE should be no higher than the average ROE authorized by state regulators in rate cases decided in 2023 and 2024 involving vertically integrated electric utilities, 9.78%, as testified to by FIPUG witness Pollock.

**FEA:** The authorized ROE of 9.60% should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year.

**SIERRA**

**CLUB:** Sierra Club adopts OPC and FL Rising/LULAC's position on this issue. The currently proposed ROE is unreasonably excessive.

**FRF:** The most appropriate ROE for Tampa Electric is 9.50 percent. This rate will provide Tampa Electric with the ability to raise sufficient equity capital to make all necessary investments to provide safe and reliable service to its customers. Moreover, consistent with State energy policy, setting TECO's rates with a 9.50 percent ROE will make TECO's service more affordable for its customers and will support Florida's economic growth.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart did not provide a summary of its position on this issue as was required under Section XIII of the Prehearing Order.

**Staff Analysis:**

**ANALYSIS**

**Synopsis**

The ROE is the cost of common equity included in a company's calculation of its weighted average overall cost of capital used to establish a revenue requirement. The *Hope* and *Bluefield* legal standards require that the ROE for TECO be comparable to returns on common equity for other companies having similar risks and that it be sufficient to assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow TECO to raise capital at reasonable costs and terms.<sup>45</sup> OPC witness Woolridge explained that the appropriate ROE for a regulated company requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk.

TECO's common equity is not publicly traded, and as such, a market-based cost rate for the Company cannot be directly observed. To support their respective positions, TECO witness D'Ascendis, OPC witness Woolridge, and FEA witness Walters each filed testimony that included cost of equity financial models applied to a proxy group of publicly-traded electric companies with risk similar to TECO's to derive estimates of the required ROE. (TR 1812-1813; TR 2796; TR 2928)

Staff's recommended ROE of 10.30 percent for TECO is based on an evaluation of the evidence and testimony in the record. Staff evaluated the witnesses cost of equity model results as discussed in the analysis of this Issue. The range of results of the witnesses' cost of equity models was 8.85 percent to 11.91 percent. The average of the DCF model results, CAPM results, and RPM results for TECO's, OPC's, and FEA's witnesses are 9.98, 10.26, and 10.56 percent, respectively. The average of these results is 10.27 percent.

Record evidence supports the risk-return concept that the higher the risk, the higher the required return and vice versa. The record evidence demonstrates that the business risks and storm damage risks facing TECO are greater than that of the companies in the comparable proxy group. The record evidence also demonstrates TECO has a higher equity ratio than the average of the electric utility company proxy group, and as such, it has less financial risk. Staff believes TECO's lower financial risk offsets TECO's higher business and weather risk and no additional adjustment to the average results of the models is necessary. In addition, the record evidence is clear that interest rates have increased since TECO's last rate case in 2021 in which the Commission authorized an ROE of 9.95 percent, later adjusted to 10.20 percent. Therefore, on balance, staff believes the record evidence supports an ROE of 10.27 percent, rounded up to 10.30 percent. Rounding up recognizes the increased interest rates since TECO's last rate case. This would enable TECO to generate the cash flow needed to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events.

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<sup>45</sup> *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692 (1923) (*Bluefield*) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*).



Date: November 22, 2024

### Staff Analysis

Both OPC witness Woolridge and FEA witness Walters used the same electric proxy group developed by witness D'Ascendis. (TR 1823-1825, 2816, 2954) Witness Woolridge also used his own electric proxy group that differed slightly from the proxy group used by the other two witnesses. (TR 2817) All three witnesses used the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM) to estimate the cost of equity. (TR 1812; TR 2798; TR 2948) Witnesses Walters and D'Ascendis also used risk premium models (RPM) to derive an estimated ROE. Witness D'Ascendis also applied the DCF Model, CAPM and RPM to a non-regulated group of companies with similar risk to the electric proxy group and obtained a result of 12.50 percent. (TR 1872; EXH 148, MPN D10-704) Witness D'Ascendis did not consider the cost of equity results from his non-regulated proxy group in his determination of his recommended range of indicated ROEs for TECO because they exceeded his recommended ranges. (TR 1997) Consequently, in the interest of brevity, staff's recommendation will not include an analysis of TECO witness D'Ascendis' non-regulated proxy group testimony. Also, witness D'Ascendis presented his cost of equity model results with and without inclusion of his Predictive Risk Premium Model (PRPM) analysis as a convenience to the Commission, and in part, did not rely on the results from his PRPM. (TR 1813, 1850, 2099) In addition, based on the Commission's decision to disregard any results using witness D'Ascendis' PRPM in the Peoples Gas Systems, Inc. rate case (PGS Rate Case) in 2023, staff did not include or consider witness D'Ascendis results from the PRPM in the instant case.<sup>46</sup> Witness D'Ascendis used the same PRPM methodology in the instant case that he used in the PGS Rate Case. The Commission already considered and disregarded the PRPM methodology in the PGS Rate Case Order, and therefore, staff believes it is not necessary to address the argument in this case.

In his rebuttal testimony, witness D'Ascendis updated the results of the cost of equity models used in his direct testimony. (TR 1907; TECO BR 44) 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 more recent interest rates. Interest rates have increased since TECO's last rate case in 2021. (TR 2803-2804) Witness Woolridge testified that the 30-year U.S. Treasury Bond yields have increased from approximately 2.50 percent in 2021 to a range of 4.50 percent to 4.75 percent in early 2024. (TR 2804) The current 30-year U.S. Treasury Bond yield was around 4.20 percent at the time of the hearing. (TR 2055) While regulated electric company authorized ROEs do not directly track the 30-year U.S. Treasury Bond yields, they can serve as an indicator of capital costs over time. Witness Woolridge testified that while ROEs reached low levels in 2020 and 2021 due to record low interest rates and capital costs, these authorized ROEs never declined to the same extent as interest rates. (TR 2813) As explained by OPC witness Woolridge:

The daily 30-year Treasury yield averaged 2.85 percent in the pre-COVID-19 period, versus 1.81 percent in the COVID-19 period, a decrease of 1.04 percent, or 104 basis points. However, the authorized ROE for electric utility companies averaged 9.63 percent in the pre-COVID-19 period and declined to an average of 9.41 in the COVID-19 period, a decline of -0.22%. In 2022, the average daily 30-

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<sup>46</sup> Order No. PSC-2023-0388-FOF-GU, Issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System, Inc.*, p. 65.

year Treasury yield increased by 105 basis points to 3.11 percent, while authorized ROEs for electric utility companies increased 0.16 percent to 9.54 percent, respectively. Likewise, the average daily 30- year Treasury yield increased by 92 basis points to 4.03 percent in 2023, while authorized ROEs for electric utility companies only increased by 0.06 percent to 9.60 percent.

(TR 2813)

TECO witness D’Ascendis used the same ROE models and methodology in his rebuttal testimony as he did in his direct testimony. In general, witness D’Ascendis employed assumptions and methods that produced an ROE estimate ranging from 10.29 percent to 11.91 percent while FEA witness Walters and OPC witness Woolridge used assumptions and methods that produced a range of results that were lower than that of witness D’Ascendis. The range of results of the witnesses’ cost of equity models is 8.85 percent to 11.91 percent. The witnesses’ cost of equity model results are summarized in Table 39-1.

**Table 39-1  
 Summary of Cost of Equity Model Results**

ROE Model	TECO – D’Ascendis	OPC - Woolridge	FEA - Walters
DCF – with analyst growth estimates	10.16%	Did not apply	10.98%
DCF – with sustainable growth estimates	Did not apply	9.70% / 10.00%* *D’Ascendis Proxy Group	9.37%
DCF – Multi-Stage growth rates	Did not apply	Did not apply	9.35%
CAPM	11.91%	8.85% (for both proxy groups)	9.29% - 11.43%
Risk Premium	11.09%	Did not apply	9.90% - 10.23%
Range of Results	10.29% - 11.91%	8.85% - 10.00%	9.29% - 11.43%
Average of Results	11.09%	9.28% / 9.43%* *D’Ascendis Proxy Group	10.07%
Witness Recommended ROE	11.50%	9.50%	9.60%

Source: Staff Analysis

Three additional interveners filed ROE testimony: FIPUG, FRF, and FL Rising/LULAC. None of the witnesses for FIPUG, FRF, nor FL Rising/LULAC included any quantitative analysis using cost of equity models to estimate the required return on equity for TECO. (TR 2034-2035)

In its brief, OPC argued that in recent years, nationally, electric companies have been earning ROEs in the range of 9.00 percent to 10.00 percent and still have strong investment-grade credit ratings, have stocks that sell over book value, and raise abundant amounts of capital. (OPC BR 35; TR 2184) OPC also argued that TECO’s requested ROE of 11.50 percent is driven by Emera, Inc.’s need to upstream dividends to the parent to service Emera, Inc.’s excessive debt and improve Emera’s weak credit profile. (OPC BR 36) However, staff believes that the authorized ROE should be determined using widely accepted cost of capital models and TECO’s

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comparable risk factors. Emera Inc.'s credit profile should not have a bearing on TECO's authorized ROE in Florida. OPC also argued TECO witness D'Ascendis' credibility comes into question as he only testified on behalf of utilities and was unaware of a single instance in which he recommended a lower ROE compared to a company's current ROE. (OPC BR 37) OPC concluded:

Given the totality of the circumstances, including the recent historical national average and the fact that the Company is relatively less risky, it would not be unreasonable for the Commission to leave the Tampa Electric ROE unchanged. Setting aside the numerous other credibility issues that arose at the hearing, the Company forfeited its credibility when it offered Mr. D'Ascendis' outlandish 11.5% ROE, which is almost 200 basis points above the national average. Ultimately, the Company failed to meet its burden to show why its current ROE should be increased. The facts of this case, combined with the darkening clouds of affordability and energy poverty, provide the Commission with ample basis for awarding no more than a 10.2% ROE without needing to reference or rely on the Commission-approved DEF ROE of 10.3%

(OPC BR 42)

FEA argued that all intervenors in this case either agree that TECO's ROE should be below 9.80 percent or did not present a position on the ROE. (FEA BR 14) FEA witness Walters observed that electric and gas ROEs have declined in the last ten years and have been below 10.00 percent for the past nine years. (FEA BR 15)

FIPUG argued TECO's proposed ROE of 11.50 percent is excessive when compared to the 9.78 percent ROE authorized by state regulatory commissions in rate cases decided in 2023 and 2024 for vertically integrated IOUs even though Florida electric IOUs are not riskier. (FIPUG BR 10; TR 2708) FIPUG witness Pollock testified that TECO's proposed 11.50 percent ROE is 172 basis points greater than the 9.78 percent average ROE authorized by state regulatory commissions nationwide for other vertically-integrated electric IOUs in rate case decisions decided in 2023 through May 2024. (TR 2708; EXH 82) He also testified that Florida is viewed as a very constructive regulatory environment for IOUs which translates into lower risk for investors. (FIPUG BR 11; TR 2708) This directly reflects the Commission's ratemaking policies, which include: the use of a projected test year and multi-year rate plans; timely cost recovery as reflected in both interim rate increases and in the various cost recovery clauses that allow rates to be adjusted outside of a rate case; allowing a return on construction work in progress; and authorizing securitization for storm damage and other major events. (FIPUG BR 11; TR 2708) These risk-lowering policies are described in a 2021 assessment of Florida regulation conducted by Regulatory Research Associates (RRA) which ranked Florida above 46 other states for investor supportiveness by giving it a score of Above Average/2. (FIPUG BR 11; TR 2708) Further, a large percentage (38 percent to 43 percent) of TECO's annual revenues are collected in various cost recovery mechanisms that allow rates to be adjusted outside of base rate cases. (TR 2710) In addition, there is no appreciable regulatory lag when setting base rates because of the use of a projected test year and the use of subsequent year adjustments as in the instant case. (FIPUG BR 12; TR 2710) Witness Pollock concluded that it is clear that TECO faces

significantly less regulatory risk than many of its peer IOUs and the lower regulatory risk should be reflected in the ROE authorized for TECO. (TR 2711) In its brief, FIPUG concluded that the average of the ROEs put forward by the intervenors is 9.56 percent. The overwhelming weight of the intervenors' respective ROE witnesses is persuasive and should be accepted such that TECO receives an ROE which is 9.78 percent or lower. FIPUG argued the intervenor's testimony provides the evidence that TECO is able to fulfill its service obligations to its customers with a single digit ROE rather than a double-digit ROE. (FIPUG BR 13)

FRF argued the Company's president, Archie Collins, confirmed that from 2022 through 2024 TECO has been able to obtain the needed capital to make all necessary investments, and to cover all necessary expenses to provide safe and reliable service with an authorized ROE of 10.20 percent and with achieved ROEs less than that. (FRF BR 4; TR 395) Moreover, FRF argued, interest rates have already begun to decline and are projected to decline further such that TECO's required ROE is not as great as it was in 2023 or 2024. Thus, the absolute maximum ROE that the Commission should even consider is 10.20 percent. (FRF BR 4; TR 2940) FRF witness Chriss testified that the average of 118 reported authorized ROEs according to data from S&P Global Market Intelligence is 9.50 percent, with a range of 7.36 percent to 11.45 percent. (TR 3100) For vertically-integrated electric companies, the average authorized ROE for 2021 through the present was 9.62 percent and, thus far in 2024, the average is 9.72 percent. (TR 3100; EXH 136) If the Commission approved an ROE of 9.72 percent for TECO, the Company's revenue requirement would decrease by \$108.6 million, or 36.6 percent. (TR 3101-3102; EXH 137) Although witness Chriss admitted that the Commission is not bound by decisions of other state regulatory commissions, he asserted that TECO's requested ROE of 11.50 percent is excessive when compared to broader electric industry trends. (TR 3100) Further, witness Chriss asserted that TECO realizes great revenue certainty through clause recovery (nearly 39 percent of retail operating revenues) which reduces risk and should be reflected in the authorized ROE. (TR 3097-3098) FRF witness Chriss recommended that the Commission should thoroughly and carefully consider the impact on customers in examining the requested ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates reflects the minimum amount necessary to compensate the Company for adequate and reliable service, while also providing TECO an opportunity to earn a reasonable return for its shareholders. (TR 3102) FRF noted that 100 basis points of ROE would have an impact of approximately \$63.19 million per year on TECO's revenue requirement. (FRF BR 13; TR 401) FRF argued the Commission should recognize that TECO does not need an ROE as high as it is currently authorized 10.20 percent and make its decision accordingly. (FRF BR 16) FRF recommended the Commission should find that an ROE of 9.50 percent, premised on an equity ratio of 54.00 percent, is fully justified by the preponderance of the evidence recorded in this case. (FRF BR 9, 16)

TECO witness D'Ascendis rebutted the recommendations by FIPUG witness Pollock and FRF witness Chriss to use historical authorized ROEs to set TECO's ROE. He testified that while authorized ROEs may be reasonable benchmarks of acceptable ROEs, they do not reflect the current cost of common equity. (TECO BR 47; TR 1911) Historical authorized ROEs do not reflect the investor-required return at the time the rate case is decided, nor are they based on market data presented in an evidentiary record. (TR 1912) TECO argued that the Commission should give little weight to the S&P Capital IQ Rate Case History in Exhibit 321, reasoning that it presented no evidence that the utilities listed in the exhibit have comparable risks to TECO.

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(TECO BR 47; EXH 321) Witness D'Ascendis asserted that historical authorized returns do not completely reflect investor-required return because the economic conditions in the past are not representative of current economic conditions and simple comparisons of his recommended ROE to previously authorized ROEs are of little value. (TECO BR 44; TR 1912) While witness D'Ascendis agreed with witness Chriss that the Commission should consider TECO's use of a future test year and cost recovery mechanisms, he disagreed that they have an effect on TECO's risk profile because the *Hope* and *Bluefield* standard requires the allowed ROE to be commensurate with the returns on investment of similar risk, that is, the proxy group of electric companies. (TR 2033) Witness D'Ascendis explained:

The cost of capital is a comparative exercise, so if the use of a FTY or cost recovery mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero; any effect of the perceived reduced risk of a future test year or cost recovery mechanism by investors would be reflected in the market data of the proxy group. To the extent the proxy companies utilize future test years or cost recovery mechanisms only serve to make it more comparable to its peers and has no impact on comparative risk.

(TR 2033)

FL Rising/LULAC witness Rábago contended that TECO's allowed ROE should not exceed the average ROE awarded to other companies, including other Emera companies, and therefore, the Commission should award TECO a midpoint ROE of no higher than 9.50 percent. (TR 2602-2603) Witness Rábago asserted that TECO's ROE proposal is out of step with awarded ROEs in recent years. Based on a report from the Edison Electric Institute, awarded ROEs since the start of 2022, and dating back for five years, have averaged 9.52 percent. (TR 2601) Witness Rábago further asserted that awarded ROEs over the past ten years have been only slightly higher, at 9.67 percent. (TR 2601) Witness Rábago testified that TECO's primary business drivers of customer and sales growth have been extremely modest in effect and do not justify the dramatic increases in spending and earnings that TECO has experienced and proposed. (TR 2601) TECO wants to spend about \$1.6 billion each year in 2025, 2026, and 2027 on capital projects, growing its rate base and profits, which witness Rábago asserted is unreasonable and unjustified in many cases. Witness Rábago claimed that if TECO's capital expenditures were moderated to reasonable levels, the Company could maintain strong financials without making outsized profits. (TR 2601) Further, witness Rábago disagreed with TECO witness D'Ascendis' weather and climate risk analysis. (TR 2601) Witness Rábago contended that while TECO faces climate change risks associated with severe weather events, such risks are now unfortunately common across the United States and around the world. Witness Rábago testified that TECO has finally started taking some steps towards reducing its dependence on fossil fuels, and if it is serious about climate risk, the Company should continue those efforts. (TR 2601) Witness Rábago concluded TECO's risk profile and actions to date do not justify returns that are out of step with regulated electric averages. (TR 2602)

TECO witness D'Ascendis disagreed with witness Rábago's testimony and asserted it is inaccurate and incorrect. (TR 2037) The risks highlighted by witness Rábago are essentially business risks witness D'Ascendis claimed are already reflected in TECO's bond rating, which is

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less risky than his proxy group. (TR 2036) Witness D'Ascendis already made an 8-basis point reduction to the results of his ROE models to reflect TECO's perceived risk as compared to his proxy group. (TR 2037)

Walmart did not provide a position statement in its post hearing brief, and instead, provided what appears to be its argument. Walmart argued TECO's authorized ROE should be no higher than 9.78 percent. (Walmart BR 7) Walmart stated that TECO witness Collins testified that through the Company's currently approved ROE of 10.20 percent, TECO had sufficient capital to make all the needed investments, including O&M expenditures, through the 2021 Settlement Agreement term. (Walmart BR 6-7) Walmart also argued that TECO's proposed ROE of 11.50 percent is excessive in comparison to the broader national average of authorized ROEs as set forth in FRF witness Chriss' testimony. In addition, five other intervenor witnesses all testified that TECO's ROE should be between 9.50 percent and 9.78 percent. (Walmart BR 5) Walmart recognized the Commission does not have to consider the ROEs approved by other Commission's nationwide but suggested the Commission consider what it approved for Duke Energy Florida, LLC (DEF) and Florida Power & Light Company (FPL). (Walmart BR 5) Walmart stated that TECO's proposed ROE is more than 100 basis points higher than the ROE approved by the Commission for DEF in Docket No. 20240025-EI, immediately before the beginning of the hearing in this docket. (Walmart BR 5)

### **Legal Standard**

TECO witness D'Ascendis, OPC witness Woolridge, and FEA witness Walters all agree that the landmark U.S. Supreme Court *Hope* and *Bluefield* decisions established standards for setting a fair rate of return for equity investment in utilities providing service to the public. (TR 1814-1815; TR 2796; TR; 2947-2948) Under the *Hope* and *Bluefield* decisions, the U.S. Supreme Court established that a fair rate of return should be comparable to returns on investments in other enterprises having similar risks, 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 1814-1815; TR 2796; TR 2947-2948) TECO witness D'Ascendis expanded on the legal standard and reasoned that the required rate of return for a regulated public utility should be established on a stand-alone basis. (TR 1816) Witness D'Ascendis asserted that it is important that the authorized ROE be sufficient to support the operational and financial risks of a regulated utility on a stand-alone basis as a subsidiary of its parent company regardless of the source of capital funding. (TR 1816-1817)

Witness D'Ascendis acknowledged that in prior rate cases for Peoples Gas System, Inc. the Commission 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 1833-1834) In particular, 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 1833-1834) TECO argued that as explained by the Commission in its decision in the Florida City Gas rate case:

Neither case law nor statute mandates 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,

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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.<sup>47</sup>

(TECO BR 43)

OPC witness Woolridge also acknowledged that the appropriate ROE for a regulated utility requires determining the market-based cost of capital for a regulated firm which represents the return investors could expect from other investments, while assuming no more and no less risk. (TR 2796) The purpose of all of the economic models and formulas in cost of capital testimony is to estimate, using market data of similar-risk firms, the rate of return on equity investors require for that risk class of firms in order to set an appropriate ROE for a regulated firm. (TR 2796) OPC argued that both the DCF and CAPM models employed by OPC witness Woolridge and TECO witness D'Ascendis are market-based approaches to calculating a regulated public utility's fair rate of return, and as such, the methodologies are generally recognized as being consistent with the market-based standards of a fair return contemplated by *Hope* and *Bluefield*. (OPC BR 35; TR 1833)

FEA witness Walters asserted that in addition to the *Hope* and *Bluefield* standards, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts, and that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures," and the Supreme Court defined the ratepayer/investor balance as follows:

The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.<sup>48</sup>

(TR 2947-2948)

Thus, witness Walters contended that a fair rate of return is based on the expectation that the Company costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. (TR 2948)

In its brief, FRF argued Florida Statutes and Florida Supreme Court precedent recognize a closely related yet finer point: that regulated utilities are to charge rates, and accordingly earn returns, that are neither insufficient for the utility nor excessive from the customers' perspective. (FRF BR 8) For example, Section 366.06(2), F.S., charges the Commission to consider whether the utility's rates are insufficient to yield reasonable compensation for the services rendered or that such rates yield excessive compensation for services rendered, and if the rates are either insufficient or excessive, the Commission is to determine the just and reasonable rates to be charged for the utility's service. (FRF BR 8) To the same effect and result, Section 366.07, F.S.,

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<sup>47</sup> 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*, p 40.

<sup>48</sup>*Bluefield*, 262 U.S. at 693.

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provides that whenever the Commission finds that the "rates . . . charged or collected by any public utility for any service . . . are unjust, unreasonable, insufficient, excessive, or unjustly discriminatory," the Commission is to "fix the fair and reasonable rates . . . to be imposed . . . in the future." (FRF BR 8) The Florida Supreme Court recognized the balance between utility interests and customer interests, and the resolution that rates are to be neither insufficient for the utility nor excessive for its customers, in *United Tel. Co. v. Mayo*, 345 So. 2d 648, 653 (Fla. 1977), where the Court stated:

The rate of return which public utility companies may be allowed to earn is a question of vital importance to both rate payers and investors. . . . That return cannot be set so low as to confiscate the property of the utility, nor can it be made so high as to provide greater than a reasonable rate of return, thereby prejudicing the consumer.

(FRF BR 8)

Thus, FRF argued, for rates to be fair, just, and reasonable, the returns afforded the utility pursuant to those rates must also be fair, just, and reasonable. (FRF BR 8)

### **Proxy Group of Electric Companies**

Because TECO is not publicly traded and does not issue publicly traded equity securities, a group of publicly-traded companies that have comparable risk characteristics to TECO must be used as a proxy group to which cost of equity models are applied to determine the required ROE. (TR 1818) In his direct testimony, Witness D'Ascendis selected 14 companies from the Value Line Investment Electric Utility Group. (TR 1824-1825; TECO BR 44) The utility proxy group includes Alliant Energy Corporation, Ameren Corporation, American Electric Power Corporation, Duke Energy Corporation, Edison International, Entergy Corporation, Evergy, Inc., IDACORP, Inc., North Western Corporation, OGE Energy Corporation, Pinnacle West Capital Corporation, Portland General Electric Company, Southern Company, and Xcel Energy, Inc. (TR 1824-1825) In his rebuttal testimony, witness D'Ascendis added PNM Resources, Inc. to his original proxy group of fourteen electric companies without explanation. (EXH 148, MPN D10-672-673) However, the addition of PNM Resources, Inc. did not materially change the average results of his cost of equity models in his rebuttal testimony.

OPC witness Woolridge used TECO witness D'Ascendis' utility proxy group in addition to a proxy group of his own selection. (TR 2817) Witness Woolridge's proxy group consists of 24 electric companies also listed by Value Line Investment Survey. (OPC BR 38; TR 2817; EXH 65, MPN C24-2499) Both witnesses used similar selection criteria with one exception: witness D'Ascendis selected only companies that are vertically integrated (i.e., utilities that own and operate regulated generation, transmission, and distribution assets). (TR 1824) Witness D'Ascendis' proxy group is more similar to TECO because TECO is also a vertically integrated electric utility. The difference between the proxy groups selected by witnesses D'Ascendis and Woolridge are described as follows.

OPC witness Woolridge's proxy group has a mean operating revenues and net plant among members of the Electric Proxy Group of \$10.78 billion and \$41.55 billion, respectively. The group on average receives 85 percent of its revenues from regulated electric operations; has a



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BBB+ bond rating from S&P and a Baa2 rating from Moody's; has a current average common equity ratio of 40.9 percent; and has an average earned ROE of 9.36 percent. (TR 2817)

The mean operating revenues and net plant among the companies in TECO witness D'Ascendis' proxy group are \$10.29 billion and \$40.90 billion, respectively. On average the group receives 90 percent of revenues from regulated electric operations; has an average BBB+ issuer credit rating from S&P and an average Baa2 long-term rating from Moody's; has a current common equity ratio of 40.1 percent; and has an earned return on common equity of 9.48 percent. (TR 2818)

On balance, these measures suggest that these two proxy groups are very low risk relative to the overall stock market and are similar in risk to each other. (TR 2819)

## **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. (OPC BR 38; TR 1834; TR 2834; TR 2955) In its basic form, the DCF model is expressed as the dividend yield of a stock plus the expected long-term growth rate. Expressed mathematically as:  $ROE = (\text{dividend} \div \text{stock price}) + \text{growth rate}$ . (OPC BR 39; TR 2955) This is known as the traditional single-stage constant growth DCF model. (TR 1834; TR 2834) TECO witnesses D'Ascendis and OPC witness Woolridge used an adjusted version of the single-stage constant growth DCF model by adjusting the annual dividend for expected growth expressed as:  $ROE = [(\text{dividend} (1 + 0.5\text{growth rate})) \div \text{stock price}] + \text{growth rate}$ . (TR 1835-1836; TR 2839) FEA Witness Walters adjusted the dividend by the full value of the growth rate in his DCF calculation to adjust the dividend upwards. (TR 2956) Staff agrees with the witnesses' use of an adjusted DCF model to account for growth in dividend payments from the utilities. (TR 1835-1836, 2839) Although witness D'Ascendis testified that DCF theory calls for using the full growth rate, he and OPC witness Woolridge used one-half the growth rate in their DCF calculations since the utilities in the proxy group increase their quarterly dividends at various times of the year which staff agrees is a reasonable assumption. (TR 1835-1836; TR 2839).

TECO witness D'Ascendis' DCF model results for each of the companies in his utility proxy group ranged from 8.21 percent to 11.52 percent with an average of 10.16 percent. (EXH 148, MPN D10-675) The average dividend yield for witness D'Ascendis' proxy group was 4.42 percent with an average growth rate of 6.01 percent. Witness D'Ascendis growth rate of 6.01 percent is based on an average of five-year forecasts of earnings per share (EPS) from three publicly available sources of published analysts' estimates from Value Line, Zacks, and Yahoo! Finance. (EXH 148, MPN D10-675) Witness D'Ascendis' excluded the result of 14.16 percent for Portland General Electric Company from his final average as the result was an outlier from the proxy group's mean. (EXH 148, MPN D10-675) Witness D'Ascendis explained investors are likely to rely on widely available financial information services. (TR 1836) 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

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lthe growth rate component in the DCF model, and over the long run, there can be no dividend growth without earnings growth. (TR 1836-1837)

OPC witness Woolridge's DCF model results from his proxy group of 24 companies was 9.70 percent, and using TECO witness D'Ascendis' proxy group, his result was 10.00 percent. (EXH 67, MPN C24-2502) For the dividend yield, witness Woolridge used the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. (TR 2838) Witness Woolridge used the mean of 4.10 percent of range of results for his proxy group. (EXH 67, MPN C24-2502) For witness D'Ascendis' proxy group, OPC witness Woolridge used the mean dividend yield of 4.30 percent. (OPC BR 38; EXH 67, MPN C24-2502) For his growth rates, witness Woolridge used 5.50 percent for his proxy group and 5.60 percent for TECO witness D'Ascendis' proxy group. (TR 2849; EXH 67, MPN C24-2502) Witness Woolridge's growth rates for both proxy groups was obtained from the average of the projected sustainable growth rate based on the average of the projected EPS, dividends per share (DPS), and book value per share growth rates from Value Line of 5.00 percent, and the projected EPS growth rates of Wall Street analysts of 5.95 percent. (TR 2849) The average of witness Woolridge's three estimates was 5.00 percent. (TR 2849). However, witness Woolridge gave more weight to the projected growth rates of Wall Street analysts and Value Line data and reasoned the appropriate growth rate is in the range of 5.00 percent to 5.95 percent, and therefore, he used the midpoint of 5.50 percent as the growth rate for his proxy group. (TR 2849) Using the same process, witness Woolridge determined the over-all range for the projected growth indicators for witness D'Ascendis' proxy group was 3.90 percent to 6.10 percent and the average was 5.10 percent. (TR 2850) Giving more weight to the projected EPS growth rate of Wall Street analysts, he used the midpoint of the range of 5.60 percent. (TR 2850) Witness Woolridge's DCF model results were 9.70 percent for his proxy group, and 10.00 percent for TECO witness D'Ascendis' proxy group. The average of OPC witness Woolridge's two DCF models was 9.85 percent.

FEA witness Walters applied three different DCF models to TECO witness D'Ascendis' proxy group to estimate TECO's ROE. Witness Walters used the single-stage constant growth model using analyst growth rates in his first model and sustainable growth rates in his second model. (TR 2955-2967) Witness Walters explained the sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment. (TR 2959) In his third DCF model, witness Walters applied a multi-stage model that uses three growth stages that reflect a reasonable expectation of a shift in growth from an initial high growth period, to a transition period, followed by a long-term growth period extending into perpetuity. (TR 2961-2962)

For his constant growth DCF model using analyst's EPS forecasts, FEA witness Walters calculated an adjusted dividend yield of 4.65 percent. (EXH 94) For his growth rate of 6.33 percent, he relied on the average of professional securities analyst's projected EPS growth estimates from three publicly available sources: Zacks, S&P Capital IQ Market Intelligence, and Yahoo! Finance. (TR 2957). The DCF results for his constant growth DCF model using security analyst EPS estimates was 10.98 percent which is significantly higher than TECO witness

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D'Ascendis' DCF average result of 10.16 percent. (EXH 94; EXH 148, MPN D10-675) There are several reasons for witness Walter's higher result. First, he included the ROE result of 15.77 percent from Portland General Electric Company in his proxy group average result while witness D'Ascendis excluded his result of 14.16 percent because it was too high. (EXH 94; EXH 148, MPN D10-675) Eliminating Portland General Electric Company from witness Walters' DCF result lowers his average to 10.61 percent. Second, witness Walters adjusted the dividend yield for each company by the full amount of the growth rate as opposed to only one-half the growth rate as did TECO witness D'Ascendis and OPC witness Woolridge. Using the full growth rate adjusted dividend yield increased witness Walters' DCF result by 13 basis points. Removing the DCF model result from Portland General Electric Company and applying a one-half the growth rate to adjust the dividend yield reduces witness Walters' DCF result using analyst forecasts by 50 basis points from 10.98 percent to 10.48 percent. Staff believes witness Walters' adjusted result of 10.48 percent is more reasonable and is more comparable with the approach used by witness D'Ascendis and witness Woolridge.

For his second DCF model analysis using a sustainable growth rate, FEA witness Walters calculated a dividend yield of 4.58 percent, and an average growth rate of 4.80 percent for an average result of 9.70 percent. (TR 2959-2960; EXH 96) For his third DCF model analysis, witness Walters' applied a multi-stage DCF methodology and obtained a result of 9.35 percent. (TR 2961-2966; EXH 96) In his multi-stage DCF model, witness Walters' estimated a growth rate of 6.33 percent in the first 5-year stage of growth, followed by a declining growth rate in years 6 through 10 from 5.97 percent to 4.51 percent, and a terminal growth rate of 4.14 percent. (TR 2961-2966; EXH 96) Overall, the average results from witness Walters' three DCF analysis ranged from 9.35 percent to 10.98 percent, with an average of 9.90 percent. (EXH 96) Witness Walters testified that his results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.33 percent, which is approximately 50 percent higher than the long-term projected gross domestic product (GDP) growth rate of 4.14 percent. (TR 2966). Witness Walters asserted that this is an unsustainable assumption and likely leads to an overstatement in the cost of equity for a low-risk regulated utility and as such, it was his opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF. (TR 2966)

Both intervenor witnesses testified that there are several issues with using the earnings per share growth rate forecasts of Wall Street securities analysts for the long-term DCF growth rates. FEA witness Walters explained his 6.33 percent growth rate is based on the three to 5-year growth rates from investment analysts and is approximately 50 percent higher than the long-term projected GDP growth rate of 4.14 percent. (TR 2958) Witness Walters testified that Blue Chip Financial Forecasts projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.14 percent. (TR 2958) As such, the average nominal growth rate over the next 10 years is around 4.14 percent, which he opined is a reasonable proxy of long-term growth. (TR 2959) Witness Walters asserted that a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the constant growth DCF model. (TR 2958) Witness Walters opined that using the long-term GDP growth rate is logical, and is generally consistent with academic and economic-practitioner accepted practices. (TR 2959)

OPC witness Woolridge testified that the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. (TR 2843) Witness Woolridge explained that according to conventional DCF model theory, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. (TR 2841) Therefore, to best estimate the cost of common-equity capital using the conventional DCF model, one must look to long-term growth rate expectations. (TR 2841) Witness Woolridge asserted that it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. (OPC BR 39; TR 2843) Witness Woolridge testified that this has been demonstrated in a number of academic studies over the years. (TR 2844) Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. (TR 2843) The sustainable growth rate, also referred to as the internal growth rate of a company, is determined by the internal proportion of the utility's earnings that is retained and reinvested in its plant and equipment. (TR 2841-2842, TR 2959-2960) Witness Woolridge asserted that internal growth is significant in determining long-run earnings and, therefore dividends. (TR 2841)

OPC witness Woolridge asserted that it is apparent that TECO witness D'Ascendis gave very little weight to his DCF results in his final analysis and recommendation. (OPC BR 39; TR 2871) Had he given his DCF results more weight, he would have arrived at an ROE lower than 11.50 percent. (TR 2871) Secondly, witness Woolridge claimed that witness D'Ascendis relied exclusively on the overly optimistic and upwardly biased EPS growth-rate forecasts of Wall Street analysts and Value Line. (TR 2871) It seems highly unlikely that investors today would rely exclusively on the EPS growth-rate forecasts of Wall Street analysts and Value Line and ignore other growth-rate measures in arriving at their expected growth rates for equity investments. (TR 2871) Witness Woolridge cited to a study he conducted using the electric utilities and gas distribution companies covered by Value Line. (TR 2872). Witness Woolridge explained his study demonstrated that Value Line's mean forecasted EPS growth rates are consistently greater than the achieved actual EPS growth rates over the 1985-2022 time period. (TR 2845, 2872) Over the entire period, the mean forecasted EPS growth rate is over 200 basis points above the actual EPS growth rate. As such, the projected EPS growth rates for utilities are overly optimistic and upwardly biased. Hence, exclusively using these growth rates as a measure of the DCF growth rate produces an overstated equity-cost rate. (TR 2845; TR 2872) In addition, FEA witness Walters asserted that it is unrealistic to expect utilities to maintain a growth rate well in excess of the anticipated growth in GDP and relying solely on the constant growth DCF model using securities analysts' forecasted EPS growth rates tends to overstate the DCF model results. (TR 2991)

TECO witness D'Ascendis dedicated 15 pages of his rebuttal testimony disputing OPC witness Woolridge's testimony that using projected EPS growth rates for utilities are overly optimistic and upwardly biased. (TR 1930-1945) Witness D'Ascendis asserted that the use of analysts' EPS growth projections in the DCF are supported by financial literature and various studies that support the use of security analysts' EPS growth forecasts and they are not overly optimistic and upwardly biased. (TR 1930-1945) The main point of witness D'Ascendis' rebuttal was that dividend and book value growth rates are not appropriate inputs to the DCF because earnings enable both dividends and book value growth. (TR 1944) Under the strict assumptions of the constant growth DCF model, earnings, dividends, book value, and stock prices all grow at the

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same constant rate in perpetuity. (TR 1944) Witness D'Ascendis stated that the analyst-projected EPS growth rates he used to derive his DCF results are confirmed to have high accuracy and limited bias. (TR 1935) However, witness D'Ascendis also stated that the level of accuracy of the analyst forecasts well after the fact does not matter. (TR 1937) He asserted that "What is important is the forecasts reflect widely held expectations influencing investors at the time they make their pricing decisions, and hence, the market prices they pay." (TR 1937) Ultimately, witness D'Ascendis concluded that the Commission should rely solely on projected EPS growth rates when determining the indicated ROE for TECO using the DCF model. (TR 1954) However, this statement contradicts witness D'Ascendis' statement on page 26 of his direct testimony where he stated, "Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgement in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate." (TR 1832) Further, as pointed out by witness D'Ascendis, witness Woolridge gave more weight to projected EPS growth rates to arrive at his DCF results of 10.00 percent for witness D'Ascendis' proxy group. (TR 1929-1930, TR 2849)

In regards to FEA witness Walters' testimony, TECO witness D'Ascendis took issue with witness Walters' use of the sustainable growth rate and his multi-stage DCF model. (TR 2004) Witness D'Ascendis testified, and staff agrees, the GDP is not an appropriate upper limit for long-term growth for electric utilities. (TR 2004-2005) Witness D'Ascendis asserted that first, GDP is not a market measure, but rather is the measure of the total output of goods and services, excluding inflation, in the economy. (TR 2005) Further, witness D'Ascendis stated that the long-term growth rate of the utility industry from 1947-2023 was 6.55 percent which is comparable to the average growth rate of his proxy group of 6.01 percent. (TR 2006) In addition, witness D'Ascendis argued that the multi-stage DCF is more appropriate for fast growing value companies, not electric utilities that are in the steady-state constant-growth stage of the business cycle. (TR 2007-2009)

All three witnesses agreed that EPS are not actual cash flows realized by the investor and that dividends are the actual cash flows shareholders receive. (TR 1834; TR 1938; TR 2834; TR 2947) Although Value Line provides a forecasted dividends per share estimate for the companies in the proxy groups, neither witness relied solely on an estimate of the forecasted dividends declared per share. While the sustainable growth rates used by OPC witness Woolridge and FEA witness Walters do not reflect market-based assumptions, staff agrees with OPC witness Woolridge that investors most likely would avail themselves to all pertinent data when they price the stocks of utilities. (TR 2872; TR 2956) Therefore, staff believes equal weight should be given to all three of the witnesses' DCF model results using growth rates from analysts' forecasts and the sustainable growth rate. Further, TECO witness D'Ascendis' argument that the Commission should only consider the DCF model using analyst forecasted growth rates was not convincing and contradicted his own opinion that the Commission should consider multiple cost of equity models. (TR 1954, TR 1832) Therefore, staff believes an appropriate approach is to give equal consideration to the results from all three witnesses DCF analyses except for FEA witness Walters' multi-stage application. Staff agrees with witness D'Ascendis that the multi-stage DCF model is not appropriate for mature firms in the constant growth business cycle such as electric utility companies. (TR 2009) The average of FEA witness Walters' revised DCF

model using analyst growth rates (10.48 percent) and his sustainable growth rate DCF model (9.37 percent) is 9.925 percent. The average of OPC witness Woolridge's two DCF model results is 9.85 percent. TECO witness D'Ascendis DCF model result was 10.16. The average of these three DCF model results is 9.98 percent. Comparably, the average of the three witnesses' highest DCF model results is 10.38 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 (MRP). (TR 1858-1859; TR 2851-2852) 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. (OPC BR 39) The beta is expressed as the volatility of an individual security compared against the stock market as a whole. A beta value of 1.0 indicates the individual security has the same volatility as the stock market. 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 1857) 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 MRP expressed in this equation:  $ROE = \text{risk-free rate} + \text{Beta} (\text{market return} - \text{risk-free rate})$ . (TR 2972) TECO witness D'Ascendis used two variations of the CAPM, the traditional CAPM and the Empirical CAPM or ECAPM. (TR 1866) The average results of his application of the CAPM and ECAPM, excluding the PRPM MRP in his rebuttal testimony, is 11.58 percent and 12.00 percent, respectively. (EXH 148, MPN D10-702) OPC witness Woolridge used the traditional form of the CAPM to calculate a cost of equity of 8.85 percent for both his proxy group and witness D'Ascendis' proxy group. (TR 2866) FEA witness Walters applied nine different iterations of the CAPM to witness D'Ascendis proxy group. The results ranged from 8.80 percent to 12.03 percent. The average of his nine results is 10.36 percent. (TR 2981-2982; EXH 105) The average of all three witnesses' traditional CAPM results is 10.26 percent ( $(11.58\% + 8.85\% + 10.36\% = 30.87) \div 3 = 10.26\%$ ).

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

The three cost of capital witnesses used three different methods to estimate the risk-free rate used in their CAPM analysis. (EXH 148, MPN D10-703; TR 2853, and TR 2973) TECO witness D'Ascendis used the average of the consensus forecasts for the yields on the 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2025, and long-term projections for the years 2026 to 2030 and 2031 to 2038 as published in the May 31, 2024, Blue Chip Financial Forecast. (EXH 148, MPN D10-698) His estimate was 4.41 percent. (EXH 148, MPN D10-703) OPC witness Woolridge's risk-free rate is based on the historical yields on 30-year U.S. Treasury Bonds from January 1, 2010 to May 1, 2024. (TR 2853) Witness Woolridge testified that the current 30-year Treasury yield is in the 4.50 percent to 4.75 percent range and he chose 4.65 percent as the risk-free rate to use in his CAPM analysis. (TR 2853) FEA witness Walters used the projected yield on the 30-year Treasury Bond for the second and third quarters of 2025 of 4.20 percent as published in the May 1, 2024, Blue Chip Financial Forecasts. (TR 2973; EXH 103)

### ***Beta Coefficient***

TECO witness D'Ascendis used the betas published by Value Line and Bloomberg. (TR 1866) While both of those services adjust their calculated (or "raw") betas to reflect the tendency of the

beta to regress to the market mean of 1.00, Value Line calculates the beta over a five-year period, while Bloomberg calculates it over a two-year period. (TR 1866) For each company in his proxy group, witness D'Ascendis averaged the Value Line and Bloomberg beta values and then averaged the company averages to arrive at an overall beta of 0.81 for his proxy group. (EXH 148, MPN D10-702) OPC witness Woolridge used betas published by Value Line and S&P Capital IQ. (TR 2857) Witness Woolridge made an upward adjustment using the Blume adjustment to the S&P betas. (TR 2857) Witness Woolridge averaged the two beta measures for each of the companies and then averaged all the companies' average betas for a proxy group average. (EXH 68) Witness Woolridge calculated an average beta of 0.81 for his proxy group and 0.82 for the D'Ascendis proxy group. (EXH 68) FEA witness Walters used three different betas in the nine iterations of his CAPM analysis. (EXH 105) He used the current betas published by both Value Line and S&P Global Market Intelligence, and the average of the historical betas over the period from the third quarter of 2014 to the fourth quarter of 2023 as provided by Value Line Investment Survey. (EXH 104) His results were 0.92 for the current Value Line beta, 0.85 for the current S&P beta, and 0.76 for the historical beta. (EXH 105)

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

The MRP is an estimate of the required return on the stock market less the estimated risk-free rate. (TR 2857-2858) In his rebuttal testimony, TECO witness D'Ascendis derived a MRP of 8.93 percent based on the average of three historical data-based market risk premiums, two Value Line data-based market risk premiums, and one using Bloomberg data. TECO witness D'Ascendis' average MRP result was 8.82 percent, excluding his derivation using his PRPM applied to Kroll Historical Data. (EXH 148, MPN D10-703) Witness D'Ascendis' estimated MRP of 8.82 indicates the expected return on the market going forward is 13.23 percent (8.82% + 4.41%). OPC witness Woolridge based his MRP estimate on his review of 19 academic and professional studies dated after January 2, 2010 that discuss and estimate the MRP. (TR 2858-2866; EXH 68) Witness Woolridge testified that the studies suggest that the appropriate MRP is within the range of 4.00 percent to 6.00 percent. (TR 2865-2866) Witness Woolridge asserted that in the last year as interest rates increased, the estimates of the MRP have declined. (TR 2865-2866) Witness Woolridge gave most weight to the market risk-premium estimates provided by Kroll, KPMG, JP Morgan, Damodaran, Fernandez, and Duke-CFO surveys. (TR 2866) Witness Woolridge concluded a MRP in the 5.00 percent to 5.50 percent range is appropriate and used the midpoint of this range, 5.25 percent, as his MRP in his CAPM analysis. (TR 2866) FEA witness Walters' MRP estimates were derived using both a risk premium approach and a DCF approach. (TR 2975) Witness Walters also used the normalized market risk premium of 5.50 percent with the normalized risk-free rate of 4.61 percent as recommended by Kroll, formerly known as Duff & Phelps. (TR 2975-2976) To calculate a MRP using a risk premium method, witness Walters used the historical, arithmetic-average, real-market return over the period 1926 to 2023 using data from Morningstar Direct. The arithmetic-average real return on the market since 1926 was 9.02 percent. (TR 2975) Witness Walters added the current consensus for projected inflation, as measured by the Consumer Price Index of 2.40 percent to derive an expected market return of 11.64 percent. (TR 2975) The MRP is the difference between the 11.64 percent expected market return and the projected risk-free rate of 4.20 percent, or 7.44 percent. (TR 2976) Witness Walters also employed two versions of the constant growth DCF model to develop his MRP estimates: the Federal Energy Regulatory Commission's (FERC) method of estimating the expected return on the market and an alternative version of the FERC

DCF method using all companies in the S&P 500 Index rather than just dividend paying companies.<sup>49</sup> (TR 2977) Witness Walters' expected market return using the FERC DCF model was 12.70 percent and using the alternative DCF model was 12.69 percent. The DCF model MRP result was the expected market return of 12.70 percent, less the projected risk-free rate of 4.20 percent, or 8.50 percent. (TR 2977) Overall, witness Walters estimated three different MRPs of 5.50 percent, 7.44 percent, and 8.50 percent, which averaged 7.15 percent. (EXP 105)

OPC witness Woolridge asserted that TECO witness D'Ascendis' CAPM results assume that the return on the U.S. stock market will be more than 50 percent higher in the future than it has been in the past. (TR 2883-2884) Witness Woolridge testified that the compounded annual return in the U.S. stock market was about 9.80 percent between 1928-2023. (TR 2883) Witness D'Ascendis' MRP estimates based on the total return of the market of 7.64 percent, 9.37 percent, and 12.02 percent, were obtained by using expected stock market returns of 12.05 percent, 13.78 percent, and 16.43 percent, respectively. (EXH 148, MPN D10-703) Witness Woolridge explained that witness D'Ascendis' MRP estimates using expected stock market returns are not reflective of the stock market returns investment firms tell investors to expect. (TR 2884) Witness Woolridge asserted that the range of forecasted U.S. annual large cap equity returns was 4.00 percent to 9.50 percent, as of December 31, 2022. (TR 2884; EXH 70) Witness Woolridge explained that the reason investment firms' expectations are lower than historical stock returns is that the valuation of the overall stock market is higher relative to historical standards. (TR 2885) When stock prices are high, investors pay higher prices for stocks which lowers their expected returns. (TR 2886) Further, TECO witness D'Ascendis used Value Line's three-to-five-year predicted annual stock return of 12.05 percent for one of his MRP estimates. (TR 2886) Witness Woolridge asserted that a study by Szakmary, Conover, and Lancaster (2008), found that over a thirty-year time period, the Value Line predicted stock-market returns to be extremely overly optimistic, well in excess of historic market returns, and were not significantly related to future returns. (TR 2886-2887) In TECO witness D'Ascendis' two market-based MRP estimates using the DCF model applied to the S&P 500, OPC witness Woolridge asserted that witness D'Ascendis used security analysts' estimated growth rates that are upwardly biased and overly optimistic. (TR 2887-2888) Witness Woolridge testified that he conducted a study that demonstrated that over the 1985 to 2022 time period, the mean projected three-to-five-year EPS growth rate forecasts of Wall Street analysts was 12.50 percent, while the average actual achieved three-to-five-year EPS growth rate was 6.50 percent. (TR 2888) OPC argued that TECO witness D'Ascendis' risk premium is much higher than published market-risk premiums and is developed using highly unrealistic assumptions of future earnings growth and stock-market returns. (OPC BR 40) Witness Woolridge also took issue with witness D'Ascendis' application and use of the ECAPM. (OPC BR 40; TR 2901) The ECAPM attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line is not as steep as predicted by the CAPM. (TR 2901) Witness Woolridge asserted that:

The ECAPM is nothing more than an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. The ECAPM

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<sup>49</sup> FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The dividend yield is adjusted by  $(1 + 0.5g)$  and the growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20 percent.



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provides for weights which are used to adjust the risk-free rate and market-risk premium in applying the ECAPM. Mr. D'Ascendis uses 0.25 and 0.75 factors to boost the equity risk premium measure, but provides no empirical justification for those figures. Beyond the lack of any theoretical or empirical validation of the ECAPM, there is another error in Mr. D'Ascendis' ECAPM. I am not aware of any tests of the CAPM that use adjusted betas such as those used by Mr. D'Ascendis. Adjusted betas address the empirical issues with the CAPM by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks.

(TR 2902)

FEA witness Walters disagreed with several aspects of witness D'Ascendis' CAPM methodology. (TR 2993) Witness Walters asserted witness D'Ascendis' MRP estimates are excessive and unreliable due to unsustainable growth rates he used to develop his expected market returns. (TR 2993) Witness Walters asserted that witness D'Ascendis' MRPs using expected stock market returns fall well outside of the range of 5.00 percent to 8.00 percent based on empirical evidence. (TR 2995) Witness Walters testified that in his book, *Modern Regulatory Finance*, Dr. Morin notes that several studies of the MRP have concluded that a MRP in the range of 5.00 percent to 8.00 percent is a reasonable estimate for the United States.<sup>50</sup> (TR 2995) Witness Walters asserted that witness D'Ascendis' expected market return derived using the DCF model applied to the S&P 500 with Value Line and Bloomberg data assumes perpetual weighted growth rates that are too high and simply irrational and cannot be sustained. (TR 2996) The growth rate used by Witness D'Ascendis is significantly higher than the growth rate of the U.S. GDP long-term outlook of 4.14 percent and it is simply not reasonable to believe that individual companies contained in the S&P 500 Index can grow in perpetuity at a rate significantly higher than the GDP. (TR 2996) For these reasons, witness Walters concluded that the majority of witness D'Ascendis traditional CAPM results are excessive and unreliable. (TR 2997) Witness Walters testified that there is no legitimate reason witness D'Ascendis' ECAPM should be used because it unjustifiably inflates a CAPM result for a company with a beta less than one such as the utility companies in his proxy group. (TR 3000) Witness Walters explained the ECAPM modifies the traditional CAPM equation by including a MRP weighted by the utility beta and the overall market beta of 1.0. (TR 2999) The original ECAPM was designed to use raw or unadjusted regression betas. (TR 2997) Witness D'Ascendis uses betas published by Value Line which are already adjusted for a stock's long-term tendency to converge to 1.00. (TR 2998) The impact of witness D'Ascendis ECAPM adjustment is to increase his beta estimate from 0.81 to 0.86. (TR 2998) Finally, the Commission has previously rejected the ECAPM with an adjusted beta, and in this case, the ECAPM should also be rejected. Because it is duplicative of the traditional CAPM and only serves to increase the overall CAPM result. (TR 300)

TECO witness D'Ascendis testified that OPC witness Woolridge's application of the CAPM is fatally flawed and serves to lower his indicated ROE results and his recommended ROE. (TR

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<sup>50</sup> Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance*, Dr. Roger A. Morin, at 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8 percent) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

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1957) Witness D'Ascendis complained that witness Woolridge's MRP is based on academic and professional studies, he uses current interest rates, and he failed to employ the ECAPM. (TR 1957) Witness D'Ascendis believes that the surveys used by witness Woolridge are not valid measures of the MRP and should be rejected. (TR 1958) Witness D'Ascendis contended that the 5.50 percent MRP quoted by Kroll should be rejected because Kroll does not reveal how they derive their estimate, and therefore, there is not a way to know if the Kroll MRP is based on market data. (TR 1959) Witness D'Ascendis' pointed out flaws and concerns with each of the surveys relied upon by witness Woolridge to estimate his MRP. (TR 1961-1970) Based on his review of these flaws, witness D'Ascendis concluded that the surveys used by witness Woolridge are not appropriate because they include: (1) investment time frames that are not consistent with TECO's going concern time frame of perpetuity; (2) they predict expected returns as opposed to required returns; (3) they estimate returns for global investment and are not specific to U.S. markets; and (4) surveys are not widely used by cost of capital practitioners. (TR 1961-1970) Witness D'Ascendis disagreed with witness Woolridge's critique of the ECAPM and explained that the use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. (TR 1971-1975) The adjusted beta used by Value Line captures the fact that betas regress toward one over time. The ECAPM corrects for the fact that the CAPM under predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one. (TR 1972)

TECO witness D'Ascendis contended that FEA witness Walters' application of the CAPM is flawed in at least five respects: (1) witness Walters used a short-term estimate of the risk-free rate and did not consider the long-term projection of the risk-free rate published by Blue Chip; (2) he relied, in part, on Vasicek betas; (3) he relied, in part, on historical betas; (4) his choice and calculation of his MRP was flawed; and (5) he did not perform an ECAPM analysis. (TR 2020) Witness D'Ascendis disagreed with using Vasicek adjusted Betas because they are not widely available in the market and are less reliable than other Beta estimates. (TR 2023) Further, witness D'Ascendis testified the use of historical Betas in neither current not expected and does not provide a measure of the expected return. (TR 2024) Witness D'Ascendis rebutted witness Walters' use of the 5.50 percent MRP quoted by Kroll because its derivation is not transparent and not accurate compared to other Kroll data. (TR 2028) Witness D'Ascendis also disagreed with excluding companies with negative growth and growth rates greater than 20 percent in witness Walters' DCF model used to calculate his MRP estimates. (TR 2024) Witness D'Ascendis explained that excluding companies with growth rates outside a certain band causes the estimate of the market return to also no longer reflect the overall market, but rather an arbitrary subset of companies within the market. (TR 2024) Witness D'Ascendis also asserted that because the beta is calculated relative to the overall market, which includes both dividend paying and non-dividend paying companies, as well as companies outside of the bounds of zero percent to 20 percent, it is important that the expected market return also reflect the overall market. (TR 2026) Therefore, it is not appropriate to combine betas calculated relative to the entire market with a MRP calculated using only a subset of the market. (TR 2026) Consequently, witness D'Ascendis recommended that the Commission should ignore the lower results from witness Walters' CAPM results. (TR 2028; EXH 105)

### ***Risk Premium Model***

The RPM theory 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 1838) Therefore, the cost rate of common equity can be derived by calculating the spread between bonds and the estimated required return on equity of investors. (TR 1838) TECO witness D'Ascendis derived an estimated ROE of 11.07 percent (excluding the PRPM) using the average of the results of three different RPMs. (TR 1838-1839; EXH 148, MPN D10-691) FEA witness Walters used two RPM analyses based on historical commission-authorized returns on common equity as compared to Treasury Bonds and A-rated and Baa- rated Utility Bonds. (TR 2970-2971) Witness Walters RPM results ranges from 9.90 percent to 10.23 percent, with an average of 10.05 percent. (TR 2971) OPC witness Woolridge did not use a RPM analysis in his testimony because he believed that risk-premium studies, of which the CAPM is one form, provide a less reliable indication of equity-cost rates for public utilities and primarily relied on the DCF model to estimate the cost of equity. (TR 2833-2834) The average of TECO witness D'Ascendis and FEA witness Walters RPM results was 10.56 percent. Staff believes the average of the witnesses RPM analysis is a fair and reasonable representation of the RPM approach.

TECO witness D'Ascendis used three separate RPM methodologies in what he called his Total Market Approach RPM (TMARPM). (TR 1838-1839) Within witness D'Ascendis' TMARPM, he added a prospective public utility bond rate to the average of three separate equity risk premium estimates. (TR1839; EXH 148, MPNs D10-691-697) Witness D'Ascendis based his three equity risk premiums estimates on: (1) a beta-adjusted total market analysis using five estimates of the spread between projected market returns and A-rated corporate bonds; (2) the spread between Moody's A2 rated public utility bond yields and the return on the S&P Utilities Index holding period returns; and (3) a regression analysis of the awarded ROEs in 1,237 fully-litigated electric rate cases as compared to Moody's A2-rated public utility bond yields. (EXH 148, MPNs D10-691-697) The average of those three risk premium estimates was 5.27 percent. (EXH 148, MPN D10-695) Witness D'Ascendis added his estimated risk premium of 5.27 percent to his estimated prospective utility bond yield of 5.80 percent that reflects the bond rating of the proxy group based on a Moody's long-term issuer rating of Baa1. (EXH 148, MPN D10-691) Witness D'Ascendis' RPM analysis result was 11.07 percent (5.27% + 5.80%).

OPC witness Woolridge testified the primary error in TECO witness D'Ascendis' RPM analysis is the excessive magnitude of the risk premiums which is caused by the use of historical and projected stock and bond market returns. (TR 2875) In three of his methods, witness D'Ascendis uses historical stock and bond return data. Using historical returns to measure an ex-ante (forward looking) market risk premium is dependent on the time period evaluated, the stock-market index employed, and the measure of central tendency used. (TR 2878) Among the errors are the U.S. stock market survivorship bias wherein historical returns include companies that fail to survive, the use of the arithmetic mean versus the geometric mean (geometric mean produces a lower estimate), the change in risk and required return over time, and the return computation procedure that presumes monthly portfolio rebalancing to avoid losses. (TR 2878) In the other three approaches, witness D'Ascendis based his market-risk premium on his estimate of projected stock-market returns which are totally unrealistic and are based on excessive corporate earnings and economic growth rates. (TR 2875-2876) Witness Woolridge testified, and staff

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agrees, that witness D'Ascendis' estimate of the average expected stock market return of 15.60 percent used to calculate a market risk premium of 11.45 percent is excessive and unrealistic. (TR 2883) The EPS growth rate projection (14.10 percent) used for the S&P 500 and the resulting expected market return (15.60 percent) and market risk premium (11.45 percent) includes unrealistic assumptions regarding future economic and earnings growth and stock returns. (TR 2883) On this point, witness D'Ascendis makes the assumption that the companies in the S&P 500 can grow their earnings, on average, at 14.10 percent annually, which is nearly triple the long-term projected growth rate of the economy as measured by GDP of 4.40 percent. (TR 2801, 2894) Based on his study, witness Woolridge determined that the annual growth in nominal GDP, S&P 500 stock-price appreciation, and S&P 500 EPS and DPS growth since 1960 has been on average 6.60 percent. (TR 2891; EXH 71) In comparison, witness D'Ascendis' average long-term EPS growth rate of 14.10 percent is grossly overstated and has little basis in economic reality. (TR 2900)

FEA witness Walters opined that TECO witness D'Ascendis' average estimates of the equity risk premium under the prospective bond yield and spot yield approaches are the results of individual estimates. (TR 2992) When each equity risk premium result is considered in isolation, it is clear to see that the overwhelming majority of his results are in excess of any reasonable estimate. (TR 2992-2993) For example, if we look at witness D'Ascendis' twelve estimates of the equity risk premium, they would produce a risk premium result in the range of 10.00 percent to 16.02 percent. (TR 2992). Considering the lowest estimate based on his risk premium analysis starts at 10.00 percent is indicative that almost all of his risk premium results are excessive in light of where recent authorized ROEs for electric utilities has been recently. (TR 2992) When individual results are looked at in isolation, it is clear that they produce excessive results that are unreliable. (TR 2992) Five of witness D'Ascendis' RPM results range from 11.69 percent to 16.02 percent. These estimates are so far removed from observable benchmarks such as the allowed ROEs recently awarded to similar utilities, that it is hard to seriously conclude these results are based on reasonable methods of estimation. (TR 2993)

FEA witness Walters' RPM methodology compared the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury Bonds and contemporary Moody's A-rated and Baa-rated utility bond yields. (TR 2967-2968) Overall, witness Walters produced five estimates of the equity risk premium as compared to regulatory commission authorized ROEs for electric utilities on an annual basis for each year since January 1986 until 2023. (TR 2967-2968) The authorized ROEs ranged from 13.93 percent in 1986 to 9.39 percent in 2021, with an average of 10.84 percent. (EXH 100) Witness Walters explained that he selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period, and the market-to-book ratio for the utility industry was consistently above a multiple of 1.0. (TR 2968; EXH 99) Witness Walters asserted that over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value, supported a utility's ability to issue additional common stock without diluting existing shares, and demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders. (TR 2968) To derive his equity risk premium using Treasury Bond yields, witness Walters' quantified the difference between regulatory commission-authorized returns on common equity (10.84 percent) and contemporary U.S. Treasury bonds (5.14 percent). (TR 2967; EXH 100) The difference between the authorized

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return on common equity and the Treasury bond yield is a risk premium of 5.70 percent. ( $10.84\% - 5.14\% = 5.70\%$ ). (TR 3011; EXH 100) Adding the equity risk premium of 5.70 percent to the projected 30-year U.S. Treasury Bond yield of 4.20 percent obtained from Blue Chip Financial Forecasts yields an indicated ROE of 9.90 percent. (TR 3013) Witness Walters also derived equity risk premiums using A-rated and Baa-rated utility bonds as published by Moody's. (TR 3011) For his estimate of the bond yields, witness Walters used the 13-week average from February 16, 2024 through May 10, 2024, and the 26-week average from November 17, 2023, through May 10, 2024, for both the A-rated and Baa-rated utility bond yields. (EXH 103) To derive his equity risk premium over utility bonds, he subtracted the average A-rated utility bond yield of 6.50 percent from the authorized ROEs of 10.84 percent which resulted in an estimated equity risk premium of 4.34 percent. (TR 3013-3014; EXH 101) Adding the 4.34 percent equity risk premium to the 13-week average A-rated utility bond yield of 5.66 percent resulted in an indicated ROE of 10 percent. The 13-week average of the Baa-rated utility bond yield was 5.89 percent and resulted in an indicated ROE of 10.23 percent ( $4.34\% + 5.89\%$ ). (TR 3013-3014) Over the 26-week period, the A-rated utility bond yield averaged 5.60 percent while the Baa-rated utility bond yield averaged 5.84 percent. (TR 3014) Adding the equity risk premium of 4.34 percent to the 26-week average A-rated utility bond yield of 5.60 percent and the Baa-rated utility bond yield of 5.84 percent, produced indicated ROEs of 9.94 percent, and 10.18 percent, respectively. (TR 3014) Witness Walters gave primary consideration to his RPM using Treasury Bonds and A-rated utility bonds. (TR 2970) The average of those results was 9.95 percent. (TR 2971) However, staff disagrees with the weight placed on the lower results. By witness Walters's analysis, the average credit rating of the proxy group reflects a Moody's credit rating of Baa2, and therefore, RPM results using the Baa-rated utility bond yields should be given equal weight. The simple average of witness Walters' five RPM results is 10.05 percent. (TR 3014)

TECO witness D'Ascendis had three concerns with FEA witness Walters' risk premium method. First, the use of the 1986-2024 time period based on a market-to-book multiple greater than 1.0. Witness D'Ascendis asserted that the time period from 1986 to 2024 is too short to reflect long-term trends in market data and that market-to-book ratios greater than 1.0 are meaningless because market values can diverge from book values for a myriad of reasons. (TR 2012-2015) Further, witness D'Ascendis contended that while regulation is a substitute for marketplace competition, it can influence, but not directly control market prices, and hence, market-to-book ratios. Also, the rates of return investors expect to achieve, which influence their willingness to pay market prices well in excess of book values have no meaningful direct relationship to rates of earnings on book equity. (TR 2015) Because of this, no valid conclusion of equity risk premiums can be drawn for the 1986-2024 period because of market-to-book ratios in excess of 1.0. (TR 2015) Second, TECO witness D'Ascendis contended that FEA witness Walters' risk premium method and recommendation ignore an important relationship revealed by his own data, i.e., that there is an inverse relationship between equity risk premiums and interest rates (whether measured by U.S. Treasury bonds or public utility bond yields). (TR 2015-2016) However, staff points out that witness D'Ascendis failed to demonstrate how witness Walters' RPM ignored an inverse relationship between ERPs and interest rates. In his rebuttal, witness D'Ascendis made a contrary statement that he reviewed the data and ". . . discovered that the ERP as presented by Mr. Walters tends to move inversely with changes in interest rates." (TR 2015) Third, witness D'Ascendis asserted witness Walters' used a mismatched application of

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projected Treasury bond yields and current utility bond yields. (TR 2012) Witness D'Ascendis contended witness Walters' use of historical A-rated utility bonds compared to current bond yields does not reflect the prospective nature of ratemaking and cost of capital. (TR 2017) Further, witness D'Ascendis claims that Mr. Walters' use of a Baa-rated public utility bond yield is incorrect for two reasons. First, Mr. Walters applied a Baa-rated public utility bond yield to an ERP derived from A-rated public utility bonds, improperly matching the ERP measured relative to A-rated public utility bond yields with a Baa rated public utility bond yield. (TR 2016) Second, Mr. Walters' use of current A- and Baa-rated public utility bond yield is inconsistent with his entire return on common equity analysis because he failed to use projected or expected rates as he had in his CAPM analysis. (TR 2016-2017)

### **Flotation Costs**

TECO witness D'Ascendis made an upward adjustment of 10 basis points to the results of his ROE analyses to reflect the effect of flotation costs. (TR 1812-1813) Witness D'Ascendis testified that all of the cost of equity models assume no transaction costs and those costs are not reflected in the market prices paid for common stocks. (TR 1879) Flotation costs are those costs associated with the sale of new issuances of common stock. (TR 1875) They include the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the company receives less than one full dollar in financing. (TR 1875) To calculate a flotation cost allowance, witness D'Ascendis modified his DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with a method that is supported in academic literature. (TR 1879) The flotation cost adjustment calculated by witness D'Ascendis recognizes the actual costs of issuing equity that were incurred by TECO's parent, Emera, in its equity issuances since its acquisition of TECO based on Emera's actual issuance costs. (TR 1879; EXH 148, MPN D10-714) Staff believes witness D'Ascendis' method to determine the flotation cost is credible and provides competent support for his recommendation to include a flotation cost of 10 basis points. The Commission's leverage formula makes a similar adjustment to the DCF Model and also adds 20 basis points to the CAPM result to recognize flotation costs.<sup>51</sup> TECO argued based on the evidence in the record, the Commission should continue to include flotation costs in the allowed ROE. (TECO BR 47)

OPC witness Woolridge disagreed that a flotation cost adjustment is justified in this case and testified that there is no evidence that TECO has paid flotation costs. (OPC BR 41; TR 2904) Hence, TECO should not receive higher revenues in the form of a higher ROE for flotation costs that the Company did not incur. (OPC BR 41; TR 2904) OPC witness Woolridge asserted that TECO witness D'Ascendis' comparison of flotation costs to the amortization of bond flotation costs is not correct. (TR 2904) Witness Woolridge explained:

If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.5 times actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a

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<sup>51</sup> Order No. PSC-2024-0165-PAA-WS, issued May 22, 2024, in Docket No. 20240006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

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price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment should be downward.

(TR 2905)

OPC witness Woolridge contended that flotation costs consist primarily of the underwriting spread and not out-of-pocket expenses. (TR 2905) The underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the Company and should not be recovered through the regulatory process. (TR 2905) Witness Woolridge asserted that the underwriting spread is known to the investors who are buying the new issue of stock, and thus, the offering price is what is material to the decision to purchase the stock based on the expected return and risk prospects. (TR 2905) Basically, flotation costs, in the form of the underwriting spread are a form of a transaction cost in the market and are reflected in the price of the stock. (TR 2906)

FEA witness Walters' testified that he was unaware of the Commission allowing for the recovery of flotation costs in the allowed ROE. (TR 2989) He also contended that TECO witness D'Ascendis has not shown the flotation costs have been reasonably incurred and allocated to TECO, nor has TECO provided any evidence that flotation costs are part of its cost of service. (TR 2989) Further, witness Walters disagreed with the method by which witness D'Ascendis calculated the flotation cost. He contended that because TECO does not issue its own stock and is a subsidiary of Emera, witness D'Ascendis used Emera's equity issuances to calculate the flotation cost. Therefore, witness D'Ascendis' flotation cost adder is not based on TECO and should be rejected. (TR 2990)

In Order No. PSC-2023-0388-FOF-GU, the Commission found that witness D'Ascendis method to determine the flotation cost for Peoples Gas System, Inc., also a subsidiary of Emera, is credible and provided persuasive evidence for his recommendation to include a flotation cost.<sup>52</sup>

The Commission has a long-standing policy to recognize flotation costs in the cost of equity models used to estimate the ROE for utilities. In the Annual Establishment of the ROE for water and wastewater utilities, the Commission recognizes and includes flotation costs for both the DCF Model and the CAPM. The record evidence in this case demonstrates that TECO witness D'Ascendis calculated a reasonable estimate for flotation costs that should be recognized in the estimated cost of equity.

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<sup>52</sup> Order No. PSC-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System, Inc.*, p. 68.

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### **Company Specific Business Risks**

TECO witness D'Ascendis asserted that TECO is subject to certain business risks not applicable to the companies in his proxy group. To reflect TECO's specific business risks, witness D'Ascendis considered TECO's size relative to the utility proxy group, lack of geographic diversification, and higher climate risk relative to the utility proxy group. (TR 1880) Witness D'Ascendis also considered TECO's high customer growth and increased capital expenditures. (TR 1883-1885) Witness D'Ascendis concluded that TECO is similar in size to the utility proxy group companies based on market capitalization and a relative risk adjustment due to size is not necessary in this proceeding. (TR 1883)

### ***Weather and Climate Risk***

Witness D'Ascendis asserted that TECO's lack of geographic diversity increases its relative risk. (TR 1885) Witness D'Ascendis testified that TECO's service area in West Central Florida is extremely compact compared to other Florida investor-owned utilities or the companies in his proxy group. (TR 1885) Witness D'Ascendis explained that in the event of a substantial storm or other catastrophic event, the entire system and customer base of TECO is at risk for damage, outages, and other customer impacts. (TR 1885) This is unlike other utilities in Florida, and more importantly, the proxy group which have more geographically diverse service areas or larger service territories. A larger service territory may only have a portion of a utilities' infrastructure and customers impacted which can help mitigate the impacts and help sustain the utility while repairs are made in the affected areas. (TR 1885) TECO's smaller geographic diversity has also been recognized as key risks in the company's recent S&P and Moody's credit ratings reports. (TR 1885) Witness D'Ascendis testified that Moody's noted that it views the Commission's regulatory treatment of storm costs as credit supportive, it also stated that "Tampa Electric is a relatively small utility with a concentrated service territory along the Gulf Coast of western central Florida, making it vulnerable to storm related event risk." (TR 1890) Witness D'Ascendis also testified that S&P similarly noted that "[Tampa Electric's] service territory is more susceptible to physical risks related to hurricanes," and also finds that "Relative to peers, physical risks associated with coastal storms are evident . . ." (TR 1890)

Further, witness D'Ascendis testified that Hillsborough County, which includes the majority of TECO's customers, is ranked 15th the Federal Emergency Management Agency's National Risk Index. (TR 1886) That ranking measures the potential for negative effects of naturally occurring hazards and is driven by the expected annual loss of value associated with hurricanes of all counties in the U.S. (TR 1887) Witness D'Ascendis asserted that TECO's risk associated with extreme weather events is relatively high as compared to the utility proxy group. (TR 1887) Witness D'Ascendis also testified that TECO's storm reserve doesn't entirely insulate the Company from the risks associated from hurricanes. (TR 1888) Witness D'Ascendis asserted that TECO's ability to recover storm costs by petitioning the Commission outside of a rate case doesn't mitigate the risk of regulatory lag, especially for significant storms with costs over \$100 million. (TR 1888) For example, TECO's storm related costs incurred in September and November 2022 will not be fully recovered until December 2024. (TR 1889) Further, the increased frequency of hurricanes and other large storms will only serve to increase restoration costs and the need to recover those costs. (TR 1889)



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Witness D'Ascendis testified that TECO faces relatively higher risk from extreme weather events as compared to the proxy group. (TR 1891) TECO's customer base is highly concentrated in the city of Tampa and Hillsborough County. Hillsborough County is one of the highest risk counties in the United States as it relates to the potential effect of natural disasters. In addition, the frequency of major storms impacting Florida has increased in recent years. Witness D'Ascendis contended that although TECO has the ability to utilize a storm reserve and petition the Commission to recover additional restoration costs above the reserve level, that regulatory framework does not eliminate the risk faced by the Company. (TR 1891) As such, TECO's relatively higher risk associated with extreme weather is unique to the Company (as compared to the proxy group) and should be considered when determining the appropriate ROE in this proceeding. (TR 1891)

### ***Capital Investment and Customer Growth***

In addition to TECO's flotation costs, relative credit rating, and its smaller relative size, witness D'Ascendis also considered TECO's high customer growth and level of capital expenditures as compared to his proxy group. (TR 1891) Witness D'Ascendis asserted that TECO's strong customer growth over the past five years necessitates increased and accelerated capital investment. (TR 1892) Witness D'Ascendis testified that TECO currently plans to invest over \$6.2 billion of additional capital over the 2024-2027 period, which represents over 68 percent of its 2022 year-end net utility plant. (TR 1892) That amount includes investments required to support growth, and to maintain safe, sufficient, and reliable service in both its transmission and distribution facilities. (TR 1892) As discussed by TECO witness Chronister, the Company will require continued access to the capital markets, at reasonable terms, to finance its capital spending plan. (TR 1892; TR 3343) Witness D'Ascendis testified that credit rating agencies recognize risk associated with increased capital expenditures. (TR 1894) 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 1894)

Witness D'Ascendis also compared TECO's expected capital expenditures to the companies in his proxy group. (TR 1895) Witness D'Ascendis calculated TECO's ratio of expected capital expenditures to net plant and compared that ratio to the ratio for each company in his proxy group. (TR 1896) Witness D'Ascendis determined that TECO had the highest ratio of projected capital expenditures to net plant relative to the proxy group, approximately 26 percent higher than the proxy group median. (TR 1896; EXH 28, MPN C13-1329) Witness D'Ascendis did not make a quantitative adjustment to the results of his cost of equity models to reflect TECO's company specific business risks. He simply "considered" TECO's relatively small service area, weather risk, high customer growth, and the Company's capital expenditure program in his determination of the appropriate ROE within the range of the results of his cost of equity models. (TR 1897) The range of witness D'Ascendis' updated cost of equity models is 10.29 percent for the DCF model to 11.91 percent for the CAPM. (TR 1909; EXH 148, MPN D10-669) His recommend ROE of 11.50 percent is above the median of 11.10 percent for his range of results to reflect the company specific risks – a difference of 40 basis points. (TR 1909)

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## Financial Risk

Financial risk is created by the introduction of debt into the capital structure. (TR 1822) The higher proportion of debt in the capital structure the greater the financial risk. Consistent with the basic principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk. There is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. (TR 2825) On cross-examination TECO witness D'Ascendis agreed that a relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. (TR 2046) OPC witness Woolridge asserted, and staff agrees, that the fundamental relationship between lower risk and the appropriate authorized return should not be ignored. (TR 2825)

TECO requested an equity ratio of 54.00 percent which is higher than the average equity ratio witness D'Ascendis' proxy group and witness Woolridge's proxy group. The mean average five-year common equity ratios for the proxy companies and their operating subsidiaries are 43.25 percent and 49.05 percent, respectively. (TR 2825) In addition, the average common equity ratios for the parent holding companies in the two proxy groups as of December 31, 2023, were 40.90 percent for witness Woolridge's proxy group and 40.10 percent for witness D'Ascendis' proxy group. (TR 2825; EXH 65) These averages clearly are materially lower than TECO's proposed common equity ratio of 54.00 percent, which demonstrate that TECO has less financial risk than the proxy groups used by the witnesses to estimate the ROE for TECO.

Witness D'Ascendis asserted that the Company's equity ratio of 54.00 percent is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained, and expected to be maintained, by the companies in his proxy group (28.90 percent to 56.13 percent) and their utility operating subsidiaries (38.14 percent to 55.90 percent). (TR 1830-1831) OPC witness Woolridge testified, and staff agrees, that TECO witness D'Ascendis' financial risk position is in error because he reports the range of equity ratios of the proxy companies and not the average. (TR 2825) In addition, witness D'Ascendis testified that "Credit ratings is a common measurement of both business and financial risk. So any type of lower financial risk that the company has, like a higher equity ratio, would be subsumed in that adjustment." (TR 2048) TECO's long-term issuer ratings are A3 and BBB+ from Moody's Investors Services and S&P, respectively, which are slightly less risky than the average long-term issuer ratings for witness D'Ascendis' proxy group of Baal and BBB+, respectively. (TR 1879) Witness D'Ascendis included a downward credit risk adjustment of 8 basis points (0.08 percent) to recognize TECO's higher long-term debt rating as compared to the average bond ratings of his proxy group. (TR 1879)

Witness D'Ascendis' credit risk adjustment is based on debt/credit ratings and did not recognize the actual difference in the amount of debt included in the regulatory capital structure of TECO which the record demonstrates is considerably less than the average of the proxy groups. This financial risk must be recognized when setting the ROE for ratemaking purposes. Witness D'Ascendis agreed that the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks. (TR 1818) Therefore, the record evidence supports the fact that TECO's lower financial risk (higher equity ratio) as

compared to the proxy group should be reflected in the overall results of the witnesses cost of equity models, and ultimately, the awarded ROE.

### **Summation**

On cross examination, TECO witness D'Ascendis testified that the Commission should continue its precedent when setting the ROE and follow the models, because the models are what represents the market. (TR 2081) Witness D'Ascendis explained, "The outcomes of rate cases are results of things like this [cost of equity models], where I am putting the -- I have my number, Dr. Woolridge has his number, Mr. Walters has his number, and it's up for the Commission and the Commission staff to kind of balance those interests." (OPC BR 37; TR 2081) The collective range of the witnesses' cost of equity model results is 8.85 percent to 11.91 percent. Within that range, the record supports an adjusted overall average of the witnesses' cost of equity model results of 10.27 percent. The average of the DCF model results, CAPM results, and RPM results for TECO's, OPC's, and FEA's witnesses are 9.98, 10.26, and 10.56 percent, respectively. The average of the results of the three cost of equity model results is 10.27 percent.

Record evidence supports the risk-return concept that utilities with lower financial risk should be awarded lower returns. The record evidence demonstrates TECO has a higher equity ratio than the average of the electric utility company proxy group, and as such, it has less financial risk. Therefore, a downward adjustment to TECO's ROE should be recognized to reflect TECO's lower financial risk as compared to the electric company proxy group. The record evidence also supports an upward adjustment for TECO's perceived higher business risk and flotation costs. Staff believes TECO's lower financial risk offsets TECO's higher business and weather risk and no additional adjustment to the average results of the models is appropriate. In addition, the record evidence is clear that interest rates have increased since TECO's last rate case in 2021 in which the Commission authorized an ROE of 9.95 percent, later adjusted to 10.20 percent. Therefore, on balance, staff believes the record evidence supports an ROE of 10.30 percent for TECO, which is above the recent national average of awarded ROEs of 9.78 percent, and would enable TECO 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.

On cross examination, TECO witnesses D'Ascendis admitted that from for the first six months of 2022, TECO operated at an allowed ROE of 9.95 percent, and since July 1, 2022, has operated with an allowed ROE of 10.20 percent. (TR 2090-2091) Witness D'Ascendis stated that he was not aware of any evidence that TECO has been unable to obtain the needed capital to provide service since January 2022 with an ROE of 10.20 percent. (TR 2091) In addition, TECO witness Collins testified that TECO has been able to provide safe and reliable service and make all necessary investments and recover all necessary expenses to do so for the past three years, continuing through 2024, with an authorized ROE that started at 9.95 percent in January 2022 and then increased to the current 10.20 percent level later in 2022. (FRF BR 10; TR 393-395) Accordingly, staff recommends an authorized ROE of 10.30 percent, with a range of 9.30 percent to 11.30 percent, should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year

### **CONCLUSION**

An authorized ROE of 10.30 percent, with a range of 9.30 percent to 11.30 percent, should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year.

**Issue 40:** What capital structure and weighted average cost of capital should be approved for use in establishing TECO’s revenue requirement for the 2025 projected test year?

**Recommendation:** A capital structure consisting of 54.00 percent common equity, 41.60 percent long-term debt, and 4.40 percent short-term debt as a percentage of investor sources should be approved for the 13-month average test year ending December 31, 2025. A weighted average cost of capital of 6.81 percent should be approved for establishing TECO’s projected test year revenue requirement and setting rates in this proceeding. (Ferrer)

**Position of the Parties:**

**TECO:** The Commission should approve the Jurisdictional Capital Structure totaling \$9.791 billion and a WACC of 7.37 percent as shown on MFR Schedule D-1a.

**OPC:** The Commission should approve the weighted average cost of capital and capital structure shown in the testimony of OPC’s experts.

**FL RISING/**

**LULAC:** The Commission should approve a 50-50 equity-to-debt ratio. The weighted average cost of capital should be adjusted to account for downward rate base adjustments and the adjusted equity-to-debt ratio.

**FIPUG:** Adopt the position of OPC

**FEA:** The capital structure and weighted average cost of capital that should be approved is demonstrated in the chart below:

Class of Capital	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
Long Term Debt	\$3,706,462	37.83%	4.53%	1.71%
Short Term Debt	376,625	3.84%	3.90%	0.15%
Customer Deposits	99,195	1.01%	2.41%	0.02%
Preferred Stock	-	0.00%	-	0.00%
Common Equity	4,423,344	45.15%	9.60%	4.33%
Deferred Income Taxes	980,855	10.01%	-	0.00%
Tax Credits - Zero Cost	-	0.00%	-	0.00%
Tax Credits - Weighted Cos	211,669	2.16%	7.14%	0.15%
	<u>\$9,798,150</u>	<u>100.00%</u>		<u>6.36%</u>

**SIERRA**

**CLUB:** Sierra Club adopts OPC’s position on this issue.

**FRF:** The most appropriate capital structure is that used by Dr. Randall Woolridge in developing his rate of return recommendations, as set forth in Table 1 of his direct testimony. The most appropriate overall weighted average cost of capital is 6.38 percent.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

The capital structure and weighted average cost of capital (WACC) is a fall-out issue that incorporates the amounts and cost rates of the capital sources into a final WACC, also referred to as the overall rate of return. OPC argued TECO's proposed capital structure and WACC should be adjusted to reflect an ROE of 9.50 percent and include zero cost deferred tax credits. (OPC BR 42; EXH 155, MPN E1308) FEA argued TECO's capital structure and WACC should be adjusted to reflect an equity ratio of 52.00 percent and an ROE of 9.60 percent. (FEA BR 23) The cost rates and amounts of the capital components are recommended in Issues 33 through 39. In MFR Schedule D-1a, page 4 of 22, TECO presented its requested projected test year capital structure based on a 13-month average as of December 31, 2025, consisting of common equity in the amount of \$4,620,873,000 (54.0 percent), long-term debt in the amount of \$3,557,446,000 (41.6 percent) and short-term debt in the amount of \$378,853,000 (4.4 percent) as a percentage of investor-supplied capital. (TECO BR 49; EXH 6, MPN J378) TECO revised the total amount to \$9,791 billion, to reflect the adjustments to rate base as described in TECO's letter dated August 22, 2024. (TECO BR 49; EXH 835) This adjustment did not materially change the Company's requested WACC. (TECO BR 49) The initial capital structure submitted by TECO is summarized in Table 40-1.

**Table 40-1**  
**TECO Recommended Weighted Average Cost of Capital (000s)**

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$4,620,873	46.89%	11.50%	5.39%
Long-Term Debt	\$3,557,446	36.09%	4.53%	1.63%
Short-Term Debt	\$378,853	3.84%	3.90%	0.15%
Customer Deposits	\$99,787	1.01%	2.41%	0.02%
ADITs	\$986,702	10.01%	0.00%	0.00%
Investment Tax Credits	\$212,932	2.16%	8.26%	0.18%
<b>Total</b>	<b>\$9,856,592</b>	<b>100.00%</b>		<b>7.37%</b>

Source: (EXH 6, MPN J378)

In its Brief, OPC referred to the testimony of its witnesses for its recommended capital structure and WACC. (OPC BR 42) OPC witness Woolridge recommended an overall fair rate of return of 7.19 percent which was based on investor sources. (TR 2798; EXH 63) OPC witness Kollen presented OPC’s revised capital structure in his work papers. (EXH 155, MPN E1308) OPC did not propose any specific adjustments to TECOs equity ratio or other capital ratios. OPC recommended including \$33.571 million of zero-cost investment tax credits, as discussed in Issue 34, which reduced the cost-based investment tax credits from \$211.669 million to \$178.098 million. Based on OPC’s ROE recommendation of 9.50 percent, and adjustment to the income tax credits, witness Kollen calculated a WACC of 6.38 percent for TECO. (EXH 155, MPN E1308) OPC’s recommended capital structure and WACC is summarized in Table 40-2.

**Table 40-2**  
**OPC’s Recommended Weighted Average Cost of Capital (000s)**

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$4,593,473	54.00%	9.50%	5.13%
Long-Term Debt	\$3,536,333	41.57%	4.53%	1.88%
Short-Term Debt	\$376,625	4.43%	3.90%	0.17%
Customer Deposits	\$99,195	1.01%	2.41%	0.02%
ADITS	\$178,098	10.01%	0.00%	0.00%
ADITS Zero-Cost	\$33,571	0.34%	0.00%	0.00%
Investment Tax Credits	\$178,098	1.82%	7.18%	0.13%
<b>Total</b>	<b>\$9,798,150</b>	<b>100.00%</b>		<b>6.38%</b>

Source: (EXH 155, MPN E1308)

FEA argued that this Commission should carefully assess the reasonableness of cost of service in this proceeding including an appropriate overall rate of return necessitated by a reasonably cost effective balanced ratemaking capital structure, and a return on equity that represents fair compensation but also maintains competitive, just and reasonable rates. (FEA BR 23)

FEA witness Walters recommended adjustments to the capital structure and the overall WACC. Witness Walters recommended the Commission set TECO’s equity ratio at 52.00 percent with a ROE of 9.60 percent. (TR 2952) FEA adjusted the ratios of common equity and long-term debt to reflect its recommended equity ratio and ROE. After FEA’s reconciliation adjustment, FEA’s recommended WACC is 6.36 percent. (FEA BR 23) FEA’s proposed capital structure and WACC is summarized in Table 40-3. (FEA BR 23; TR 2952)

**Table 40-3**  
**FEA Recommended Weighted Average Cost of Capital (000s)**

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$4,423,344	45.15%	9.60%	4.33%
Long-Term Debt	\$3,706,462	37.83%	4.53%	1.71%
Short-Term Debt	\$367,625	3.84%	3.90%	0.15%
Customer Deposits	\$99,195	1.01%	2.41%	0.02%
ADITs	\$980,855	10.01%	0.00%	0.00%
Investment Tax Credits	\$211,669	2.16%	7.14%	0.15%
<b>Total</b>	<b>\$9,798,150</b>	<b>100.00%</b>		<b>6.36%</b>

Source: (FEA BR 23)

Based on staff's recommendations in Issues 33 through 39, staff recommends a capital structure consisting of an equity ratio of 54.00 percent based on investor sources as summarized in Table 40-4.

**Table 40-4**  
**Staff Recommended Weighted Average Cost of Capital (000s)**

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$4,553,645	46.89%	10.30%	4.83%
Long-Term Debt	\$3,505,671	36.10%	4.53%	1.64%
Short-Term Debt	\$373,359	3.84%	3.90%	0.15%
Customer Deposits	\$98,335	1.01%	2.41%	0.02%
ADITs	\$972,094	10.01%	0.00%	0.00%
Investment Tax Credits	\$208,205	2.14%	7.90%	0.17%
<b>Total</b>	<b>\$9,711,310</b>	<b>100.00%</b>		<b>6.81%</b>

Source: (Staff Analysis)

## CONCLUSION

A capital structure consisting of 54.00 percent common equity, 41.60 percent long-term debt, and 4.40 percent short-term debt as a percentage of investor sources should be approved for the 13-month average test year ending December 31, 2025. A weighted average cost of capital of 6.81 percent should be approved for establishing TECO's projected test year revenue requirement and setting rates in this proceeding.



### **2025 NET OPERATING INCOME**

**Issue 41:** Has TECO correctly calculated the revenues at current rates for the 2025 projected test year?

**Recommendation:** If staff's recommended adjustments to TECO's 2025 energy and demand forecasts in Issue 2 are approved, TECO's estimated revenues at current rates should be increased by \$11.985 million, resulting in total revenues of \$1.492 billion, to reflect such adjustments. If the Commission approves OPC's proposed adjustment to TECO's 2025 energy and demand forecasts in Issue 2, TECO's estimated revenues at current rates should be increased by \$12.260 million, resulting in total revenues of \$1.493 billion. If the Commission approves TECO's customer, energy sales, and demand forecasts as-filed, then TECO's projected revenues at current rates is \$1.481 billion, and no adjustment is necessary. (Kunkler)

#### **Position of the Parties:**

**TECO:** Yes. Test year revenues at current rates is \$1.481 billion, which was determined by applying the company's current tariff rates to the electricity sales reflected in its Customer, Demand, and Energy forecasts by customer rate classes in Issue 2.

**OPC:** No. Tampa Electric's energy sales forecast should be rejected as inconsistent with historic trends and is biased due to subjective out-of-model adjustments. A conservative, modified version of Tampa Electric's forecast that removes subjective out-of-model adjustments should be approved. Removal of out-of-model adjustments will increase Tampa Electric's test year sales forecast, resulting in a 2025 sales projection of 20,635,457 MW-hours, and a \$12.3 million increase in test year projected retail revenues.

#### **FL RISING/**

**LULAC:** No. TECO continues to under forecast revenues based on its summer sales projections that fail to account for climate change.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

#### **SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. TECO's sales forecast is significantly understated. The Commission should increase 2025 test year retail revenues by at least \$12.3 million.

#### **FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue addresses the level of TECO's revenues from the sale of electricity for the 2025 test year. As explained in Issue 2, TECO provided forecast models which detail the Company's forecasted customer counts, energy sales, and demand across the Company's rate classes for the 2025 test year. Once the forecasted customer counts, energy sales, and demand forecasts are established, they are then multiplied by TECO's current rates for each customer class and summed to yield total revenues.

According to TECO, its estimated revenue at current rates, approximately \$1.481 billion, is supported by the Company's MFRs and the direct testimony of TECO witnesses Cifuentes and Chronister (EXH 5, MPN J222; TR 1491-1505; TR 3373-3374) TECO argued the resulting test year revenues at current rates of \$1.481 billion is reasonable and should be approved by the Commission. (TECO BR 50)

OPC witness Dismukes argued that TECO's test year revenues at current rates are understated and should be increased by \$12.260 million to account for OPC's proposed increase to TECO's energy sales projection in Issue 2. (TR 2181; OPC BR 43) FL Rising/LULAC, FIPUG, FRF, and Walmart agree with OPC while FEA, Sierra Club, and Fuel Retailers take no position on the issue. If the Commission approves OPC's proposed adjustment to TECO's 2025 energy and demand forecasts in Issue 2, TECO's estimated revenues at current rates should be increased by \$12.260 million, resulting in projected revenues at current rates of \$1,492,987,000. (EXH 35, MPN C20-1977)

TECO contends that OPC's proposed adjustments to test year revenues at current rates are unreasonable and erroneously suggest that the base revenues are understated for reasons discussed in Issue 2. (TR 1511; TECO BR 50)

As discussed in Issue 2, staff does not agree with OPC's suggested removal of TECO's out-of-model adjustments based on alleged lack of supporting evidence and documentation. Thus, staff does not agree with OPC's proposed increase of \$12.3 million increase to TECO's test year revenues related to the related sales adjustment proposed by OPC witness Dismukes.

Staff confirmed that TECO used the correct current rates for all customer classes in its calculations of test year revenue. (EXH 7, MPN 455-472) However, as also discussed in Issue 2, staff believes TECO's energy sales and demand forecasts do not adequately reflect recent weather trends and are understated, resulting in understated test year revenues at current rates. TECO provided the projected revenue impact, using current rates, of basing its sales and demand forecasts on a 10-year weather normal assumption in place of its proposed assumption of 20-year weather normals. The resulting test year revenue impact is \$11.985 million. (EXH 216, MPN E8272)

## **CONCLUSION**

If staff's recommended adjustments to TECO's 2025 energy and demand forecasts in Issue 2 are approved, TECO's estimated revenues at current rates should be increased by \$11.985 million, resulting in total revenues of \$1.492 billion, to reflect such adjustments. If the Commission approves OPC's proposed adjustment to TECO's 2025 energy and demand forecasts in Issue 2, TECO's estimated revenues at current rates should be increased by \$12.260 million, resulting in total revenues of \$1.493 billion. If the Commission approves TECO's customer, energy sales, and demand forecasts as-filed, then TECO's projected revenues at current rates is \$1.481 billion, and no adjustment is necessary.

Date: November 22, 2024

**Issue 42:** What amount of Total Operating Revenues should be approved for the 2025 projected test year?

**Recommendation:** If staff's recommended adjustments to TECO's test year energy sales/demand and revenue forecasts in Issue 2 and 41 are approved, the appropriate amount of Total Operating Revenues is \$1.530 billion. If the Commission approves OPC's recommended adjustments in Issues 2 and 41, the appropriate amount of Total Operating Revenues is \$1.531 billion. If the Commission approves TECO's customer, energy sales, demand, and revenue forecasts as-filed, the appropriate amount of Total Operating Revenues is \$1.518 billion. (Kunkler)

**Position of the Parties:**

**TECO:** The correct amount of total operating revenues for the 2025 projected test year is \$1.518 billion, which reflects the amount of revenue from sales in Issue 41 plus a reasonable estimate of Other Operating Revenues for the 2025 test year.

**OPC:** This is a largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness of its forecast of test year revenues. The Total Operating Revenues for the 2025 projected test year should reflect all of OPC's recommended adjustments, the adjustments for Issue 7 and should be no more than \$43.8 million.

**FL RISING/**

**LULAC:** This is largely a fallout issue from other issues. Total operating revenues to be approved should be adjusted to reflect the disallowance of TECO's proposed projects as specified in other issues and should also be adjusted to reflect a more accurate projection of kWh sales.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** This is also a fallout issue. The amount of Total Operating Revenues that is ultimately approved should be adjusted in accordance with the substantive recommendations outlined in this brief and issues statement, including the removal of O&M expenses associated with burning coal at Polk 1 and Big Bend 4.

**FRF:** This should be a fall-out calculation based on TECO's proposed 2025 revenues less the OPC's sales forecast adjustments and less the ROE, depreciation expense, other expense, and rate base-related revenue reductions recommended by the FRF and OPC.

**FUEL**

**RETAILERS:** No Position.

Date: November 22, 2024

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO stated that its projected Total Operating Revenues totaling \$1.518 billion are supported by the Company's MFRs and witness Chronister's testimony. (EXH 5, MPN J222; TR 3374) TECO argued this amount is reasonable, not challenged by the intervenors, and should be approved by the Commission. (TECO BR 50)

OPC did not provide a specific amount of what TECO's Total Operating Revenue projection for the 2025 test year should be, stating this is largely a fall-out issue. OPC proposed an increase to TECO test year revenue of \$12.3 million, indicated in its positions on Issue 2 and 41, but did not specifically mention that adjustment its position on this Issue. OPC further contended that TECO has the burden of proof to demonstrate the reasonableness of its revenues for the 2025 test year. (OPC BR 43) The other intervenors either adopted the position of OPC, stated it was a fall-out issue, or took no position on the issue.

Considering no intervenors challenged TECO's calculation of "other operating" revenue, if the Commission approves OPC's recommended adjustments in Issue 2 and 41, the appropriate amount of Total Operating Revenues for the 2025 test year is \$1.531 billion.

If staff's recommendations on Issues 2 and 41 are approved, TECO's base revenues at current rates should be increased by \$11.985 million resulting in test year revenue from energy sales of \$1.492 billion. (EXH 216, MPN E8272) Staff agrees with TECO that the appropriate amount of "other operating" revenues, which include miscellaneous service charges, rent from electric property, and other electric revenue at current rates for the projected test year is \$37.746 million. (EXH 5, MPN J222; EXH 7, MPN J409) The combination of staff's recommended test year revenue from energy sales (\$1.492 billion) and all other test year revenue (\$37.746 million) yields projected total operating revenues in the amount of \$1.530 billion for the 2025 test year.

If the Commission approves TECO's energy sales and base revenue at current rates forecasts as filed in Issues 2 and 41, TECO's base revenues would remain unchanged. When combined with TECO's projected other revenues for the test year of \$37.746 million, this would result in projected total operating revenues of \$1.518 billion for the 2025 test year.

Table 42-1 provides a breakdown of TECO's 2025 total operating revenue based on the Commission's decision on Issues 2 and 41.

**Table 42-1**  
**Calculation of TECO’s Total Operating Revenue for the 2025 Projected Test Year**  
**(Dollars in 000’s)**

	<b>Total Base Revenues (A)</b>	<b>Other Operating Revenues (B)</b>	<b>Total Operating Revenues (A+B)</b>
TECO’s proposal on Issues 2 and 41 approved	\$1,480,725	\$37,746	\$1,518,471
OPC’s proposal on Issues 2 and 41 approved	\$1,492,987	\$37,746	\$1,530,771
Staff’s recommendation on Issues 2 and 41 approved	\$1,492,710	\$37,746	\$1,530,456

Source: EXH 7, MPN J409; EXH 216, MPN E8272; EXH 35, MPN C20-1977

### CONCLUSION

If staff’s recommended adjustments to TECO’s test year energy sales/demand and revenue forecasts in Issue 2 and 41 are approved, the appropriate amount of Total Operating Revenues is \$1.530 billion. If the Commission approves OPC’s recommended adjustments in Issues 2 and 41, the appropriate amount of Total Operating Revenues is \$1.531 billion. If the Commission approves TECO’s customer, energy sales, demand, and revenue forecasts as-filed, the appropriate amount of Total Operating Revenues is \$1.518 billion. (Kunkler)

Date: November 22, 2024

**Issue 43:** What amount of O&M expense associated with Polk Unit 1 has TECO included in the 2025 projected test year? Should this amount be approved and what, if any, adjustments should be made?

**Recommendation:** TECO included \$9,685,047 of non-fuel O&M expense for Polk Unit 1. Consistent with Issue 24, staff recommends adjustments to reflect the retirement of the non-simple cycle components of Polk Unit 1, which reduce O&M expense by \$1,500,332, for a resulting non-fuel O&M expense of \$8,184,715. (G. Davis, Vogel)

**Position of the Parties:**

**TECO:** The company included \$9,685,047 of Polk Unit 1 non-fuel O&M costs in the 2025 projected test year. These costs are justified in light of the significant fuel diversity, reliability, and flexibility benefits that Polk Unit 1 provides to customers. Sierra Club's recommendations to disallow the O&M expenses associated with wastewater injection and the IGCC components at Polk Unit 1 should be rejected and the company's forecasted amount should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** Adopt Sierra Club position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club opposes the inclusion of any O&M expenses at Polk Unit 1 that cover the procurement or combustion of coal or petcoke. This includes O&M expenses of keeping Polk Unit 1's IGCC equipment in service. TECO should not be permitted to recover O&M expenses at Polk Unit 1 unless it conducts an updated retirement study that demonstrates that continuing to operate this unit is needed for reliability and more cost-effective than immediate retirement.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 24, Polk Unit 1 is a 220 MW IGCC plant that entered service in 1996. (EXH 117, MPN C32-3445-C32-3446) TECO intends to convert the unit to a simple cycle combustion turbine as part of the Polk Flexibility project and retain the remaining IGCC components, including the gasifier, heat recovery steam generator, and steam turbine. (TR 652-653) In discovery, TECO estimated the non-fuel O&M for Polk Unit 1 to be \$9,685,047 in the 2025 projected test year. (EXH 114) This is inclusive of expenses needed to maintain the gasifier in long-term reserve status.

Sierra Club witness Glick argued that TECO should not be allowed to operate Polk Unit 1 on coal and not recover O&M costs associated with the unit without an analysis showing it is more economic than alternative generation. (TR 2507; BR 48) He asserted that Polk Unit 1 after the Flexibility Project will be only marginally cost-effective. (TR 2528) He further argued that TECO should instead retire Polk Unit 1 as soon as possible. (TR 2533) Staff notes that no other intervenor filed testimony on this Issue; and, in their briefs, OPC, FIPUG, FEA, FRF, Fuel Retailers, and Walmart have taken no position on this Issue. FL Rising adopted Sierra Club's position. TECO witness Aponte rebutted witness Glick's arguments, asserting that TECO has demonstrated the Polk Flexibility project is cost-effective. (TR 1011-1013) As discussed in Issue 24, staff recommends that the Polk Flexibility Project is cost-effective but that the gasifier, HRSG, and ST components of Polk Unit 1 should be retired. Therefore, staff recommends that O&M expenses associated with these components be removed, which are estimated at \$1,500,332. (EXH, MPN E6133) The resulting non-fuel O&M for Polk Unit is therefore \$8,184,715 (\$9,685,047 - \$1,500,332)

**CONCLUSION**

TECO included \$9,685,047 of non-fuel O&M expense for Polk Unit 1. Consistent with Issue 24, staff recommends adjustments to reflect the retirement of the non-simple cycle components of Polk Unit 1, which reduce O&M expense by \$1,500,332, for a resulting non-fuel O&M expense of \$8,184,715.



**Issue 44:** What amount of O&M expense associated with Big Bend Unit 4 has TECO included in the 2025 projected test year? Should this amount be approved and what, if any, adjustments should be made?

**Recommendation:** TECO included \$12,472,909 of non-fuel O&M expense for Big Bend 4. This amount should be approved with no adjustments. (G. Davis, Vogel)

**Position of the Parties:**

**TECO:** The company included \$12,472,909 in Big Bend Unit 4 non-fuel O&M costs in the 2025 projected test year. These costs are justified in light of the significant fuel diversity, reliability, and flexibility benefits that Big Bend Unit 4 provides to customers. Sierra Club's recommendations to disallow the O&M expenses associated with coal combustion operation of the unit should be rejected and the company's forecasted amount should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** Adopt Sierra Club position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club urges the Commission to reject inclusion of O&M expenses associated with coal combustion at Big Bend 4 for 2025, including fuel costs, maintenance costs, operating costs, and environmental compliance costs. TECO should not be permitted to recover O&M expenses at Big Bend 4 unless TECO conducts an updated retirement study that demonstrates that continuing to operate this unit is needed for reliability and more cost-effective than retiring it immediately.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

Big Bend Unit 4 (BB4) is a 437 MW (summer) steam turbine that entered service in 1985. (EXH 117, MPN C32-3445-C32-3446) It is a dual-fuel unit and capable of burning coal or natural gas to produce power. TECO witness Aldazabal testified that during the test year, BB4 is scheduled for one-month outage for replacement or improvements to several systems. (TR 641-642) In discovery, TECO estimated the non-fuel O&M for BB4 to be \$12,472,909 in the 2025 projected test year. (EXH 114, MPN C32-3207)

Sierra Club witness Glick argued that TECO should not be allowed to operate on coal and not recover O&M costs associated with the unit without an analysis showing it is more economic than alternative generation. (TR 2507) Witness Glick asserted that TECO engages in coal-firing at BB4 in an uneconomic fashion to maintain the equipment. (TR 2535) The witness also asserted that BB4 has been uneconomic to operate in three of the last 5 years prior to 2024. (TR 2536-2537) They also argued that BB4 will be uneconomic to operate in 9 of the next 10 years, starting in 2024, based on its low-capacity factor and comparably high variable O&M costs when operating with coal. (TR 2539) Sierra Club reiterated this argument in its brief. (BR 30; BR 39)

In cross examination, TECO witness Collins disagreed that power plants are necessarily more expensive as they become older, arguing that while Big Bend 4 is the oldest unit in TECO's fleet, reliability is a function of investment to maintain operability. (TR 361-363) Witness Collins noted that as BB4 is the least efficient units in TECO's generating fleet, and therefore last units to be dispatched, the Company has attempted to reduce overall expense. (TR 364-365) In TECO witness Aldazabal's rebuttal, he argued that Sierra Club witness Glick did not perform a proper economic analysis and compared long-term capital investments with single year operating values which resulted in inaccurate conclusions. (TR 701) In his rebuttal and cross examination, witness Aldazabal stated that TECO will dispatch the unit based on economic dispatch notwithstanding operational or other regulatory requirements. (TR 702, TR 760) Witness Aldazabal further testified that BB4's dual fuel capability allows TECO to reduce its natural gas requirements and continue to serve in the event of supply shortages or reduce overall prices in the event of price shocks. (TR 706) He identified BB4 as the only dual fuel unit capable of switching quickly and for an extended period of time. (TR 706) No intervenor, other than Sierra Club, filed testimony on this Issue. In their briefs, OPC, FIPUG, FEA, FRF, Fuel Retailers and Walmart have taken no position. FL Rising/LULAC adopted Sierra Club's position. Staff agrees that BB4 appears to be operated based on economic dispatch and that the fuel switching capability of BB4 is beneficial to ratepayers by allowing long-term access to fuel in the event of a supply disruption. Therefore, staff does not recommend any adjustments to the non-fuel O&M expense.

**CONCLUSION**

TECO included \$12,472,909 of non-fuel O&M expense for Big Bend 4. This amount should be approved with no adjustments.

Date: November 22, 2024

**Issue 45:** What amount of generation O&M expense should be approved for the 2025 projected test year?

**Recommendation:** Consistent with Issues 22, 24, and 43, generation O&M expense should be reduced to reflect the denial of the South Tampa Resilience project and retirement of some of the Polk Unit 1 generating assets. In addition, staff recommends amortizing the atypical expenses in 2025 over a three-year period, for a total reduction of \$8,286,667 million. Therefore, generation O&M should be \$113,813,950 for the 2025 projected test year. (G. Davis, O. Wooten, Vogel)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Production (generation) O&M Expense for the 2025 test year of \$125.0 million, less \$285,000 per the company's July and August Filings, for a total of \$124.7 million. OPC's proposed adjustment to test year generation O&M expense should be rejected. If the Commission adjusts planned outage expenses for the test year, it should allow the company to defer costs above the annual amount allowed for recovery in future years.

**OPC:** The Commission should only include in the test year a "normalized" level of major maintenance expense. Tampa Electric's filing overstated the level of regular recurring major maintenance expense in the test year. The level of O&M should be reduced by \$12.4 million for purposes of setting rates that are fair, just, reasonable, and affordable.

**FL RISING/**

**LULAC:** The generation O&M expense for the 2025 test year should be normalized by averaging the actual expense incurred from 2019 through 2023 and the budget and forecast expenses for 2024 and 2025. This results in a \$12.392 million reduction in 2025 planned generation maintenance expense. The generation O&M expense should also be reduced by about \$2.6 million to account for the removal of the following projects from rate base: South Tampa Resilience; Polk 1 Flexibility.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Generation O&M expenses approved for Polk Unit 1 and Big Bend Unit 4 should be modified to reflect no coal or petcoke-related costs. More generally, generation O&M expenses should not be recoverable unless TECO conducts updated retirement studies for Polk Unit 1 and Big Bend 4, as outlined in Sections III.C and III.D above, that demonstrate that continuing to operate the units is needed for reliability purposes and more cost-effective than retiring them as soon as possible.

Date: November 22, 2024

**FRF:** The Commission should set rates based on normalizing TECO's planned generation maintenance expense in the 2025 test year and reduce TECO's 2025 revenue requirement by \$12.430 million.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO argued that the Commission should approve Jurisdictional Adjusted Production (generation) O&M Expense for the 2025 test year of \$125.0 million, less \$285,000 per the Company's July and August Filings, for a total of \$124.7 million. (EXH 117) TECO witness Aldazabal testified that O&M expenses are incurred during planned outages, which are typically staggered on a four-to-five year interval for major units. (TR 648-649) Witness Aldazabal stated that \$14.5 million of the projected 2025 test year generation O&M is associated with three outages at Bayside Unit 1, Big Bend Unit 4, and Polk Unit 2. (TR 649) Bayside Unit 1 requires a 70-day major outage to replace steam turbine rotors and other steam components. He asserted this outage is necessary, as the total run hours of the steam turbine has exceeded 380,000 hours, beyond the original equipment manufacturer's (OEM) recommended 250,000 hours. (TR 640-641) This translates into 14.8 operating-years, or approximately 21.2 calendar years at a 70 percent capacity factor, past the recommended replacement period. The Bayside Unit 1 outage contributes a projected \$6 million in O&M expense. (TR 650) Polk Unit 2 requires a 70-day major outage for steam turbine and generator inspections, pressure seal and rotor blade replacements, and other activities. He asserted this outage is necessary as the OEM recommends a major overhaul at 50,000 hours of operation, and the unit is expected to reach 66,000 hours by the time of the outage. (TR 640-641) This translates into 1.8 operating-years, or approximately 2.6 calendar years at a 70 percent capacity factor, past the recommended outage period. Polk Unit 2 outage contributes a projected \$6.0 million in O&M expense. (TR 650) Big Bend Unit 4 requires a 30-day outage for improvements to the compressed air system, seawall cathodic protection, and other activities. (TR 640-642) He asserted this is necessary to continue safe operation of the unit. Big Bend Unit 4 outage contributes a projected \$2 million in O&M expense. (TR 650)

OPC witness Kollen argued that TECO's projected test year expenses are abnormally high compared to prior years, comparing the projected test year's generation maintenance of \$68.5 million to actual expenses of \$52.2 million in 2021, \$44.8 million in 2022, \$46.7 million in 2023, and budgeted expenses of \$59.1 million in 2024. (TR 2285-2286) Witness Kollen highlighted planned generation maintenance expense specifically, projected at \$25.2 million in the 2025 test year, versus the actual expenses of \$8.0 million in 2019, \$11.1 million in 2020, \$10.3 million in 2021, \$12.0 million in 2022, \$9.5 million in 2023, and budgeted expenses of \$13.3 million in 2024. (TR 2286) Witness Kollen asserted that the cause of the increased expense is the number

and scope of outages during the projected test year due to TECO choosing to delay maintenance and bunch the outages into 2025. (TR 2286-2287) The witness argued that TECO has not demonstrated that the years subsequent to the projected test year will have a similar level of generation expense, and that it would be appropriate to allow TECO's requested level of generation expense as it would recover the abnormally high 2025-year expenses in future years until the next base rate proceeding. (TR 2287) Witness Kollen recommended normalizing planned generation expenses and using an average of the period 2019 through 2025, using a mix of actual and budgeted values as available, for a reduction of \$12.4 million. (TR 2288-2289) He also proposed other alternatives available to the Commission are capitalizing the expenses or allowing TECO to amortize the deferred expenses over an extended period of time. (TR 2288)

In his rebuttal testimony, TECO witness Aldazabal argued that OPC witness Kollen's assertion that TECO has bunched outages into the projected test year is inaccurate, arguing instead that outages are scheduled based upon maintenance schedules and resource availability. (TR 686) In cross-examination, he testified that TECO is ultimately in control of the maintenance schedule of its units. (TR 724-725) He further testified that exceeding the original equipment manufacturer's recommendation for the Bayside Unit 1 steam turbine is attributable to good maintenance, and that deferral of the outage was beneficial to customers. (TR 724-726) Further, the other two outages were not deferred, but occurring as previously scheduled. (TR 726) He also admitted in cross-examination that the forecasted budgets for 2026 and 2027 expenses are below the projected 2025 test year, but are higher than the 2023 actual values. (TR 730) TECO witness Chronister's also testified in his rebuttal testimony that the Company opposes witness Kollen's normalization approach, as it would not spread costs over the period but instead results in a disallowance of maintenance expense. (TR 3435) He agreed with witness Kollen's calculation of \$12.8 million for average generation outage expense, but recommends a five-year average (\$14.1 million) or a three-year average (\$16.0 million) could also be considered by the Commission. (TR 3436-3437) Witness Chronister proposed if the Commission opts to make an adjustment, it should allow TECO to amortize the balance over three years, or approximately \$4.1 million annually for 2025 through 2027. (TR 3437-3438) Staff recommends that a three-year amortization appears reasonable and addresses both the need for TECO to expend funds to maintain its generating fleet but also reflects that these are non-repeating expenses in future years. This reduces generation O&M by \$8.3 million. (TR 3438)

In their briefs, FL Rising/LULAC argued to include a normalized level of actual average or planned generation expenses from 2019-2025 and reduce \$2.6 million for removal of the STR and Polk 1 Flexibility projects; Sierra Club argued to eliminate generation expenses associated with the use of coal or petcoke in Big Bend 4 and Polk Unit 1, and eliminate expenses entirely if they are not needed for reliability or more cost-effective than retiring; and, FRF argued to reduce normalized generation expenses by \$12.430 million. However, no intervenor, other than OPC, filed testimony on this Issue. FEA and Fuel Retailers have taken no position. FIPUG and Walmart adopted OPC's position.

### **Prior Issue Impacts**

As addressed in Issue 22, staff recommends denying approval for the STR Project. Consistent with staff's recommendation, generation O&M should be reduced by \$1,169,051. Consistent with staff's recommendation in Issues 43 and 44, staff recommends reductions of O&M

expenses associated with the retirement of the gasifier, steam turbine, and HRSG at Polk Unit 1. This reduces generation O&M by \$1,500,332. The resulting Generation O&M for the projected 2025 test year is therefore \$113,813,950 ( $\$124,770,000 - \$8,286,667 - 1,169,051 - \$1,500,332$ ).

### **CONCLUSION**

Consistent with Issues 22, 24, and 43, generation O&M expense should be reduced to reflect the denial of the South Tampa Resilience project and retirement of some of the Polk Unit 1 generating assets. In addition, staff recommends amortizing the atypical expenses in 2025 over a three-year period, for a total reduction of \$8,286,667 million. Therefore, generation O&M should be \$113,813,950 for the 2025 projected test year.

**Issue 46:** What amount of transmission O&M expense should be approved for the 2025 projected test year?

**Recommendation:** Transmission O&M should be \$11,491,000 for the 2025 projected test year. This amount is below the Commission's benchmark amount, is reasonable, and should be approved. (G. Davis, P. Buys, Vogel)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Transmission O&M Expense for the 2025 test year of \$11,491,000. This amount is below the Commission's benchmark amount, is reasonable, and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** TECO's requested transmission O&M for 2025 should be reduced to reflect disallowance of Grid Reliability and Resilience Projects.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO projects \$11.491 million in transmission O&M during the projected test year. (EXH 5) TECO witness Chipworth testified that this value is below the Company's O&M benchmark by \$4.6 million due to efforts TECO has taken to reduce transmission O&M expenses. (TR 1137, EXH 5) No intervenor filed testimony on this Issue. In their briefs, OPC, FIPUG, FEA, Sierra Club, FRF, Fuel Retailers and Walmart have taken no position. FL Rising/LULAC, assert in their brief, that O&M should be reduced to reflect eliminating the Grid Reliability and Resilience Projects. (BR 15) However, as discussed in Issue 19, staff is recommending no adjustments to transmission O&M associated with the GRR Projects. Staff has found no other adjustments and is recommending a Transmission O&M expense of \$11,491,000 for the projected test year.

### **CONCLUSION**

Transmission O&M should be \$11,491,000 for the 2025 projected test year. This amount is below the Commission's benchmark amount, is reasonable, and should be approved.



Date: November 22, 2024

**Issue 47:** What amount of distribution O&M expense should be approved for the 2025 projected test year?

**Recommendation:** Distribution O&M should be \$54,243,000 for the 2025 projected test year. This amount is below the Commission's benchmark amount, is reasonable, and should be approved. (G. Davis, P. Buys, Vogel)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Distribution O&M Expense for the 2025 test year of \$54,243,000. This amount is below the Commission's benchmark amount, is reasonable, and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** TECO's requested distribution O&M for 2025 should be reduced to reflect disallowance of Grid Reliability and Resilience Projects.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO projects \$54.243 million in distribution O&M during the projected test year. (EXH 5) TECO witness Chipworth testified that this value is below the Company's O&M benchmark by \$13.4 million due to efforts TECO has taken to reduce distribution O&M expenses. (TR 1137, EXH 5) No intervenor filed testimony on this Issue. In their briefs, OPC, FIPUG, FEA, Sierra Club, FRF, Fuel Retailers and Walmart have taken no position. FL Rising/LULAC, assert in their brief, that O&M should be reduced to reflect eliminating the Grid Reliability and Resilience Projects. (BR 15) However, as discussed in Issue 19, staff is recommending no adjustments to distribution O&M associated with the GRR Projects. Staff is recommending a distribution O&M expense of \$54,243,000 for the projected test year.

### **CONCLUSION**

Distribution O&M should be \$54,243,000 for the 2025 projected test year. This amount is below the Commission's benchmark amount, is reasonable, and should be approved.

**Issue 48:** Has TECO made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel Adjustment Clause?

**Recommendation:** Yes. Staff recommends that TECO has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause. (G. Kelley)

**Position of the Parties:**

**TECO:** Yes. The appropriate adjustments are shown on MFR Schedules C-2 and C-3 and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Fuel revenues and fuel expenses are processed through the Fuel and Purchased Power Cost Recovery Clause and associated fuel cost recovery charge. As such, fuel revenues and expenses should not be included in the derivation of base rates and therefore must be removed. As shown on MFR Schedule C-2, page 1, TECO removed a total operating expense of (\$682,393,000) for “Fuel Revenues and Expenses”; however, this amount consists of both fuel- and capacity-related revenues and expenses. (EXH 5, MPN J225) In response to staff discovery, TECO identified the fuel-only portion of the adjustment to be (\$681,258,000). (EXH 201, MPN E6124) The remaining capacity-only portion is addressed in Issue 50. No contravening evidence has been entered into the record regarding this amount.

## **CONCLUSION**

Staff recommends TECO has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause.

**Issue 49:** Has TECO made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause?

**Recommendation:** Yes. Staff recommends that TECO appropriately adjusted its Net Operating Income for the 2025 test year to remove conservation revenues and conservation expenses that are recoverable through the Energy Conservation Cost Recovery Clause. (Panek, Barrett)

**Position of the Parties:**

**TECO:** Yes. The appropriate adjustments are shown on MFR Schedules C-2 and C-3 and should be approved.

**OPC:** No position.

**FL RISING/  
LULAC:** No position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

For the 2025 test year, the revenue and expense amounts are reflected as adjustments to Net Operating Income (EXH 5, MPN J225, CLM 3).

For the 2025 test year, the Energy Conservation Cost Recovery Clause (ECCR) estimated amount of gross revenue and expenses that will be attributable to the ECCR were estimated by multiplying forecasted clause rates by billing determinants. The test year amounts are recorded as negative adjustment entries, which indicates the amounts are reductions to total revenue and total expenses of the Company. (EXH 204, MPN E6572). Such reductions are appropriate

because the referenced revenue and expense amounts are subject to review and recovery through the ECCR mechanism, not through base rate recovery.

No party in this proceeding challenged TECO's proposed conservation revenue and expense adjustments that are recorded in MFR Schedule C-2, Column 3. (EXH 5, MPN J225, CLM 3).

### **CONCLUSION**

Staff recommends that TECO appropriately adjusted its Net Operating Income for the 2025 test year to remove conservation revenues and conservation expenses that are recoverable through the ECCR.

Date: November 22, 2024

**Issue 50:** Has TECO made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause?

**Recommendation:** Yes. Staff recommends that TECO has made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause. (G. Kelley)

**Position of the Parties:**

**TECO:** Yes. The appropriate adjustments are shown on MFR Schedules C-2 and C-3 and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Capacity revenues and expenses are processed through the Capacity Cost Recovery Clause and associated capacity cost recovery charge. As such, capacity revenues and expenses should not be included in the derivation of base rates and therefore must be removed. As shown on MFR Schedule C-2, page 1, TECO removed a total operating expense of (\$682,393,000) for “Fuel Revenues and Expenses;” however, this amount consists of both fuel- and capacity-related revenues and expenses. (EXH 5, MPN J225) In response to staff discovery, TECO identified the capacity-only portion of the adjustment to be (\$1,135,000). (EXH 201, MPN E6124) No contravening evidence has been entered into the record regarding this amount.

## **CONCLUSION**

Staff recommends TECO has made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause.



**Issue 51:** Has TECO made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause?

**Recommendation:** Yes. TECO removed \$9.2 million of net operating income (NOI) from the test year calculations for the appropriate revenues and expenses associated with the Environmental Cost Recovery Clause. (P. Buys)

**Position of the Parties:**

**TECO:** Yes. The appropriate adjustments are shown on MFR Schedules C-2 and C-3 and should be approved.

**OPC:** No position.

**FL RISING/  
LULAC:**

No position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA  
CLUB:**

Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL  
RETAILERS:**

No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO's MFR Schedules C-2 and C-3 demonstrate that TECO removed \$9.2 million in the 2025 projected test year of NOI for the ECRC. This includes \$25.8 million of Operating Revenues and \$16.6 of Operating Expenses for the ECRC. For 2024, TECO removed \$9.8 million of NOI for the ECRC, which includes \$23.8 million of Operating Revenues minus \$14.0 million of Operating Expenses. For 2023, TECO removed \$9.4 million of NOI, which includes \$21.4 million of Operating Revenues minus \$11.9 million of Operating Expenses for the ECRC. (EXH 5, MPN J225-236; TECO BR 56)

No intervenor testified or directly disputed TECO's adjustments for this Issue. However, FL Rising/LULAC's position is that TECO has the burden to show it has appropriately removed the

revenues and expenses recoverable through the ECRC. Staff agrees with FL Rising/LULAC's position and believes TECO has appropriately demonstrated its ECRC adjustments. Staff believes that TECO's adjustments are reasonable and consistent with prior years. Therefore, staff recommends that TECO has made the appropriate ECRC adjustments, as shown on MFR Schedules C-2 and C-3.

### **CONCLUSION**

TECO removed \$9.2 million of NOI from the test year calculations for the appropriate revenues and expenses associated with the Environmental Cost Recovery Clause.

Date: November 22, 2024

**Issue 52:** Has TECO made the appropriate test year adjustments to remove all storm hardening revenues and expenses recoverable through the Storm Protection Plan Cost Recovery Clause?

**Recommendation:** Yes. Staff recommends that TECO has made the appropriate test year adjustments to remove all storm hardening revenues and expenses recoverable through the SPPCRC. (Sumner)

**Position of the Parties:**

**TECO:** Yes. The appropriate adjustments are shown on MFR Schedules C-2 and C-3 and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO's MFR Schedules C-2 and C-3 show that TECO removed a NOI of \$42.021 million in 2025 for the SPPCRC, which includes \$104.364 million in total operating revenues minus \$62.344 million in total operating expenses. TECO removed an NOI of \$33.042 million in 2024 for the SPPCRC, which includes \$86.126 million in total operating revenues minus \$53.084 million in total operating expenses. TECO removed an NOI of \$23.433 million in 2023 for the SPPCRC, which includes \$63.570 million in total operating revenues minus \$40.137 million in total operating expenses. (EXH 5, BSP 4-16)

In discovery, TECO was asked to provide all SPPCRC includable costs that TECO recorded, by account, in 2023, and what TECO expects to record in 2024 and 2025. (EXH 171, BSP 13352-

13353) TECO provided this information, and was subsequently asked to clarify why the figures did not match what was filed in MFR Schedule C-2. (EXH 194, BSP 43270) TECO explained that MFR Schedule C-2 contains additional components not included in its response to OPC, and provided explanations for these differences.

Staff recommends that TECO's adjustments are reasonable; therefore, staff recommends that TECO has made the appropriate SPPCRC adjustments, as shown on MFR schedules C-2 and C-3 and in the prior mentioned discovery. No party takes a position disputing whether TECO made the appropriate test year adjustments to remove all storm hardening revenues and expenses recoverable through the SPPCRC.

### **CONCLUSION**

Staff recommends TECO has made the appropriate test year adjustments to remove all storm hardening revenues and expenses recoverable through the Storm Protection Plan Cost Recovery Clause.

Date: November 22, 2024

**Issue 53:** What amount of salaries and benefits, including incentive compensation, should be approved for the 2025 projected test year?

**Recommendation:** Staff recommends salaries and benefits of \$376,802,000 for the 2025 projected test year. (Mason)

**Position of the Parties:**

**TECO:** The Commission should approve salaries and benefits expense, including incentive compensation, for the 2025 test year in the amount of \$376.9 million as shown on MFR Schedule C-35.

**OPC:** Tampa Electric customers should not be forced to pay any of the stock-based long term incentive compensation that is designed to incentivize financial performance to motivate Tampa Electric executive management to increase costs and rates for the benefit of shareholders. Instead, all \$7.170 million of compensation expense should be assigned to shareholders for recovery.

**FL RISING/**

**LULAC:** Incentive compensation that exceeds the amount of compensation that the top public officers of the state receive should be paid by shareholders, not ratepayers. The amount of salaries and benefits should be reduced to reflect shareholder payment of at least 50 percent of incentive compensation for 2025. Should be less than \$359.77 million.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts OPC's position on this issue, as it is concerned about awarding excessive executive compensation when many TECO customers are energy burdened.

**FRF:** Tampa Electric's Long Term Incentive Plan (LTIP) provides incentives to executives to increase costs and rates paid by TECO's customers so as to benefit the financial performance of TECO and its parent and sole shareholder, Emera Corporation, as distinguished from incentivizing performance metrics that benefit customers, such as safety and reliability. The Commission should remove \$7.170 million in LTIP compensation expense from the Company's authorized revenue requirements.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Cacciatore claimed that the Commission should approve TECO's full salaries and benefits expense. (TR 1426-1427; TECO BR 57) Witness Cacciatore stated that TECO's salary and benefits expenses are reasonable and necessary to have a competitive hiring process. (TR 1426-1427) Witness Cacciatore explained that TECO needs its compensation package, that includes base pay and long-term and short-term incentive plans, in order to attract and retain skilled team members. (TR 1384-1385) Witness Cacciatore went on to explain that ultimately these compensation practices benefit the customer as they allow TECO to best hire and incentivize team members that will focus on safe and reliable service, which results in lowered costs for the Company and therefore customers as well. (TR 1434-1435)

OPC witness Kollen's analysis identified the Long Term Incentive Plan (LTIP) as an incentive program for department directors and officers, and paid out in the form of Emera shares. (TR 2291) Witness Kollen concluded that the purpose of the LTIP is to incentivize reaching Emera's financial performance goals, specifically Earnings-Per-Share (EPS) goals. (TR 2291-2292) Witness Kollen claimed that it has been Commission precedence to disallow expenses that are incurred for the purpose of meeting shareholder goals, citing Order Nos. PSC-10-0131-FOF-EI and PSC-10-0153-FOF-EI. (TR 2292-2293) Witness Kollen then argued that allowing the LTIP expense would be a detriment to customers, as the increase to revenue requirement would give TECO executives motivation to increase Emera's stock price as much as possible by raising rates on customers. Based on this, witness Kollen concluded that all LTIP expense related to Emera's financial performance should be disallowed. (TR 2294-2295)

In her rebuttal, TECO witness Cacciatore disagreed with OPC witness Kollen's method of focusing on the LTIP specifically, and instead stressed a total compensation approach. (TR 1433) Witness Cacciatore asserted that the LTIP incentivizing Emera's financial health is for the good of the Company, as Emera is TECO's source of equity. Furthermore, witness Cacciatore argued that witness Kollen did not show that disallowing LTIP would not hurt the Company and customers, and claimed that removing LTIP could hurt TECO's ability to attract and retain executives responsible for customer obligations, as well as, force the Company to increase base pay. (TR 1435-1436) Witness Cacciatore also rejected witness Kollen's use of precedence to show that LTIP EPS goals have historically been disallowed, by supplying Commission Order Nos. PSC-92-1197-FOF-EI and PSC-02-0787-FOF-EI.<sup>53</sup> Order No. PSC-92-1197-FOF-EI concluded that variable incentive plans tied to the achievement of corporate goals are appropriate, and Order No. PSC-02-0787-FOF-EI concluded that incentive pay plans allow for companies to be competitive in hiring high quality employees, which ultimately benefits the customer. (TR 1438-1439) Additionally, witness Cacciatore also provided Order Nos. PSC-2023-0388-FOF-GU and PSC-2023-0103-FOF-GU, both of which found the use of total

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<sup>53</sup> Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 19910890-EI, *In re: Petition for rate increase by Florida Power Corporation*; Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 20010949-EI, *In re: Petition for rate increase by Gulf Power Company*.

compensation appropriate.<sup>54</sup> More specifically, Order No. PSC-2023-0388-FOF-GU, was for Peoples' Gas System (PGS), a subsidiary of TECO, with a similar variable compensation design. Witness Cacciatore stated that in this decision, the Commission found PGS's total salary and benefits plan to be reasonable and prudent, and that no party objected to PGS's compensation and benefits plan. (TR 1437-1438)

FIPUG and Sierra Club have adopted the position of OPC, and FRF has supported OPC in recommending a \$7.170 million reduction in LTIP compensation expense. FL Rising/LULAC recommended that ratepayers should not be responsible for any TECO incentive compensation that exceeds the amount received by the top public officers of the state. FL Rising/LULAC witness Rábago addressed incentive compensation in his testimony, suggesting that TECO create a compensation plan that focuses on the customer's benefits and affordability, but FL Rising/LULAC's position was not included. (TR 2609-2610) FL Rising/LULAC also recommended a maximum salaries and benefits amount of \$359.77 million. (FL Rising/LULAC BR 16)

Staff agrees with TECO witness Cacciatore about considering LTIP in the context of total compensation. Staff does acknowledge OPC witness Kollen's use of precedence to show that compensation related to shareholder goals has previously been disallowed for recovery. However, given the more recent Commission precedence in the PGS and other cases, addressing individual aspects of TECO's compensation plan does not seem appropriate, when previously a similar benefits plan was found to be reasonable and beneficial to customers.

TECO witness Cacciatore pointed out that no parties have taken issue with TECO's overall level of compensation, besides the Supplemental Executive Retirement Plan (SERP) expense, which sits at 99.5 percent of the market median. Therefore, witness Cacciatore claimed that if a total compensation approach is used, no adjustments should be made. (TR 1432-1433)

Staff believes that as TECO's total compensation is 99.5 percent of the market median, the Company's salary and benefits package is reasonable, as that is competitive. Staff agrees with witness Cacciatore's previous claim, and in light of no party taking issue with total compensation, believes that the LTIP expense should not be reduced.

OPC witness Kollen additionally recommended disallowing the SERP expense (\$107,000) on the basis that it is a non-qualified expense provided only to executives, whose goals are closer to TECO's shareholders than the customers. (TR 2296) A non-qualified pension plan is one that does not meet the IRS's Employee Retirement Income Security Act guidelines.

TECO witness Cacciatore argued that the SERP expense is necessary to recruit and retain talented executive leadership, which ultimately benefits the customer. Witness Cacciatore also

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<sup>54</sup> Order No. PSC-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System Inc.*; Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-FOF-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.*

noted that the SERP expenses contribute to executive compensation that is at the market median. (TR 1445-1447)

Staff disagrees that the SERP is intended to attract or retain employees. In TECO witness Cacciatore's rebuttal testimony, she claimed that the SERP has no actively employed participants. (TR 1446) Furthermore, during cross examination, she indicated that TECO has no plans to open the SERP to new employees. In light of this, staff has concluded that the SERP primarily compensates retired executives, with little benefit to the customer. Staff agrees with OPC witness Kollen's assessment that the SERP expense should be removed.

Staff agrees with the Company's use of a total compensation approach to its benefits package, and suggests that the consumer parties' suggestions to remove some or all of STIP and LTIP be rejected. However, staff does agree with OPC witness Kollen's assessment of the SERP, and recommends that it be disallowed from recovery. Therefore, staff recommends the appropriate level of TECO's salaries and benefits package to be \$376,802,000 (\$376,909,000 – \$107,000), after the SERP expense is removed.

### **CONCLUSION**

Staff recommends salaries and benefits of \$376,802,000 for the 2025 projected test year.



Date: November 22, 2024

**Issue 54:** Does TECO's pension and Other Post-Retirement Employee Benefits (OPEB) expense properly reflect capitalization credits in the 2025 projected test year? If not, what adjustments, if any, should be made?

**Recommendation:** TECO has made the proper adjustments to reflect capitalization credits. Therefore, no adjustments to the OPEB expense is necessary. (Mason)

**Position of the Parties:**

**TECO:** Yes. The Commission should approve the company's pension and OPEB expenses for the test year as shown on MFR Schedule C-17.

**OPC:** The Commission should reduce the pension and OPEB cost to reflect the credit for the portions of the costs that will be capitalized. The effect is a reduction of \$0.489 million in the revenue requirement for the reduction in pension expense and a reduction of \$0.806 million in the revenue requirement for the reduction in OPEB expense to reduce the requested amounts for the capitalized portions.

**FL RISING/**

**LULAC:** No. The Commission should reduce the pension and OPEB expense to reflect capitalization credits, resulting in a reduction of \$0.489 million in revenue requirement in pension expense and a reduction of \$0.806 million in the revenue requirement for the reduction in OPEB expense.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. The Commission should reduce pension and OPEB costs to reflect the credit for the portions of the costs that will be capitalized. The effect is a reduction of \$0.489 million in the revenue requirement for the reduction in pension expense and a reduction of \$0.806 million in the revenue requirement for the reduction in OPEB expense to reduce the requested amounts for the capitalized portions.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

OPC witness Kollen testified that TECO has not provided a breakdown between expense and capital for total pension and total OPEB costs for the test year, despite multiple requests from OPC. (TR 2290) Staff agrees that the lack of transparency in transactions is an issue, which will further be addressed in Issue 55.

OPC Witness Kollen also testified that TECO had not capitalized portions of the pension and OPEB costs it is requesting recovery for. (TR 2289) Witness Kollen explained that TECO recorded total pension and OPEB costs to Account 926 and then used a “fringe rate” methodology to credit the account for the capitalized portion of pension and OPEB costs. Witness Kollen claimed that this treatment was incorrect, as the total pension costs and total OPEB costs do not show that they have been credited for the amount being capitalized. (TR 2290) Witness Kollen identified this crediting as taking place in historic years, but not for the 2025 test year or 2024 budgeted year. Because of this, witness Kollen recommends reducing total pension expense and an OPEB expense by \$0.489 million and \$0.806 million respectively to credit the portion of costs that were capitalized. (TR 2290- 2291)

FIPUG has adopted the position of OPC, and FL Rising/ LULAC and FRF have supported OPC in recommending reducing the pension and OPEB expense to reflect capitalization credits. However, no parties have submitted a witness to give an argument on this Issue.

TECO witness Chronister refuted OPC witness Kollen’s suggestions in his rebuttal testimony, and argued that the Company has made the necessary adjustments to reflect capitalization credits. Witness Chronister did not disagree with Witness Kollen’s description of TECO’s “fringe rate” methodology to capitalize its pension and OPEB costs in his testimony, but rather with the conclusions drawn by OPC. Witness Chronister identified this “fringe rate” methodology as the process in which the Company removes the necessary capitalized amount of pension and OPEB costs from the Company’s forecasted benefits expense. Witness Chronister explained that all benefit costs are initially posted to account 926, including total pension and OPEB costs. He went on to explain that the credits that come from the capitalized portion of the costs are subsequently applied to account 926. Witness Chronister pointed out that MFR Schedule C-17, where pension costs are shown, reflect pension and OPEB costs before reductions are made. Witness Chronister concluded that the reductions suggested by OPC are inappropriate as the Company has already deducted the proper amounts from its benefit expense. (TR 3439; TR 3521-3527)

Based on the rebuttal testimony of witness Chronister, staff believes that the Company has already made the required reductions to benefit costs and recommends that the Commission should accept TECO’s pensions and OPEB expenses with no adjustments.

**CONCLUSION**

TECO has made the proper adjustments to reflect capitalization credits. Therefore, no adjustments to the OPEB expense is necessary.

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**Issue 55:** What cost allocation methodologies and what amount of allocated costs and charges with TECO's affiliated companies should be approved for the 2025 projected test year?

**Recommendation:** Staff recommends approving \$28,650,000 in allocated costs and charges from Tampa Electric to its affiliate, and a total of \$11,841,973 for allocated costs (\$7,263,973) and direct charges (\$4,578,000) incurred by TECO from affiliated companies for the 2025 projected test year. The amount for allocated costs reflects a reduction of \$3,811,027 for the removal of half of allocated corporate responsibility costs. Staff recommends no changes to the cost allocation methodology. (Mason)

**Position of the Parties:**

**TECO:** The company accounts for affiliated transactions in accordance with Rule 25-6.1351 and no party alleges that the company has violated that rule. The Commission should approve (\$28,650,000) of allocated costs and charges from Tampa Electric Company to affiliates and \$15,653,000 of allocated costs (\$11,075,000) and direct charges (\$4,578,000) incurred by the company from affiliates for the test year. OPC's proposed other measures are not needed, or alternatively, should only be prescribed through rulemaking.

**OPC:** The Commission should reduce the Corporate Support Allocations from Emera to Tampa Electric by \$0.858 million related to the dissolved TSI and the shared service allocation from Tampa Electric to TECO by \$5.457 million to reflect unsupported corporate overhead. Tampa Electric should change its MMM allocation factor by substituting a Headcount allocation factor in place of the Net Income allocation factor. Tampa Electric should discontinue its central service provider responsibilities or in the alternative implement steps to ensuring transparency.

**FL RISING/**

**LULAC:** A Revised Modified Massachusetts Model (MMM) should be used to allocate affiliate costs and charges using the following inputs: (1) Operating Assets factor; (2) Revenue factor; and (3) Headcount factor. The Revised MMM Rate for TECO should be 67.62%, a 4.96% reduction from TECO's proposed rate. In total, TECO's Shared Service expense should be reduced by \$5.50 million from TECO's 2025 Budget amounts.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The Commission should require TECO to use a Headcount allocation factor instead of the Net Income allocation factor. The Commission should reduce the Corporate Support Allocations from Emera to Tampa Electric by \$0.858 million related to the dissolved TSI and the shared service allocation from Tampa Electric to TECO by \$5.457 million to reflect unsupported corporate overhead.

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**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:****ANALYSIS**

TECO witness Chronister testified that the Company's projected affiliate transactions are all for historically standard products and services that are shared to and from TECO's affiliates. (TR 3410-3411) Witness Chronister identified three ways shared services are provided to affiliates: through direct charges, assessed charges, and allocated charges. (TR 3413) He then explained that when services are split between multiple affiliates, the charges are shared either through assessments or an allocation, with assessed charges being those that can be assigned based on some metric of usage, such as employee headcount. (TR 3413) Witness Chronister further explained that charges that cannot be directly assigned to an affiliate or distributed amongst multiple affiliates through assessed charges are shared through an allocation using a MMM, which is reflected in the Company's Cost Allocation Manual (CAM). (TR 3413-3414) This MMM uses total operating revenues, total operating assets, and net income as its allocation factors. (TR 3413) Witness Chronister testified that, when applicable, the Company is in compliance with Rule 25-6.1351, F.A.C., which governs how a regulated utility allocates costs to its affiliates, which is shown in the Company's MFR Schedule C-30. (TR 3411; TR 3414; EXH 5 MPN J287-288) Witness Chronister also asserted that the Company's MMM has previously been considered reasonable by the Commission. (TR 3413) In its post-hearing brief, TECO addressed how no party has alleged that the Company has violated the Commission affiliate transactions rule. (TR 3412-3414; TECO BR 58) The Company further claimed that its test year affiliated transactions are below the Commission's Administrative and General functional expense group benchmark, which are reasonable and allow TECO to efficiently conduct business. (TECO BR 58-59)

OPC witness Ostrander raised concerns about TECO's expense allocation process in his testimony. Witness Ostrander identified TECO's Net Income MMM allocation factors as an issue, suggesting a Headcount input factor, using numbers from 2023, instead. (TR 2468) In its post-hearing brief, OPC stated that the use of a Net Income factor is "not causative, measurable, objective, stable, or predictive" and further claimed that TECO witness Chronister has not met the burden of proof to show that a Headcount input factor is not prudent. (OPC BR 50) The effect of witness Ostrander's adjustment was that TECO's 2025 budget allocation factor went from 72.07 percent to 67.62 percent, corresponding to a reduction of \$470,606 to TECO's shared service expenses. (EXH 61) Witness Ostrander also made adjustments to TECO's HR expenses that are subject to a Headcount allocation factor. Witness Ostrander claimed this was a routine adjustment to update TECO's budgeted headcount information, which resulted in HR expenses being reduced by \$227,646. (TR 2478)

TECO witness Chronister rebutted, stating that changing the Company's MMM allocation factors would be inappropriate as this would cause inconsistencies with what has been approved

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by the Commission in previous rate cases. (TR 3475) Witness Chronister argued that because OPC did not supply proof as to why changing to its methodology would be prudent, that the recommendation should not be approved. (TR 3475) Furthermore, witness Chronister argued that OPC witness Ostrander's \$227,646 adjustment for headcount is inappropriate as it is based off of TECO's 2023 historical data rather than its 2025 test year data which is more accurate for the time period. (TR 3476)

OPC witness Ostrander also testified on the complex nature of affiliate transactions, claiming they require time to properly review and raising concerns that the Company could be allocating costs that are too high or do not entirely benefit the Company's regulated operations. (TR 2409-2410) Witness Ostrander claimed that due to a lack of transparency from TECO, OPC is unable to confirm the veracity of some of the transactions. (TR 2410-2411) Witness Ostrander specifically recommended a correction resulting in a reduction of \$3,575,548 to shared service allocations for corporate responsibility, after the MMM factors have been adjusted. (TR 2468)

TECO witness Chronister disagreed, stating that TECO has done its due diligence in providing the required supporting documents. (TR 3469) Witness Chronister argued that OPC witness Ostrander might have misunderstood or missed an explanation or document provided by TECO. (TR 3469-3470) Witness Chronister further stated that the Commission has oversight of the Company's corporate responsibility, and that the expense is under a spending group that is \$56 million below the Commissions benchmark, demonstrating that TECO is making efforts to keep expenses down. (TR 3320; TR 3475-3477)

OPC also expressed concern regarding TECO's procurement expenses. In his testimony, OPC witness Ostrander addressed how PGS has begun relying less on TECO for its procurement services. (TR 2431-2432) Witness Ostrander stated that TECO's increased Procurement department expenses coupled with having less shared services with PGS has resulted in TECO bearing 94 percent of all procurement expenses. (TR 2439) Witness Ostrander suggested correcting this by replacing the "Purchase Order Spend" allocation factor with a "Net Plant Investment" factor, resulting in a \$1,243,052 reduction to TECO's allocated expenses. (TR 2478) OPC identified part of this Issue as being due to TECO acting as the centralized service provider (CSP) after TECO Services Inc., the previous CSP was dissolved in 2020. (TR 2433) Witness Ostrander raised the concern that the Company is now acting as a CSP while also being a regulated utility. (TR 2433) Witness Ostrander claimed that this can make it hard to audit affiliate transactions as well as lead to a utility unfairly recovering costs related to procurement, evidencing that shared service expenses have increased since TECO took up CSP functions. (TR 2434-2435) For these reasons, OPC also suggests that TECO discontinue its CSP functions. (OPC BR 50) However, if TECO is not divested of its CSP role, then witness Ostrander suggested nine practices TECO should take up in order to have increased transparency:

- 1) TECO should propose a timeline and plan for achieving all of the following recommendations with periodic updates to the Commission, OPC, and interested parties. The Plan should be filed and available to all parties, and in place within one year or before the next TECO or PGS rate case.

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- 2) TECO should identify all prior and ongoing cost savings associated with becoming the centralized service provider, and TECO should identify these cost savings by year and account number (and any specific cost savings by affiliate) and provide all other supporting documentation and calculations. TECO should propose a plan for flowing these cost savings back to customers in this rate case and future rate cases, or explain why this is not appropriate.
- 3) TECO should provide supporting documentation to explain and calculate the impact of all instances when an affiliate takes back certain centralized shared services in-house (and reduces or eliminates the reliance on the centralized shared services). TECO should provide alternative suggestions regarding how the residual costs of the related centralized shared service can be equitably treated among remaining affiliates, and explain why it would not be reasonable to reduce the overall costs of these shared services if demand is reduced for the service or if the costs are not comparable with the fair market value of similar services from third parties (or surrogate calculations of third party services). This documentation should be made available for all TECO and PGS rate cases all in Florida and filed at the outset of each rate case as an MFR.
- 4) TECO should make significant changes in its accounting system to more easily track, identify, and provide a proper audit trail for all affiliate transactions by each affiliate. TECO should have various expense subaccount balances that shows only the specific gross expense (not netted with other affiliate or non-affiliate transactions) it pays to each affiliate for each year. This account should include only “affiliate” transactions and not any other accounting transactions related to the regulated utility operations. Likewise, similar to expense transactions, TECO should have a separate contra expense account balance with similar tracking, showing all “credits” or reductions to expense accounts by affiliate (with no other accounting transactions related to regulated utility operations). These accounts should allow TECO or third parties to identify and know the amount of gross expense that TECO pays to an affiliate at any point in time for services provided to TECO by affiliates, and the same information should exist for any contra expenses (or revenues) related to services that TECO provides to other affiliates.
- 5) The amounts in item (4) above should reconcile to TECO’s FERC Form 1 affiliate diversification data. The FERC Form 1 affiliate diversification data should separately show all affiliate “expense” amounts by affiliate and major services/agreements, all “contra-expense” amounts by affiliate and major services/agreements.
- 6) TECO should require an external management audit of TECO’s role as central service provider and the review of the affiliate transaction process, including Emera and Tampa/TECO provision of corporate support and shared services to TECO and other affiliates – including allocation factors and inputs. All of the previous concerns that I have raised should be subject to review.

This management audit should not be performed by a Certified Public Accounting firm or its management/consulting audit affiliate that has had a prior or current relationship with Emera, TECO, or any affiliate. Preferably, TECO should not hire a Certified Public

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Accounting firm or its management/consulting audit affiliate because these entities establish a confidential internal “materiality factor” for such engagements. The “materiality factor” establishes a dollar value which the firm believes is material enough to require disclosure for accounting errors, incorrect allocations, improper allocation factors and other dollar-value or policy impacts. These firms do not disclose their materiality factors and these firms can have a vastly different opinion of what constitutes a material error or impropriety from their accounting perspective, compared to the perspective of materiality by regulators in a rate case proceeding.

7) Separate and specific monthly invoices should be sent by TECO to affiliates which identify and document only the centralized shared services (and related contra expenses or revenues) provided by TECO to affiliates. Likewise, monthly invoices should be sent by affiliates to TECO which identify and document only the centralized shared services expenses for services provided to TECO by the affiliate. All gas purchases transactions should be billed separately by all affiliates, and not comingled or netted in billings with centralized services.

8) Emera and TECO should establish a formalized written set of internal controls and safeguards to address the accounting for centralized services, cross-subsidy issues, objectivity and independence, and other potential concerns regarding the centralized service provider.

9) Emera should perform an internal audit of TECO’s role as centralized service provider, along with a review of affiliate transactions, allocation processes, issues related to cross-subsidy, the treatment of the take-back of shared services by affiliates and other important matters. The internal audit report, recommendations, and the results of implemented recommendations be filed with the Commission and available to interested parties.

(TR 2449-2454)

TECO witness Chronister testified that TECO taking up CSP functions has allowed the Company to run its business more efficiently by consolidating costs to avoid duplicate transactions. (TR 3478) Witness Chronister further stated that the Commission monitors affiliate transactions through the Company’s Diversification Pages and in Commission audits, which ensure that the Company maintains a functional structure with a reasonable cost level. (TR 3478) Witness Chronister disagreed with OPC’s nine suggestions for TECO to maintain its CSP role for three reasons. Witness Chronister questioned if this rate case is the proper proceeding to change TECO’s affiliate transactions rule, and stated that an amendment to Rule 25-6.1351, F.A.C., would be more appropriate. (TR 3479) In its post-hearing brief TECO also suggested that OPC took issue with affiliate transaction rules in general and not with TECO’s transaction history. (TECO BR 59-60) Witness Chronister also noted that the charges OPC witness Ostrander takes exception to represent a small portion of TECO’s overall O&M expense, which are consistently reviewed. (TR 3478-3479) Witness Chronister also noted that of OPC witness Ostrander’s suggestions, TECO has already put into practice suggestions five, seven, eight, and

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nine, and that the other suggestions would be unduly burdensome, resulting in greater costs being put on customers. (TR 3480)

Witness Ostrander also claimed that dissolving TECO Services Inc. will result in employee expenses being allocated to TECO instead, which will increase costs. (TR 2461-2462) Witness Ostrander argued this point stating that even though this expense is recorded so that it doesn't impact TECO's expense accounts, it still affects Emera's, which influences TECO's expenses. (TR 2461) Witness Ostrander stated that TECO has not shown transferring these costs is reasonable, and so he recommended removing \$858,561 in Emera affiliate expenses. (TR 2461-2462)

TECO witness Chronister disagreed with OPC witness Ostrander's adjustment. Witness Chronister claimed that this reduction is for an amount that TECO did not include in its budget. (TR 3472) Witness Chronister identified that OPC witness Ostrander has shown in his testimony that this is not an expense TECO budgeted for, despite claiming that it will impact TECO's expenses. (TR 3472-3473) Witness Chronister acknowledged that TECO does not record the expenses to the account OPC witness Ostrander identified, but that is because the Company budgets them to other expense accounts. (TR 3473) Furthermore, witness Chronister stated that this charge is not due to the dissolution of TECO Services, Inc., and that the \$858,561 cost was for a shared service expense budgeted for years prior to 2024. (TR 3473-3474) Witness Chronister also rebutted the idea that the dissolution of TECO Services, Inc. will result in increasing charges being budgeted to the Company, stating that the expenses budgeted to TECO for the 2025 test year are lower than the actual amounts for 2022 and 2023. (TR 3474)

OPC also took issue with TECO's use of Nova Scotia Power's CAM as Emera's CAM. OPC witness Ostrander alleged that Nova Scotia Power's CAM is not specifically named as an Emera CAM and does not address the allocation or direct assignment of services from Emera to TECO or its other U.S. affiliates. (TR 2417) OPC alleged that TECO witness Chronister has not supplied an argument as to why there is no Emera specific CAM. (OPC BR 51) Furthermore, OPC questioned if the Nova Scotia Power CAM has been approved by the FERC or the Commission. For this reason OPC suggested that the Commission require that TECO have Emera make a CAM outlining the rules for its transactions with TECO. (OPC BR 51)

TECO witness Chronister disagreed with the need for an Emera specific CAM. Witness Chronister posited that Nova Scotia Power's CAM is under the jurisdiction of the Nova Scotia Utility and Review Board, which monitors the Utility for Compliance, and the FPSC monitors TECO and its affiliates' transactions. (TR 3471-3472) Witness Chronister further argued that a CAM that isolates Emera's charges would only be redundant. (TR 3471)

FIPUG has adopted the position of OPC, and FL Rising/LULAC and FRF have supported OPC in recommending that TECO revise its MMM allocation factors and reduce its shared service expenses. However, no parties other than OPC have submitted a witness to give an argument on this Issue.

Staff recommends that TECO's use of allocation factors for its MMM are appropriate and that no change is needed. This recommendation is based on TECO witness Chronister's justification, including Commission precedence previously allowing for it.



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Additionally, staff believes that OPC witness Ostrander's \$858,561 reduction should not be accepted on the basis that the adjustment is for a charge not being allocated by the Company. Staff does agree with witness Ostrander regarding the corporate responsibility expense. While the Commission does allow for prudent corporate responsibility costs, due to a lack of transparency on the nature of these costs, staff recommends removing half of corporate responsibility costs, resulting in a reduction of \$3,811,027.

Further, while staff has concerns regarding TEOC's cost allocation transparency, staff agrees with TECO witness Chronister that this rate case is not the appropriate setting to change TECO's affiliate transaction rules.

### **CONCLUSION**

Staff recommends approving \$28,650,000 in allocated costs and charges from TECO to its affiliate, and a total of \$11,841,973 for allocated costs (\$7,263,973) and direct charges (\$4,578,000) incurred by TECO from affiliated companies for the 2025 projected test year, which reflects a reduction of \$3,811,027 for the removal of half of allocated corporate responsibility costs. Staff recommends no changes to the cost allocation methodology, but that the Company should adopt witness OPC Ostrander's nine suggestions for increased transparency.

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**Issue 56:** What amount of Directors and Officers Liability Insurance expense for the 2025 projected test year should be approved?

**Recommendation:** Staff recommends that \$151,500 in Directors and Officers Liability Insurance and \$376,000 in Board of Director expense be approved, resulting in a total reduction of \$527,500 for the 2025 test year. (Mason)

**Position of the Parties:**

**TECO:** The Commission should approve \$303,000 of Directors and Officers (“D&O”) Liability Insurance expense and \$752,000 of Board of Director expense for the 2025 projected test year.

**OPC:** OPC recommends that shareholders bear half the cost of, or \$0.151 million, for the Directors & Officers Liability Insurance premium costs and half, or \$0.376 million, of the cost of the Board of Directors expense. This will properly allocate the benefits provided by these elements of the shareholders and the regulated utility.

**FL RISING/**

**LULAC:** The Directors and Officers (D&O) Liability Insurance expense should, at least, be shared equally between customers and shareholders (if not borne entirely by shareholders), resulting in a \$0.151 million reduction in the D&O Liability Insurance expense.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The Commission should allocate half the cost, or \$0.151 million, of Directors & Officers (“D&O”) Liability Insurance premium costs and half, or \$0.376 million, of the cost of the Board of Directors expense. This will properly allocate the costs and benefits provided by these expenses between the shareholder and the regulated utility.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Chronister testified that D&O Liability Insurance and Board of Director expenses have a long Commission precedence of being approved for recovery. (TR 3441) Witness Chronister also claimed that the costs are reasonable and that the expense group that these expenses are classified under is \$56 million below the Commission benchmark. (TR 3441-3442)

In his testimony, OPC witness Kollen claimed that some of TECO's included expenses are for its parent company, Emera. Witness Kollen testified that Emera incurred certain D&O Liability Expenses, related to the risk faced by its directors and officers on behalf of Emera, and charges them to various affiliates, including TECO. (TR 2297-2298; EXH 48) Witness Kollen further claimed that the Company received charges from Emera related to Emera's Board of Director Expenses, which go to maintaining relationships with and attracting new investors. (TR 2298; EXH 49) Witness Kollen argued that because these expenses are from activities that primarily benefit Emera and TECO's shareholders, and not customers, that the expenses should be evenly split between shareholders and customers. Furthermore, witness Kollen has identified instances where the Commission has previously called for an equal sharing of D&O expenses, and so they claim this action is supported by precedence.<sup>55</sup> (TR 2298-2299)

FIPUG has adopted the position of OPC, and FL Rising/ LULAC and FRF have supported OPC in recommending an equal split of D&O Liability Insurance expense. However, no parties other than OPC have submitted a witness to give an argument on this Issue.

TECO witness Chronister posited that all D&O Liability Insurance and Board of Director expenses are reasonable costs for doing business, and that OPC's adjustments should be rejected. (TR 3441-3442) However, witness Chronister provided no further argument beyond this.

Staff agrees with witness Chronister that D&O Liability Insurance and Board of Director expenses are necessary for the Company to be able to do business. However, they have not shown that the charges will not primarily benefit the shareholders. It is Commission precedence in these instances to recommend an equal split of expenses between customers and shareholders. Staff recommends an equal split of these expenses, resulting in a reduction of D&O Liability Insurance and Board of Director expenses of \$527,500 for the projected test year.

**CONCLUSION**

Staff recommends that \$151,500 in Directors and Officers Liability Insurance and \$376,000 in Board of Director expense be approved, resulting in a total reduction of \$527,000 for the 2025 test year.

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<sup>55</sup> See Orders Nos PSC-12-0179-FOF-EI, issued April 3, 2012, Docket No. 20110138-EI, *In re: Petition for increase by Gulf Power Company*; and PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 20090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc.*

**Issue 57:** What amount of Economic Development expense for the 2025 projected test year should be approved?

**Recommendation:** Staff recommends that \$446,502 should be approved. (Mason)

**Position of the Parties:**

**TECO:** The Commission should approve economic development expenses for the 2025 projected test year of \$446,502.

**OPC:** No position.

**FL RISING/**

**LULAC:** \$0.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Pursuant to Rule 25-6.0426, F.A.C., utilities are allowed to recover reasonable economic development expenses, provided that such expenses are prudently incurred. TECO witness Chronister contends that the Company has shown, for the historic and future test years, that all expenses are prudent as per Rule 25-6.0426(7), F.A.C. (TR 3395-3396)

FL Rising/ LULAC contend that the appropriate level of economic development expense to be approved is \$0; however, no witness has been proffered to testify to this position.

TECO witness Chronister argued that due to no intervener providing an argument for this Issue and as TECO has shown that their economic development expenses are prudent, that the amount of \$446,502 should be approved. (TECO BR 60)

Staff agrees with TECO that the Company's economic development expenses comply with the criteria of Rule 25-6.0426, F.A.C., based on the evidence in the record. Staff believes that TECO's expenses are reasonable and prudently occurred, and that the full amount of \$446,502 should be approved.

### **CONCLUSION**

Staff recommends that \$446,502 should be approved.

**Issue 58:** What amount and amortization period for TECO's rate case expense for the 2025 projected test year should be approved?

**Recommendation:** Staff recommends the Commission approve a total rate case cost of \$2,048,000 with a three-year amortization period. The corresponding annual amortization expense is \$683,000. (Zaslow)

**Position of the Parties:**

**TECO:** The Commission should approve total rate case expense of \$2,048,000, an amortization period of three years, and \$683,000 of rate case expense for the projected 2025 test year as shown on MFR Schedule C-10.

**OPC:** Rate case expense should be amortized over at least a three-year period.

**FL RISING/**

**LULAC:** \$0, as this rate case was not for customers, but rather at the behest of Emera.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Rate case expense should be amortized over three years.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue addresses two areas of rate case expense: the total cost and the amortization period, with the annual expense being a fall-out of the two. As shown on MFR Schedule C-10, TECO requested total rate case cost of approximately \$2,048,000 with a three-year amortization period. (EXH 5, MPN J257) This yields a test year amortization expense of \$683,000. Staff evaluated TECO's currently requested rate case cost and found it in-line with the Company's last three rate cases filed in 2008, 2013, and 2021. The nominal estimated cost range for those cases was \$1.84 million to \$1.97 million. (EXH 171, MPN E2364-E2365) The components of TECO's currently requested rate case cost is summarized in Table 58-1.

**Table 58-1  
Rate Case Cost**

Category	Cost
Legal Services	\$1,200,000
Outside Consultants	748,000
Travel	<u>100,000</u>
Total Cost	<u>\$2,048,000</u>

Source: EXH 5, MPN J257

Concerning intervenor positions, staff notes that FL Rising/LULAC did not submit any specific prefiled testimony in support of its suggested rate case expense of \$0. Staff believes the recovery of reasonable and prudent expense is sound ratemaking practice. Thus, staff believes that a rate case cost of \$2,048,000 amortized over a period of three years is reasonable.

### **CONCLUSION**

Staff recommends the Commission approve a total rate case cost of \$2,048,000 with a three-year amortization period. The corresponding annual amortization expense is \$683,000.

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**Issue 59:** What amount of O&M Expense for the 2025 projected test year should be approved?

**Recommendation:** The amount of O&M Expense that should be approved for the 2025 projected test year is \$374,919,781. (Mason)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Other O&M Expenses of \$391.8 million for the 2025 projected test year as shown on MFR Schedule C-1, less \$285,000 per the company's July and August Filings for a total of \$391.5 million.

**OPC:** This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The O&M expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.

**FL RISING/**

**LULAC:** O&M expense should be adjusted to reflect the removal of O&M expenses as specified in Issues 43-58.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** This is a fallout issue. The amount of O&M Expense that is approved for the 2025 projected test year should be adjusted in accordance with the substantive recommendations outlined in this brief and issues statement.

**FRF:** This is generally a fall-out issue. The Commission should make all of the adjustments to TECO's O&M expenses recommended by the OPC's witnesses reflected in Attachment 1 to the FRF's Brief.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. TECO requested O&M Expense of \$391.8 million for the projected 2025 test year. (TECO BR 61) Based on the adjustment from Issues 11, 43, 45, 53, 55, 56, and 64, staff recommends a reduction of \$16,851,219 to O&M Expense.

**CONCLUSION**

Staff recommends O&M Expense for the projected 2025 test year to be \$374,919,781.

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**Issue 60:** What amount of depreciation and dismantlement expense for the 2025 projected test year should be approved?

**Recommendation:** The amount of depreciation and dismantlement expense should be \$507,268,091 for the 2025 projected test year. (Vogel, J. Wu)

**Position of the Parties:**

**TECO:** Based on the depreciation parameters and rates proposed in Issue 7, the Commission should approve Jurisdictional Adjusted Depreciation and Amortization expense in the amount of \$531.4 million for the projected 2025 test year as shown on MFR Schedule C-1, less \$5,198,021 per the company's July and August Filings for a total of \$526.2 million.

**OPC:** This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The depreciation and dismantlement expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.

**FL RISING/**

**LULAC:** Adopt OPC position and then adjusted to reflect the disallowance of projects that do not belong in rate base as reflected in other issue positions.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** This is a fallout issue. The amount of depreciation and dismantlement expense that is approved for the 2025 projected test year should be adjusted in accordance with the substantive recommendations outlined in this brief and issues statement.

**FRF:** This is generally a fall-out issue. The Commission should make all of the adjustments to TECO's depreciation and dismantlement expenses recommended by the OPC's witnesses reflected in Attachment 1 to the FRF's Brief, and also the adjustments to TECO's depreciation expense recommended by FEA witness Brian Andrews.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. Based on the previous adjustments in Issues 7, 20, 22, 24, 43, and 64, staff is recommending a reduction of depreciation and dismantlement expense of \$24,167,909 for the projected 2025 test year. This results in a depreciation and dismantlement expense of \$507,268,091 for the projected 2025 test year.

**CONCLUSION**

Based on the reductions in depreciation and dismantlement expense in previous issues, staff recommends a total depreciation and dismantlement expense of \$507,268,091 for the 2025 projected test year.

**Issue 61:** What amount of Taxes Other Than Income Taxes for the 2025 projected test year should be approved?

**Recommendation:** Staff recommends that Taxes Other Than Income Taxes for the 2025 projected test year should be \$101,592,000. (Zaslow)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Taxes Other Than Income expense of \$101.6 million for the projected 2025 test year as shown on MFR Schedule C-1, plus \$923 per the company's July and August Filings, for a total of \$101.6 million.

**OPC:** No position.

**FL RISING/**

**LULAC:** Adopt OPC position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Taxes Other Than Income Taxes (TOTI) generally consists of ad valorem, gross revenue or gross receipts taxes, state unemployment insurance, franchise taxes, federal excise taxes, social security taxes, and all other taxes assessed by federal, state, county, municipal, or other local governmental authorities with the exception of income taxes.

The proposed TOTI per books is \$228,359,000 (system). This amount equates to a jurisdictional TOTI of \$227,796,000 (jurisdictional). Combined with the net operating income adjustments of (\$126,204,000), this results in an adjusted jurisdictional TOTI amount of \$101,592,000. (EXH 5, MPN J226) No specific contravening evidence has been entered in the record regarding TECO's requested TOTI.

### **CONCLUSION**

Staff recommends that Taxes Other Than Income Taxes for the 2025 projected test year should be \$101,592,000.

**Issue 62:** What amount of Parent Debt Adjustment is required by Rule 25-14.004, F.A.C., for the 2025 projected test year?

**Recommendation:** The amount of Parent Debt Adjustment as contemplated by Rule 25-14.004, F.A.C., for the 2025 projected test year is \$13,420,123 based on a jurisdictional common equity balance of \$4,553,645 million. (D. Buys)

**Position of the Parties:**

**TECO:** The Commission should approve a Parent Debt Adjustment calculated in accordance with Rule 25-14.004, F.A.C., of \$12.9 million for the projected 2025 test year. The adjustment decreased the company's 2025 revenue requirement by \$17.4 million.

**OPC:** The requirements of rule 25-14.004, F.A.C., must be applied to all test years and ratemaking periods in this case. Apart from the differences in the proper equity ratio, OPC and Tampa Electric are in agreement on the application and calculation of the adjustment.

**FL RISING/**

**LULAC:** Adopt OPC position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO and OPC agree that a parent debt adjustment should be made. (TECO BR 62; OPC BR 54) TECO is a wholly owned subsidiary of TECO Holdings, Inc., which is a wholly owned subsidiary of Emera United States Holdings, Inc. (EUSHI), which is a wholly owned subsidiary of Emera, Inc. Tampa Electric and the other TECO Holdings companies file United States and state income tax returns on a consolidated basis with EUSHI. (TR 3202) TECO witness Strickland asserted that TECO does not expect that being included in a consolidated tax return will cause any significant benefit or detriment to TECO or its customers in the 2025 test year.

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(TR 3202; EXH 5, MPN J284) TECO calculated a parent debt adjustment (PDA) of \$12.939 million using the capital structure of Emera Inc. consistent with the methodology used in the 2021 rate case proceeding using a common equity balance of \$4,390,373,000. (EXH 5, MPN J281) This adjustment decreased the Company's 2025 revenue requirement by \$17.4 million. (TR 3201-3203)

Rule 25-14.004(4), F.A.C., describes the parent debt adjustment calculation adjustment as:

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.

Based on adjustments made to the capital structure and common equity balance in Issue 38, the jurisdictional recommended common equity balance for TECO is \$4,553,645,000. The parent debt adjustment based on the adjusted common equity balance is \$13,420,123 ( $1.1628\% \times 25.345\% \times \$4,553,645,000 = \$13,420,123$ ). This results in an increase to the Company's proposed parent debt adjustment of \$481,123 ( $\$13,420,123 - \$12,939,000$ ). Consequently, the amount of projected test year income tax expense in Issue 70 should be decreased by \$481,123. This would decrease the recommended revenue requirement in Issue 73 by \$646,456 ( $\$481,123 \times 1.34364 = \$646,456$ ).

OPC did not propose its own calculation of the PDA in this case and agreed with TECO's PDA adjustment of \$12.939 million. (OPC BR 54)

### **CONCLUSION**

The amount of Parent Debt Adjustment as contemplated by Rule 25-14.004, F.A.C., for the 2025 projected test year is \$13,420,123 based on a jurisdictional common equity balance of \$4,553,645 million.

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**Issue 63:** What amount of Production Tax Credits should be approved and what is the proper accounting treatment for the 2025 projected test year?

**Recommendation:** The amount of Production Tax Credits that should be approved for the 2025 projected test year is \$38.6 million as a reduction to income tax expense and the proper treatment is flow-through accounting. (McGowan, O. Wooten)

**Position of the Parties:**

**TECO:** The company reduced projected 2025 test year income tax expense by approximately \$38.6 million to reflect the “flow through” of the estimated amount of PTC to be generated in 2025 by its solar plants placed in service in 2022 and thereafter; this amount should be approved by the Commission.

**OPC:** The amount of PTC credits should be updated to reflect the increase in the 2025 PTC rate from \$2.75 per kilowatt-hour to \$3.00 per kilowatt-hour which was effective January 1, 2024. Tampa Electric included \$35.4 million in PTCs as a reduction to income tax expense for the 2025 projected test year, grossed-up, the PTCs reduced the revenue requirement by \$47.5 million. The 2025 PTC rate change further decreases Tampa Electric’s proposed revenue requirement by \$4,917,948.

**FL RISING/**

**LULAC:** For 2025, TECO should immediately flow Production Tax Credits to its customers. The costs should also be flowed back to customers on a capacity basis. If the Commission adopts 50% AD, then costs should flow back as 50% energy and 50% capacity.

**FIPUG:** The Commission should adopt a consumer protection by requiring TECO to flow-through the higher of the actual production tax credits earned or 100% of the projected production tax credits associated with the proposed solar projects. Also see Issue 18.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC’s position on this issue.

**FRF:** The amount of PTC credits should be updated to reflect the increase in the 2025 PTC rate from \$2.75 per kilowatt-hour to \$3.00 per kilowatt-hour which became effective January 1, 2024. This 2025 PTC rate change decreases Tampa Electric’s proposed revenue requirement by \$4,917,948.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

The IRA, which was signed into law on August 16, 2022, implemented substantial changes in tax law.<sup>56</sup> The IRA included incentives for taxpayers in the energy markets such as the extension and modification of existing ITCs and PTCs for solar projects. (TR 3182) TECO witness Strickland testified the IRA extended the PTCs in Section 45 of the Internal Revenue Code (IRC) to electricity produced by solar energy facilities. (TR 3182-3183) Witness Strickland affirmed that PTCs are not calculated based on the cost of a qualifying asset, but rather, on the energy the asset produces over a 10-year period and the IRA did not impose a normalization requirement for solar PTCs. (OPC BR 55; TR 3184)

At the time of TECO's filing, the Production Tax Credit was a tax credit that reduces income tax expense in the amount equal to \$2.75 per kWh, or \$27.50 per MWh, of solar energy produced by a qualifying facility during a tax year and is available for solar energy facilities that were placed in service on or after January 1, 2022. (TR 3183) Furthermore, witness Strickland testified that under Section 45 of the IRC, the Internal Revenue Service (IRS) has authority to adjust the rate. (TR 3183) Witness Strickland explained that the Company calculated the PTCs for the 2025 test year using the \$2.75 per kWh rate prescribed by applicable federal statutes multiplied by the estimated amount of energy to be produced by its qualified solar assets placed in service in 2022 and thereafter. (TECO BR 62; TR 3191) Additionally, witness Strickland asserted because PTCs are allowed for a period of 10 years following the in-service date of the solar facility, the cumulative amount of PTCs expected to be claimed in the test year 2025 contributes to an income tax expense reduction of \$35.4 million, which decreases the revenue requirement by \$47.5 million. (TR 3186; OPC BR 54; Walmart BR 9) Finally, witness Strickland proclaimed the PTCs are the primary reason that income tax expense is lower in the 2025 test year than previous years. (TR 3186)

During the course of the proceeding, TECO filed with the Commission on August 22, 2024, an updated revenue requirement after the issuance of the prehearing order addressing a tax law provision that occurred in July 2024, in which the IRS announced an increase to the PTC rate from \$2.75 to \$3.00 per kWh, or an increase from \$27.50 to \$30.00 per MWh generated by a qualifying asset, effective January 1, 2024. (EXH 835, MPN 38090; FRF BR 40; OPC BR 54) With the change in PTC rate applicable to qualifying solar assets during calendar year 2025, the \$35.4 million in PTCs increased to an amount of \$38.6 million in PTCs as a reduction to income tax expense for the 2025 projected test year. (TECO BR 62; OPC BR 54; Walmart BR 9) FL Rising/LULAC took the position that the PTCs should be flowed back to customers on a capacity basis. (FL Rising/LULAC BR 18) However, FL Rising/LULAC did not sponsor a witness that testified on this position, nor did it proffer an argument in its brief. As noted in TECO's brief, FL Rising/LULAC's position on allocation of the PTCs is a cost of service/rate design issue and not a NOI issue. (TECO BR 63)

FIPUG took the position that the Commission should adopt a consumer protection by requiring TECO to flow-through the higher of the actual PTCs earned or 100 percent of the projected

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<sup>56</sup> H.R. 5376; Inflation Reduction Act of 2022; Title 26 U.S. Code §48

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PTCs associated with the proposed solar projects. (FIPUG BR 15) FIPUG witness Ly testified that as a prerequisite for recovering any of the solar projects investment, the future solar projects should be required to qualify for the PTCs and any portion of the investment that does not qualify should either be disallowed or not be included in rate base. (TR 2775) Witness Ly recommended that as an alternative, customers should be held harmless and TECO should compensate customers for the value of the lost PTCs for any portion of the future solar projects that do not fully qualify. (TR 2775; FIPUG BR 15) Witness Ly also testified the Commission should require that all PTCs (grossed-up for income taxes) be included as offsets to TECO's base revenue requirements associated with each future solar project that is placed into commercial operation and for which cost recovery is authorized. (TR 2775)

TECO witness Chronister rebutted FIPUG witness Ly's recommendations and emphasized each of the solar projects included in the 2025 test year and the 2026 and 2027 SYA qualify for PTCs and the Company anticipates that solar projects included in future proceedings, beyond the ones included in this proceeding, will also qualify for PTCs. (TR 3482) Furthermore, witness Chronister affirmed for each of the solar projects included in the 2025 test year and the 2026 and 2027 SYA, the Company has reduced the revenue requirement for PTCs (grossed-up for taxes). (TR 3482-3483) Witness Chronister proclaimed the Company agrees that when the Commission establishes cost recovery for solar projects included in future proceedings, beyond the ones included in this proceeding, PTCs (grossed-up for income taxes) should be offsets to base revenue requirements associated with each future solar project for which cost recovery is authorized. (TR 3483) Witness Chronister detailed how PTCs are flow-through tax credits, and TECO has forecasted the use of flow-through accounting for solar PTCs in the 2025 test year and the 2026 and 2027 SYAs. (TR 3493) Witness Chronister testified that the Company will continue to use flow-through accounting for PTCs associated with solar projects. (TR 3483)

As discussed above, with the change in PTC rate applicable to qualifying solar assets during calendar year 2025, the forecasted amount of \$35.4 million in PTCs increased to an amount of \$38.6 million, which equates to an increase of \$3.2 million ( $\$38.6 - \$35.4 = \$3.2$ ). Therefore, the income tax expense should be further reduced by \$3.2 million.

## **CONCLUSION**

The amount of Production Tax Credits that should be approved for the 2025 projected test year is \$38.6 million as a reduction to income tax expense and the proper treatment is flow-through accounting.

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**Issue 64:** What treatment, amounts, and amortization period for the Production Tax Credits that were deferred in 2022-2024 should be approved for the 2025 projected test year?

**Recommendation:** The PTC benefit that was deferred in 2022-2024 in the amount of \$58.74 million should be accounted for as a regulatory liability, amortized over a three-year period for annual amortization in the amount of \$19.58 million, with an additional \$1.56 million carrying charge, resulting in an annual amount of \$21.14 million. Therefore, staff recommends that TECO's requested revenue requirement should be reduced by \$15.64 million. A corresponding adjustment to decrease rate base by \$219,567 should also be made. (McGowan)

**Position of the Parties:**

**TECO:** The Commission should approve \$58.7 million of "deferred" PTC (2022-2024) as of December 31, 2024, a ten-year amortization period, and a \$5.9 million NOI reduction for 2025. The three-year amortization period proposed by OPC is too short and would create intergenerational inequities and an abnormal ratemaking earnings profile. A five-year amortization period and an annual amortization of \$11.7 million would be a middle ground. No carrying charge should be added to the deferred balance.

**OPC:** \$0.460 million in carrying costs (representing the customer's time value of money) should be added to the deferred PTC balance. The effect of this addition is a reduction of at least \$0.887 million in the revenue requirement, assuming an amortization period of 10 years as filed by Tampa Electric. The deferred PTC should be amortized over three years. This results in an additional reduction of at least \$13.182 million in revenue requirements.

**FL RISING/**

**LULAC:** The Production Tax Credits (PTCs) that were deferred in 2022-2024 totaling \$0.460 million should go to customers by adding the deferred carrying costs calculated at the allowed return from the prior case to the regulatory liability. The amortization period should be three years.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC's position on this issue.

**FRF:** TECO's deferred PTC balance should be increased by \$3.437 million in carrying costs to a total of \$44.587 million, grossed-up for income taxes to \$59.844 million (total Tampa Electric) and \$59.634 million (jurisdictional). Adding the carrying charges reduces approximately \$0.887 million in the 2025 revenue requirement, assuming TECO's proposed 10-year amortization period. The Deferred PTCs should be amortized over three years, resulting in an additional revenue requirement reduction of \$13.182 million.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue arises due to changes in corporate income tax law as a result of the IRA and interpretation of the meaning of the term “normalization” as set forth in the 2021 Settlement Agreement. As discussed in Issue 63, the IRA implemented substantial changes in corporate income tax law which modified the tax incentives for solar projects to allow utilities to claim PTCs, which are more beneficial to the Company and customers instead of the former ITCs. (OPC BR 55; TR 3185-3186) TECO witness Strickland affirmed the Company determined the PTCs would be more beneficial to customers and as a result, TECO elected to claim the PTCs for its solar plants placed in service in 2022 and thereafter. (OPC BR 55; TR 3185-3186) Beginning in 2022, TECO recorded a regulatory liability to defer the incremental tax benefits of the PTCs in place of the original estimated ITC tax amortization calculated in its 2022 base rates and 2023 and 2024 GBRA assets (Deferred PTC). (TR 3190)

The as-filed Deferred PTC benefit on a revenue equivalent basis as of December 31, 2024, was expected to be \$55.3 million as shown on Exhibit No. VS-1, Document No. 2, page 1 of 4 attached to TECO witness Strickland’s direct testimony. (TR 3190; EXH 30, MPN C15-1425) In addition to recording a regulatory liability to defer the incremental tax benefits, TECO proposed to amortize the regulatory liability as a reduction to income tax expense over a period of 10 years beginning January 1, 2025. Witness Strickland testified that the proposal would reduce the as-filed 2025 test year revenue requirement by approximately \$5.5 million and is consistent with the 10-year period for which PTCs are available for a project under the IRC. (TR 3192) The \$5.5 million reduction was reflected on line 7 of MFR Schedule C-4, page 4 of 8. (EXH 5, MPN J240)

As also discussed in Issue 63, TECO filed with the Commission on August 22, 2024, an updated revenue requirement that addressed the change in PTC rate announced by the IRS in July 2024, increasing the rate from \$2.75 to \$3.00 per kWh generated by a qualifying asset, effective January 1, 2024. (EXH 835, MPN 38090) Given the Company’s updated revenue requirement, the Deferred PTC benefit from calendar years 2022 through 2024 increased to \$58,743,299 (revenue equivalent basis), which reflects \$3,516,213 of additional PTC benefit from the original filing due to the change in PTC rate applicable to qualifying assets for calendar year 2024. (EXH 835, MPN 38090) With the change in PTC rate applicable to calendar year 2024, and using the Company’s proposed 10-year amortization period, the \$5.5 million reduction to the as-filed 2025 test year revenue requirement increased to approximately \$5.85 million. (EXH 5, MPN J240)

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OPC witness Kollen recommended the treatment of the Deferred PTC regulatory liability, including a deferred return (carrying costs) on the regulatory liability for the years 2022 through 2024, be refunded over a three-year amortization period. (TR 2316) Witness Kollen asserted the Company offered no rationale for the 10-year amortization period other than the fact that PTCs are available for new solar resources annually for 10 years. (TR 2316) Furthermore, witness Kollen emphasized there is no true nexus between the number of years the PTCs are available for new solar generating assets going forward (test year and subsequent years) and the refunds related to the deferral period preceding the test year. (TR 2316; OPC BR 57)

In addition, witness Kollen elaborated on how a 10-year amortization period is unjustifiably long as customers were entitled to the PTCs as they were earned through reductions to the base revenue requirement and reductions to the 2023 and 2024 GBRA's pursuant to the 2021 Settlement in the prior rate case. (TR 2316; OPC BR 57) Witness Kollen proclaimed the refunds to the customers should be made sooner rather than later, especially since the Company failed to record deferred carrying costs on the deferred PTCs and failed to include the PTCs as cost-free capital in the capital structure. (TR 2316; OPC BR 57) Witness Kollen expanded on how a three-year amortization period is more reasonable, and given TECO's recent filing history, three years is the likely number until the Company's next base rate case proceeding. (TR 2316; OPC BR 56)

Witness Kollen testified that the Company should have added a deferred return (carrying costs) to the Deferred PTCs on a revenue equivalent basis to ensure that customers received the same economic value as if the PTCs had been flowed-through as reductions to the 2023 and 2024 GBRA rate increases as if the PTCs were earned each year. (TR 2314; OPC BR 57) Witness Kollen recommended the Commission compensate customers for carrying costs on the Deferred PTCs by adding the carrying costs calculated at the allowed return from the prior rate case to the regulatory liability. (TR 2315; OPC BR 57) Witness Kollen affirmed the effects of the recommended carrying costs are a reduction of at least \$0.887 million in the claimed revenue requirement and requested base revenue increase, consisting of an increase of \$0.460 million in the negative amortization expense and a decrease of \$0.427 million due to the additional regulatory liability in the test year times the grossed-up rate of return (equity only). (TR 2315)

Witness Kollen testified the effects of his recommended treatment, including the three-year amortization period and carrying costs, are a reduction of at least \$13.182 million in the claimed revenue requirement and requested base revenue increase, consisting of a \$13.845 million increase in the negative amortization expense, offset in part by \$0.663 million for the increase in the test year rate base due to shorter amortization period multiplied by the grossed-up cost of capital. (TR 2317; OPC BR 57-58)

In rebuttal, TECO witness Strickland claimed the proposed three-year amortization period recommended by OPC witness Kollen is too short because it will create an abnormal profile in the revenue requirement. (TR 3212) The IRS allows the Company to claim a PTC for 10 years following a qualifying asset's in-service date; therefore, the Company believes it is reasonable to mirror this period for amortization of the Deferred PTCs. (TR 3212) Staff notes that the IRS does not require the tax credit to be amortized over any period because the PTCs are expected to be claimed on the tax return in the year they are earned. During cross-examination by OPC, TECO witness Strickland agreed that for each year, TECO claims the PTCs earned for the kilowatt

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hours of energy produced in that tax year for all the qualified solar facilities in-service. (TR 3239)

TECO witness Chronister disagreed with OPC's proposal to include carrying costs on the Deferred PTCs through December 31, 2024, in the test year NOI. (TR 3452) Witness Chronister testified that carrying costs should not be included because the Deferred PTCs were recorded as regulatory liabilities from 2022 through 2024. Witness Chronister emphasized that over this period, they were properly reflected as rate base reductions in the Company's Earnings Surveillance Reports. (TR 3452) Furthermore, witness Chronister testified that in the 2025 test year, the unamortized balance of the regulatory liabilities related to Deferred PTCs are reductions to rate base. (TR 3452) As a result, the revenue requirement requested in this proceeding is lower already and there is no need for the adjustment proposed by OPC. (TR 3452-3453)

In addition, witness Chronister testified that the Commission should not approve OPC's proposed three-year amortization period for the Deferred PTC benefit regulatory liability simply due to the fact the benefits associated with the Deferred PTCs were put on the balance sheet for the express purpose of flowing them to customers as new rates were set in the Company's next rate proceeding. (TR 3453) Furthermore, witness Chronister affirmed the Company's proposed amortization period of 10 years is reasonable because it shares the benefit of deferral with customers over a longer period while in contrast, using a three-year amortization period would be beneficial to customers for three years and would create an abnormal expense reduction and enhance the potential need for rate relief at the end of the amortization period. (TR 3453)

During cross examination, TECO witness Chronister was asked, "Would you agree that the production tax credits earned by TECO are intended to be flowed through to the customers in the year that they are earned?" (TR 3632) In response, the witness stated, "The IRS established PTC credits as a flow-through credit." (TR 3632) Witness Chronister proclaimed if the Commission prefers a middle ground, a five-year amortization period would spread the benefit of the deferral over a longer period than proposed by OPC and would moderate the impact of the atypical expense reduction. (TR 3454; TECO BR 63; OPC BR 57) Furthermore, witness Chronister continued with what would seem to be a compromise, emphasizing if the Commission did in fact approve a five-year amortization period for the regulatory liability (Deferred PTC Benefit), the 2025 NOI adjustment would be \$5.520 million. (TR 3454)

In its brief, OPC argued that Section 11(c)(iv) of the 2021 Settlement Agreement states, "[t]he company will adjust any GBRA that has not gone in effect up or down to reflect the new corporate income tax rate and the normalization of any new tax credits applicable to Future Solar Projects on the revenue requirement for the GBRA." (OPC BR 56; TR 2311) Instead, TECO deferred the excess amount from the election of PTCs from 2022 through 2024 and created a regulatory liability for this difference rather than adjust the 2023 and 2024 GBRA. (OPC BR 56; TR 2313) OPC argued that the regulatory liability represents a benefit that the customers are entitled to in the year earned and should have received as a reduction to the GBRA rate increase. (OPC BR 56; TR 2316)

Staff believes that the record indicates there was ambiguity between OPC and TECO regarding the meaning of normalization and how it pertains to this Issue given the timing of the 2021

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Settlement Agreement and the enactment of the IRA. (OPC BR 56; TR 3242-3243) Furthermore, staff notes PTCs are available for solar energy facilities placed in-service on or after January 1, 2022, and may be claimed annually for ten years following the in-service date of the solar facility. Staff notes that under TECO's proposal, the solar facilities placed in-service during calendar years 2022 through 2024 would earn PTCs for ten years but the amortization period would not begin until 2025, therefore extending the actual recovery period for the customers beyond the 10-year amortization period even though the IRS established PTCs as a flow-through tax credit in the year it was earned. (TR 3632)

Additionally, the customers would not see the same value of the Deferred PTC benefit as the Company for those assets placed in-service during calendar years 2022 through 2024 if the Commission approved the 10-year period proposed by TECO due to the amortization period being extended beyond the 10-year eligibility period. OPC addressed this aspect in its brief, adding that the IRA legislation giving rise to the PTCs made the benefit of the PTCs available annually for only a 10-year period. (OPC BR 57) Therefore, using the Company's proposed amortization period of 10 years (starting in 2025 for PTCs earned from 2022 through 2024) would flow through the Deferred PTC benefits to customers outside the 10-year period. (OPC BR 57)

Upon staff's review of the parties' arguments and evidence in the record, staff believes OPC's argument is more persuasive than TECO's argument. The record is clear that the intent of the term "normalization" in Section 11 of the 2021 Settlement Agreement contemplated the normalization for ITCs as required by Section 45 of the IRC before the enactment of the IRA. (OPC BR 56) Therefore, staff believes the tax law change provision in the 2021 Settlement Agreement should not take precedence over the requirements and provisions of the new tax law for which Section 11 in the 2021 Settlement Agreement was intended to implement. Staff agrees with OPC witness Kollen that a three-year amortization period is more reasonable given the nature of the PTCs being established as a flow-through credit and the customers should receive the same benefit or economic value of the PTCs as the Company.

In addition, staff believes the evidence in the record supports a three-year amortization period as being more rational, and given TECO's recent filing history, is also the likely number of years until the Company's next base rate case proceeding. (OPC BR 56; TR 2316) Based on a review of the evidence in the record, staff believes the appropriate treatment for the Deferred PTCs is to return the benefit to customers as soon as possible unless TECO demonstrated that its cash flow would be impacted to the extent it would harm its financial integrity and credit ratings. TECO has not demonstrated that a three-year amortization period would be detrimental to its financial integrity or credit ratings, which in part, is inferred by TECO witness Chronister's rebuttal to OPC's recommended three-year amortization period with the Company's counterproposal of a five-year amortization period. (TR 3454; TECO BR 63)

Finally, staff notes the fact FIPUG, FL Rising/LULAC, FRF, Sierra Club, and Walmart are in agreement with or adopted OPC's position regarding both the three-year amortization period and the addition of carrying costs to the Deferred PTC regulatory liability. (FIPUG BR 15-16; FL Rising/LULAC BR 18; FRF BR 40; Sierra Club BR 56; Walmart BR 9)

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Witness Strickland testified that OPC witness Kollen's proposed NOI adjustment of \$12.993 million, excluding carrying charges is correct. (TR 3212) However, witness Kollen's estimated revenue impact did not consider the increase in the PTC rate from \$2.75 to \$3.00 per kWh for 2024 and thereafter. Therefore, staff believes using witness Kollen's methodology to calculate the deferred PTC benefit for an amortization period of three years is reasonable and supported by the evidence. Based on TECO's revised Deferred PTC benefit filed in its August 22, 2024 letter, staff calculated the necessary adjustment to reflect a three-year amortization period, including a carrying charge, for the treatment of the Deferred PTC benefit. The PTC benefit that was deferred in 2022-2024 in the amount of \$58.74 million should be accounted for as a regulatory liability, amortized over a three-year period for annual amortization in the amount of \$19.58 million ( $\$58.74 \text{ million} \div 3 \text{ years}$ ), with an additional \$1.56 million carrying charge, resulting in an annual amount of \$21.14 million.

In its original filing and MFRs, the Company included a PTC benefit of approximately \$5.50 million for the 2025 projected test year ( $\$55.3 \text{ million} \div 10 \text{ years}$ ). Therefore, staff recommends that TECO's requested revenue requirement should be reduced by \$15.64 million ( $\$21.14 \text{ million} - \$5.50 \text{ million} = \$15.64 \text{ million}$ ). The reduction adjusted to not reflect the multiplier results in a decrease of \$11.64 million to the annual Amortization Expense. A corresponding adjustment to decrease rate base by \$219,567 should also be made. The rate base should be decreased by the difference between TECO's revenue requirement reduction in its original filing (\$55.227 million) and staff's recommended revenue requirement reduction (\$63.223 million), which equates to \$7.996 million (\$7.968 jurisdictional). The rate base reduction should be offset by the 13-month average of the Amortization Expense (\$15.497 million), which is \$7.749 million. The net rate base adjustment is a decrease of \$219,567 ( $\$7.968 \text{ million} - \$7.749 \text{ million} = \$219,567$ ).

## CONCLUSION

The PTC benefit that was deferred in 2022-2024 in the amount of \$58.74 million should be accounted for as a regulatory liability, amortized over a three-year period for annual amortization in the amount of \$19.58 million, with an additional \$1.56 million carrying charge, resulting in an annual amount of \$21.14 million. Therefore, staff recommends that TECO's requested revenue requirement should be reduced by \$15.64 million. A corresponding adjustment to decrease rate base by \$219,567 should also be made.



Date: November 22, 2024

**Issue 65:** What treatment and amount of the Investment Tax Credits pursuant to the Inflation Reduction Act should be approved for the 2025 projected test year?

**Recommendation:** The Commission should approve a five-year amortization period for Investment Tax Credits for Battery Storage assets as if the Company opted out of normalization. The amount of the Investment Tax Credits related to the battery storage assets is \$37.031 million and the annual amortization should be \$6.627 million for the 2025 projected test year. (Souchik, D. Buys)

**Position of the Parties:**

**TECO:** The Commission should approve ITC amortization for pre-2022 solar based on a 30-year book depreciation life that reduces income tax expense by \$9.9 million and for energy storage devices based on a 20-year book depreciation life that reduces test year income tax expense by \$1.4 million. The Commission should not require the company to opt-out of normalization for energy storage ITC, but if it does, OPC's proposed three-year amortization period is too short.

**OPC:** ITCs should be reflected as if Tampa Electric elects out of the normalization requirements. The effects of the recommendation is a reduction of \$3.493 million in the revenue requirement and a reduction of \$0.100 million in the CETM revenue requirement due to the reduction in the cost of capital by including the new ITCs since 2022 as cost-free capital in the capital structure instead of including the new ITCs at the WACC.

**FL RISING/**

**LULAC:** The Investment Tax Credits (ITCs) should be treated as if TECO elected and will continue to elect out of normalization requirements. The Commission should also direct TECO to defer the ITCs each year and amortize the deferred ITCs over a ten-year amortization period.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC's position on this issue.

**FRF:** The Commission should treat the ITCs, and set TECO's rates, as if Tampa Electric elected and will continue to elect out of the normalization requirements. This will reduce base revenue requirements by \$3.493 million and reduce the CETM revenue requirement by \$0.100 million due to the reduction in the cost of capital by including the new ITCs since 2022 as cost-free capital instead of at the weighted average cost of capital.

**FUEL**

**RETAILERS:** No Position.

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**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue addresses the impact of ITCs for ratemaking purpose as a result of the IRA, which became effective on August 16, 2022. (TR 3182) The IRA made a 30 percent ITC available for energy storage facilities placed in service beginning in 2023. (TR 3184) In general, ITCs are calculated as a fixed percentage or rate times the total cost of the qualifying asset and are reflected on the tax return for the year in which the asset goes in service. Prior to the IRA, for ratemaking purposes, the IRC and IRS Treasury Regulations require that the total amount of the ITC be amortized over the life of the asset as a reduction to income tax expense (i.e., be “normalized”). This creates a smoothing effect that minimizes large, ITC-based changes to tax expense by recognizing the value of the credit for ratemaking purposes ratably, not all at once when an asset goes in service. (TR 3183-3184) TECO witness Strickland explained the general normalization rules have been in place since 1986 and is a method of accounting in which tax benefits associated with accelerated depreciation and ITC from regulated companies are spread over the same time period that the costs of investments are recovered from customers. (TR 3187) The objective of normalization is to ensure that current and future customers are treated equitably by allowing all customers to enjoy the tax benefits associated with the utility assets. (TR 3187-3188) Normalization accounting has the effect of levelizing customers’ rates over time, and therefore avoiding volatility in the company tax expense profile, which would occur should the company elect out of normalization. (TR 3188) The IRA introduced a provision that allows a taxpayer to elect out of the IRS normalization rules for energy storage facilities and amortize the ITC at a faster rate than the depreciation rate or regulatory life of the asset. (TR 3187) However, for ratemaking purposes, TECO calculated the ITC in accordance with the IRS normalization rules and deferred and amortized the ITC over the regulatory live of the asset, which at time of filing was 10 years, later revised to 20 years. (TR 3187-3188; EXH 835) TECO will claim the new 30 percent ITC in the amount of \$42.3 million for its qualified standalone energy storage facilities expected to be placed in service in 2025. This would reduce the 2025 projected test year income tax expense by \$1.4 million. (TECO BR 64)

OPC witness Kollen asserted that the new IRS rules that allow a utility the option to elect out of the normalization requirements for stand-alone energy storage facilities means the Company could now elect to provide both the ITC amortization benefit and the ITC cost-free capital benefit to customers rather than electing one or the other. (OPC BR 60; TR 2312) Witness Kollen confirmed that the new IRS normalization “opt-out” provision allowed the Commission to separately specify the amortization period for the ITC untethered to the service life of the asset used for depreciation purposes. (OPC BR 60; TR 2312)

TECO acknowledged the current tax laws permit the Company to opt-out of normalization requirements for ITCs on energy storage facilities if they choose to do so. (TECO BR 64; TR 3214) However, TECO pointed out that the Company has not filed a tax return including ITCs for energy storage, and has not elected one way or the other regarding the opt-out. However,

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TECO admitted it will opt-out of normalization if directed to do so by the Commission. (TECO BR 64; TR 3257) TECO argued that normalization of the ITCs for energy storage devices should be approved because this approach is consistent with the Commission's long-standing practice of normalizing ITCs and will avoid intergenerational cost inequities, which would allow customers who will pay for the asset to enjoy the benefit of the tax credits over the life of the asset. (TECO BR 64-65; TR 3215)

In its brief, OPC argued TECO's proposal to not elect out (opt-out) of the normalization requirements would allow the Company to retain a significant portion of the economic value of the ITCs rather than providing the entirety of the tax saving to the customers who are required to pay the entirety of the cost of the new battery storage. (OPC BR 59; TR 2318) OPC argued Emera documents showed that in 2023, the flow back to customers of tax credits related to solar investments had the effect of reducing revenues, decreasing cash flow, and contributing to reducing Emera's credit metrics. (OPC BR 59; EXH 445, BSP 16097)

OPC witness Kollen recommended the Commission reflect the ITCs as if the Company elected and will continue to elect out of the IRS normalization requirements. (OPC BR 60; TR 2320) It is an annual election and the Company has not yet filed its 2023 federal income tax return or its 2024, 2025, 2026, or 2027 federal income tax returns. (TR 2320) Witness Kollen also recommended the Commission direct the Company to defer the ITCs pursuant to the IRA earned each year, and to amortize the deferred ITCs over a three-year amortization period, the same period that he recommended for the deferred PTCs earned in the years 2022 through 2024 and for the same reasons. (TR 2320) Witness Kollen's recommendation would produce a reduction of \$3.493 million in revenue requirement. (OPC BR 60) Witness Kollen also recommended that the new ITCs be recorded as cost-free capital in the capital structure instead of including them at the weighted average cost of capital. (TR 2320)

TECO argued that if the Commission requires the Company to opt-out of normalization, the three-year amortization period for battery storage proposed by OPC is too short, would create intergenerational inequities (benefits will accrue only in early years of an asset's life) and an abnormal ratemaking earnings profile, and should be rejected in favor of a longer period of 10 years or more. (TECO BR 65; TR 3257-3258) Further, TECO witnesses Chronister and Strickland disagreed with OPC's proposal to reflect the deferred ITCs as zero-cost capital in the capital structure. The Company's methodology complies with IRS normalization rules and is consistent with the Company's historical treatment of its deferred ITCs. (TR 3458) The Company's treatment is consistent with FPSC practice, which is to assign a cost of capital for the deferred ITCs using the weighted average cost rate of investor sources of capital. This practice has been codified in Commission orders for the last several decades. (TR 3214-3215, 3458) Staff agrees with TECO that the deferred ITCs should be assigned the average cost rate for the investor sources of capital (7.64 percent) which is discussed in Issue 34.

On July 24, 2024, TECO submitted an adjustment letter that revised the in-service dates for Lake Mabel Energy Storage and South Tampa Energy Storage. In regard to Lake Mabel, the Company updated the in-service date from April 2025 to January 2025 and for South Tampa from April 2025 to December 2025. The effect of these updates would be an increase in the 2025 revenue

requirement by \$2.1 million dollars and a decrease in the SYA 2026 and 2027 by \$2.4 million dollars and \$0.4 million dollars, respectively. (EXH 217, MPN E8283)

On August 22, 2024, TECO filed an updated revenue requirement document which changed the proposed service life as originally filed for energy storage assets of 10-years to 20-years. According to the filed document, the changes decreased the Company’s proposed 2025 revenue requirement by \$2,623,117 and decreases its proposed 2026 and 2027 SYA by \$1,352,721 and \$91,305, respectively. (EXH 835, P 3)

Based on a review of the parties’ testimony and arguments, staff believes TECO should take advantage of the IRS’s revised normalization rules and opt-out of the normalization requirements for energy storage assets. However, staff agrees with TECO that a three-year amortization period is too short, but believes a five-year amortization period is beneficial to customers without causing financial harm to TECO. TECO did not provide any testimony showing that using a five-year amortization period would negatively impact the Company’s earnings.

FL. Rising/LULAC did not proffer an argument but took the position that the ITCs should be treated as if TECO opted out of the normalization requirements and the ITCs should be deferred and amortized over 10 years. (FL. Rising/LULAC BR 18-19) FIPUG adopted the position of OPC (FIPUG BR 16), FEA and Fuel Retailers took no position (FEA BR 26; Fuel Retailers BR 10), FRF essentially took the same position as OPC (FRF BR 40), Sierra Club adopted FL Rising/LULAC’s position (Sierra Club BR 56), and Walmart adopted OPC’s position and argument. (Walmart BR 9)

Staff adjusted the battery storage ITC annual amortization amount to reflect an amortization period of five years based on TECO witness Strickland’s ITC calculations in her revised rebuttal testimony filed on July 31, 2024. (TR 3226-3229) Staff’s calculation is summarized in Table 65-1.

**Table 65-1  
 Staff Calculation of 5-year Amortization for 2025**

Project	Cost	ITCs	Annual Amortization	In service proration	2025 Amortization
Wimauma	\$50,709,000	\$15,212,000	\$3,042,540	0.8333333	\$2,535,450
Lake Mabel	\$54,457,495	\$16,337,249	\$3,267,450	0.9166667	\$2,995,162
Dover	\$18,270,000	\$5,481,000	\$1,096,200	1.0	\$1,096,200
<b>Total</b>					<b>\$6,626,812</b>

Source: (TR 3226-3229; Staff Analysis)

TECO’s original filing included an estimated annual amortization expense amount of \$3.743 million. (TR 3226-3229) After the change of in-service dates for some of the battery storage assets, staff calculated amortization expense in the amount of \$6.627 million (including the Dover battery storage asset), which equates to an increase of \$2.883 million. (\$6.627 million -

\$3.743 million) After applying the NOI multiplier of 1.34364, staff's recommended revenue requirement reduction is \$3.874 million for the 2025 projected test year.

### **CONCLUSION**

The Commission should approve a five-year amortization period for Investment Tax Credits for Battery Storage assets as if the Company opted out of normalization. The amount of the Investment Tax Credits related to the battery storage assets is \$37.031 million and the annual amortization should be \$6.627 million for the 2025 projected test year.

Date: November 22, 2024

**Issue 66:** What amount of Income Tax expense should be approved for the 2025 projected test year?

**Recommendation:** The amount of Income Tax expense that should be approved for the projected 2025 test year is (\$1,011,625). (Vogel)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Income Tax Expense (Benefit) totaling (\$8.3 million) for the projected 2025 test year as shown on MFR Schedule C-1, plus \$668,825 per the company's July and August Filings, for a total of (\$9.0 million). The July and August Filings provided revenue requirement impacts and the \$668,825 of Income Tax expense adjustments includes the appropriate tax impacts to NOI.

**OPC:** This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The Income Tax expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.

**FL RISING/**

**LULAC:** Adopt OPC position.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Fall-out issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. TECO requested an Income Tax expense of (\$8.3 million) for the projected 2025 test year. Based on adjustments to Issues 64, 65, and 70, along with corresponding adjustments to all NOI issues, staff recommends an increase in Income Tax expense of \$7,316,375.

### **CONCLUSION**

Therefore, staff recommends an Income Tax expense amount of (\$1,011,625) for the projected 2025 test year.

Date: November 22, 2024

**Issue 67:** What amount of Net Operating Income should be approved for the 2025 projected test year?

**Recommendation:** The amount of Net Operating Income that should be approved for the 2025 projected test year is \$547,059,693. (Mason)

**Position of the Parties:**

**TECO:** The Commission should approve Jurisdictional Adjusted Net Operating Income (“NOI”) for the projected 2025 test year of \$501.4 million as shown on MFR Schedule C-1, plus \$5,915,753 of NOI adjustments per the company’s July and August Filings, for a total of \$507.3 million. The July and August Filings provided revenue requirement impacts and the \$5,915,753 of NOI adjustments includes the appropriate tax impacts to NOI.

**OPC:** This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The Net Operating Income for the projected 2025 test year should reflect all of OPC’s recommended adjustments.

**FL RISING/**

**LULAC:** This is largely a fallout issue. The Net Operating Income for the projected 2025 test year should reflect all of Florida Rising’s and LULAC’s recommended adjustments.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** This is a fallout issue. The amount of Net Operating Income that is approved for the 2025 projected test year should be adjusted in accordance with the substantive recommendations outlined in this brief and issues statement.

**FRF:** Fall-out issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. Based on the previous adjustments in Issues 7, 11, 20, 22, 24, 41, 43, 45, 53, 55, 56, 64, 65, and 70, staff is recommending a Net Operating Income of \$547,059,693 for the projected test year.

**CONCLUSION**

The amount of Net Operating Income that should be approved for the 2025 projected test year is \$547,059,693.

**2025 REVENUE REQUIREMENTS**

**Issue 68:** What revenue expansion factor and net operating income multiplier, including the appropriate elements and rates, should be approved for the 2025 projected test year?

**Recommendation:** Staff recommends that the appropriate revenue expansion factor should be 74.424 percent and net operating income multiplier should be 1.34364 for the 2025 projected test year. The appropriate elements and rates are discussed in the analysis portion of this recommendation. (G. Kelley)

**Position of the Parties:**

**TECO:** The Commission should approve a revenue expansion factor and NOI multiplier of 0.74424 and 1.34364, respectively, for the projected 2025 test year based on the following elements and rates: regulatory assessment fee (0.085 percent), bad debt rate (0.224 percent), state income tax rate (5.5 percent) and federal income tax rate (21.0 percent).\*

**OPC:**

Assume pre-tax income of		1.0000%
Regulatory Assessment		0.00085%
Bad Debt Rate		0.00224%
Net Pretax Subtotal		<u>0.99691%</u>
State income tax	5.50%	0.054830%
Taxable income for Federal income tax		<u>0.94208%</u>
Federal income tax at 21%	21.0%	0.19784%
Revenue Expansion Factor		<u><u>0.74424%</u></u>
Gross-Up		1.34364%

**FL RISING/**

**LULAC:** The revenue expansion factor and net operating income multiplier should be adjusted to reflect a 50-50 equity-to-debt ratio.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The appropriate revenue expansion factor is 1.34364.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

On MFR Schedule C-44, TECO calculated a net operating income multiplier of 1.34364. (EXH 5, MPN J343) This multiplier is based on a revenue expansion factor of 74.424 percent, formulated using a 0.0848 percent factor for regulatory assessment fees, a 0.224 percent bad debt rate, a 5.5 percent state income tax, and a 21.0 percent federal Income Tax rate. No other party to this proceeding took an alternative position to TECO's requested net operating income multiplier. The net operating income multiplier calculation is shown in Table 68-1.

Concerning intervenor positions on this Issue, FL Rising/LULAC took the position that "the revenue expansion factor and net operating income multiplier should be adjusted to reflect a 50-50 equity-to-debt ratio." (FL Rising/LULAC BR 19) Staff notes the net operating income multiplier will be applied to any net operating income differential the Commission deems appropriate. Staff believes the net operating income multiplier is "downstream" of the equity ratio determination as addressed in Issue 38 and thus, disagrees with FL Rising/LULAC.

**Table 68-1  
 NOI Multiplier**

Description	Value
Revenue Requirement	100.000%
Less Regulatory Assessment Fee	0.0848%
Less Staff Calc. Bad Debt Rate	<u>0.224%</u>
Net Before Income Taxes	99.691%
Less State Income Tax @ 5.5%	5.483%
Net Before Federal Income Tax	94.208%
Less Federal Income Tax @ 21.0%	<u>19.784%</u>
Revenue Expansion Factor	<u>74.424%</u>
NOI Multiplier (100/74.424)	<u>1.34364</u>

Source: EXH 5, MPN J343

**CONCLUSION**

Staff recommends that the appropriate revenue expansion factor should be 74.424 percent and net operating income multiplier should be 1.34364 for the 2025 projected test year, including the elements and rates discussed in the analysis portion of this recommendation.

**Issue 69:** What amount of annual operating revenue increase for the 2025 projected test year should be approved?

**Recommendation:** The amount of annual operating revenue increase that should be approved for the projected 2025 test year is \$153,379,370. (Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve a \$288.0 million annual operating revenue increase for the 2025 projected test year as shown on the company's August Filing.

**OPC:** The Commission should approve a revenue increase of no more than \$43.8 million for 2025.

**FL RISING/**

**LULAC:** \$0. The Commission should deny TECO's requested rate increase.

**FIPUG:** Adopt the position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No more than \$36.7 million per year.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. In its original filing, TECO requested a total operating revenue increase of \$297,802,000 for the projected 2025 test year. Based on the previous adjustments to Plant in Service, ROE, and Net Operating Income, staff is recommending an operating revenue increase of \$153,379,370 for the projected test year 2025.

**CONCLUSION**

The amount of annual operating revenue increase that should be approved for the projected 2025 test year is \$153,379,370.

**2025 COST OF SERVICE AND RATES**

**Issue 70:** Is TECO's proposed separation of costs and revenues between the wholesale and retail jurisdictions appropriate?

**Recommendation:** Yes. TECO's proposed separation of costs and revenues between the wholesale and retail jurisdictions is appropriate and should be approved as shown in MFR Schedule E, Volume I. (McClelland)

**Position of the Parties:**

**TECO:** Yes. Tampa Electric's proposed Jurisdictional Separation Study is appropriate and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** Adopt OPC position.

**FIPUG:** No position at this time.

**FEA:** FEA supports TECO's jurisdiction allocation study.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's jurisdictional separation cost of service study.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

TECO provided an explanation of the methodology used to develop separation factors for each cost component in MFR Schedule E, Volume I. (EXH 8) TECO witness Williams explained the need for the jurisdictional separation study in his direct testimony, stating that it allowed TECO to allocate costs to wholesale and retail customers in a manner consistent with TECO's previous filings. (TR 3657) Witness Williams stated that TECO does not currently provide long-term firm requirements electric power service to any wholesale customers. (TR 3658) TECO provides transmission service to two Open Access Transmission Tariff customers, Seminole Electric Cooperative, Inc. and DEF. (TR 3658) Retail business represents 100 percent of production and distribution plant and 93.52 percent of transmission plant. (TR 3659)

In its brief, FEA supported TECO's jurisdictional separation cost of service study. No other party took a position on this Issue.

### **CONCLUSION**

TECO's proposed separation of costs and revenues between the wholesale and retail jurisdiction is appropriate and should be approved as shown in MFR Schedule E, Volume I.

**Issue 71:** What is the appropriate methodology to allocate production costs to the rate classes?

**Recommendation:** The appropriate methodology is the 12 Coincident Peak (CP) and 1/13 Average Demand (i.e., energy) methodology. The gasifier of Polk Unit 1 and the scrubber of the Big Bend Unit 4 should continue to be allocated on an energy basis. TECO should file a revised cost of service study, including rates and tariffs, that reflect the Commission vote on all issues by December 9, 2024, close of business. The Commission-approved methodology should also be utilized in other cost recovery clauses for allocation of production demand classified costs to the rate classes. (Draper, McClelland)

**Position of the Parties:**

**TECO:** The company has proposed to allocate production costs using the 4 Coincident Peak methodology as provided in the 2021 Agreement. The Big Bend Unit 4 scrubber and Polk 1 gasifier should continue to be allocated on an energy basis, which is consistent with Tampa Electric's last four approved Cost of Service Studies.

**OPC:** No position.

**FL RISING/**

**LULAC:** The Twelve Coincident Peak and 50% Average Demand cost allocation methodology.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** FEA supports the use of 4CP methodology as proposed by TECO. See below.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

Five witnesses testified in this proceeding regarding the appropriate allocation of production costs to the rate classes. The selection of the appropriate production cost allocation affects how

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much of the revenue requirement should be allocated to each rate class and is an area of disagreement in this case.

The four parties (TECO, FIPUG, FRF, and FEA) testifying in support of the Coincident Peak (4 CP) method are parties to the 2021 Settlement Agreement. The 2021 Settlement Agreement provides that TECO will, in its next rate case proceeding, file the cost of service MFRs using the 4 CP and full MDS methods for cost allocation and that all parties will either not oppose, or will support, the 4 CP (and full MDS) implementation.<sup>57</sup> FL Rising/LULAC were not a party to TECO's 2021 rate case and filed testimony objecting to the use of the 4 CP method.

## **TECO**

Consistent with the language in the 2021 Settlement Agreement, TECO proposed the 4 CP cost allocation methodology. (TR 3654) CP demand reflects the contribution to the system monthly peak demand for each of the rate classes. (TR 3672) To illustrate, TECO witness Williams explained at the hour of the system peak in a particular month, the CP demand for the residential class would be the class's proportion of that hour's system peak demand. (TR 3672)

Pursuant to the MFR requirements set forth in Rule 25-6.043(1)(a), F.A.C., TECO also filed a cost of service study allocating production demand costs using the 12 Coincident Peak and one-thirteenth Average Demand (12 CP and 1/13 AD) cost allocation methodology. (TR 3654; TR 3732) The 12 CP and 1/13 AD methodology looks at the coincident peak for each of the 12 months and recognizes there is an energy component associated with production plants. (TR 3734) Stated in percentages, the 12 CP and 1/13 AD methodology allocates approximately 92 percent of production plant based on each rate class' demand that is projected to occur coincident with each of the 12 monthly system peaks and approximately 8 percent on each rate class's share of average demand. (TR 2713) Average demand is mathematically the same as allocating costs on an annual energy usage.<sup>58</sup> (TR 2713; TR 3734) During cross examination, witness Williams agreed that "proponents of the 12 CP recognize" that one of the advantages of the 12 CP methodology is that it recognizes that TECO is required to serve load all throughout the year, including the shoulder months. (TR 3735)

TECO witness Williams explained in his direct testimony that the 2021 Settlement Agreement requires TECO to implement a 4 CP cost allocation methodology. (TR 3654) Witness Williams explained that the 4 CP methodology allocates costs to the rate classes based on the rate classes' projected average contribution to the system peak during the test year period months of January, June, July, and August. (TR 3674) The selected months were agreed upon in the 2021 Agreement. (TR 3674)

To support the use of the 4 CP methodology, witness Williams asserted that the 4 CP methodology was a requirement of the 2021 Agreement and is an accepted cost allocation methodology. (TR 3675) First, witness Williams explained that TECO's peaks are primarily a function of energy consumption associated with weather and there is a strong correlation between weather and residential and small commercial energy consumption. (TR 3675) Large commercial and industrial customers tend to be high load factor customers and their

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<sup>57</sup> Order No. PSC-2021-0423-E-EI, Attachment A, p. 31.

<sup>58</sup> Average demand is total energy usage divided by the number of hours of use.



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consumption is not as strongly correlated to weather; therefore, witness Williams asserted, their energy consumption stays fairly consistent throughout the year. (TR 3675) Second, witness Williams stated that TECO's transition from large coal-fired generation units to cleaner resources like solar has diminished the importance of shoulder months for operational planning and cost attribution purposes. (TR 3675) Third, witness Williams stated that the 4 CP methodology can serve as a catalyst for economic development. (TR 3676)

While the Commission approved the 4 CP methodology in TECO's 2021 Settlement Agreement, staff notes that TECO did not propose a 4 CP method during its 2008, 2013, and 2021 rate cases. In its 2008 rate case, TECO proposed, and the Commission approved by Order No. PSC-09-0283-FOF-EI (page 85) the 12 CP and 25 percent AD method.<sup>59</sup> In its 2013 rate case, which resulted in a settlement approved in Order No. PSC-13-0443-FOF-EI, rates reflected the use of the 12 CP and 1/13 AD method. In its MFRs for the 2013 rate case, TECO had proposed the 12 CP and 50 percent AD method. (TR 3742-3743) Cost allocation is therefore a matter of judgement upon which reasonable people can disagree. In response to discovery by FL Rising/LULAC, TECO stated that "Tampa Electric acknowledges other methodologies can be used to analyze cost allocation." (EXH 164, MPN E2119)

Staff does not find the evidence presented by TECO in support of the 4 CP method persuasive. During cross examination, witness Williams relied heavily on the fact that the 2021 Settlement Agreement required TECO to file the 4 CP cost of service study. (TR 3737-3738; TR 3743: TR 3744; TR 3746; TR 3766) However, although the 2021 Settlement Agreement required TECO to file a 4 CP method in its next rate case, the Commission is not bound to approve the 4 CP method here, after considering all the evidence in the record.

During cross examination, witness Williams was asked about the allocation of certain projects such as building improvements at power plants, dismantlement costs for Big Bend, and the costs of the new headquarters. Under the proposed 4 CP method the allocation to the rate classes are based on their projected coincident peaks in June, July, August and January of 2025. However, witness Williams admitted that the projected residential coincident peak of January 2025 does not change the costs of the new headquarters. (TR 3748) This suggests that projects like the headquarters, for instance, are more reasonably allocated on a 12 CP basis. FL Rising/LULAC asserted that "not a single piece of evidence was presented showing that any kind of the fossil or solar generation investments, and certainly not Big Bend dismantlement costs or new headquarter costs, are being made because of the hypothetical peaks at issue in the 4 CP cost of service study." (FL Rising/LULAC BR 3)

With respect to the four months chosen, TECO explained the parties agreed during the 2021 Settlement Agreement to use June, July, August, and January as these are the four months in which peak demand was projected to be above 4,000 MW in TECO's most recent Ten-Year Site Plan with each of these months exceeding 90 percent of TECO's system peak demand. (EXH 84, MPN C27-2869)

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<sup>59</sup> Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 20080317-EI, *In re: Petition for rate increase by Tampa Electric*.

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Staff agrees that TECO's Ten-Year Site Plan, filed April 1, 2024, Schedule 4, shows a 2025 forecast peak demand of over 4,000 MW for June, July, August, and January. (EXH 408, MPN F2.2-7750) However, TECO's Ten-Year Site Plan also shows 2025 forecast peak demand of over 4,000 MW for the months of May and September; and for the month of December the forecasted peak demand is 3,918 MW. Therefore, considering months in which peak demand is projected to be above 4,000 MW, without the 90 percent of TECO's system peak demand threshold, could support a 6 CP method, or 7 CP if December were to be included. The remaining months (February, March, April, October, and November) show a forecast peak demand that ranges from 3,436 MW to 3,873 MW. (EXH 408, MPN F2.2-7750) The peak demand values stated above represent total retail and wholesale demand and exclude conservation impacts. However, production facilities are used year round, and should be allocated accordingly. Furthermore, 4 CP versus 12 CP is a cost allocation issue, not a planning tool to address reliability.

TECO stated that the Ten-Year Site Plan focuses on two system peaks for calculating reserve margin: a summer and a winter peak, and this consideration alone could support a 2 CP methodology. (EXH, MPN C27-2867) TECO further asserted that the 4 CP in the 2021 Settlement Agreement is a middle ground between the historical 12 CP and the summer and winter peak focus implicit in the Ten-Year Site Plan. (EXH 84, MPN C-27-2867-2868)

Witness Williams testified that TECO's transition from large coal-fired generation units to cleaner resources like solar has diminished the importance of shoulder months for operational planning and cost attribution purposes. (TR 3675) Staff does not disagree that TECO has reduced coal as a generation source. TECO witness Aldazabal also addressed the reduction in coal, testifying that since 2013, coal went from 58.7 percent of TECO generation mix to 3.8 percent in 2023. (TR 619)

TECO witness Allis addressed the retirement of coal plants and noted that environmental regulations impacted the cost of existing coal-fired generation, while gas-fired generation became much less expensive and renewable generation became more economical. (TR 1769-1700) Finally, witness Allis addressed the year-round operational concerns of solar facilities as solar energy is not created consistently throughout out the day and therefore other generation needs to come online quickly and frequently to follow load. (TR 1710) Witness Allis testimony, however, does not support the assertion that shoulder months are less important for operational planning purposes. For example, when discussing the impetus for the Polk Unit 1 conversion project, TECO indicated its purpose was for energy flexibility, not to meet peak demand. (TR 654)

Witness Williams also ignores the influence of projected fuel savings from solar. TECO witness Collins testified that fuel savings is one of the major benefits of having solar power plants on the grid. (TR 306) TECO's Ten-Year Site Plan states that TECO is adding solar generation to "promote fuel diversity, protect customers from fuel price volatility, and lower fuel costs on customers' bills." (EXH 408, MPN F2-2-7702) Having an energy weighted allocation of 8 percent as under the 12 CP and 1/13 AD method recognizes the role energy is given in generation facility planning. For solar assets, in the 2021 rate case, TECO proposed allocating them as 50 percent demand related and 50 percent energy related. (TR 3742) Under the proposed

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4 CP method, no costs are allocated based on an energy responsibility. Fuel savings are apportioned on an energy basis, and therefore, staff does not believe the addition of solar is a convincing argument to support the use of the 4 CP methodology (with no energy allocator), especially in the light that TECO proposed a 50 percent energy allocation for solar in its 2021 rate case filing. If customer classes receive energy-based benefits through lower fuel costs afforded by solar investment, costs should accordingly be allocated to the customer classes with an energy allocator.

In response to an interrogatory by FL Rising/LULAC, TECO stated that currently its solar facilities do not contribute the entirety of the nameplate capacity to peak load. (EXH 163, MPN E2095) TECO also stated that solar photovoltaic has a zero-capacity value for winter reserve margin, because solar output starts after the peak morning load in January. (EXH 163, MPN E2100) Finally, TECO responded that solar photovoltaic provides fuel cost savings that justify the solar additions. (EXH 163, MPN E2100) FL Rising/LULAC noted that DEF supported a 12 CP and 25 percent AD cost of service study in their rate case “given the amount of solar on their system and diminishing capacity value of standalone solar assets.” (FL Rising/LULAC, BR 3)

With respect to witness Williams’ testimony that the 4 CP methodology can serve as a catalyst for economic development, staff notes that TECO has other tools available to attract new businesses. (TR 3806) Specifically, TECO already has a Commission-approved Economic Development Rider as well as a Commercial/industrial Service Rider tariffs. (TR 3806) To address economic development, TECO proposed changes to its Economic Development Rider tariff to remain competitive. (TR 3690-3691). The changes to the Economic Development Rider tariff are addressed in Issue 88. TECO itself acknowledges that the benefit of the Economic Development Rider is “that it helps attract and retain business to the area which translates into job creation, places for residents to go and shop, and tax revenue.” (EXH 165, MPN E2197) Therefore, staff concludes that using economic development as an argument to support 4 CP does not provide a compelling reason to favor a 4 CP method over another cost of service methodology.

### **FL Rising/LULAC**

FL Rising/LULAC opposed TECO’s use of the 4 CP production demand allocator. FL Rising/LULAC witness Rábago testified that the use of the 4 CP allocation method unjustly increases the share of production and demand-related retail costs that residential customers must bear relative to other rate classes when compared to the 12 CP or 12 CP and 1/13th AD methods. (TR 2605 – 2606)

Witness Rábago asserted that, along with the use of the Minimum Distribution System (MDS), the use of the 4 CP allocation method adds about \$71 million in costs to residential customers. (TR 2606) Witness Rábago explained that residential customers are viewed as generating a larger share of peak demand under a 4 CP approach, and therefore are allocated more of the costs. (TR 2606) Whereas, if the highest peak days on each of the 12 months are sampled, larger customers will be assigned more costs based on their consistently high usage across the year. (TR 2606) On cross examination, TECO witness Williams agreed that a 4 CP methodology with MDS allocates less cost onto the large commercial and industrial customers and more costs to

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the residential and small commercial customers as compared to the other cost of service study filed in this case. (TR 3757)

TECO agreed with FL Rising/LULAC's assertion regarding the impact on the residential revenue requirement between the two cost of service models presented. Specifically, TECO stated that using the 4 CP, with MDS, method would allocate about \$1.114 billion to residential customers; using the 12 CP and 1/13 AD method, without MDS, would allocate \$1.043 billion to residential customers. (EXH 165, MPN E2163) Staff notes this comparison between the two cost of service models includes the impact of the MDS method. Both the MDS method and the 4 CP method increase the revenue requirement for the residential and small commercial rate classes. (EXH 165, MPN E2182)

Staff reviewed the evidence presented by TECO with respect to the impact on a monthly 1,000 kWh residential bill. Under TECO's proposed 4 CP, with MDS method, the base rate portion of the residential bill would increase from \$87.80 to \$107.01, a \$19.21 increase. (EXH 3, MPN J3) Under the 12 CP and 1/13 AD method, without MDS, the base rate portion of the residential bill would increase from \$87.80 to \$99.35, a \$11.55 increase. (EXH 198, MPN E5952)

Commercial/industrial customers would see lower bills under the proposed 4 CP, with MDS, method. While there is no "typical" commercial/industrial customer, to illustrate, for a General Service Demand (GSD) customer, using 219,000 kWh and having a demand of 500 kW, the base rate portion of the bill would increase from \$8,744 to \$11,554 under TECO's proposed cost of service study. (EXH 3, MPN J6) Under the 12 CP and 1/13 AD method, without MDS, the base rate portion of the same GSD bill would increase from \$8,744 to \$13,406. (EXH 198, MPN E5953)

Witness Rábago presented several arguments in opposition to the 4 CP method. Witness Rábago asserted that TECO's increased use of solar generation as a justification for 4 CP is flawed as it is an argument about the performance of generators, not cost causation characteristics of customers. (TR 2608) Witness Rábago further asserted that under the 4 CP method, 25 percent of allocated costs are based on the January coincident peak, which has no relationship to solar production costs. (TR 2608) Witness Rábago also stated that low-use, low-income customers often have flat load shapes, especially in the South. (TR 2608) Finally, witness Rábago testified that in the 2021 rate case, TECO proposed to allocate 50 percent of solar production to energy. (TR 2608) In its brief, FL Rising/LULAC argue that "TECO's investments are being made for their energy, i.e., fuel savings, and thus, under a cost-causation principle, those costs should be allocated on an energy basis". (FL Rising/LULAC BR. 3) Staff agrees with witness Rábago's assertions regarding solar generation not being a persuasive argument for 4 CP.

In sum, witness Rábago recommended the use of the 12 CP and 50 percent AD methodology. (TR 2609) Alternatively, if the Commission does not accept the 12 CP and 50 percent AD methodology, witness Rábago advocated that the Commission direct TECO to use the 12 CP and 1/13 AD methodology. (TR 2069) Staff believes that an argument could be made to allocate the solar production facilities on a 50 percent energy basis; however, the 12 CP and 1/13 AD method provides a reasonable resolution to the different positions of the parties on this Issue and has an extensive history of regulatory approval in Florida.

## FIPUG

FIPUG witness Pollock testified that the 4 CP methodology is preferable to the 12 CP and 1/13 AD methodology. (TR 2713) Witness Pollock further testified that the 4 CP method is consistent with cost causation and that peak demand drives cost causation. (TR 2714) Witness Pollock presented a chart in his direct testimony to highlight the differences in TECO's monthly system peak demands, with the summer months of June, July, August, and September showing the highest peaks based on the historical period of 2020 through 2025. (TR 2715) While January is not peak month in the chart, witness Pollock asserted that TECO is currently projecting a winter peak in January 2025 and is also projecting more peak load growth during the winter months than the summer months. (TR 2715) Witness Pollock based this information on TECO's Ten-Year Site Plan 2024, page 20. Witness Pollock places great focus on peak months in his direct testimony to support the 4 CP method and stated that under a 12 CP method "the lights would go out". (TR 2718) However, utilities also plan for year-round operations and meeting the winter peak is not the only consideration. TECO's Ten-Year Site Plan states that TECO's ". . . current and projected resources meet operating reserve requirements under normal peak demand scenarios." (EXH 408, MPN F2.2-7728)

Witness Pollock then went on to present reasons why the 12 CP method does not reflect cost causation. (TR 2717) Specifically, witness Pollock argued that meeting system peak demand is the cost-causer and TECO must plan for sufficient capacity to meet the expected summer peak and secondary winter peak demand. (TR 2717) Witness Pollock further testified that the National Associate of Regulatory Utility Commissioner's cost allocation manual states that the "12 CP method is usually used when the monthly peaks lie with a narrow range, i.e., when the annual load shape is not spiky." However, witness Pollock asserted, that TECO's annual load shape is spiky. (TR 2718) While staff agrees that TECO's load shape varies monthly, staff also believes that that is expected and how "spiky" an annual load shape is a judgement call. Staff is not persuaded that the so-called "spikes" are extreme enough to obviate the utility of the 12 CP method.

Finally, witness Pollock objected to TECO's classification of the gasifier investment of Polk Unit 1 and the scrubber at Big Bend Unit 4 as energy-related as there is no valid reason to classify these investments differently than the remaining investments in these plants. (TR 2724) Polk Unit 1 is an integrated Gasification Combined Cycle Unit. (EXH 158, MPN E1927)

Witness Williams, in his rebuttal testimony, addressed the allocation of Polk Unit 1 gasifier and the Big Bend Unit 4 scrubber. (TR 3706) Witness Williams noted that witness Pollock made the same arguments in TECO's 2008 rate case and the Commission rejected these arguments in Order No. PSC-09-0283-FOF-EI.<sup>60</sup> (TR 3707)

As shown on pages 85 and 86 of Order No. PSC-09-0283-FOF-EI, the Commission considered all the evidence presented in the TECO's 2008 rate case regarding the gasifier of Polk Unit 1 and the scrubber of the Big Bend Unit 4. Furthermore, the Big Bend Scrubber allocation on an energy basis had also previously been approved in TECO 1992 rate case. The scrubber captures

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<sup>60</sup> Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, Docket No. 20080317-EI, *In re: Petition for rate increase by Tampa Electric Company*.

unwanted emissions from the plant. During cross examination, witness Williams testified that “the Commission has considered the gasifier to be fuel related, thus energy related, since at least Tampa Electric’s last four rate cases.” (TR 3734) Staff agrees with TECO that these two investments should continue to be allocated on an energy basis and witness Pollock has not presented any new rationale to change the allocation. As discussed in Issue 24, staff recommends that the Polk Unit 1 gasification system should be retired; therefore, if the Commission votes to retire the Polk Unit 1 gasification system, the allocation for this asset would be moot.

### **FEA and FRF**

FEA’s witness Gorman supported the 4 CP methodology as it reflects cost causation. (TR 3060) In his summary of direct testimony, witness Gorman stated that the 4 CP allocation aligns with the amount of capacity the Company has to invest for production and transmission resources in order to reliably serve customers throughout the year. (TR 3075) Finally, FRF witness Chriss, testified that for purposes of this docket, FRF does not oppose TECO’s proposed cost of service study. (TR 3103) FEA and FRF did not provide any additional evidence and as signatories to the 2021 Settlement Agreement are required to either not oppose or support the 4 CP with MDS method.

## **CONCLUSION**

Based on the evidence presented, the appropriate methodology is the 12 CP and 1/13 AD (i.e., energy) methodology. The gasifier of Polk Unit 1 and the scrubber of the Big Bend Unit 4 should continue to be allocated on an energy basis. TECO should file a revised cost of service study, including rates and tariffs, that reflect the Commission vote on all issues by December 9, 2024, close of business. The Commission-approved methodology should also be utilized in other cost recovery clauses for allocation of production demand classified costs to the rate classes.

**Issue 72:** What is the appropriate methodology to allocate transmission costs to the rate classes?

**Recommendation:** Transmission costs should be allocated on a 12 CP basis. (Draper, Guffey)

**Position of the Parties:**

**TECO:** Tampa Electric has proposed to allocate transmission costs using the 4 Coincident Peak methodology as provided in the 2021 Agreement.

**OPC:** No position.

**FL RISING/**

**LULAC:** The Twelve Coincident Peak cost allocation methodology.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** FEA supports the use of 4CP methodology as proposed by TECO.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams testified that as required by the 2021 Settlement Agreement, TECO proposed to use the 4 CP methodology to allocate the demand-related transmission costs. (TR 3673) Witness Williams explained that the 4 CP methodology allocates costs to the rate classes based on the rate classes' projected average contribution to the system peak during the test year period months of January, June, July, and August. (TR 3674) The selected months were agreed upon in the 2021 Agreement. (TR 3674)

Transmission costs should be allocated consistent with the Commission's vote on Issue 71. If the Commission approves TECO's proposed 4 CP methodology, then transmission costs should also be allocated based on the 4 CP methodology. If the Commission rejects the 4 CP methodology, and approves staff's recommendation for a 12 CP and 1/13 AD allocator, then transmission costs

should be allocated on a 12 CP basis. Transmission costs have typically been allocated on a 12 CP basis, with no energy weighting, by all Florida's investor-owned utilities.

### **CONCLUSION**

Transmission costs should be allocated on a 12 CP basis.



**Issue 73:** What is the appropriate methodology to allocate distribution costs to the rate classes?

**Recommendation:** Distribution plant in accounts 369 (service drops) and 370 (meters) should be classified as customer-related and distribution costs in accounts 364 through 368 (poles, overhead lines, underground lines, and transformers) as demand-related. The use of the Minimum Distribution System (MDS) should be rejected. (Hampson)

**Position of the Parties:**

**TECO:** Tampa Electric proposes to classify distribution costs using a full MDS approach as provided in the 2021 Agreement. Distribution costs should be allocated the same way in which they were derived and provided in MFR Schedule E-10. The allocation methodology relies on a mixture of rate class non-coincident peaks and customer maximum demands.

**OPC:** No position.

**FL RISING/**

**LULAC:** The Twelve Coincident Peak cost allocation methodology.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** FEA supports TECO's proposed use of the MDS to classify primary distribution cost as customer and demand. FEA supports the primary distribution cost classified as customer to be allocated across rate classes on class customer numbers. FEA supports allocating primary distribution costs classified as demand on a non-coincident class demand allocator.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

Five witnesses testified in this proceeding regarding the appropriate methodology to allocate distribution costs to the rate classes. The selection of the appropriate distribution cost allocation methodology affects how much of the revenue requirement should be allocated to each rate class which has a direct impact on the rates customers pay.

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The four parties (TECO, FIPUG, FEA, and FRF) that testified in support, or did not oppose, the MDS methodology are parties to the 2021 Settlement Agreement. The 2021 Settlement Agreement provided that TECO will, in its next rate case proceeding, file the cost of service MFRs using the 4 CP and full MDS methodologies for cost allocation and that all parties will either not oppose, or will support, the full MDS (and 4 CP) implementation.<sup>61</sup> FL Rising/LULAC were not a party to TECO's 2021 rate case and filed testimony objecting to the use of the MDS methodology.

The standard classification of electric utility costs are demand-, customer-, and energy-related costs. Distribution costs are composed of both demand- and customer-related costs. Without the use of the MDS method, only distribution plant in accounts 369 (service drops) and 370 (meters) are classified as customer-related and distribution costs in accounts 364 through 368 (poles, overhead lines, underground lines, and transformers) are classified as demand-related. The rationale for this classification method is that only the line from the transformer to the meter (service drop) and the meter itself are customer-related and should therefore be allocated on the basis of number of customers. All other distribution facilities are allocated on a demand allocator on the theory that load determines the size of facilities. The customer allocator is calculated by dividing the number of customers in each rate class by total customers. Customer and demand allocators vary by rate class, resulting in assigning more or less costs to a rate class, depending on the allocator used.

MDS is an alternative method for classifying distribution plant in accounts 364 through 368. Specifically, the MDS method classifies a portion of the costs in accounts 364 through 368 as customer-related and the remaining portion as demand-related. To arrive at this allocation between a demand and customer classification, TECO applied a zero-intercept analysis to determine how much of each account is to be allocated on demand and how much on customers. MDS is based on the recognition that the number of poles, lines (conductors), and transformers varies with the number of customers on the system. The zero-intercept methodology involves creating a graph of the unit costs of distribution equipment of varying sizes and estimating a regression line which passes through the zero intercept, or vertical axis, at some positive value. The value of the zero intercept is the statistical estimate of the customer component of the cost of a single unit of the equipment that has, theoretically, zero capacity.

The Commission has previously approved the MDS methodology for investor-owned electric utilities as a provision in rate case settlement agreements. The Commission approved two settlement agreements for Gulf Power Company in 2013 and 2016, which contained a provision for the use of MDS, in Order Nos. PSC-2013-0670-S-EI<sup>62</sup> and PSC-2017-0178-S-EI.<sup>63</sup> In Gulf's 2011 rate case, MDS was approved in a partial settlement agreement.<sup>64</sup> Similarly, the

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<sup>61</sup> Order No. PSC-2021-0423-E-EI, Attachment A, p. 31.

<sup>62</sup> Order No. PSC-13-0670-S-EI, issued December 19, 2013, in Docket No. 20130140-EI, *In re: petition for rate increase by Gulf Power Company*.

<sup>63</sup> Order No. PSC-17-0178-S-EI, issued May 16, 2017, in Docket No. 20160186-EI, *In re: Petition for rate increase by Gulf Power Company*.

<sup>64</sup> Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 20110138-EI, *In re: Petition for increase in rates by Gulf Power Company*.

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Commission approved MDS for TECO in its 2018 and 2021 Settlement Agreements. Outside of settlement agreements, by Order No. PSC-02-0787-FOF-EI (2002 Gulf order), the Commission denied the MDS methodology in the 2002 Gulf Power Company rate case.<sup>65</sup> The 2002 Gulf order refers to numerous Commission orders from the 1980s in which the Commission rejected the use of the MDS system.

## **TECO**

To support the use of the MDS methodology, TECO witness Williams stated that the 2021 Settlement Agreement requires TECO to implement a full MDS cost classification methodology. (TR 3654) Witness Williams explained that the MDS methodology classifies a portion of the primary and secondary voltage distribution system as customer-related costs. (TR 3664)

Besides the language in the 2021 Settlement Agreement, TECO put forth additional reasons why the MDS methodology should be approved in this case. TECO witness Williams stated that:

Second, the MDS methodology is a reasonable and accepted methodology in the utility industry. The principles underlying this methodology are supported in the National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual. The MDS methodology identifies the costs a utility must incur to provide a customer with access to an appropriate utilization voltage at the point at which that customer connects to the distribution system. In other words, MDS represents the utility's readiness to serve customers. Readiness to serve costs are not related to the amount of electricity a customer consumes; thus, MDS costs are classified as customer-related cost components. Fully implementing MDS aligns with cost causation principles.

(EXH 163, MPN 2094)

Witness Williams provided supporting work papers for the MDS analysis in Volume II of the MFR E Schedules. (EXH 9) TECO also prepared a 12 CP and 1/13 AD cost of service study, which does not utilize MDS, to comply with the MFR requirements set forth in Rule 25-6.043(1), F.A.C. (TR 3654; EXH 10)

TECO witness Williams explained that "MDS represents the readiness to serve a customer, not the capacity needed to meet a customer's peak demand requirements." (TR 3664) He classifies MDS costs as customer-related cost components because "[t]he readiness to serve costs are independent of how much electricity a customer consumes." (TR 3664-3665) In other words, TECO witness Williams asserts that customer-related costs are independent of kW and kWh usage and "generally vary with the number of customers on the system." (TR 3662)

In order to separate the total costs of poles, transformers, and overhead and underground lines into two cost components, TECO conducted a MDS study using the zero-intercept method. (TR 3666) As witness Williams explains, "The zero-intercept method is a linear regression analysis

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<sup>65</sup> Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 20010949-EI, *In re: Request for rate increase by Gulf Power Company*.

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that relates a distribution item's unit costs (dependent variable) to its associated capacity values (independent variable)." (TR 3666) Based on a linear regression of the cost data, TECO determined the hypothetical unit cost of distribution facilities with no voltage capacity, which defined the per unit customer-related cost. (TR 3667) The per unit customer-related cost was then multiplied by the total number of that equipment, with the resulting amount classified as customer-related costs and the remaining costs associated with the equipment classified as demand-related. (TR 3667) The resulting customer- and demand-related costs are expressed as percentages and applied to the appropriate embedded plant account. (TR 3667) Separate regression analyses were conducted for each of the FERC accounts associated with overhead transformers, underground transformers, primary and secondary overhead conductors, underground conductors, and distribution poles. (TR 3667-3668)

The resulting percentages of customer and demand-related costs were summarized by account and by secondary and primary voltage. (TR 3668) For instance, total costs for secondary overhead lines would be allocated 73 percent on a customer basis and 27 percent on a demand basis. (TR 3668) Similarly, more than half of the transformer costs would be allocated on a customer basis. Witness Williams also agreed that the majority of costs associated with poles, transformers, and conductors on the secondary system are assigned as customer-related costs under the proposed MDS methodology. (TR 3755)

The Commission has previously denied the MDS methodology, due to the hypothetical nature of relying on linear regressions.<sup>66</sup> In 2002, the Commission found that: "The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load."<sup>67</sup> The Commission further found that there was no real equipment that equated to the costs identified by the MDS methodology and that, "MDS was rejected in the past for this very reason."<sup>68</sup> Similarly here, witness Williams agreed during cross examination that "TECO does not have transformers designed for zero load." (TR 3753) Witness Williams argued in response, ". . . that's not what MDS is particularly for. It's to recognize that there is a cost to be connected to the grid." (TR 3753)

Record evidence does not support allocating the majority of poles, transformers, and lines on a customer basis. On cross examination, witness Williams admitted that just because a new customer is added to the system doesn't necessarily mean that the transformers in the area need to be upgraded if they are of sufficient size to handle the new load." (TR 3754) Even if one were to accept that the number of customers is a partial cause of transformer costs, in addition to load, the zero intercept analysis would allocate 65 percent of secondary transformers and 72 percent of primary transformers on a customer basis, which is a significant percentage of total costs.

TECO also explained that the primary factor considered in planning its distribution system is kW load requirements, even though it also considers the number of customers served. (EXH 202, MPN E6191) Based on that response, kW demand requirements should receive a much larger

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<sup>66</sup> Order No. PSC-02-0787-FOF-EI, p. 76.

<sup>67</sup> *Id.*

<sup>68</sup> *Id.*

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weighting of the reason for installing distribution equipment, not the number of customers served.

Furthermore, TECO agreed that the Company must, at a minimum, install an additional meter and service line when new customers establish service. (EXH 165, MPN E2166) When further questioned on this topic during cross examination, witness Williams agreed that for poles, conductors, and transformers, there is not necessarily a one to one for new customers. (TR 3756) TECO explained that it adds new residential customers to existing transformers if there is suitable capacity on the existing transformer. (EXH 202, MPN E6194)

### **FL Rising/LULAC**

FL Rising/LULAC's position in its post-hearing brief is that the appropriate methodology to allocate distribution costs to the rate classes was the 12 CP cost allocation methodology. (FL Rising/LULAC BR 20) Staff notes that the 12 CP methodology only applies to production and transmission plant, and not distribution plant; therefore, the position does not address the issue of MDS. Demand-related distribution costs are allocated on a mixture of non-coincident peak demand and customer maximum demand.

In the executive summary of its brief, however, FL Rising/LULAC did address the MDS methodology. FL Rising/LULAC stated, "that customers should not pay for hypothetical transformers and poles that do not exist on TECO's system based on a hypothetical construct." (FL Rising/LULAC BR 4) Additionally, FL Rising/LULAC witness Rábago testified that:

TECO's MDS is based on a fantasy [sic] hypothetical distribution system sized to meet the demands of its customers when those customers use no energy and place no demand on the system. The MDS uses mathematical formula to extrapolate these artificial costs for a distribution system that is sized to meet load but then serves no load because it is installed "in readiness." TECO assigns those artificial costs to customers as customer costs. This assignment is made despite TECO's assertion that customer costs are costs associated with customer "connectivity" to the grid and are not related to capacity requirements and that TECO defines demand costs as costs associated with customer maximum load requirements, and despite the fact that customers don't connect to the grid in order to *not* use energy.

(TR 2576)

Witness Rábago further testified that "if the cost disappears because the customer leaves the system, the cost is a customer cost. The consumption function of the meter, the service drop, and a reasonable share of the customer service spending would meet this test . . ." (TR 2583) Witness Rábago continued, stating that "if the cost remains after a customer leaves the system, the cost is not a customer cost." (TR 2583) This is the basis for the basic customer method, which witness Rábago believed is the most appropriate method of classifying customer-related costs. (TR 2584)

Another argument presented by witness Rábago in opposition to the MDS method is his assertion that "TECO uses the MDS to perpetrate a massive cost shift "as low use customers who require

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much smaller and less expensive distribution system investments would be required to subsidize the higher demand-related costs of larger users. (TR 2577)

In his direct testimony, witness Rábago provided an excerpt discussing the MDS methodology from the Regulatory Assistance Project (RAP) Cost Allocation Manual published by RAP in 2020. (TR 2588-2594) Among the limitations of the MDS methodology raised by the RAP Cost Allocation Manual, it noted that since some customers directly pay for extensions of the system with contributions in aid of construction (CIAC), not all of the distribution system is embedded in rates. (TR 2592) By factoring in the entire length of the system, including facilities paid by customers through CIAC, the MDS analysis overstates the customer-related component. (TR 2592-2593) TECO confirmed that its CIAC policy ensures that customers pay for the cost of line extensions required to serve them when the expected revenues do not offset the cost of the extension. (EXH 202, MPN E6196) The Commission's CIAC policy is outlined in Rule 25-6.064, F.A.C.

Witness Rábago further argued that the higher fixed charges resulting from MDS methodology can lead to less incentive for the utility to operate and spend in a "least-cost manner." (TR 2596) Witness Rábago explained that "When marginal distribution costs are allocated to volumetric rates, demand elasticity means that sales will go down as customers seek alternatives to high usage and higher bills." (TR 2596) Conversely, witness Rábago argued, when "a utility is allowed to increase spending and allocate those costs to fixed charges it will have less incentive to operate and spend in a least-cost manner, because it is impacted less by consumption changes that accompany higher prices." (TR 2596)

TECO provided calculations in response to an interrogatory by FL Rising/LULAC comparing the revenue deficiency for all rate classes with and without MDS (assuming the 4 CP method). The results show that the residential and small commercial classes show a larger revenue deficiency with MDS, while the commercial and industrial classes show a smaller revenue deficiency with MDS. (EXH 165, MPN E2182)

For the residential class, the revenue deficiency with MDS is \$196.8 million; without MDS it is \$151.0 million, a difference of \$45.8 million. (EXH 165, MPN E2182) The record evidence is clear that by classifying demand-related costs as customer-related, significantly more distribution plant costs would be assigned to the residential customers.

## **FIPUG**

FIPUG supports the use of the MDS methodology. Witness Pollock contended that MDS is consistent with the principles of cost causation, because when TECO installs a distribution network, it does so partially to provide voltage support and the readiness to serve new customers, irrespective of the amount of power and energy they will consume. (TR 2704)

Witness Pollock argued that the central roles of the distribution network are to provide access to the power grid and to meet the customers' peak electrical power needs (TR 2725) Witness Pollock further argued that the cost to provide customers with access to the power grid are related to the existence of the customer and that classifying all distribution costs as demand-related would not be consistent with cost causation. (TR 2725-2726)

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Witness Pollock explained in direct testimony that without a distribution network and the voltage support it provides, electricity could not flow to customers. (TR 2726) Therefore, witness Pollock concludes the, “investment is essential and unrelated to the amount of power and energy consumer by customers, which is why classifying these costs entirely to demand is not consistent with cost causation.” (TR 2726)

On cross examination, witness Pollock admitted the meter and service drop would not be used if a customer is not a customer. (TR 2578) However, he argued that the same is not true for transformers as they are being shared with multiple customers and do not go away if a customer leaves and is thus not one-for-one. (TR 2678-2679) While witness Pollock asserted that “you build out line transformers in anticipation of serving a certain number of customers in a certain area, and as well as meeting their electricity peak demands,” no support was provided that allocating 65 percent of secondary transformers is the precise portion of the secondary transformer costs that are customer-related.

### **FEA**

FEA witness Gorman also supports TECO’s proposal to use the MDS methodology. (TR 3062) Witness Gorman testified that “employing the MDS to develop the demand and customer-related functionalized costs properly reflect cost-causation.” (TR 3061) According to witness Gorman, “The central idea behind MDS is that there is a minimum cost incurred by a utility when it extends its primary and secondary distribution systems and connects and additional customer to them.” He goes on to assert that “MDS has been accepted for decades as a valid consideration of numerous state public utility commissions.” (TR 3062)

In its brief, FEA argued that the MDS methodology is reasonable and reflects cost-causation because “distribution costs are incurred in order to connect customers to the system, and to serve customers demands.” (FEA BR 30-31) FEA further argued that connecting customers to the distribution system concerns the length of the distribution circuit that are needed to connect all customers to the system, regardless of the demands customers place on the circuits. (FEA BR 31)

### **FRF**

FRF witness Chriss stated that for purposes of this docket, FRF does not oppose TECO’s proposed cost of service study. (TR 3103) FRF did not provide any additional evidence and as signatory to the 2021 Settlement Agreement, is required to either not oppose or support the 4 CP with MDS method. Furthermore, witness Chriss explained that “it is important to note that the settlement was the result of negotiation between the parties with give and take across the breadth of issues, and signing is not necessarily an endorsement of any individual provision of the settlement.” (TR 3103)

TECO, FIPUG, and FEA each individually argued in favor of the MDS methodology by citing its inclusion in the National Association of Regulatory Utility Commissioners’ (NARUC) Electric Utility Cost Allocation Manual. (TR 3666; TR 2727-2728; TR 3062) As the Commission noted in the 2002 Gulf order, the preface of the NARUC manual states three objectives: (1) it should be simple enough to be used a primer on the subject of cost allocation yet offer enough substance for experienced witnesses; (2) it must be comprehensive yet fit in one

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volume; and (3) the writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

Staff notes that the NARUC manual has previously been discussed by the Commission in a prior rate case. In the 2002 Gulf order denying MDS, the Commission found that the NARUC manual was “designed to educate, not mandate any particular methodology.”<sup>69</sup> Furthermore, the 2002 order notes that the NARUC manual “discusses only major methodologies and recognizes that no single costing methodology will be superior to any other and the choice of the methodology will depend on the unique circumstances of each utility.”<sup>70</sup> Staff believes that the NARUC manual is widely accepted as a reference guide for the assignment of costs, but is not mandated, and the arguments stated in the 2002 Gulf order are still valid.

In sum, the record evidence does not support the MDS method. Based on the zero-intercept analysis, with the exception of secondary underground lines, almost half or more than half of the total costs for accounts 364 through 368, secondary and primary voltage level would be allocated based on the number of customers. Neither TECO, nor FIPUG, nor FEA, have provided sufficient evidence that number of customers has such a significant impact on TECO’s method of planning and building its distribution system. Based on TECO’s responses, it appears demand load requirements are the central criterion used in planning, not customers served. The parties supporting MDS also rely on the NARUC manual and the fact that MDS has been an accepted practice in Florida or other states. As stated earlier, the NARUC manual is a reference for assignment of costs and not mandated. While MDS has been approved in the past within the context of settlement agreements, the evidence in this record before the Commission is not sufficient to support MDS.

## CONCLUSION

Distribution plant in accounts 369 (service drops) and 370 (meters) should be classified as customer-related and distribution costs in accounts 364 through 368 (poles, overhead lines, underground lines, and transformers) as demand-related. The use of MDS should be rejected.

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<sup>69</sup> Order No. PSC-02-0787-FOF-EI, p. 75.

<sup>70</sup> *Id.*



**Issue 74:** How should any change in the revenue requirement approved by the Commission be allocated among the customer classes?

**Recommendation:** The appropriate allocation of the change in revenue requirement, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, the revenue deficiency of each class as determined from the approved cost of service study and move the classes toward parity to the extent practicable. The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. (Guffey)

**Position of the Parties:**

**TECO:** Any changes in the revenue requirement should be allocated among customers based on the cost allocation methodology approved by the Commission in this case.

**OPC:** No position.

**FL RISING/**

**LULAC:** Changes in the revenue requirement should be allocated among customer classes using a Twelve Coincident Peak and 50% Average Demand methodology. “Gradualism,” invoked to continue a transfer of wealth from residential and small businesses to the largest commercial and industrial customers, finds no basis in Florida law and should not be used.

**FIPUG:** The approved revenue requirement should be determined using an accepted class cost of service study, except when it would result in a class receiving an increase higher than 1.5 times the system average base revenue increase, and no class should receive a rate decrease.

**FEA:** The revenue change should be allocated across rate classes based on the results of TECO’s class cost of service study, with FEA’s recommended adjustment to the GSLDPR class.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO’s proposed revenue allocation methodology for allocating any increase or decrease in revenue requirements to rate classes.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

This Issue addresses the allocation of any revenue increase granted (Issue 70) to the various customer classes, and is therefore largely dependent on the final revenue increase amount. In consideration of how to allocate a change in revenue requirement to the rate classes, one of the Commission's long standing practices is that to the extent possible, the revenue increase should be allocated so as to bring all classes as close to parity as practicable. TECO witness Williams stated that the parity index is the ratio of each class's rate of return to the retail system rate of return. (TR 3685) A parity index that is greater than one means that a class is providing a rate of return higher than the system average (i.e., the class is served above cost) while a parity index less than one indicates that a class is providing a rate of return below the system average (i.e., the class is served below cost). (TR 3685) Parity is useful when determining the development of class revenue targets. (TR 3685)

MFR Schedule E-8 reflects each rate class's current and proposed rate of return, based on TECO's proposed 4 CP with MDS cost of service. (EXH 7, MPN J419) Rate of returns for the rate classes depend on the cost of service methodology used.

FL Rising/LULAC took the position that changes in revenue requirement should be allocated among customer classes using a 12CP and 50 percent AD methodology. Cost of service is addressed in Issues 71, 72, and 73. FIPUG witness Pollock testified that the approved revenue requirement should be determined using an accepted class cost of service study, except when it would result in a class receiving an increase higher than 1.5 times the system average base revenue increase, and no class should receive a rate decrease. (TR 2705) FEA stated that the revenue change should be allocated across rate classes based on the results of TECO's class cost of service study. FRF stated that it does not oppose TECO's proposed revenue allocation methodology for allocating any increase or decrease in revenue requirements to rate classes. OPC, Fuel Retailers, and the Sierra Club took no positions while Walmart adopted the position of FRF.

In allocating the increase to the various rate classes, TECO stated that it followed the Commission practice of gradualism, which limits the increase of each rate class to 1.5 times the system average increase in revenue, including adjustment clauses. (EXH 202, MPN E6189) The practice of gradualism, including limiting the increase to no greater than 1.5 times the system average percentage increase in total, has been affirmed in several prior Commission orders.<sup>71</sup>

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<sup>71</sup> Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 20080317-EI, *In re: Petition for rate increase by Tampa Electric Company*, p. 87; 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 Company*, p. 179; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 20070304-EI; *In re: Petition for rate increase by Florida Public Utility Company*, p. 63.

## **CONCLUSION**

The appropriate allocation of the change in revenue requirement, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, the revenue deficiency of each class as determined from the approved cost of service study and move the classes toward parity to the extent practicable. The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease.

**Issue 75:** Should the proposed modifications to the delivery voltage credit be approved?

**Recommendation:** TECO's calculations of the delivery voltage credits are appropriate; however, TECO should be required to recalculate the credits if the Commission's vote in other issues affects the calculations. (Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

A delivery voltage credit is included in the General Service-Demand, Time-of-Day General Service-Demand, Standby and Supplemental Demand Service, and Time-of-Day Standby and Supplemental Demand Service rate classes. When a customer under the standard rate takes service at primary voltage level or at subtransmission or higher voltage, a per kilowatt discount is applied. TECO's calculations of the delivery voltage credits are shown in MFR Schedule E-14, Supplement B, page 6 of 12. (EXH 7, MPN J610) The discount is based on distribution or subtransmission investment the customer does not need by taking service at a higher voltage. The proposed demand charge credits are included in the proposed tariffs. (EXH 7, MPN J524, J537, J 542)

FL Rising/LULAC stated, “No” in its post-hearing brief but did not provide any supporting evidence. (FL Rising/Lulac BR 20)

None of the other parties took a position on this Issue.

### **CONCLUSION**

TECO’s calculations of the delivery voltage credits are appropriate; however, TECO should be required to recalculate the credits if the Commission’s vote in other issues affects the calculations.

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**Issue 76:** What are the appropriate service charges (initial connection, reconnect for nonpayment, connection of existing account, field visit, temporary overhead and underground, meter tampering)?

**Recommendation:** The appropriate service charges are \$168.00 for initial connection, \$18.00 for reconnection of service which has been disconnected due to nonpayment, \$15.00 for reconnection of service which has not been disconnected due to nonpayment, \$37.00 for field visit, \$480.00 for temporary overhead and underground, and \$75.00 for meter tampering. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate service charges are the proposed charges provided in MFR Schedule E-13b.

**OPC:** No position.

**FL RISING/**

**LULAC:** TECO's proposed initial connection charge and all proposed reconnection service charges for residential customers should be reduced by 80%.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams stated in his direct testimony that TECO projected an increase of \$2,976,000 to service charge revenues, indicated in MFR Schedule E-13b. (EXH 8) TECO filed MFR Schedule E-7 and Time-of-Motion study, in which it justified the proposed increases by showing a cost breakdown for the development of each service charge. (EXH 8) MFR Schedule E-7 detailed the amount of time spent to complete each task, versus the cost of each task to TECO in the form of an hourly rate. (EXH 8) MFR Schedule E-7 showed that TECO is currently

charging below cost for each basic service charge. TECO witness Williams explained in his direct testimony that TECO proposed a gradual increase. (TR 3678) TECO also stated that with the exception of the return check charge, the unit cost “significantly exceeded TECO’s currently approved rate. TECO is proposing to employ rate gradualism and cap the service charge increases at 50 percent of the currently approved rate.” (EXH 199, MPN E6020)

Table 76-1 displays a comparison of the four service charges; each charge is discussed individually below.

**Table 76-1  
 Service Charge Comparison - 2025**

	Current Charge	Proposed Charge	Actual Cost	Staff Recommended
Initial Connection	\$112.00	\$168.00	\$330.73	\$168.00
Reconnection (Nonpayment)	\$12.00	\$18.00	\$20.42	\$18.00
Reconnection	\$10.00	\$15.00	\$22.73	\$15.00
Field Visit	\$25.00	\$37.00	\$78.75	\$37.00
Temporary Overhead and Underground	\$320.00	\$480.00	\$567.52	\$480.00
Meter Tampering	\$50.00	\$75.00	\$187.26	\$75.00

Source: EXH 8, MFR Schedule E-7 and E-13b, all pages.

**Initial Connection**

TECO proposed an increase to \$168.00 from the current charge of \$112.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 1 of 7. (EXH 7, MPN J412) The expenses to TECO comprise of customer service expenses, field labor, administrative expense, and vehicle cost. (EXH 7, MPN J412)

FL Rising/LULAC witness Rábago argued in his direct testimony that TECO should reduce their initial connection charge by 80 percent, citing that electric service is necessary for survival and that the initial connection fees requested by TECO are “out of step” with other utilities in Florida. (TR 2610) Witness Rábago also argued that residential customer costs should only reflect the equipment and infrastructure used to connect residential customers, and should not reflect the higher-cost equipment and infrastructure used to connect larger power users. (TR 2598) TECO’s proposed initial connection charge is higher than the currently approved charges for FPL (\$13), DEF (\$58), and FPUC (\$61). (EXH 167, MPN E2246)

However, in TECO’s filed MFR Schedule E-7, page 1 of 7, TECO included a breakdown of the costs to connect a new customer. (EXH 7, MPN J412) MFR Schedule E-7 detailed the tasks required, the amount of time to complete each, and the hourly rate for the employee(s) involved. (EXH 7, MPN J412) As shown in Table 76-1, TECO’s proposed charges are set below costs. TECO explained that for the initial service connection charge, the cost is higher than the currently approved rate, thus TECO proposed to increase the charge using a “gradualistic approach.” (EXH 167, MPN E2245)

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### **Reconnection of Service at Meter (Nonpayment)**

TECO proposed an increase to \$18.00 from the current charge of \$12.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 3 of 7. (EXH 7, MPN J414) The expenses to TECO comprise of customer service, field labor, administrative expense, customer noticing, and vehicle cost. (EXH 7, MPN J414)

### **Reconnection of Service**

TECO proposed an increase to \$15.00 from the current charge of \$10.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 2 of 7. (EXH 7, MPN J413) The expenses to TECO comprise of customer service, field labor, administrative expense, and vehicle cost. (EXH 7, MPN J413)

### **Field Visit**

TECO proposed an increase to \$37.00 from the current charge of \$25.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 5 of 7. (EXH 7, MPN J416) The expenses to TECO comprise of customer service, field labor, administrative expense, customer noticing, and vehicle cost. (EXH 7, MPN J416)

### **Temporary Overhead and Underground**

TECO proposed an increase to \$480.00 from the current charge of \$320.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 7 of 7. (EXH 7, MPN J418) The expenses to TECO comprise of customer service, field labor, administrative expense, and vehicle cost.

### **Meter Tampering**

TECO proposed an increase to \$75.00 from the current charge of \$50.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 6 of 7. (EXH 7, MPN J417) The expenses to TECO comprise of customer service, field labor, administrative expense, vehicle cost, and a meter security lock. (EXH 7, MPN J417)

In summary, TECO has provided cost justification for their proposed service charges and explanation about capping the increase at 50 percent. Therefore, staff believes the requested increases are appropriate and reflect the record evidence.

## **CONCLUSION**

The appropriate service charges are \$168.00 for initial connection, \$18.00 for reconnection of service which has been disconnected at the meter due to nonpayment, \$15.00 for reconnection of service which has not been disconnected due to nonpayment, \$37.00 for field visit, \$480.00 for temporary overhead and underground, and \$75.00 for meter tampering.



**Issue 77:** Should the modifications to the emergency relay power supply charge be approved?

**Recommendation:** Yes, TECO proposed methodology to calculate emergency relay power supply charges is appropriate and should be approved. The final charges are subject to the Commission vote on the final revenue requirement; therefore, TECO should recalculate the charges. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/  
LULAC:** Yes.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO's emergency relay power supply option was originally approved in Order No. PSC-98-0508-FOF-EI, to provide a higher-than-standard level of reliability for commercial customers to prevent more than a few seconds' of service interruption.<sup>72</sup> Customers subscribing to relay service are connected to a primary distribution circuit and a back-up distribution circuit (or trunk line). The back-up distribution circuit connected to a back-up substation, on which capacity is reserved for relay service customers. When an outage is sensed on the primary line, a switch will change power to the back-up circuit.

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<sup>72</sup> Order No. PSC-98-0508-FOF-EI, issued April 13, 1998, in Docket No. 19980131-EI, *In re: Petition by Tampa Electric Company for approval of emergency relay power supply service option for general service customers.*

Relay service customers pay a CIAC and a monthly charge that is calculated in part using a per kW charge. TECO's MFR Schedule E-14, Supplement B, page 7 and 8 of 12, provides a breakdown of the costs and methodology used to calculate the charges. (EXH 7) TECO proposed an increase from \$50.27 per kW to \$62.51 per kW for the CIAC of trunk line capacity and an increase in the monthly emergency relay charge from 0.68 cents per kW to \$1.02 per kW. Costs included in the calculations are distribution substation plant, primary distribution plant, and associated O&M costs. Staff believes that TECO's methodology to calculate emergency relay service charges is appropriate; however, the charges are subject to change based on the Commission vote in other Issues.

No other party took a position on this Issue.

### **CONCLUSION**

TECO proposed methodology to calculate emergency relay power supply charges is appropriate and should be approved. The final charges are subject to the Commission vote on the final revenue requirement; therefore, TECO should recalculate the charges.

**Issue 78:** What are the appropriate basic service charges?

**Recommendation:** The final basic service charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. The calculation of the basic service charges is dependent on the Commission's vote on the final revenue requirement, cost of service issues, including whether to use the MDS method or not. TECO should be required to recalculate the basic service charges based on the Commission vote on all prior issues. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate basic service charges are shown in MFR Schedule E-13c.

**OPC:** The basic service charges should reflect all the adjustments recommended by OPC.

**FL RISING/**

**LULAC:** TECO's basic service charge for residential customers should be no more than \$0.43 per customer per day or no more than \$13.08 per customer per month for residential customers.

**FIPUG:** The adjustments recommended by OPC should be adopted.

**FEA:** The GSLDPR demand charges should be increased, and the energy charges reduced

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** \*he FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

The final basic service charges, or customer charges, are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. The final basic service charges will depend on the Commission's decision on the revenue requirement and cost of service, including whether to approve an MDS system or not. The MDS system assigns a portion of the distribution costs as

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customer costs. (TR 3742) As discussed below, the Commission's vote on the cost of service issue impacts the final rates.

TECO proposed to increase the residential basic service charge (which is billed as a daily charge) from \$0.71 per day (\$21.30 per month) to \$1.07 per day (\$32.10 per month). In cross examination, TECO witness Williams admitted that a 12 CP and 1/13 AD methodology, without MDS, would result in a lower customer charge. (TR 3766) The evidence presented by TECO shows that under a 12 CP and 1/13 AD cost of service methodology, without MDS, the daily basic service charge would remain at its current level of \$0.71 per day with only the non-fuel energy charge showing an increase. (EXH 198, MPN E5956)

FL Rising/LULAC witness Rábago testified that the Commission should reject TECO's proposed customer charges and instead approve a customer charge of no more than \$0.43 per day (\$12.90 per month), based on a re-calculation of customer costs that exclude the MDS method. (TR 2575) Witness Rábago further testified that TECO should calculate customer charges only using the basic customer method and to allocate any demand-related changes in revenue requirement to volumetric base rates. (TR 2575) Witness Rábago explained that the basic customer method identified costs vary only with the number of customers – costs that are incurred to connect a customer to the system. (TR 2577) As discussed in Issue 73, FL Rising/LULAC object to the MDS method.

### **CONCLUSION**

The final basic service charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. The calculation of the basic service charges is dependent on the Commission's vote on the final revenue requirement, cost of service issues, including whether to use the MDS method or not. TECO should be required to recalculate the basic service charges based on the Commission vote on all prior issues.

**Issue 79:** What are the appropriate demand charges?

**Recommendation:** The methodology used by TECO to determine the demand charges is appropriate. The appropriate rate design for the demand charges is discussed in conjunction with the appropriate rate design for the energy charges decided in Issue 80. The final demand charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate demand charges are shown in MFR Schedule E-13c.

**OPC:** The demand charges should reflect all the adjustments recommended by OPC as approved by the Commission.

**FL RISING/**

**LULAC:** The appropriate residential energy and demand charge should be no more than 8.59 cents/kWh for the first 1,000 kWh and no more than 9.52 cents/kWh for all additional kWh of usage and reduced to reflect the reduced rate base from the disallowance of TECO's proposed investments as reflected in other issues.

**FIPUG:** The adjustments recommended by OPC should be adopted.

**FEA:** See Issue 78 concerning demand charge for GSLDPR rate class.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

The final demand charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. The final demand charges will depend on the Commission's decision on the revenue requirement and cost of service. While the final demand charges are a fall-out issue, the Commission needs to vote in this Issue on TECO's proposed methodology to calculate the charges.

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Per the current rate schedules, TECO customers are enrolled in a demand rate class and issued a demand meter when they consume more than 9,000 kWh in any one billing period out of the past 12 billing periods. Demand is determined using the customers' 30-minute interval with the highest demanded kW. Customers will be entered into a large demand rate class when their demand consumption reaches more than 1,000 kW over any 30-minute interval at any point of their billing period, for at least one billing period in the past 12 billing periods.

TECO provided its proposed demand charges in MFR Schedule E-13c, pages 5-18. (EXH 7, MPN J459 – MPN J472) TECO witness Williams stated in his direct testimony that demand cost is a function of the capacity of plant and maximum kW of power demanded by customers. (TR 3662) Witness Williams further stated that demand costs occur at the production, transmission, and distribution level. (TR 3662)

FEA witness Gorman addressed in his direct testimony the rate design for the General Service Large Demand – Primary (GSLDPR) and Time of Day General Service Large Demand – Primary (GSLDTPR) rate schedules. These rate schedules are applicable to customers with a registered demand of 1,000 kilowatt or above once in the last 12 months.

With respect to those two rate schedules, Witness Gorman stated that TECO is over-recovering on the energy charges and under-recovering on the demand charges. (TR 3068) Based on information provided in TECO's cost of service study and derivation of unit costs, witness Gorman provided in his direct testimony a table (Table 6) demonstrating a breakdown of TECO's revenue requirement costs for its GSLDPR rate class. (TR 3069; EXH 9, MPN J706) Based on the information included in Table 6, witness Gorman concluded that 86.3 percent of TECO's revenue requirement costs are demand-related. (TR 3069) Witness Gorman compared these costs to the demand revenue requirement illustrated in Table 5 of his direct testimony, which shows that only 67.6 percent of GSLDPR revenues are collected through demand charges. (TR 3068) Witness Gorman concluded, based on his analysis, that TECO should increase demand charges and reduce energy charges. (TR 3069)

Staff does not dispute the information provided by witness Gorman regarding the GSLDPR rate class; however, following strict unit cost in setting demand rates may make it difficult to maintain rate design goals and principles. Furthermore, a significant increase in the demand charges could adversely impact low load factor customers.

TECO witness Williams addressed FEA witness Gorman's argument in his rebuttal testimony, disagreeing with FEA witness Gorman's assertion that TECO should increase demand charges for the GSLDPR rate class to match unit cost. (TR 3712) TECO witness Williams agreed that FEA witness Gorman had correctly identified a mismatch between unit cost and customer cost, but stated that this was done intentionally and in accordance with terms that FEA agreed to in the 2021 Settlement Agreement. (TR 3712) TECO witness Williams also stated that he did not support the GSLDPR energy charge being lower than it currently is. (TR 3712)

FL Rising/LULAC in its post-hearing brief addressed the residential energy and demand charge; however, residential customers are not billed a demand charge. (FL Rising/LULAC BR 21)

No other party took a position on this Issue.

## **CONCLUSION**

The methodology used by TECO to determine the demand charges is appropriate. The appropriate rate design for the demand charges is discussed in conjunction with the appropriate rate design for the energy charges decided in Issue 80. The final demand charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**Issue 80:** What are the appropriate energy charges?

**Recommendation:** The appropriate rate design for the energy charges is discussed in conjunction with the appropriate rate design for the demand charges decided in Issue 79. The final energy charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate energy charges are shown in MFR Schedule E-13c.

**OPC:** The energy charges should reflect all the adjustments recommended by OPC as approved by the Commission.

**FL RISING/**

**LULAC:** The appropriate residential energy and demand charge should be no more than 8.59 cents/kWh for the first 1,000 kWh and no more than 9.52 cents/kWh for all additional kWh of usage and reduced to reflect the reduced rate base from the disallowance of TECO's proposed investments as reflected in other issues.

**FIPUG:** The adjustments recommended by OPC should be adopted.

**FEA:** See Issue 78 concerning energy charge for GSLDPR rate class.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

Energy charges refer to the cents paid by customer per kWh. As the energy revenue and energy rates will be calculated following the determination of the demand revenue and demand charges, this Issue is a fall-out issue and will be determined at the December 19, 2024 Commission Conference.



TECO witness Williams addressed the energy charges in his direct testimony and in MFR Schedule E-13c. (EXH 7, MPN J455 – J472) These costs are allocated using a 4 CP method, which is addressed in Issues 71 and 72.

OPC stated that the energy charges should reflect all adjustments to ROE as recommended by OPC as approved by the Commission. This is discussed in depth in issue 39.

FL Rising/LULAC opposed the proposed energy charges, stating in their prehearing statement that the residential energy charge should be reduced to 8.59 cents per kWh for the first 1,000 and 9.52 cents per kWh for all subsequent usage. (FL Rising/LULAC BR 21)

### **CONCLUSION**

The appropriate rate design for the energy charges is discussed in conjunction with the appropriate rate design for the demand charges decided in Issue 79. The final energy charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**Issue 81:** What are the appropriate Lighting Service rate schedule charges?

**Recommendation:** The appropriate Lighting Service rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate Lighting Service charges are shown in MFR Schedule E-13c and E-13d.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

The appropriate Lighting Service rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**CONCLUSION**

The appropriate Lighting Service rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**Issue 82:** What are the appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges?

**Recommendation:** The appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (McClelland)

**Position of the Parties:**

**TECO:** The appropriate Standby Services rate schedule charges are shown in MFR Schedule E-13c.

**OPC:** No position.

**FL RISING/**

**LULAC:** Even though the rate increase should be denied, these rates should be increased to reflect a 12CP and 50% AD cost of service.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

The appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**CONCLUSION**

The appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges are a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**Issue 83:** Should the proposed modifications to the time-of-day periods be approved?

**Recommendation:** No. The proposed modifications to the time-of-day periods should not be approved. (Draper, Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications to the time-of-day periods should be approved. Tampa Electric's proposed modifications to the time-of-day periods are reasonable and more accurately reflect a change in the company's marginal energy cost profile.

**OPC:** No position.

**FL RISING/**

**LULAC:** Yes.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams explained the proposed changes to TECO's time-of-day periods for each of its optional time-of-day rate schedules available to commercial or industrial customers. Currently, the on-peak hours vary between the summer and winter season. Specifically, the current peak hours are noon to 9 p.m., Monday through Friday, during April 1 through October 31. For the months November 1 through March 31, the on-peak hours are 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. All other weekday hours and all hours on weekends and holidays are off-peak hours. (TR 3679-3680)

TECO witness Williams stated that TECO is proposing to add a super off-peak period and to remove the seasonality of its time-of-day periods. (TR 3679) Specifically, the proposed year-round peak period is 6 a.m. to 10 a.m. and 5 p.m. to 9 p.m. The proposed super-off period is 10 a.m. to 5 p.m.; the off-peak period is all other hours. The cents per kWh energy charges vary between the different peak periods, with the charge being the highest during the peak hours and the lowest during the super-off-peak hours.

The current and proposed time-of-day periods are summarized in the table below.

**Table 83-1  
 Current and Proposed Time-of-Day Periods**

	Current		Proposed
Period	April – October	November - March	Year-Round
Peak	Mon – Fri 12 p.m. (noon) – 9 p.m.	Mon – Fri 6 a.m. – 10 a.m. 6 p.m. – 10 p.m.	Mon – Fri 6 a.m. – 10 a.m. 5 p.m. – 9 p.m.
Off-Peak	All other weekday hours and holidays	All other weekday hours and holidays	Sat – Sun 12 a.m. – 10 a.m. 5 p.m. – 12 a.m.
Super Off-Peak	n/a	n/a	Mon – Sun 10 a.m. – 5 p.m.

Source: (TR 3680, 2734)

Witness Williams testified that TECO has not changed the time periods for the optional time-of-day rate schedules since the 1980s. Witness Williams asserted that with the TECO’s recent and continued investment in renewable generation assets, TECO’s hourly cost profile has changed and this new structure will better align with the TECO’s hourly cost profile. (TR 3681) Witness Williams stated that eliminating the seasonal change in its pricing periods was designed to achieve simplicity and understandability. (TR 3682) In response to an interrogatory by FIPUG, who objects to the proposed time-of-day periods, TECO stated that “trading simplicity for seasonality will allow customers participating in time-of-day to more effectively set their operations.” (EXH 162, MPN E2079)

To derive its proposed base rates for its optional time-of-day rate schedules, TECO used a marginal cost methodology to help determine its time periods and the rate differentials. (TR 3681) TECO ensured that the rates were revenue neutral to 2024 base rates. This means that the average customer on a time-of-day rate schedule would not experience an increase or decrease to their bill because of the time-period change; the increase to a customer’s bill is a function of TECO’s request to increase base rates. (TR 3681-3682)

To further support the proposed time-of-day changes, witness Williams stated that the super off-peak period was added to due to the change in TECO’s hourly cost profile. Today, TECO continues to invest in renewable generation assets, primarily solar assets. The cost to generate a

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MWh in the early afternoon relative to other time periods is generally cheaper because of TECO's solar assets. (EXH 199, E6016)

TECO explained that to communicate the proposed changes to its time-of-day rate periods to its customers TECO's Account Management team will reach out to mid-market and large commercial and industrial customers currently on a time-of-day rate. Additionally, TECO will program an Important Message to appear on all commercial and industrial bills (all eligible customers) creating awareness of the time-of-day rate change. (EXH 164, MPN E2120)

FIPUG witness Pollock disagreed with TECO on this Issue. (TR 2733-2737) FIPUG stated that TECO's proposed time-of-day periods, which include very low super off-peak energy charges, would be unique in Florida and no other investor-owned utility in Florida similarly offer a super off-peak period that encourages electricity usage during hot summer afternoons when TECO (and Florida utilities generally) regularly experiences its system peaks. (FIPUG BR 18) In his summary of direct testimony, witness Pollock testified that TECO's proposed super-off peak period would be implemented during daytime hours when most of the system peaks generally occur, especially in the summer months. (TR 2674) Finally, witness Pollock asserted that the proposed super-off-peak period is also based on an assumption that TECO will continue to expand its investment in renewable generating assets. (TR 2705)

Witness Pollock presented an analysis showing marginal energy costs by hour by month. (EXH 87, MPN C27-2874) Based on the analysis, witness Pollock concluded that with exception of April and May, the marginal energy costs are not consistently low during TECO's proposed super off-peak period. (TR 2735) Witness Pollock concluded that TECO's proposal is dramatic; low energy prices during the day send the wrong price signal because peak demand occur during daytime hours; and it is premature to premise a major rate change based on TECO's investment in solar. (TR 2737)

Witness Williams attempted to address FIPUG's assertions in rebuttal testimony. (TR 3709-3712) First, witness Williams stated that customers will only need to reset their operations once to reflect the new time periods, instead of adjusting them seasonally. (TR 3710) Furthermore, TECO's business and industrial customers taking service under an optional time-of-day rate are generally high load factor customers, meaning their energy consumption level does not vary substantially, relative to their demand, over time. (TR 3710)

Witness Williams also disagreed with witness Pollock's analysis showing that "marginal energy costs are not consistently low" during the proposed super off-peak period because witness Pollock presented a heat map of the average marginal cost by hour within each month but fails to show the average marginal energy cost over the course of a year. (TR 3710-3711) Witness Williams testified that while witness Pollock is correct that there are hourly variations in marginal pricing, TECO is not proposing real-time pricing or different rates for each day and/or hour of the year in this rate case. Instead, TECO proposed three time-of-day time periods. The proposed super off-peak period has an average marginal energy cost that is cheaper than the proposed off-peak and peak periods over the course of a year. (TR 3711)

Witness Williams presented TECO's average marginal energy costs per kWh during the three proposed periods. (EXH 152, MPN D14-1030) The marginal energy costs shown in Exhibit 152 have been granted confidentiality.<sup>73</sup> The analysis shows that the average marginal energy costs, over the course of a year, are the lowest during the proposed super off-peak period and highest during the on-peak period. (TR 3711) TECO also provided its most recent projection of 8,760 marginal energy costs to support its assentation that because of the change in generation mix, marginal costs during the day have decreased. (EXH 152, MPN D14-1031–D14-1036)

As witness Pollock pointed out, that the proposed super off-peak period would overlap during the hours of noon to 5 p.m. with the current peak period. Staff agrees with FIPUG that this does appear to be a drastic change in time-of-day periods. TECO's confidential Exhibit 152 does show that the average marginal energy costs, for 12 months, are lowest during the super-off peak. However, staff does not believe that the differences in marginal cost are sufficient to justify this significant change in time-of-day periods. Furthermore, TECO's analysis does not support elimination of the seasonal winter/summer time-of-day periods. Based on the marginal energy costs presented by TECO in Exhibit 152, the average super-off peak marginal cost during the summer months April through October are not the lowest (when compared to the off-peak and on-peak periods). Therefore, based on the evidence, staff believes that having a super-off peak period in the afternoon during the summer months is not supported.

Currently, customers on the optional time-of-day rate schedules are encouraged through price signals to conserve during the summer noon to 5 p.m. hours. Changing the price signal to now add load during the same period does not appear reasonable. Staff agrees with TECO that time-of-day periods have been determined in the 80s and that changes in the generation mix may warrant modifications to the time-of-day periods; however, TECO's proposed elimination of the seasonal rates and addition of a super off-peak period during the hours 10 a.m. – 5 p.m. (year round) which are not sufficiently supported at this time.

FL Rising/LULAC's position is to approve TECO proposed changes. (FL Rising/LULAC BR 21) The remaining interveners did not specifically address or take a position on this Issue.

## CONCLUSION

The proposed modifications to the time-of-day periods should not be approved.

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<sup>73</sup> Order No. PSC-2024-0310-CFO-EI, issued August 7, 2024, in Docket No. 20240026-EI, *In re: Petition for rate increase by Tampa Electric Company*.

**Issue 84:** Should the proposed modifications to the Non-Standard Meter Rider tariff (Tariff Sheet No. 3.280) be approved?

**Recommendation:** No modification was proposed. The Non-Standard Meter Rider (NSMR) tariff is appropriate and no modifications should be made. (McClelland)

**Position of the Parties:**

**TECO:** No. Tampa Electric did not propose any modifications to the Non-Standard Meter Rider tariff.

**OPC:** No position.

**FL RISING/  
LULAC:** Yes.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO included in its MFR schedules a supplemental opt-out study that calculated the incremental costs to serve customers taking service under the optional NSMR tariff. (EXH 9, MPN J890-893) The NSMR tariff is a smart meter opt-out tariff and was approved in Order PSC-2019-0112-TRF-EI.<sup>74</sup> Customers who choose to take service under the NSMR tariff receive a meter that does not utilize radio frequency communications or is otherwise required to be read manually. TECO's study indicated the cost of installation and maintenance of NSMR meters to be lower than the rates currently charged to customers under that tariff. (EXH 9)

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<sup>74</sup> Order No. PSC-2019-0112-TRF-EI, issued March 25, 2019, in Docket No. 20190024-EI, *In re: Petition for approval of smart meter opt-out tariff, by Tampa Electric Company.*



The currently approved optional NSMR tariff includes a \$100.00 initial one-time set-up fee and a \$0.67 daily rate. TECO's opt-out study shows that the one-time charge cost consists of administrative costs and installation costs to enroll the customer in the program and set up the meter, while its monthly costs consist of meter reading and IT system maintenance expenses. (EXH 9, MPN J890) TECO's cost for the one-time set up charge is shown to be \$44.95, while the daily cost is shown to be \$0.6239 (or \$19.13 per NSMR customer per month). (EXH 9, MPN J890) TECO stated that the need for IT development and analysis of meter reading schedules was found to be less labor-intensive than originally estimated. (EXH 199, MPN E6019) However, TECO did not file a revised NSMR tariff (Tariff Sheet No. 3.280) to reflect a decrease in cost to customers under the NSMR rider. TECO stated that the NSMR charge is used to address costs of AMR meters, and any remaining money is used to reduce RS, GS, and GSD rate classes. (EXH 208, MPN E7780) TECO stated that its AMI provide value to customers, with a 98 percent success rate that reduce personnel visits to accomplish functions that can be handled remotely. (EXH 208, MPN E7780) TECO further stated in its post-hearing brief that this is an optional program and no party presented evidence challenging TECO's position. (TECO BR 75)

### **CONCLUSION**

No modification was proposed. The NSMR tariff is appropriate and no modifications should be made.

**Issue 85:** Should the proposed tariff modifications to the Budget Billing Program (Fifth Revised Tariff Sheet No. 3.020) be approved?

**Recommendation:** Staff recommends approval of the proposed tariff modifications to the Budget Billing Program, indicated on the Fifth Revised Tariff Sheet No. 3.020. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, although other modifications should be made.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams stated that the tariff language is being rewritten to reflect changes to the methods used to calculate bills for participants in the Budget Billing Program. (TR 3690) The intent of the program is to provide customers with similar charges from month to month. (TR 3690) Bills are currently calculated on a "backward-looking" basis with annual recalculations, which do not properly take into account fuel price volatility, base rate increases, storm restoration costs, and customer increases in consumption. (TR 3690) Witness Williams stated that the current methods of calculation have subjected participants to irregular billing. (TR 3690) Witness Williams discussed some of the proposed changes in his direct testimony, which are found in full in the proposed modified tariffs. (TR 3690) TECO proposed a quarterly recalculation, rather than annual, with the ability to recalculate more frequently if deemed necessary by prices or consumption. (TR 3690) TECO also proposed to show any deferred balance on the customer's bill. TECO proposed that the deferred debit balance will be applied

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after a periodic review, while a deferred credit balance will be applied during an annual true-up period. Witness Williams stated in his direct testimony that these changes will prevent large changes. (TR 3690)

FL Rising/LULAC took an opposing stance on this Issue, although they did not elaborate on why. (FL Rising/LULAC BR 22)

Staff requested additional information from TECO regarding the revisions to the Budget Billing Program. (EXH 199, MPN E6013) The proposed modified tariffs stated that the customer's bill may be recalculated outside of the quarterly review period; TECO's responses to the interrogatory clarified that this is done at the customer's request. (EXH 199, MPN E6013)

No other party has taken a position on this Issue. Staff has reviewed the proposed modifications to the Budget Billing Program and finds that they are appropriate and supported by the record evidence. The revisions to the program are beneficial to customers and will serve the program's intended purpose of keeping customer bills as consistent as possible.

### **CONCLUSION**

Staff recommends approval of the proposed tariff modifications to the Budget Billing Program, indicated on the Fifth Revised Tariff Sheet No. 3.020.

**Issue 86:** Should the proposed tariff modifications regarding general liability and customer responsibilities (Fifth Revised Tariff Sheet No. 5.070 and Original Tariff Sheet No. 5.081) be approved?

**Recommendation:** Yes. The Commission should approve the proposed tariff modifications regarding general liability and customer responsibilities (Fifth Revised Tariff Sheet No. 5.070 and Original Tariff Sheet No. 5.081). The proposed revisions will provide greater clarity regarding customer responsibilities and Company responsibilities. (Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/  
LULAC:** No.

**FIPUG:** No position.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams explained that TECO is proposing to provide greater clarity regarding customer responsibilities and Company responsibilities with the proposed tariff revisions. (TR 3689) The proposed language can be seen in TECO's proposed Original Sheet No. 5.081. (EXH 7, MPN J495) Proposed tariff Sheet No. 5.070 adds additional clarity regarding customers' responsibilities. (EXH 7, MPN J490)

No other parties took a position on this Issue.

## **CONCLUSION**

The Commission should approve the proposed tariff modifications regarding general liability and customer responsibilities (Fifth Revised Tariff Sheet No. 5.070 and Original Tariff Sheet No. 5.081). The proposed revisions will provide greater clarity regarding customer responsibilities and Company responsibilities.

**Issue 87:** Should the proposed tariff modifications to Contribution in Aid of Construction (Fifth Revised Tariff Sheet No. 5.105) be approved?

**Recommendation:** The proposed tariff modifications to Contribution in Aid of Construction (Fifth Revised Tariff Sheet No. 5.105) are reasonable and should be approved. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** Yes.

**FL RISING/**

**LULAC:** No.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO proposed a modification to its CIAC tariff that would allow customers to enter into alternative payment arrangements. TECO witness Williams explained that TECO has historically collected CIAC prior to commencing construction, which protects the general body of ratepayers from the risk of non-payment. (TR 3691) Witness Williams explained the need for alternative payment arrangements to accommodate some customers, such as governmental customers for example. (TR 3691) The witness stated that governmental customers are bound to payment processing schedules that did not align with upfront payment of CIAC. Furthermore, witness Williams stated TECO would put procedures in place to monitor and mitigate risk associated with alternative payment arrangements to the general body of ratepayers. (TR 3692) In addition, TECO will establish a four-Director committee that would monitor outstanding CIAC payments and ensure that any outstanding CIAC payments are collected. (TR 3692)

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Staff requested further information in Staff's Seventh Set of Interrogatories, responses to which were prepared by TECO witness Williams. Staff wished to clarify the proposed changes to CIAC and further evaluate the potential increased risk to the general body of ratepayers. TECO witness Williams stated that TECO will extend alternate payment arrangements, i.e. CIAC without an upfront payment, to private customers as well as the aforementioned governmental customers. TECO does not have a formula or model used to calculate a customer's risk of nonpayment, but takes a customer's payment history and standing with TECO into account. TECO also will cap CIAC without upfront payment at \$1 million. (EXH 202, MPN E6212-6213)

OPC and Walmart stated in their brief that the modifications to CIAC should be approved so long as the installment payments of CIAC are fully credited as a reduction of rate base once the agreement to pay CIAC is completed, even if there is an outstanding balance. (OPC BR 63; Walmart BR 9) FRF did not oppose the proposed tariff modification. (FRF BR 45)

Staff acknowledges that the proposed alternate payment method introduces increased risk to the general body of ratepayers. By completing work before receiving payment, TECO risks incurring bad debts. However, TECO has proposed methods of vetting customers as well as ensuring continued payment. Staff believes these methods to be appropriate. Staff also believes the risk is outweighed by the benefits of allowing more customers to utilize CIAC. Overall, the record evidence supports that the proposed alternate payment arrangements are appropriate.

### **CONCLUSION**

Staff has reviewed the revised Fifth Revised Tariff Sheet No. 5.105 and believes it is reasonable and supported by the record evidence. The proposed tariff modifications to Contribution in Aid of Construction (Fifth Revised Tariff Sheet No. 5.105) are reasonable and should be approved.

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**Issue 88:** Should the proposed tariff modifications to the Economic Development Rider (Third Revised Tariff Sheet Nos. 6.720, 6.725, 6.730) be approved?

**Recommendation:** Yes. The proposed tariff modifications to the Economic Development Rider (Third Revised Tariff Sheet Nos. 6.720, 6.725, 6.730) should be approved. The proposed Economic Development Rider (EDR) modifications would allow TECO to remain competitive in attracting new commercial and industrial customers to its service area. (Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, the entire Rider should be stricken.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO's EDR was first introduced as a three-year pilot in the stipulation and settlement agreement approved by the Commission in TECO's 2013 base rate proceeding.<sup>75</sup> In Order No. PSC-16-0210-TRF-EI, the Commission extended the EDR tariff on a permanent basis.<sup>76</sup> The EDR requires a five-year contract and provides base rate discounts for new business that meet certain requirements such as minimum size, job creation, and verification that the availability of

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<sup>75</sup> Order No. PSC-13-0443-FOF-EI, issued September 30, 2013, in Docket No. 20130040-EI, *In re: Petition for rate increase by Tampa Electric Company*.

<sup>76</sup> Order No. PSC-16-0210-TRF-EI, issued May 25, 2016, in Docket No. 20160059-EI, *In re: Petition to extend economic development rider on a permanent basis, by Tampa Electric Company*.



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the EDR is a significant factor in the customer's location or expansion decision. The EDR is not available to existing load.

TECO witness Williams testified that TECO wants to remain competitive in attracting new business and companies are becoming more efficient in their electric consumption and labor usage. (TR 3690)

The proposed EDR program changes are:

- (1) The minimum qualifying load will be 300 kW instead of 350 kW.
- (2) The required new full-time equivalent jobs in TECO's service area will be 20 instead of 25; or
- (3) A customer will qualify for the EDR if the customer makes \$500,000 or greater capital investment in TECO's service area and increases full time equivalent jobs.
- (4) A customer may request an effective date of the EDR which is no later than two years after the Customer Service Agreement is approved and signed by the Company. (EXH 7, MPN J566)

The EDR has no impact on the RS, GS, GSLDPR, GSLDSU, or LS rate classes' revenue requirement. The EDR increases the GSD rate class's revenue requirement in the test year by \$89,106. (EXH 165, MPN E2201)

TECO explained that the proposed reduction from 350 kW to 300 kW is a reasonable threshold to capture the declining average use trends, including customers reducing their brick-and-mortar footprint and continued investment in more efficient equipment such as LED lights and motion sensors. (EXB 199, MPN E-6017) Types of customers who would use 300 kW could be healthcare centers, a grocery store, a hardware store, a small call center, or a small manufacturer. The 300 kW minimum load is an amount that must be achieved at least once within a year for each year that the participating customer takes service under the EDR. Currently, at the 350 kW requirement, TECO has eight customers enrolled in its EDR program in which each company is required to create 25 jobs at a minimum. (EXH 199, MPN E6018)

TECO also stated that some eligible customers who elect to participate do not always ramp up their kW load to full capacity right away and may not meet the minimum requirements until they have ramped up their operations. For this reason, TECO may attract commercial customers to the area by delaying the full implementation of the credit for up to two years. A customer may request this option if they believe their build out and ramp up will take some time rather than it immediately occurring. (EXH 199, MPN E6018)

FL Rising/LULAC took the position that the entire EDR tariff should be stricken. (FL Rising/LULAC BR 22) The Commission has a long history of approving economic development tariffs for electric utilities and FL Rising/LULAC have provided no evidence as to why the EDR should be stricken.

## **CONCLUSION**

The proposed tariff modifications to the Economic Development Rider (Third Revised Tariff Sheet Nos. 6.720, 6.725, 6.730) should be approved. The proposed EDR modifications would allow TECO to remain competitive in attracting new commercial and industrial customers to its service area.

**Issue 89:** Should the proposed modifications to LS-1 (Eleventh Revised Tariff Sheet No. 6.809) regarding lighting wattage variance be approved?

**Recommendation:** Yes. Staff recommends approval of the proposed modifications to LS-1 regarding lighting wattage variance. The lighting wattage variance will increase to 25 percent, from the previously approved variance of 10 percent. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed modifications are reasonable and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** Yes.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO proposed a change in the lighting wattage variance, contained in the Eleventh Sheet No. 6.809, to twenty-five percent, from the previous variance of ten percent. (TR 3694; EXH 7, MPN J571) TECO witness Williams explained in his direct testimony that LED technology is continuing to develop and products are becoming more efficient, reducing the wattage while increasing the lumen output. (TR 3695) Witness Williams stated that the larger variance amount will allow TECO to more accurately calculate monthly energy consumption while minimizing impacts to customers. (TR 3695)

No other party took a position on this Issue. Staff believes that the proposed changes to the LS-1 lighting wattage variance are supported by the record and are reasonable. Therefore, staff recommends that the lighting wattage variance should increase to 25 percent, from the previously approved variance of 10 percent.

## **CONCLUSION**

Staff recommends approval of the proposed modifications to LS-1 regarding lighting wattage variance. The lighting wattage variance will increase to 25 percent, from the previously approved variance of 10 percent.

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**Issue 90:** Should the proposed LS-2 Monthly Rental Factors (Original Tariff Sheet No. 6.845) be approved?

**Recommendation:** TECO's calculations of the LS-2 monthly rental factors shown on Original Tariff Sheet No. 6.845 are appropriate; however, TECO should be required to recalculate the factors if the Commission's vote in other issues affects the calculations. The new factors will permit customers to contract lighting service for a period between 1 and 25 years. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed LS-2 Monthly Rental Factors offers optionality to customers, are reasonable, and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO witness Williams stated in his direct testimony that TECO's LS-2 rate schedule was introduced in 2022. (TR 3693) TECO's current LS-2 rate schedule offers 20-year contracts with one monthly rental factor of 0.93 percent, calculated to recover the net present value of the asset(s) over a 20-year-period, allowing TECO to fully recover the assets during the rental period. (TR 3693; TR 3694) To offer customers more flexibility, regarding the term of the agreement, TECO proposed to offer rental terms between 1 and 25 years, with adjusted rental factors to permit TECO to recover its assets accordingly. (TR 3694) According to the LS-2

tariff, the monthly charge to the customer is calculated by applying the corresponding LS-2 monthly rental factor to the in place value of the customer specific lighting facilities.

Staff believes offering a wider range of rental term lengths is fair and reasonable. TECO indicates that the factors allow it to offer more options to customers while also permitting TECO to recover its assets in full. The proposed arrangement ensures that the general body of ratepayers is protected from subsidizing the rental costs, which will be paid by cost-causing customers only.

No other party took a position on this Issue. Staff recommends approval of the proposed LS-2 monthly rental factors as they are reasonable and supported by the record.

### **CONCLUSION**

TECO's calculations of the LS-2 monthly rental factors shown on Original Tariff Sheet No. 6.845 are appropriate; however, TECO should be required to recalculate the factors if the Commission's vote in other issues affects the calculations. The new factors will permit customers to contract lighting service for a period between 1 and 25 years.

**Issue 91:** Should the proposed termination factors for long-term facilities (Fifth Revised Tariff Sheet No. 7.765) be approved?

**Recommendation:** TECO's calculations of the monthly rental and termination factors for facilities rental agreement are appropriate; however, TECO should be required to recalculate the factors shown on Fifth Revised Tariff Sheet No. 7.765 if the Commission's vote in other issues affects the calculations. (Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed termination factors for long-term facilities are reasonable and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No position.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

Proposed Fifth Revised Tariff Sheet No. 7.7.65 provides the monthly rental and termination factors for long-term facilities. (EXH 7, MPN J582) These factors apply if a customer and TECO enter into a facilities rental agreement pursuant to which TECO is renting facilities to the customer who requested them. The customer is required to pay a monthly rental factor that is applied to the in-place value of the facilities rented. The term of the agreement is 20 years; the termination factors apply if the agreement is terminated early.

The current monthly rental factor is 0.93 percent and TECO is proposing to increase the monthly rental factor to be applied to the in-place value of the facilities to 0.99 percent per month plus

applicable taxes. Pursuant to the Fifth Revised Sheet No. 7.765, if the long-term rental agreement for Facilities is terminated, a termination fee shall be computed by applying the termination factors to the in-place value of the facilities based on the year in which the Agreement is terminated. TECO's calculations of the monthly rental and termination factors for facilities rental agreement are shown in Schedule E-14, Supplement B, pages 11-12 of 12. (EXH 7, MPN J615-616)

The other parties took no position on this Issue.

### **CONCLUSION**

TECO's calculations of the monthly rental and termination factors for facilities rental agreement are appropriate; however, TECO should be required to recalculate the factors shown on Fifth Revised Tariff Sheet No. 7.765 if the Commission's vote in other issues affects the calculations.



**Issue 92:** Should the non-rate related tariff modifications be approved?

**Recommendation:** The non-rate related tariff modifications are appropriate and should be approved. (McClelland)

**Position of the Parties:**

**TECO:** Yes. The proposed revisions are reasonable and should be approved.

**OPC:** No position.

**FL RISING/  
LULAC:** No.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL  
RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

TECO proposed non rate-related tariff modifications to update basic information such as revision number, page number, President's name, and the effective date. Staff has reviewed the proposed changes and believes they are vital to the legibility and readability of the tariffs.

TECO proposed a modification to Seventh Revised Sheet No. 5.130, which addresses customer deposits. (EXH 7, MPN J498) TECO proposed a modification to the language regarding return of deposit money following termination of service. An agency may pay the deposit fee on behalf of a customer for a number of reasons, and TECO wished to clarify the language to allow the deposit fee to be refunded to the agency when appropriate. (EXH 7 MPN J498) Staff concurs that TECO's explanation is reasonable and the change is appropriate.

**CONCLUSION**

Staff believes the non-rate related tariff modifications are appropriate and should be approved.

**Issue 93:** Should the Commission give staff administrative authority to approve tariffs reflecting Commission approved rates and charges?

**Recommendation:** This is a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (Guffey)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No position.

**FL RISING/  
LULAC:** No.

**FIPUG:** Yes.

**FEA:** No position.

**SIERRA  
CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes.

**FUEL  
RETAILERS:** Yes.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**CONCLUSION**

This is a fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**2026 AND 2027 SUBSEQUENT YEAR ADJUSTMENTS (SYA)**

**Issue 94:** What are the considerations or factors that the Commission should evaluate in determining whether a SYA should be approved?

**Recommendation:** The Company has the burden to prove, by a preponderance of the evidence, that the annualization or project(s) that underlie the SYA are necessary to be accounted for in the current rate case as opposed to a future rate case. In analyzing whether to approve a SYA, the Commission should consider whether the project(s) associated with the requested SYA will substantially improve safety, reliability, or operational efficiency, and whether the project(s) will put pressure on the Company's ability to earn within its range of return. In doing so, it should consider whether it appears sufficiently likely that approval of the project(s) will result in cost savings by avoiding or minimizing future rate proceedings. In a SYA, rates should only be increased for projects that are placed into service, as verified by the Company. (Sparks, Marquez, Harper, Norris, Ellis)

**Position of the Parties:**

**TECO:** The Commission should consider the projects proposed to be included for cost recovery via an SYA, the projected costs of those projects, the impact those plant additions will have on the company's ability to earn within its authorized range of return on equity, and the extent to which the proposed SYA can mitigate the company's need for successive general rate increases.

**OPC:** A SYA should not be necessary or allowed absent compelling circumstances, nor is it good policy to approve one without significant limitations. If the test year is chosen appropriately, it should be representative of rates on a going-forward basis, negating the need for another rate adjustment so soon thereafter, absent any extraordinary circumstances. To evaluate if extraordinary circumstances exist to grant an SYA, the Commission should consider the criteria articulated in the issue.

**FL RISING/**

**LULAC:** SYAs, if ever authorized, should be based on very specific, large, usually singular, generation investments. These SYAs should not be approved. If the Commission does approve an SYA, the Commission should apply the factors proposed by OPC to establish a framework, limitations, guidance, and customer protections when assessing which projects and costs, if any, should be included in an SYA.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC's position on this issue.

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**FRF:** The FRF agrees with the Citizens that subsequent year adjustments should only be allowed where compelling circumstances exist to support such post-rate-case rate increases. Among other things, the Commission should evaluate whether any proposed SYA is truly representative of future circumstances, and whether it is necessary to enable the utility to have sufficient revenues, but not a penny more, to enable the utility to provide safe and reliable service to its customers.

## **FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

## **Staff Analysis:**

### **ANALYSIS**

#### **Legal Framework**

The Commission's authority to implement a SYA has been previously confirmed by the Legislature, by the Florida Supreme Court, and by the Commission.<sup>77</sup> Pursuant to Section 366.076(2), F.S., the Commission may adopt rules that provide for incremental adjustments in rates for periods subsequent to the period new rates are to be in effect. Under the Rule adopted to implement Section 366.076(2), F.S., Rule 25-6.0425, F.A.C., the Commission may, in a full revenue requirements proceeding, approve incremental adjustments in rates for periods subsequent to the initial period in which new rates will be in effect. A SYA is a regulatory mechanism that involves an incremental adjustment to a company's revenue requirement. In a rate proceeding, the revenue requirement is established based on a projected test year, and a SYA would be an incremental adjustment (increase) to the revenue requirement in the year or years following the projected test year to account for any approved SYA. Because SYAs apply to projects that are implemented during and beyond the projected test year, they are inherently more speculative and, therefore, require additional scrutiny.

Consistent with this existing authority, staff submits that a company has the burden to prove by a preponderance of the evidence that a SYA is needed or necessary to implement in the current proceeding. In this case, TECO's proposed 2026 and 2027 SYAs reflect two types of requests: the annualization of projects placed into service in a period prior to the proposed SYA and projects placed into service subsequent to the projected test year.

#### **TECO's Request**

The first type of request is the annualization of projects that were placed into service in a period prior to the proposed SYA. For example, the 2026 SYA reflects the annualization of projects placed into service in 2025 and the 2027 SYA reflects the annualization of projects placed into

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<sup>77</sup> See Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for rate increase for Florida Power & Light Company*, and Docket No. 20090130-EI, *In re: Depreciation and Dismantlement study by Florida Power and Light Company*.

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service in 2026. A projected test year in a rate case reflects a 13-month average for all rate base components. Therefore, the revenue requirement from that period will not reflect the full amount of revenues, expenses, and rate base associated with projects if they are not placed into service for the entirety of that timeframe. For significant and material plant projects (i.e., not typical additions that are expected in a typical year), this could potentially reduce the ability of a company's ability to recover its investment, especially for those placed into service towards the end of a projected test year.

The second type of request made by TECO in this case are projects that will be placed into service subsequent to the projected test year. Specifically, the 2026 and 2027 SYAs reflect the 13-month average of projects placed into service in 2026. The Commission has only considered base rate increase requests with SYAs in the context of settlement agreements. In evaluating settlement agreements, the Commission first focuses on the major issues in the settlement by considering all of the evidence presented at a hearing on the settlement and making ultimate findings of fact based on the evidence in the record that is supported by a preponderance of the record evidence. Secondly, in light of findings of fact, the Commission determines whether the settlement is in the public interest and results in rates that are fair, just, and reasonable.

In the instant docket, TECO's rate request is a fully litigated case before the Commission for resolution and the proposed SYAs are major issues in the case. Therefore, in the context of a fully litigated case, each SYA project must be evaluated. In so doing, staff recommends that the Commission consider certain factors for evaluating SYA projects in light of TECO's specific requests in this proceeding.

### ***Proposed Criteria for Evaluating SYAs***

There is competing testimony and argument as to what criteria should be considered by the Commission when evaluating TECO's SYA requests in this proceeding. OPC asserts SYA projects generally come with the additional risks inherent in attempting to forecast beyond the projected test year. (OPC BR 65) OPC's position, adopted by FIPUG and Walmart, is that a SYA project should not be allowed absent compelling circumstances, and should not be necessary if the test year is chosen appropriately. (OPC BR 64; FIPUG BR 25; Walmart BR 9) OPC also proposed that the Commission weigh whether TECO would earn below the approved range during the years immediately following a rate case and if TECO has demonstrated the need for generation or other facilities in the subsequent year. (OPC BR 66)

Additionally, OPC witness Kollen suggested a SYA project should be limited to known, material costs and that there should be no allowance of a SYA project that is a "business as normal" project and making sure customer growth and other cost offsets are properly accounted for. (TR 2326-2327; OPC BR 66) Finally, OPC proposed three criteria to evaluate whether extraordinary circumstances exist to warrant approval of a SYA project: (1) if the SYA represents a discrete, material generation-type capital project; (2) if the associated cost would cause the company to earn below its approved range; and (3) if TECO can demonstrate that the project is cost effective. (OPC BR 66)

FL Rising/LULAC's position, adopted by Sierra Club, is that SYA projects should be limited to specific, large, singular generation investments unlike the ones proposed by TECO. (FL

Rising/LULAC BR 23) Should one be approved in this case, FL Rising/LULAC proposes applying the factors proposed by OPC to establish a framework including limitations, guidance, and customer protections when assessing what to include in the SYA. (FL Rising/LULAC BR 23)

TECO agrees that in the past SYAs have been used for large generation projects, but notes that there is nothing in the applicable statutes or rules that limits the Commission's consideration to these types of projects. (TECO BR 82) TECO argues that the projects included in its requests should be accounted for in SYAs for 2026 and 2027 because they are "major projects, their costs are reasonable and prudent, placing them in service will have a material impact on the company's ability to earn within its authorized range of returns, and including them in the proposed SYA will mitigate the company's need for successive general rate increases." (TECO BR 82) In support of its proposed SYAs, TECO also emphasized the avoidance of a near future rate case (and substantial corresponding associated rate case expenses) if the proposed SYA projects are approved. Additionally, TECO also offered witness testimony that it "understands that it will be accountable to the Commission in a future proceeding if the Commission approves a project for SYA cost recovery and the company does not execute the project as proposed in this case." (TR 3635-36)

#### ***Staff Recommended Considerations for SYAs***

Staff reviewed all of the parties' arguments and testimony as to SYA criteria. Staff agrees with OPC that TECO must demonstrate a need to implement the proposed SYAs in the instant rate case. Staff likewise submits that the Commission should consider evidence of the need for the SYA as well as the projected savings from avoiding or minimizing future rate case proceedings. If the preponderance of the evidence demonstrates a need, and the Commission finds the SYA is necessary, the Commission should also consider the projected cost savings from the avoidance of future rate proceedings, whether from the elimination altogether of a future rate proceeding or potential reduction in the scope of future proceedings. It should be noted that evaluating a company's ability to earn within its authorized range requires evaluating additional revenues (customer growth) and cost savings, as well as expenses, in the subsequent period(s).

Staff agrees with TECO that the likelihood of cost avoidance from anticipated rate proceedings in the near future is a relevant consideration when evaluating whether to approve a SYA project. And the likelihood of cost avoidance should include an assessment of the accuracy of a company's forecasts as urged by OPC. (OPC BR 65) However, the avoidance of a near future rate case expense is only one of the factors to consider. This is because there is no guarantee of the avoidance of a rate case in the near future, as unforeseeable economic and other external factors may occur in the future that are beyond the control of the Company and the Commission.

#### ***Annualization***

Staff notes that as a general proposition, if a project is needed and placed into service during the projected test year, the costs recognized during the projected test year will only represent a portion of the total annual costs a project will incur in subsequent periods. Therefore, it is reasonable to reflect the known and measurable change in a SYA, so the company has the opportunity to recover the full investment. It is reasonable to annualize the cost of such projects (i.e., make a SYA), if such projects are needed and have certainty, because they are to be placed

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in service during the projected test year. Of course, if a project is delayed or not constructed in the projected test year and a SYA was approved, the company would still receive revenues associated with the SYA without incurring the commensurate costs. This would potentially inflate a company's earnings. As such, the Commission should require that the company verify to the Commission that the asset(s) has been placed into service prior to the implementation of the SYA rate increase. TECO acknowledged as much at hearing and in its brief. (TR 3635-36; TECO BR 82)

### ***Subsequent Year Projects***

The overarching consideration for a SYA project placed into service after the projected test year is the purpose and necessity of the asset to be implemented in the timeframe proposed by a company. The need for a project must be supported by evidence in the record. The necessity of a SYA project may be supported depending on a particular company's specific circumstances. Regardless, the company has the burden of offering evidence to support the need and necessity for a SYA project. Specifically, the Commission should consider whether the reasons to approve cost-recovery for the project in the current rate case outweigh the countervailing arguments and evidence, including the inherent uncertainty in forecasting beyond a projected test year.

Staff suggests that need can be supported by evidence showing the project will substantially improve safety or reliability, or solve an operational problem in a more efficient manner. For example, the need for a generating unit may be demonstrated when the evidence shows that the generating unit is necessary to maintain a minimum level of reliability or other reliability standards. On the other hand an asset that is added for purely economic reasons, such as reduced fuel costs, is inherently speculative by nature because fuel costs are not entirely predictable with definitive accuracy. Thus, whether projects will increase safety or reliability or further a significant operational efficiency, and not solely economic considerations, are important considerations for determining the necessity of any SYA projects.

## **CONCLUSION**

The Company has the burden to prove, by a preponderance of the evidence, that the annualization or project(s) that underlie the SYA are necessary to be accounted for in the current rate case as opposed to a future rate case. In analyzing whether to approve a SYA project, the Commission should consider whether the SYA project will substantially improve safety, reliability, or operational efficiency, and whether the project will put pressure on the company's ability to earn within its range of return. In doing so, it should consider whether it appears sufficiently likely that approval of the project will result in cost savings by avoiding or minimizing future rate proceedings. In a SYA, rates should only be increased for projects that are placed into service, as verified by the Company. The individual components of TECO's requested SYAs in 2026 and 2027 are discussed in Issues 95 through 102.

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**Issue 95:** Should the Commission approve the inclusion of TECO's proposed Solar Projects in the 2026 and 2027 SYA? What, if any, adjustments should be made?

**Recommendation:** In part. The annualization associated with the 2025 proposed Solar Projects should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation, but the proposed 2026 Solar Projects should be removed and there should be no 2027 SYA. While staff does not recommend the inclusion of the 2026 Solar Projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery in a future proceeding. (O. Wooten, Vogel)

**Position of the Parties:**

**TECO:** Yes. The Future Solar Projects proposed for recovery through SYA are prudent for the reasons explained under Issue 18 and should be included in the 2026 and 2027 SYA without adjustments.

**OPC:** This project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** If the SYA is approved, then yes, with the following solar-specific adjustments: a 35-year service life of the assets; use of a 9.50% ROE.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF supports the addition of solar generating resources to Florida's power supply grid, provided that such resources satisfy the normal standards of cost-effectiveness, reasonableness, and prudence of the utility's investment. These principles require that TECO's solar assets be depreciated over 35 years, and fair ratemaking policy requires that TECO only be allowed to recover costs associated with its solar facilities beginning when each facility achieves commercial service status.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

In this docket, TECO is requesting full year revenue requirement values for the 2024 and 2025 Solar Projects, as well as a SYA for the 2026 Solar Projects.

**Annualization of 2025 Solar Projects**

As discussed in Issue 94, staff recommends allowing a SYA for the incremental costs associated with the annualization of projects if the Company meets certain conditions for projects with an in-service date during the projected test year. Staff notes that the 2025 Solar Projects have a projected in-service dates prior to the end of the 2025 projected test year. (EXH 208, MPN E7811–E7817) Therefore, staff recommends inclusion of the annualization associated with the 2025 Solar Projects in the 2026 SYA. However, after reviewing the Company’s calculation of the 2026 SYA, it appears the associated Accumulated Depreciation annualization of all the projects was omitted from the calculation of the incremental return on rate base. Therefore, there should be an adjustment to include the corresponding Accumulated Depreciation annualization, as calculated in its breakdown of the 2025 projects. (EXH 201)

**New 2026 Solar Projects**

TECO has proposed adding four future solar facilities by the end of 2026. (TR 819) The 2026 Solar Projects consist of the Big Four, Farmland, Brewster and Wimauma projects. These 2026 Solar Projects represent an addition of 242.2 MW of solar energy to TECO’s system, with an in-service date of May 2026 for Big Four and December 2026 for the remaining units. (TR 819; EXH 20 MPN C5-337) Witness Aponte further testified that the 2026 Solar Projects have a projected installed costs of approximately \$365.2 million. (EXH 19 MPN C4-272–C4-295; EXH 201, MPN E6133)

Witness Aponte testified that the 2026 Solar Projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the solar facilities and the omission of the solar facilities to determine the system CPVRR. (TR 988-989) The conclusion of the analyses determined that the addition of the 2026 Solar Projects would result in a CPVRR savings for customers of \$78.7 million excluding emissions, primarily from system fuel savings of \$385.6 million. (EXH 20, MPN C5-346–C5-347)

In its evaluation of the 2026 Solar Projects, staff considered the need for the facilities. The need for additional physical plant can vary from a necessity for maintaining a minimum level of reliability (such as 20 percent planning reserve margin) or economic reasons (such as reduced fuel costs). Maintaining minimum reliability standards is paramount and not discretionary in terms of the timing of capital spending and subsequent recovery. In cross-examination, witness Aponte states that the solar facilities provide no reserve margin benefit for winter peak which TECO uses for planning, and only a small percentage benefit for summer. (TR 1050-1051) Plant additions that are projected to reduce future fuel costs are more speculative and therefore provides utility management more discretion in terms of the timing of capital spending and recovery. By evaluating something further outside the projected test year staff notes that the

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CPVRR analysis results are subject to greater uncertainty than compared to a forecast conducted closer to the in-service dates of the facilities. For example, during the hearing, witness Stryker agreed that although the revenue requirements would be recovered from customers starting in January 2026 there was no guarantee that the solar facilities would meet the scheduled in-service dates. (TR 866) Staff notes that the in-service dates for other units have already changed even during the current proceeding, such as the Bayside Energy Storage unit, delayed from an original April 2025 to December 2025 in-service date. (TR 842; EXH 208, MPN E7811–E7817) Because of the uncertainty of the factors that determine overall cost-effectiveness, especially fuel forecasts, determination on the cost-effectiveness of the 2026 Solar Projects would be more accurate closer to the in-service dates of the units. Staff notes that in traditional ratemaking, TECO would be able to construct the units if existing rates would suffice or request a limited proceeding closer to the in-service date of the generating facilities. This would increase certainty in the forecasts and project completion while also better timing any rate increase associated with the cost of the facilities with the avoided system fuel benefits it produces. Therefore, staff recommends that the 2026 Solar Projects should not be included in the 2026 or 2027 SYA. Furthermore, while staff does not recommend the inclusion of the 2026 Solar Projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery in a future proceeding.

No intervenor provided testimony specifically addressing this Issue. However, in its brief OPC argued that the projects should only be included if: the projects represent new capital investment, would cause TECO to earn below its earning range, and the Company can demonstrate a need for the projects. (OPC BR 67) FIPUG adopted OPC's position on this Issue. FL Rising/LULAC and FRF argued that the projects should have a 35-year depreciation life. (FL Rising/LULAC BR 23, FRF BR 46) Staff's recommendation on depreciation life is reflected in Issue 7. No other parties provided positions on this Issue.

## **CONCLUSION**

The annualization associated with the 2025 proposed Solar Projects should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation, but the proposed 2026 Solar Projects should be removed and there should be no 2027 SYA. While staff does not recommend the inclusion of the 2026 Solar Projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery in a future proceeding.

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**Issue 96:** Should the Commission approve the inclusion of TECO’s proposed Grid Reliability and Resilience Projects in the 2026 and 2027 SYA? What, if any, adjustments should be made?

**Recommendation:** In part. The Grid Communications Network Project has an in-service date of August 2025 and the annualization amount should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. The Customer Information Device Expansion Project (\$24.3 million) and the Grid Communications Network Hardware, Back Office IT Systems, and Control Systems Projects (\$108.3 million) will not be completed until 2026 and should be removed and there should be no 2027 SYA. While staff does not recommend the inclusion of the 2026 projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery in a future proceeding. (P. Buys, Vogel)

**Position of the Parties:**

**TECO:** Yes. The proposed GRR projects are prudent for the reasons explained under Issue 19 and should be included in the 2026 and 2027 SYA without adjustments. There is nothing in Section 366.076, Florida Statutes, that limits SYA to cost recovery for generation projects, thus OPC’s proposal to disallow the GRR Projects should be rejected.

**OPC:** No, the Commission should deny the inclusion of Tampa Electric’s proposed GRR Projects for the following reasons: (1) these projects are historically, traditional “business as normal” activities; (2) these projects are NOT for specific new and material generation capital investment costs and operation expenses (i.e. a discrete, material capital project); (3) “delivery infrastructure” investments have not previously been allowed recovery in an SYA.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF agrees with the Citizens that the Commission should deny inclusion of these projects in any 2026 or 2027 SYAs because they are usual, non-extraordinary projects of a type that is not appropriate for inclusion in SYAs.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 19, TECO requested full recovery of its GRR Projects in rate base. The GRR Projects consist of over 40 interdependent projects that include telecommunications, control center operational technology, back-office information technology, distributed energy resources and substations. TECO proposed to include 12 projects in rate base for the 2025 projected test year and to include two additional new projects as part of the 2026 and 2027 SYAs. (TR 1240) While TECO witness Lukcic also identifies the Grid Communications Network projects as one of three new projects to be included in the 2026 SYA, this project has an in-service date of August 2025. (TR 1245-1246) Therefore, staff has included this project as part of its analysis for Issue 19 and recommended approval of this project.

As discussed in Issue 94, staff recommends allowing a SYA for incremental costs associated with the annualization of projects if the Company meets certain conditions for projects with an in-service date during the projected test year. Staff notes that the GRR Projects identified and discussed in Issue 19 have projected in-service dates prior to the end of the 2025 projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, staff recommends inclusion of the incremental cost associated with the annualization of the projects in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

***New 2026 GRR Projects***

TECO proposed two additional GRR projects that would be completed in 2026: (1) Customer Information Device Expansion; and (2) Grid Communications Network Hardware, Back Office IT Systems, and Control Systems. (TR 1245-1246)

The Customer Information Device Expansion project consists of reconstructing data models for lighting and non-meter devices, integration with existing systems, and revamping the business process for device billing. The projected costs for this project are \$24.3 million in capital costs, with an in-service date of September 2026. The Grid Communication Network Hardware, Back Office IT Systems, and Control Systems project consists of Line Sensor Software, Private PLTE implementation, a WMS, and Distribution Planning Software Upgrades. The projected costs for this project are \$120.6 million in capital costs, with an in-service date of December 2026. However, TECO adjusted its original proposal for this project by removing the Line Sensor Software and Distribution Planning Software Upgrades reducing the total amount by \$12.3 million for a total of \$108.3 in capital costs. (TR 1247-1249; EXH 194, MPN E5495; EXH 835)

OPC maintained that the GRR projects include the maintenance and replacement of obsolete equipment, which is normally included in the Company's annual budgets and would be accounted for in a representative test year. Additionally, OPC witness Mara argued that the GRR projects should be planned for and deployed between rate cases or during a rate case's test year. OPC asserted that the GRR projects are a continuation of various projects that TECO began planning and deploying before this rate case. (TR 2376-2378; OPC BR 67-69) OPC set forth its

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three criteria for SYAs and argued that the GRR Projects do not meet the criteria and should not be approved for the following reasons: (1) none of the GRR projects are generation-type; (2) TECO failed to demonstrate a need for the increase; and (3) TECO would be under no obligation to spend the revenues on these projects if approved by Commission. (OPC BR 70-71)

Witness Mara testified that the GRR projects in the SYAs, have compounded the problem of the speculative nature of the costs and deployment timing of the GRR projects since they are further out into future (i.e., the further out into the future, the less reliable the forecast). Staff agrees with witness Mara and considered this argument while evaluating the need for the GRR projects that are outside the 2025 projected test year. While staff believes the Customer Information Device Expansion Project and Grid Communication Network Hardware, Back Office IT Systems, and Control Systems Projects are reasonable, staff believes the costs are too speculative at this time, given that the in-service dates are in 2026. (TR 2376-2377) Furthermore, while staff does not recommend the inclusion of the two new projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery of these two new projects in a future proceeding.

As explained in Issues 14, 16, 17, and 19, FL Rising/LULAC's witness Rábago recommended that the Commission should disapprove any capital spending project of \$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommended that the Commission should disapprove most, if not all, of the rate recovery for the GRR Projects, as he believes that it is additional spending by TECO that is unjustified and unreasonable. (TR 2609-2612) As discussed in Issue 19, TECO witness Lukcic refuted these arguments. He testified that TECO believes that the SYA was the appropriate mechanism for the GRR Projects in order to help release pressure for going back into a rate case. To further support his argument, he testified that the projects are co-dependent and drive towards the most effective deployment of capital to maximize the benefits to customers and that the projects should be deployed in a certain order to maximize value for the customer. (TR 1257-1261; 1268; 1282-1283; TECO BR 83) Staff understands witness Lukcic's arguments and agrees that there may be a need for these projects but believes TECO's request for these projects are too speculative at this time, given that the in-service dates are in 2026. Based on the above, staff recommends that the Customer Information Device Expansion Project and the Grid Communications Network Hardware, Back Office IT Systems, and Control Systems Projects should not be included in the 2026 or 2027 SYA. While staff does not recommend the inclusion of the 2026 projects as part of the SYAs, this does not preclude TECO from filing a request for the cost recovery in a future proceeding.

## **CONCLUSION**

The Grid Communications Network Project has an in-service date of August 2025 and the annualization amount should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. The Customer Information Device Expansion Project (\$24.3 million) and the Grid Communications Network Hardware, Back Office IT Systems, and Control Systems Projects (\$108.3 million) will not be completed until 2026 and should be removed and there should be no 2027 SYA. While staff does not recommend the inclusion of the 2026 projects as part of the SYA, this does not preclude TECO from filing a request for the cost recovery in a future proceeding.

Date: November 22, 2024

**Issue 97:** Should the Commission approve the inclusion of TECO's proposed Polk 1 Flexibility Project in the 2026 SYA? What, if any, adjustments should be made?

**Recommendation:** Yes. The annualization of TECO's proposed Polk 1 Flexibility project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. (G. Davis, Vogel)

**Position of the Parties:**

**TECO:** Yes. The Polk 1 Flexibility Project is prudent for the reasons explained under Issue 24 and should be included in the 2026 SYA without adjustments.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF agrees with the Citizens that the Commission should not include recovery of this project in the 2026 SYA unless TECO can demonstrate a need for the generation and the project's revenue requirements, if demonstrably needed and prudent, would cause TECO to fall below its approved earnings range in 2026.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 24, the Polk 1 Flexibility Project is the conversion of the existing Polk Unit 1, a 220 MW IGCC plant, to a 200 MW natural gas-fired simple cycle CT plant with an in-service date of May 2025. (TR 652) No intervenor other than OPC filed testimony on this Issue. In their briefs, FL Rising/LULAC, FEA, Sierra Club, and Fuel Retailers have taken no position on this Issue. OPC's position is to disallow 2026 SYA if its three conditions are not met. (OPC BR 72) FIPUG, FRF and Walmart adopted OPC's position. As discussed in Issue 94, staff recommends allowing a SYA for the incremental costs associated with the annualization of projects if the Company meets certain conditions for projects with an in-service date during the projected test year. Staff notes that the Polk 1 Flexibility Project has a projected in-service date of May 2025. (EXH 208) However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, staff recommends inclusion of the annualization associated with the Polk 1 Flexibility Project in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

**CONCLUSION**

The annualization of TECO's proposed Polk 1 Flexibility project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.



Date: November 22, 2024

**Issue 98:** Should the Commission approve the inclusion of TECO's proposed Energy Storage Projects in the 2026 SYA? What, if any, adjustments should be made?

**Recommendation:** The annualization associated with TECO's proposed Energy Storage Projects should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. The Investment Tax Credits related to the battery storage projects in the 2026 SYA should be adjusted to reflect a 5-year amortization period. The annual ITC amortization should be \$8,792,608, which results in a revenue requirement decrease of \$1,713,381 for the 2026 SYA (O. Wooten, Vogel, D. Buys)

**Position of the Parties:**

**TECO:** Yes. The company's 115 MW of Future Energy Storage Capacity projects are prudent for the reasons explained under Issue 20 and should be included in the 2026 and 2027 SYA. The calculation of the company's proposed 2026 SYA should be adjusted as shown in the July Filing, which results in a net revenue requirement decrease of \$1,693,056 for the 2026 SYA.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** If the SYA is approved, yes, with the following battery-specific adjustments: a 20-year service life of the assets; reflection of the assets as cost-free capital in the cost of capital applied to rate base; use of a 9.50% ROE. A ten-year ITC amortization period should also be used.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF supports the addition of battery energy storage resources to Florida's power supply grid, provided that such resources satisfy the normal standards of cost-effectiveness, reasonableness, and prudence of the utility's investment. These principles require that battery storage assets be depreciated over 20 years, not 10 years as proposed by TECO, and fair ratemaking policy requires that TECO only be allowed to begin recovering those costs when each facility achieves commercial service status.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As previously discussed in Issue 20, TECO requested approval of the energy storage projects: Dover, Lake Mabel, Wimuuama and Bayside.<sup>78</sup> Dover has a projected in-service date prior to the test year, in September 2024. The Lake Mabel, Wimuuama, and Bayside projects all enter service during the projected test year, in January 2025, February 2025 and December 2025, respectively. (TR 842, 979; EXH 208, MPN E7811–E7817) In that issue, staff recommended approval of including the projects in the 2025 projected test year. This Issue will discuss the 2026 SYA associated with the four energy storage projects.

As discussed in Issue 94, staff recommends allowing a SYA for the incremental costs associated with the annualization of projects that are in-service during the projected test year. As noted above, each of the four energy storage projects have an in-service date prior to the end of projected test year. (EXH 208 MPN E7811–E7817) However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA and it should be included.

In OPC's brief, OPC argued that the projects should only be included if the projects represent new capital investment, would cause TECO to earn below its earning range, and the Company can demonstrate a need for the projects. (OPC BR 73) FIPUG adopted OPC's position on this Issue. FL Rising/LULAC and FRF argued that the projects should have a 20-year depreciation life. (FL Rising/LULAC BR 23; FRF BR 47) Staff's recommendation on depreciation lives is reflected in Issue 7. No other party took a position on this Issue.

As discussed in Issue 65, staff is recommending an adjustment to the ITC's related to the energy storage projects to reduce the 10-year amortization period proposed by TECO to a 5-year amortization period. In its original filing, TECO included an incremental annual ITC amortization amount of \$1,196,669 to reflect the full in-service amounts for the energy storage projects. (EXH 32, MPN C16-1701) In TECO witness Strickland's revised rebuttal testimony, she provided a schedule listing the updated amounts for the battery storage ITCs in SYA 2026. (TR 3228) The total amount of ITC's reported was \$43,963,042. The annual amount of the 5-year ITC amortization in 2026 SYA is \$8,792,608. The incremental amount of annual amortization of ITC's from 2025 is \$2,165,796. Grossed-up for fees and taxes the amount is \$2,910,050. The amount of the revenue requirement adjustment to reflect a 5-year amortization period as opposed to a 10-year amortization period is the difference between TECO's original incremental amount of \$1,196,669 and staff's recommended incremental amount of \$2,910,050, which equates to \$1,713,381.

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<sup>78</sup> Formerly known as South Tampa Energy Storage Project.

## **CONCLUSION**

The annualization associated with TECO's proposed Energy Storage Projects should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. The Investment Tax Credits related to the battery storage projects in the 2026 SYA should be adjusted to reflect a 5-year amortization period. The annual ITC amortization should be \$8,792,608, which results in a revenue requirement decrease of \$1,713,381 for the 2026 SYA.

Date: November 22, 2024

**Issue 99:** Should the Commission approve the inclusion of TECO’s proposed Bearss Operations Center Project in the 2026 SYA? What, if any, adjustments should be made?

**Recommendation:** Yes. TECO’s proposed annualization of the Bearss Operations Center project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. (P. Buys, Hinson)

**Position of the Parties:**

**TECO:** Yes. The Bearss Operations Center is prudent for the reasons explained under Issue 23 and should be included in the 2026 SYA without adjustments.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF agrees with OPC on this issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 23, the BOC is a facility designed to withstand major hurricanes, protect all TECO’s cyber assets, and operate TECO’s command and control capabilities. The anticipated in-service date for the BOC is June 2025. TECO briefed that including the BOC in the 2026 SYA will mitigate the need for a successive general rate increase. (TR 658-659, 668; TECO BR 85) In Issue 23, staff recommended approval of including this project in the 2025 projected test year. This Issue addresses the 2026 SYA associated with the BOC.

As discussed in Issue 94, OPC has three criteria for inclusion of a project in a SYA. OPC briefed that the BOC meets the first criteria of a new and material capital investment; however, the BOC would not cause TECO to earn below its earning range. (OPC BR 74) The remaining intervenors did not specifically address or take a position on this Issue.

Staff recommends allowing a SYA for incremental costs associated with the annualization of projects that are in-service during the projected test year. As stated above, the BOC's in-service date is June 2025, which is prior to the end of the projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, staff recommends that the annualization associated with the BOC should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

### **CONCLUSION**

TECO's proposed annualization of the Bearss Operations Center project should be included in the 2026 SYA with an adjustment to include the annualization of the associated Accumulated Depreciation.

Date: November 22, 2024

**Issue 100:** Should the Commission approve the inclusion of TECO's proposed Corporate Headquarters Project in the 2026 SYA? What, if any, adjustments should be made?

**Recommendation:** Yes. TECO's proposed annualization of the Corporate Headquarters project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. (P. Buys, Hinson)

**Position of the Parties:**

**TECO:** Yes. The company's new corporate headquarters project is prudent for the reasons explained under Issue 21 and should be included in the 2026 SYA without adjustments.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF agrees with OPC on this issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 21, TECO is relocating its headquarters from TECO Plaza in Downtown Tampa to Midtown Tampa. The new headquarters location will provide several qualitative benefits such as, value, resilience, and employee retentions and satisfaction perspective. The anticipated in-service date for the new headquarters is June 2025. TECO briefed that including the new headquarters in the 2026 SYA will mitigate the need for a successive general rate increase. (TR 669-670, 672; TECO BR 85) In Issue 21, staff recommended approval of including

this project in the 2025 projected test year. This Issue addresses the 2026 SYA associated with TECO's proposed Corporate Headquarters Project.

As discussed in Issue 94, OPC has three criteria for inclusion of a project in a SYA. OPC briefed that the new headquarters meets the first criteria of a new and material capital investment; however, the new headquarters would not cause TECO to earn below its earning range. (OPC BR 75) The remaining intervenors did not specifically address or take a position on this Issue.

Staff recommends allowing a SYA for incremental costs associated with the annualization of projects that are in service in the middle of the test year. The Corporate Headquarters' in-service date is June 2025, which is prior to the end of the projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, staff recommends that the annualization associated with the Corporate Headquarters Project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

### **CONCLUSION**

TECO's proposed annualization of the Corporate Headquarters Project should be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

Date: November 22, 2024

**Issue 101:** Should the Commission approve the inclusion of TECO’s proposed South Tampa Resilience Project in the 2026 and 2027 SYA? What, if any, adjustments should be made?

**Recommendation:** No. Consistent with Issue 22, staff recommends removal of the South Tampa Resilience Project from the 2026 and 2027 SYAs. (G. Davis, Hinson)

**Position of the Parties:**

**TECO:** Yes. South Tampa Resilience Project is prudent for the reasons explained under Issue 22 and should be included in the 2026 and 2027 SYA without adjustments.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** No. As admitted by TECO, the South Tampa Resilience Project is not needed for reliability in the 2025-2027 timeframe and the cost-effectiveness results to show it is economic are infected by the deferral of a combustion turbine that, thanks to other plant additions, would not actually have been added or deferred by whether the South Tampa Resilience project goes forward.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.



**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 22, the STR Project is a two-phase project consisting of two pairs of 18.5 MW RICE with in-service dates of December 2024 for Phase I and October 2025 for Phase II. (TR 654-655, EXH 208). No intervenor other than OPC and FL Rising/LULAC filed testimony on this Issue. FEA, Sierra Club, FRF, and Fuel Retailers have taken no position. FL Rising/LULAC's position is to disallow SYA for 2026 and 2027 because the STR project is not needed to meet reliability requirements. (FL Rising/LULAC BR 24) OPC's position is to disallow SYA in 2026 and 2027 if their three criteria are not met. (OPC BR 76). FIPUG and Walmart adopted OPC's position. In Issue 22, staff recommends that the STR Project should be denied. As a result, the STR Project should not be included in TECO's 2026 or 2027 SYAs.

**CONCLUSION**

Consistent with Issue 22, staff recommends removal of the South Tampa Resilience Project from the 2026 and 2027 SYAs.

Date: November 22, 2024

**Issue 102:** Should the Commission approve the inclusion of TECO's proposed Polk Fuel Diversity Project in the 2026 and 2027 SYA? What, if any, adjustments should be made?

**Recommendation:** No. TECO's proposed Polk Fuel Diversity project should be removed from the 2026 and 2027 SYAs because its in-service date is beyond the projected test year and TECO has not demonstrated a definitive reliability need associated with the Polk Fuel Diversity project. (G. Davis, Hinson)

**Position of the Parties:**

**TECO:** Yes. The Polk Fuel Diversity Project is prudent and should be included in the 2027 SYA without adjustments. The Project will mitigate customer exposure to natural gas price spikes and supply disruptions and is not proposed to be recovered in the 2026 SYA.

**OPC:** To the extent the Commission authorizes an SYA, this project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** No. TECO has not proven that additional fuel diversity is necessary at Polk 1, nor has it proven that the proposed project provides fuel diversity at all. On the contrary, the project attempts to solve fuel availability issues by adding another delivered fuel to Polk 1. Furthermore, Polk 1's low utilization rate and planned retirement date of 2036 make the project an unfair, unjust, and unreasonable use of ratepayer dollars.

**FRF:** The FRF agrees with OPC on this issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO's Polk Fuel Diversity project involves adding fuel supply diversity to the generation at Polk Power Station by adding dual-fuel capability to three CTs at the site, allowing them to burn natural gas or fuel oil. According to TECO witness Aldazabal, two of the five CTs are already dual-fuel capable and the site already has fuel oil infrastructure that can serve the additional three units. Witness Aldazabal stated that this project helps to mitigate natural gas price spikes, fuel supply disruption risk, and energy demand in excess of natural gas supply and transportation capability. This project is estimated to cost approximately \$53.9 million with an in-service date of December 31, 2026. (TR 675-676, 678; EXH 208)

Witness Aldazabal explained that multiple options were reviewed for mitigating fuel supply disruption risks and determined that adding dual-fuel capacity to the remaining three CTs was the most cost effective option. He testified that TECO considered several options to address risks associated with fuel supply limitations or disruptions, including liquid natural gas (LNG) storage, incremental firm gas transportation, solid fuel generation, purchased power, transmission, and renewable generation. Witness Aldazabal further testified that the most viable options were LNG or oil, but that LNG had high capital expense and long-term O&M cost uncertainty coupled with permitting complexities and potential community opposition eliminated this option. (TR 676-677) Adding dual-fuel capability to Polk Power Station units was ultimately selected as it had pre-existing oil infrastructure, as other oil-based options such as adding oil pipelines or additional generation raised more permitting and economic challenges. (TR 677-678)

FL Rising/LULAC witness Rábago recommended that the Commission should disallow the Polk Fuel Diversity Project because the Company has not demonstrated the cost-effectiveness of the project. (TR 2611) In TECO witness Aldazabal's rebuttal testimony, he stated the decision to invest in a backup oil project of this nature was based upon the need to mitigate risk. Even with the growth in TECO's solar generation, TECO projects over 80 percent of its electricity for customers will come from natural gas fired generation. Florida's peninsular geography means that the state and TECO can face challenges importing fuel or power when one or more of the current sources is constrained or fully subscribed. The fact that surrounding interconnection options are limited by geography makes on-site fuel diversity even more important than for utilities with interconnection options all around them. (TR 690-691) During cross-examination, witness Aldazabal confirmed the retirement date for Polk Unit 1, one of the three units to be upgraded to dual fuel capability, as 2036 but noted the retirement date could be extended. In response to further cross-examination on whether TECO could achieve the project's fuel diversity goal using clean energy instead, witness Aldazabal testified he feels confident that TECO can add additional oil fuel storage cheaper than any clean energy alternative. (TR 784-785) No intervenor, other than OPC, FL Rising/LULAC and Sierra Club filed testimony. FEA, and Fuel Retailers have taken no position on this Issue. FL Rising/LULAC's position is no. (FL Rising/LULAC BR 24) Sierra Club's position is no because of Polk Unit 1's low utilization rate and planned retirement in 2036 that makes this project unfair, unjust and unreasonable for ratepayers. (Sierra Club BR 60) OPC's position is to disallow SYAs in 2026 and 2027 unless its three conditions are met. (OPC BR 76) FIPUG, FRF and Walmart adopted OPC's position.

In its evaluation of the Polk Fuel Diversity Project, staff considered the need for the facilities. The need for additional physical plant can vary from a necessity for maintaining a minimum level of reliability (such as 20 percent planning reserve margin) or economic reasons (such as reduced fuel costs). Maintaining minimum reliability standards is paramount and not discretionary in terms of the timing of capital spending and subsequent recovery. Plant additions that are projected to reduce future fuel costs are more speculative and therefore provides utility management more discretion in terms of the timing of capital spending and recovery. In this case, the project neither adds to TECO's reserve margin, nor does it improve the economics of the upgraded units. Instead, the project adds a fuel diversity option for TECO to utilize in addressing the potential risk of short-term fuel supply disruptions. Regardless of the merits of the Polk Fuel Diversity project however, staff must evaluate whether it is appropriate to include them in the 2026 and 2027 SYA. As discussed in Issue 94, staff recommends allowing a SYA for the incremental costs associated with the annualization of projects that are in-service during the projected test year. As noted above, the project has an in-service date by December 31, 2026, outside the projected test year. Staff notes that in traditional ratemaking, TECO would still be able to construct the facilities if existing rates were sufficient or request a limited proceeding closer to the in-service date of the project. Staff recommends that as it is outside the projected test year and TECO has not demonstrated a definitive reliability need associated with the Polk Fuel Diversity project, the project should not be included in the 2026 or 2027 SYA.

### **CONCLUSION**

TECO's proposed Polk Fuel Diversity project should be removed from the 2026 and 2027 SYAs because its in-service date is beyond the projected test year and TECO has not demonstrated a definitive reliability need associated with the Polk Fuel Diversity project.

**Issue 103:** What overall rate of return should be used to calculate the 2026 and 2027 SYA?

**Recommendation:** As discussed in Issue 40, an overall rate of return of 6.81 percent should be used to calculate the 2026 and 2027 SYA. (Ferrer, D. Buys)

**Position of the Parties:**

**TECO:** The Commission should use the overall rate of return approved in Issue 40, which the company believes should be 7.37 percent.

**OPC:** The overall rate of return should be the OPC proposed ROR for 2025 of 7.19% using OPC proposed ROE of 9.50%.

**FL RISING/**

**LULAC:** If the Commission approves the SYAs, the rate of return should be adjusted to reflect the reduced rate base and adjusted capital structure.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts OPC's position on this issue.

**FRF:** If the Commission approves any SYA for 2026 or 2027, the appropriate overall rate of return is 6.38 percent, based on the FRF's recommended ROE of 9.50 percent.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

This Issue is essentially uncontested wherein the parties contended that the overall rate of return for the 2026 and 2027 SYAs should reflect their respective positions and arguments for the projected 2025 test year overall rate of return in Issue 40. TECO proposed to use the overall rate of return approved by the Commission for the 2025 projected test year to calculate the 2026 and 2027 SYA. (TECO BR 87; TR 3421) In its brief, OPC referred to its argument in Issue 39 (the ROE issue) as its argument in this Issue. However, OPC did not provide any argument for the 2026 and 2027 SYA overall rate of return in its argument for Issue 39. (OPC BR 32-42) Further, OPC's position statement describes its recommended overall rate of return based on investor sources (7.19 percent), not the overall rate of return OPC recommended for the WACC in Issue

40 (6.38 percent). (OPC BR 76-77) FRF's position to use an overall rate of return of 6.38 percent for the 2026 and 2027 SYAs is the same as FRF's position to use OPC witness Woolridge's recommended overall rate of return in Issue 40. (FRF BR 35, 48) No other parties provided any specific argument on this Issue. Staff is recommending an overall rate of return of 6.81 percent for the 2025 projected test year in Issue 40. Upon a review of the testimony and exhibits in the record, there is not a compelling reason or argument to use a different overall rate of return for the 2026 or 2027 SYA than the overall rate of return approved for the 2025 projected test year in Issue 40. Based on the record evidence and the parties' positions, staff recommends the Commission approve an overall rate of return of 6.81 percent to be used to calculate the 2026 and 2027 SYAs.

### **CONCLUSION**

As discussed in Issue 40, an overall rate of return of 6.81 percent should be used to calculate the 2026 and 2027 SYA.

Date: November 22, 2024

**Issue 104:** Should the SYA for 2026 and 2027 reflect additional revenues due to customer growth? What, if any, adjustments should be made?

**Recommendation:** No. Any SYAs for 2026 and/or 2027 approved by the Commission should not reflect additional revenues resulting from customer growth. No adjustments should be made. (Kunkler)

**Position of the Parties:**

**TECO:** No.

**OPC:** Yes. Should the Commission allow a 2026 SYA, the additional forecasted revenues reflected due to customer growth should be increased by at least \$7.994 million. Should the Commission allow a 2027 SYA, additional forecasted revenues reflected due to customer growth should be increased by at least \$6.123 million.

**FL RISING/**

**LULAC:** If the Commission approves the SYAs, then yes. The 2026 SYA should be reduced by \$7.994 million, and the 2027 SYA should be reduced by \$6.123 million to reflect additional revenues due to customer growth.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes. If the Commission allows a 2026 SYA, the additional forecasted revenues due to customer growth should be increased by at least \$7.994 million. If the Commission allows a 2027 SYA, additional forecasted revenues due to customer growth should be increased by at least \$6.123 million.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 94, staff is not recommending approval of TECO's full SYA requests for 2026 and 2027. However, should the Commission decide to approve any SYA requests, this

Issue addresses whether the incremental revenues associated with an increase in TECO's customer base should be included in the Company's 2026 and 2027 SYA.

While TECO argued that any revenue associated with customer growth should not be included in its requested 2026 and 2027 SYAs, OPC and other intervenors argued against TECO's position. OPC witness Kollen argued that, in the event the Commission grants any SYA, the Commission should reduce the requested 2026 and 2027 SYA revenue requirements and requested increases by OPC witness Dismukes' proposed adjustments. OPC argued that an adjustment to reflect an increase in base revenues due to both growth in TECO's customer base and an increase in forecasted sales should be considered. (TR 2324, 2334-2335) OPC believes, without these customer growth and sales considerations, TECO's 2026 and 2027 SYA requests are overstated. (TR 2332) These proposed adjustments to SYA revenue by witness Dismukes are a reduction for the 2026 and 2027 SYAs of \$7.994 million and \$6.123 million, respectively. (OPC BR 77) The other Intervenors either adopted the position of OPC or took no position on the issue.

TECO argued that the Commission should reject OPC's proposed adjustments to include additional revenue from customer growth into SYA calculations for four reasons: (1) TECO witness Chronister stated that revenue from customer growth is "needed to cover costs associated with general rate base growth" and "the revenue requirements for the projects included in the Company's proposed SYA are needed to cover the costs of the major rate base additions included in the SYA;" (2) Inclusion of incremental revenues from customer growth would "moderate" the benefits of the SYA and may cause the need for additional rate relief for TECO in 2026 and/or 2027; (3) The Company contends that the inclusion of additional revenue from customer growth is "inconsistent with the method used to calculate the company's previous SoBRA and GBRA;" and (4) TECO witness Cifuentes argued that OPC witness Dismukes' methodology to project additional revenues is flawed. (TECO BR 87; TR 1511-1520, 3419-3420, 3462-3463, 3517)

Staff is persuaded by the Company's arguments that TECO's SYA adjustments for 2026 and 2027 should not reflect additional revenues generated from customer growth. Staff believes that, while the Company's revenues will gradually rise due to customer growth, so will the associated expenses that are incurred to provide service to those new customers. Staff agrees with TECO that this approach aligns with established precedent set forth by the Company's prior solar base rate adjustment (SoBRA) and GBRA proceedings which have not included such considerations of incremental revenues.<sup>79</sup>

Furthermore, staff believes that a revenue projection methodology which includes additional revenues from customer growth without a thorough analysis of corresponding additional expenses in 2026 and 2027 creates an incomplete and potentially skewed financial composition of the Company. Therefore, staff believes it is inappropriate to account for increased revenues

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<sup>79</sup> Order PSC-2020-0448-TRF-EI, issued November 20, 2020, in Docket 20200064-EI, *In re: Petition for a limited proceeding to approve fourth [solar base rate adjustment] SoBRA, by Tampa Electric Company*; Order PSC-2023-0348-TRF-EI, issued November 17, 2023, in Docket 20230090-EI, *In re: Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2021 stipulation and settlement agreement, by Tampa Electric Company*.



alone. Lastly, staff agrees with TECO that the inclusion of additional customer growth revenue as a credit against TECO's SYAs could possibly reduce the intended effects of the SYAs.

By maintaining consistency with past treatment of SYAs and ensuring that all relevant financial factors are considered, staff is persuaded by and agrees with TECO's arguments that the SYA for 2026 and 2027 should not reflect additional revenues due to customer growth.

### **CONCLUSION**

Any SYAs for 2026 and/or 2027 approved by the Commission should not reflect additional revenues resulting from customer growth. No adjustments should be made.

**Issue 105:** Should the Commission approve the inclusion of TECO's proposed incremental O&M expense associated with the SYA projects in the 2026 and 2027 SYA?

**Recommendation:** The amount of incremental O&M expenses that should be approved are \$2.3 million for the 2026 SYA and \$0 for the 2027 SYA. (P. Buys, G. Davis)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No, the Commission should subtract the variable O&M expense savings that Tampa Electric estimated in its cost effectiveness determinations. Otherwise, the requested SYA revenue requirement, if even authorized, would be overstated.

**FL RISING/**

**LULAC:** No.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Not as requested by TECO. If the Commission allows an SYA for 2026 or 2027, or both, the Commission should, at a minimum, subtract all variable O&M cost savings that TECO estimated in its cost-effectiveness calculations for the projects. Otherwise, the actual cost impacts of the projects will be overstated and customers will overpay for the projects.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO requested \$6.8 million in incremental O&M expenses for the 2026 SYA and \$4.8 million in incremental O&M expenses for the 2027 SYA. (EXH 32, MPN C16-1701) TECO briefed that the incremental O&M expenses should be included in the SYAs and that the expenses are consistent with the method used to calculate the revenue requirement for prior GBRA and SoBRAs. (TECO BR 88) OPC briefed that the incremental O&M expenses should be excluded from the SYAs due to TECO's failure to reflect the O&M expense savings from TECO's cost

effectiveness determinations. (OPC BR 77-78) The remaining intervenors did not specifically address or take a position on this Issue. As addressed in Issues 95, 96, and 101, staff is recommending adjustments to the South Tampa Resilience Project, Grid Reliability and Resilience Projects, and the Solar Projects. These adjustments result in a total reduction of \$4.6 million for the 2026 SYA and \$4.8 million for the 2027 SYA O&M expenses. This results in incremental O&M expenses of \$2.3 million for the 2026 SYA and \$0 for the 2027 SYA.

### **CONCLUSION**

The amount of incremental O&M expenses that should be approved are \$2.3 million for the 2026 SYA and \$0 for the 2027 SYA.

**Issue 106:** Should the depreciation expense and Investment Tax Credits amortization used to calculate the proposed 2026 and 2027 SYA be adjusted to reflect the Commission's decisions on depreciation rates and ITC amortization for the 2025 projected test year?

**Recommendation:** Yes. If the Commission authorizes the utilization of the proposed 2026 and 2027 SYA, staff recommends that the depreciation expense and Investment Tax Credits amortization used to calculate the proposed 2026 and 2027 SYA be adjusted to reflect the Commission's decisions on depreciation rates and Investment Tax Credit Amortization for the 2025 projected test year. (J. Wu, Souchik)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** To the extent that the Commission even authorizes an SYA, then yes, these adjustment should be reflected.

**FL RISING/**

**LULAC:** Yes.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes, if the Commission approves an SYA for either 2026 or 2027, then the Commission's decisions regarding depreciation rates and ITC amortization for the 2025 test year should be reflected in the revenues and rates approved for 2026 or 2027.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

If the Commission authorizes the utilization of the proposed 2026 and 2027 SYA, the depreciation expense used to calculate the proposed 2026 and 2027 SYA must be adjusted to reflect the Commission's decisions on depreciation rates for the 2025 test year in accordance with Rule 25-6.0436(4)(f), F.A.C. This rule prescribes that upon Commission approval by final

order establishing an effective date, the utility shall reflect on its books and records the implementation of the depreciation rates approved by the Commission.

For the ITC amortization, this Issue is a fall-out of the Commission's decision for the 2025 projected test year. None of the parties proposed an adjustment to the ITC amortization approved for the 2025 projected test year. TECO argued the ITC amortization should be based on the depreciable lives of the assets giving rise to the ITCs as reflected in its positions on Issues 10 and 65. (TECO BR 88) OPC agreed the adjustments approved by the Commission should be reflected in the 2026 and 2027 SYA. (OPC BR 78) All the other parties either had no position or adopted the position of OPC. As discussed in Issues 10, 65, and 98, staff recommends the amortization of ITCs should be revised to match the depreciation lives of the related property, except for the ITCs related to TECO's battery storage assets. In Issue 65, staff recommends changing the amortization period for the battery storage assets from 10-years to 5-years for the 2025 projected test year, which is a shorter period than the depreciation life. Therefore, the ITC amortization period for the battery storage assets should be set at 5 years for the 2026 SYA. All other ITC amortization periods should match the depreciation lives for the related property as discussed in Issue 10.

### **CONCLUSION**

To the extent that the Commission authorizes the utilization of the proposed 2026 and 2027 SYA, staff recommends that the depreciation expense and Investment Tax Credits amortization used to calculate the proposed 2026 and 2027 SYA be adjusted to reflect the Commission's decisions on depreciation rates and Investment Tax Credit Amortization for the 2025 projected test year. In addition, the ITC amortization expense should reflect the Commission's decision on Issues 10, 65, and 98 for the 2025 test year.

**Issue 107:** What annual amount of incremental revenues should be approved for recovery through the 2026 and 2027 SYA?

**Recommendation:** The annual amount of incremental revenues that should be approved for recovery through the 2026 SYA is \$74,674,147, which is for recovery of the annualization associated with projects added in 2025 only, and \$0 through the 2027 SYA. (Norris, Hinson)

**Position of the Parties:**

**TECO:** The Commission should approve SYA for 2026 and 2027 to recover incremental revenues of \$92,373,608 and \$65,473,847, respectively. These amounts have been updated to reflect the impact of the adjustments shown in the July and August Filings and Issue 98 and no income tax gross up on non-equity return capital structure components.

**OPC:** To the extent that the Commission even authorizes an SYA, the Commission should reduce the revenue requirement for the GRR Projects by at least \$4.599 million in the 2026 SYA and by at least \$28.788 million in the 2027 SYA.

**FL RISING/**

**LULAC:** \$0.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** If the Commission allows an SYA for 2026 or 2027, or both, the Commission should approve an increase of no more than \$54.651 million per year for 2026 and an increase of no more than \$20.890 million per year for 2027.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

This is a fall-out issue. In Exhibit 5 to TECO witness Chronister's adopted direct testimony, the Company provided its calculation of the 2026 and 2027 SYAs. TECO requested the recovery of incremental revenues in the amount of \$100,074,841 and \$71,847,925 through its proposed 2026 and 2027 SYA, respectively. The Company's proposed incremental revenues for each year are

the sum of the return on rate base and incremental operating expenses associated with each project reflected in 2026 and 2027.

As discussed in Issues 94 through 102, staff is recommending a 2026 SYA reflecting the incremental annualization of projects that went in service in 2025: Polk 1 Flexibility, Energy Storage, Corporate Headquarters, and the Bearss Operation Center, along with components of the proposed GRR and Solar projects. As such, the return on rate base for the 2026 SYA was adjusted to reflect staff’s recommended changes in those issues, along with the rate of return of 6.80 percent from Issue 103 and the updated NOI multiplier recommended in Issue 68. Likewise, the incremental operating expenses were also adjusted to reflect only the amounts associated with annualization in 2026. In total, the 2026 SYA should be decreased by \$25,439,865, for a total annual amount of \$74,634,976. Staff’s recommended total adjustment for the 2026 SYA is reflected in Table 107-1.

**Table 107-1  
 2026 SYA**

<b>Project</b>	<b>Original Request</b>	<b>Staff Total Adj.</b>	<b>Staff Recommended</b>
Polk 1 Flexibility	\$5,185,793	(\$518,368)	\$4,667,425
Energy Storage	\$8,990,287	(\$3,354,619)	\$5,635,668
Corporate HQ	\$10,787,343	(\$799,042)	\$9,988,301
Bearss Operation Center	\$27,025,746	(\$1,943,783)	\$25,081,963
South Tampa Resilience	\$9,963,097	(\$9,963,097)	\$0
Polk Fuel Diversity	\$2,137,872	(\$2,137,872)	\$0
GRR	\$4,599,348	(\$2,094,618)	\$2,504,730
Solar	\$31,385,355	(\$4,589,295)	\$26,796,060
<b>Total</b>	<b>\$100,074,841</b>	<b>(\$25,439,865)</b>	<b>\$74,674,147</b>

Source: Staff Analysis

**CONCLUSION**

The annual amount of incremental revenues that should be approved for recovery through the 2026 SYA is \$74,674,147, which is for recovery of the annualization associated with projects added in 2025 only, and \$0 through the 2027 SYA.

Date: November 22, 2024

**Issue 108:** What rate design approach should be used to develop customer rates for the 2026 and 2027 SYA?

**Recommendation:** TECO's proposed rate design to develop customer rates for the 2026 and 2027 SYA is reasonable. If the Commission approves any SYAs, TECO should file a petition for proposed rates for January 2026 in September 2025 and for proposed rate for January 2027 in September 2026. The rate calculation should reflect the Commission-approved cost of service. (Guffey)

**Position of the Parties:**

**TECO:** The Commission should apply the incremental 2026 and 2027 SYA revenues approved in Issue 107 on a pro rata basis to the customer, energy, and demand charges for the non-lighting classes approved in Issues 75 through 85.

**OPC:** No position.

**FL RISING/**

**LULAC:** If the Commission approves the SYA, then 12 CP & 50% AD should be used to allocate the increased revenue requirement.

**FIPUG:** The rate design approach as proposed by FIPUG above.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose TECO's proposed cost of service study or its proposed revenue allocation methodology.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

TECO provided its subsequent years 2026 and 2027 rate calculations in Exhibit No. TEC-13. (EXH 15) This Exhibit also includes an explanation of TECO's proposed rates for 2026 and 2027. (EXH 15, MPN J1379) TECO proposed applying its proposed 2026 and 2027 SYA amounts pro rata to customer, energy, and demand charges for its non-lighting classes. Under TECO's proposed SYA amounts, the percent increase to rates for 2026 is 5.9407 percent and



4.0180 percent for 2027. TECO stated that it did not apply SYA revenues to its lighting classes to continue to move the lightings rate classes to parity in 2026 and 2027. Staff confirmed in MFR Schedule E-8 that the lighting class is above parity. (EXH 7)

The final SYA adjustments, if approved by the Commission, will depend on the SYA amounts granted and the cost of service approved. If the Commission approves SYA adjustments, TECO would file proposed rates for January 2026 in September 2025 and proposed rate for January 2027 in September 2026. (EXH 15, MPN J1379)

### **CONCLUSION**

TECO's proposed rate design to develop customer rates for the 2026 and 2027 SYA is reasonable. If the Commission approves any SYAs, TECO should file a petition for proposed rates for January 2026 in September 2025 and for proposed rate for January 2027 in September 2026. The rate calculation should reflect the Commission-approved cost of service.

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**Issue 109:** When should the 2026 and 2027 SYA become effective?

**Recommendation:** If the Commission approves any projects to be included for cost recovery via a SYA, the 2026 SYA should become effective with the first billing cycle in January 2026. The 2027 SYA, if approved, should become effective with the first billing cycle in January 2027. (McClelland)

**Position of the Parties:**

**TECO:** The 2026 and 2027 SYA should be effective with the first billing cycle in January 2026 and 2027, respectively.

**OPC:** The 2026 SYA, if allowed over the objection of OPC, should not become effective any sooner than the first billing cycle in 2026. The 2027 SYA, if allowed over the objection of OPC, should not become effective any sooner than the first billing cycle in 2027.

**FL RISING/**

**LULAC:** Never. If the Commission approves the SYAs, then January 1, 2026, and January 1, 2027.\*

**FIPUG:** The SYAs should be applied as equal percentage increases in the demand and energy charges, as applicable.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** If approved, any 2026 SYA should become effective for service rendered on the first day of the first billing cycle of January 2026, and any 2027 SYA should become effective for service rendered on the first day of the first billing cycle of January 2027.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

TECO witness Chronister adopted TECO witness Latta's testimony and exhibits regarding the proposed SYAs. (TR 3509–3510) TECO supports both the 2026 and 2027 SYAs, and believes they should be implemented on the first billing cycle of each respective year.

OPC witness Kollen argued that TECO should reduce its SYA for both 2026 and 2027. Regardless of the amount of SYA approved for either year, witness Kollen stated in his summarized testimony that the first SYA should take place on January 1, 2026, and the second SYA should take place “on or about” January 1, 2027. (TR 2270)

FL Rising/LULAC stated in their prehearing statement that the SYA should not be approved; however, if the Commission were to approve the SYA anyway, FL Rising/LULAC stated it should become effective on January 1 of the respective year. FIPUG stated in its brief that the SYA should be applied as equal percentage increases in the demand and energy charges. (FIPUG BR 27) The ratio between demand and energy charges, as well as FIPUG's argument and TECO's rebuttal on the matter, are addressed in Issues 80 and 81. Rate design of the SYA is further addressed in Issue 108. FRF stated in its brief that the SYA should go into effect on the first billing period of each year. (FRF BR 49) Walmart took the position of FRF. No other party took a position on this Issue.

**CONCLUSION**

If the Commission approves any projects to be included for cost recovery via a SYA, the 2026 SYA should become effective with the first billing cycle in January 2026. The 2027 SYA, if approved, should become effective with the first billing cycle in January 2027.

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**Issue 110:** Should TECO be required to file its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027, respectively, reflecting then current billing determinants?

**Recommendation:** Yes. TECO should be required to file its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027, respectively, verifying the in-service dates of all projects and using then current billing determinants. (Guffey, Kunkler)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** To the extent that the Commission even authorizes an SYA, over OPC objection, yes.

**FL RISING/**

**LULAC:** Yes, if the Commission approves the 2026 and 2027 SYAs.

**FIPUG:** The SYAs should be effective 30 days after the assets are placed in commercial operation.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

In its pre-hearing statement, TECO stated that filing its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027, respectively, reflecting then current billing determinants, ensures that SYA rates will be based on the most recent available information.

OPC, FL Rising/LULAC, FRF, and Walmart agreed that TECO should be required to file its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027,

respectively, reflecting then current billing determinants. (OPC BR 78; FL Rising/LULAC BR 25; FRF BR 49; Walmart BR 10)

FEA and Sierra Club took no position on this Issue.

### **CONCLUSION**

TECO should be required to file its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027, respectively, verifying the in-service dates of all projects and using then current billing determinants.

**OTHER**

**Issue 111:** Should TECO's proposed Corporate Income Tax Change Provision be approved?

**Recommendation:** No. If there is a change in state or federal tax laws, TECO or other intervenors have the opportunity to file a petition for a limited proceeding pursuant to Section 366.076, F.S., requesting the Commission consider the issues affected by a potential corporate tax law change. (Souchik)

**Position of the Parties:**

**TECO:** Yes, with the prospective clarification that normalization will be required for new tax credits if and only if required by the Internal Revenue Code or related tax regulations.

**OPC:** No. It will be reversible error if the Commission approves Tampa Electric's proposed Corporate Income Tax Change Provision under the circumstances of this case. See § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

**FL RISING/**

**LULAC:** No. Florida Rising and LULAC adopt OPC's arguments on this issue.

**FIPUG:** Yes.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. The FRF agrees with OPC's analysis and positions on this issue.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

As part of its petition, TECO requested a corporate income tax change provision similar to the method presented in Section 11 in the 2021 Settlement Agreement.<sup>80</sup> (EXH 31, MPN C16-1522) However, TECO has not accounted for or included any potential tax law changes in the instant petition. TECO argued that the tax reform provision, and others like it in previous agreements,

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<sup>80</sup> 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*.

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have served the Company and its customers well by providing an efficient regulatory mechanism for addressing corporate income tax changes that occur after a rate proceeding is over. (TECO BR 90; TR 3353-3354) In its brief, TECO recognized the ambiguity of the term “normalization” in Section 11 of the 2021 Settlement Agreement that gave rise to Issue 64 in this docket. (TECO BR 90) Consequently, TECO proposed to modify the language of the tax law provision reflected in paragraph 11(c)(iv) be clarified prospectively such that normalization will be required for new tax credits if and only if required by the Internal Revenue Code or related tax regulations. (TECO BR 90) TECO further argued that provisions like the Company’s proposed tax change mechanism may have only been approved by the Commission as part of a settlement agreement does not mean the Commission lacks jurisdiction to approve the proposed mechanism in this proceeding. (TECO BR 90)

OPC argued that the Commission not approve the corporate income tax change provision in this rate case and it will be a reversible error if the Commission approves TECO’s proposal. (OPC BR 78) The corporate tax change provision in Section 11 of the 2021 Settlement Agreement describes the effects on income tax expense, including the amortization of deficient or excess-deferred income taxes, both protected and unprotected, accumulated deferred income taxes, and tax credits resulting from changes in income tax rates and the modification of existing tax credits and new tax credits. (TR 2337) OPC witness Kollen contended that the effects of any potential corporate income tax change can be addressed by the Commission on its own initiative and on a statewide basis or through a petition filed for the Company on its own initiative if and when some such corporate income tax changes are enacted. (TR 2337) There is no need in this proceeding to attempt to preemptively prescribe future Company petitions or calculation methodologies in such filings, which may be considered to have presumptive validity. (TR 2337)

OPC argued the Commission has established a policy in a final order that a rate case is not the proper venue for establishing a prospective change in rates as a result of a future change in federal income taxes.<sup>81</sup> The Commission previously rejected proposals for similar tax change law provisions in Docket Nos. 20220067-GU and 20220069-GU. (OPC BR 80) In Order No. PSC-2023-0103-FOF-GU, the Commission denied Florida Public Utilities Company’s (FPUC) request and concluded that “If there is a change in State or Federal tax laws FPUC or OPC has the opportunity to file a petition for a limited proceeding pursuant to Section 366.076, F.S., requesting that we consider the issues and expenses affected by a potential corporate tax law change.”<sup>82</sup> In Order No. PSC-2023-0177-FOF-GU, the Commission found that:

. . . a tax law change provision in this case is unnecessary because there is no evidence supporting a need for it. Should there be a tax law that comes into effect that will affect the rates set forth in this order, a limited proceeding pursuant to Section 366.076, F.S., is available for FCG or OPC to address any potential future State or Federal income tax law changes, which would provide an opportunity to

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<sup>81</sup> 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 – Ft. Meade, and Florida Public Utilities Company – Indiantown Division.*

<sup>82</sup> *Id.*

consider all of the issues arising from such tax law changes and to establish the appropriate rates at that time.<sup>83</sup>

The status of potential tax law changes in the instant case is no different from the two previously cited natural gas rate cases. That is, there is no evidence in the record that any state or federal tax law changes are pending, and TECO did not provide any evidence the tax law change provision is necessary and would benefit customers. In fact, TECO did not implement the tax law changes related to PTCs as a result of the IRA as described in the 2021 Settlement Agreement from its prior rate case, and deferred disposition of the PTC benefits to this proceeding, which is addressed in Issue 64. (EXH 54) Accordingly, the most appropriate process to address any potential future State or Federal income tax law change is through a limited proceeding or rate case to allow the Commission and interested parties an opportunity to address all the issues that may arise and set the appropriate rates at that time. A provision for a potential corporate income tax law change is not necessary.

### **CONCLUSION**

If there is a change in state or federal tax laws, TECO or other interveners have the opportunity to file a petition for a limited proceeding pursuant to Section 366.076, F.S., requesting that the Commission consider the issues and expenses affected by a potential corporate tax law change.

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<sup>83</sup> 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*.



**Issue 112:** Should TECO's proposed Storm Cost Recovery Provision be approved?

**Recommendation:** Yes. The proposed Storm Cost Recovery Provision should be approved. (P. Buys)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No. It will be reversible error if the Commission approves Tampa Electric's Storm Cost Recovery Provision under the circumstances of this case. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

**FL RISING/**

**LULAC:** No. Florida Rising and LULAC adopt OPC's arguments on this issue.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No. While the FRF supports timely recovery of storm restoration costs subject to equally timely and thorough Commission review, including a point of entry for parties to contest any utility claims for cost recovery, TECO's proposed Storm Cost Recovery Provision is based on settlement terms, not Commission precedent, and diverges from even the terms in TECO's 2021 settlement. Accordingly, the Commission should not approve TECO's proposal as filed.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart did not provide a summary of its position on this issue as was required under Section XIII of the Prehearing Order.

**Staff Analysis:**

**ANALYSIS**

As part of this rate case, TECO requested to continue its Storm Cost Recovery Provision, consistent with its 2021 Agreement, approved by Order No. PSC-2021-0423-S-EI. The agreement states that TECO may seek recovery of costs associated with any tropical systems named by the National Hurricane Center. Specifically, the recovery of storm costs will begin, on an interim basis (subject to refund) sixty days following the filing of TECO's petition for storm cost recovery. The storm cost recovery charge will be based on a 12-month recovery period if the storm costs do not exceed \$4.00/1,000 kWh and will be a monthly charge. If the cost exceeds \$4.00/1,000 kWh, the costs shall be recovered in subsequent years as determined by the

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Commission. All storm costs shall be calculated pursuant to Rule 25-6.0143, F.A.C. The costs shall be limited to the following:

- Costs resulting from such tropical system named by the National Hurricane Center.
- The estimate of incremental storm restoration costs above the level of the storm reserve prior to the storm.
- The replenishment of the storm reserve to \$55,860,642.

(EXH 31, MPN C16-1516-1518; TR 3354)

At the hearing, TECO witness Chronister explained that TECO will adhere to the Commission's storm cost recovery rules that assure the amount TECO wants to collect through the surcharge does not include any expenses that are already being recovered in base rates. Witness Chronister testified that TECO would still petition the Commission for recovery of the amount of restoration costs. (TR 3612) In addition, witness Chronister agreed that for its true-up, TECO would refund any over collected storm costs to customers the same way those costs were originally collected. TECO would flow the over collected amount through the ECCR use to be part of that factor thereby avoiding a separate docket for the true-up amount. (TR 3613-3614) Further, TECO argued that because a mechanism was approved by the Commission through a settlement agreement, does not mean the Commission lacks jurisdiction to approve the mechanism outside of a settlement agreement. (TECO BR 90-91)

Walmart and FRF expressed concern, in their briefs, regarding the cost allocation and rate design associated with storm cost recovery and that this Issue should not be addressed through a rate case proceeding. However, neither party filed testimony specific to this Issue. Walmart briefed that TECO should not recover storm costs from demand-metered customer via energy charges. Walmart argued the storm cost recovery rate design was not squarely presented to the Commission in this rate case. Walmart asserted that even though TECO witness Williams admitted that TECO would collect storm costs from demand-metered customers via demand charges, witness Williams did not have an understanding of TECO's plan for future storm cost collection on a going forward basis. (TR 3804-3805) Walmart requested that if the Commission decides that storm cost recovery rate design is not an issue in this case, that the Commission state that it is an issue for TECO's next storm cost recovery docket. (Walmart BR 8-9) TECO responded to Walmart's concerns by stating that customers will be refunded the same way the storm costs were collected, and that the rate design of the storm costs should be addressed in TECO's next storm cost recovery docket. (TR 3613-3614) Staff believes this Issue addresses the overall methodology as to how TECO will seek recovery of incurred storm costs and what costs are appropriate for recovery. TECO will still petition the Commission for recovery of the restoration costs, at which time Walmart can address the Commission regarding rate design.

Additionally, OPC briefed that as it argued in Issue 111, the Commission should deny the Storm Cost Recovery Mechanism. OPC stated that the elements of the Storm Cost Recovery Mechanism are available to TECO and the Commission by operation of law and can be implemented regardless of the provisions of the 2021 Settlement Agreement. OPC further argued that the various threshold or numeric values in the provision were negotiated and have no basis in evidence or law. OPC points out that the Paragraph 8(d) of the 2021 Agreement says that the

Storm Cost Recovery Mechanism expires when the rates are set in this case. Furthermore, OPC argued that TECO's approach does not provide the Commission with an alternative record that is supported by evidence to implement it. (OPC BR 83-84) Staff agrees with OPC that the Storm Cost Recovery Mechanism can be implemented regardless of the provisions of the 2021 Agreement as the Commission has jurisdiction to approve a Storm Cost Recovery Mechanism. Staff believes the mechanism has worked well in the past, not because it originated from a settlement but because the process allows for timely recovery of storm restoration costs subject to Commission review, party intervention, and a true-up process that protect ratepayers.<sup>84</sup> Furthermore, none of the intervenors argued to change specific aspects of the Provision or put forth evidence supporting which aspects should be revised. It should also be noted that in its Prehearing Statement, OPC believed this Provision should be approved as long as it allowed for a tariff filed by the Company to become effective subject to a hearing. However, OPC amended its position in its brief to recommend that this Provision should not be approved for the reasons discussed above.

The 2021 Agreement specified that TECO's Storm Cost Recovery Provision would remain in effect until its base rates were reset by the Commission. As the instant docket is the subsequent base rate proceeding to the 2021 Settlement Agreement, staff believes this Issue is appropriate for inclusion here and recommends the continuation of TECO's Storm Cost Recovery Provision which has been in effect for many years. In addition, staff believes this Provision is an appropriate way for the Company to recover costs in a timely manner subject to scrutiny by the Commission and intervening parties.

## **CONCLUSION**

The proposed Storm Cost Recovery Provision should be approved.

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<sup>84</sup> See Docket No. 20230019-EI, *In re: Petition for recovery of costs associated with named tropical systems during the 2018-2022 hurricane seasons and replenishment of storm reserve, by Tampa Electric Company.*

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**Issue 113:** Should TECO’s proposed Asset Optimization Mechanism be approved, and what, if any, modifications should be made?

**Recommendation:** Yes. The proposed AOM should be approved, effective January 1, 2025, with modifications. As the customer-sharing threshold has not been increased, the requested renewable energy credit (REC) sales and natural gas sales should not be added to the allowable optimization activities. In addition, staff recommends a docket should be opened to establish a generic proceeding to address incentives for all investor-owned utilities. (O. Wooten, Sparks, Marquez)

**Position of the Parties:**

**TECO:** Yes. The company’s existing Asset Optimization Mechanism (“AOM”) has provided over \$45 million of customer benefits since 2018. Adding capacity release of gas pipeline transportation and renewable energy credit (“REC”) sale revenues to the AOM will reasonably incent the company to engage in beneficial transactions that will lower fuel expenses for customers; therefore, the company’s proposed AOM should be approved without modifications.

**OPC:** No. It will be reversible error if the Commission approves Tampa Electric’s proposed Asset Optimization Mechanism under the circumstances of this case. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

**FL RISING/**

**LULAC:** No. Florida Rising and LULAC adopt OPC’s arguments on this issue.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club adopts FL Rising/LULAC’s position on this issue.

**FRF:** No. The FRF agrees with OPC that the Company’s proposal is unlawful because it violates the terms of the existing TECO 2021 settlement agreement approved by the Commission in Order No. PSC-2021-0423-S-EI, which settlement agreement, adopted by the Commission, by its own terms prohibits any party from asserting it as precedent.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

## ANALYSIS

In 1984, the Commission established a shareholder incentive program to encourage all IOUs to make economy energy sales.<sup>85</sup> This shareholder incentive program established that revenues for economy sales were moved from base rates to the Fuel and Purchased Power Cost Recovery Clause and allowed the IOUs to retain 20 percent of the gains on the sales. The Commission stated that the intended purpose of the shareholder incentive program was to encourage IOUs to use their excess capacity to make economy sales and eliminate the potential for over-recovery or under-recovery of revenues associated with economy energy sales.

In 2000, the Commission modified the shareholder incentive program for all IOU's that applied to gains from certain economic wholesale power sales.<sup>86</sup> The shareholder incentive program established that a three-year moving average of gains to be an appropriate threshold and that all gains below that threshold would be credited to ratepayers and all gains above that threshold to be split 80 percent to 20 percent between ratepayers and shareholders, respectively.<sup>87</sup> As stated in the order approving the incentive mechanism, the Commission believed that this incentive structure "minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring."<sup>88</sup> This structure also maintained that ratepayers would receive 100 percent of the gains from wholesale purchases and any gains generated from the use of other ratepayer-supported assets.

In 2012, the Commission approved a settlement for FPL which established FPL's AOM as a four-year pilot that was designed to allow FPL to share gains created through electric wholesale purchases, wholesale sales, and asset optimization.<sup>89</sup> In 2016, the Commission approved a second FPL settlement that continued FPL's AOM with modifications that increased the sharing thresholds and recovery for variable O&M associated with economy sales.<sup>90</sup> In 2021, FPL's 2021 Settlement Agreement modified the Company's previously approved AOM to apply to all fuel sources, allow the monetization of RECs and increase the sharing threshold thresholds.<sup>91</sup> Per the 2021 Settlement Agreement, FPL's current AOM has been approved as a program by the Commission with no expiration date.

In 2016, TECO requested a pilot incentive mechanism, the Optimization Mechanism, which would allow the Company to make gains on wholesale sales, wholesale purchases and include asset optimization activities. Following this in 2017, the Commission approved a settlement agreement for TECO (2017 Settlement) which established TECO's pilot AOM for a four year

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<sup>85</sup> Order No. 12923-PAA-EU, issued January 24, 1984, in Docket No. 19830001-EU-B, *In re: Fuel Adjustment Recovery Clauses of electric utilities – treatment of gain on economy sales*.

<sup>86</sup> Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 19991779-EI, *In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities*.

<sup>87</sup> *Id.* at 10.

<sup>88</sup> *Id.* at 11.

<sup>89</sup> Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*.

<sup>90</sup> Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company*.

<sup>91</sup> 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*.

period beginning in January 2018.<sup>92</sup> The 2017 Settlement adopted TECO's proposed AOM which allowed the Company to receive gains from engaging in wholesale sales, wholesale purchases and optimization activities. Optimization activities include, but are not limited to: (1) gas storage utilization; (2) delivered gas sales; (3) gas production area sales; (4) gas transportation sales; (5) outsourcing of optimization functions; and (6) coal transportation savings. (TR 3123-3125) These activities did not include sales of renewable energy credits (RECs), which the 2017 Settlement established were retained for customers and 100 percent of net gains flowed back to customers through the ECRC.

The 2017 Settlement AOM shared net gains on eligible activities based upon the total amount of gains through a series of sharing thresholds that each had a different allocation of the net gains. Customers would receive the benefit of 100 percent of the first \$4.5 million in net gains, only 40 percent of the net gains between \$4.5 million and \$8 million, and just 50 percent of net gains in excess of \$8 million. The remaining net gains flowed to TECO shareholders. Staff notes that this differs from TECO's original Optimization Mechanism proposal, which had an initial \$3.5 million threshold which represented the savings TECO achieved from wholesale power purchase savings and power sales over the prior four years, rounded up to the nearest half million dollar amount, then establishing the second threshold point at double this value. (EXH 158, MPN E1921-E1923) The 2017 Settlement AOM increased each of these values by \$1 million.

In 2021, the Commission extended TECO's AOM when it approved TECO's 2021 Settlement Agreement with a revised expiration date of December 31, 2024.<sup>93</sup> The 2021 Settlement did not alter the previously established savings thresholds or allocated percentage of gains, but did clarify that two activities were not included in the eligible asset optimization activities; release of natural gas pipeline capacity and retirement/release of railcars.<sup>94</sup> Gains from these activities were to be returned 100 percent to ratepayers. The 2021 Settlement also reiterated that the full benefits of RECs associated with the future solar projects subject to the settlement would be retained for customers and 100 percent of net gains flowed back to customers through the ECRC. Between 2018 and 2023, TECO's existing AOM has generated a total of \$67.5 million in gains, with \$45.6 million of the total benefits allocated directly to ratepayers. (EXH 29, MPN C14-1394)

### **TECO Rate Case Petition**

In this docket, TECO is requesting to: (1) extend the established AOM beyond the December 2024 expiration date; (2) modify the allowable optimization activities to include the release of natural gas pipeline capacity and the sale of RECs, and (3) maintain the existing sharing thresholds and allocation percentages. (TR 3127, 3132)

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<sup>92</sup> Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

<sup>93</sup> Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20200264-EI, *In re: Petition for approval of 2020 depreciation and dismantlement study and capital recovery schedules, by Tampa Electric Company.*

<sup>94</sup> *Id.*

### ***Extension of AOM***

The structure of any shareholder incentive program is intended to allow ratepayers to continue to receive benefits that were generated from the IOU's activities using ratepayer supported assets and reward the IOUs for performing better than they performed previously, while minimizing the possibility of IOUs being rewarded for behavior that was already occurring. During cross examination, FIPUG questioned TECO witness Heisey if the benefits accrued from AOM activities would continue regardless of the AOM being adopted. In response, witness Heisey stated that the benefits produced by the optimization activities in the AOM would continue without the approval of AOM, but could not guarantee the same level of benefits would be generated absent the program. (TR 3166-3168) While the Commission has not made a previous judgement on the appropriateness of the AOM revenue-sharing thresholds or percentages, TECO's existing AOM has generated savings for TECO ratepayers. (EXH 29, MPN C14-1394) Staff believes that there is a value to mechanisms that incentivize companies to seek additional activities to produce savings for ratepayers. As such, staff recommends that TECO's proposed AOM be extended beyond its December 2024 expiration date, with an effective date of January 1, 2025. This would allow the AOM to continue in its current form until the program is terminated or modified by the Commission. As detailed below, staff recommends not including additional activities if the current sharing thresholds are maintained.

### ***Additional Eligible Activities***

Regarding the release of natural gas pipeline capacity, witness Heisey testified that the gains would be generated for customers through the AOM by selling excess natural gas pipeline capacity not needed for TECO's native load. Currently, net gains from the release of natural gas pipeline capacity return 100 percent to ratepayers. However, the witness testified that value of capacity release is currently uncertain, and TECO projects the annual gains from these activities to be between \$0 and \$2 million. (TR 3128-3129; EXH 158, MPN E1923) However, the witness testified that value of capacity release is currently uncertain and that when capacity release was previously included in TECO's AOM from 2018 to 2021, the Company was not in a position to release capacity or the value of capacity release did not provide benefits to customers. (TR 3131) Staff notes that the release of natural gas pipeline capacity is an activity the Company can currently engage in that would provide 100 percent benefits towards ratepayers.

Regarding REC sales, witness Heisey testified that only RECs not needed for TECO's retail program would be sold and the Company would not engage in forward REC sales. (TR 3130) Currently, net gains from the release of REC sales return 100 percent to ratepayers through the ECRC.

The witness further testified that the proposed inclusion of the revenues associated with REC sales would flow to customers as gains through the AOM, which would lower ratepayer fuel expenses. (TR 3129-3130, 3159) However, witness Heisey testified that in 2023 TECO began to engage in sales of RECs on the voluntary market and per the terms of the 2021 Settlement all revenues generated from REC sales are returned to customers through the Environmental Cost Recovery Clause. (TR 3129-3130, 3159) The witness further testified that the value of RECs in the voluntary market were low and were expected to experience continued downward pressure. (TR 3131)

Although capacity release of gas pipeline was included in TECO's AOM previously, TECO did not engage in the activity due to market conditions and has not provided evidence in the record to indicate that these market conditions have changed. Staff notes that nothing prohibits TECO from engaging in capacity release and if market conditions did improve, the inclusion of capacity release as an allowable optimization activity would reduce the amount that ratepayers would benefit. Similarly, TECO currently engages in REC sales, with all revenues being returned to ratepayers. The inclusion of REC sales in the AOM would reduce the value of benefits associated with REC sales that TECO ratepayers would otherwise receive. Staff believes that TECO's proposed additions of releasing natural gas pipeline capacity and REC sales as allowable optimization activities lack enough supporting evidence in the record. Therefore, staff recommends that no modifications should be made to the allowable optimization activities.

### ***Maintaining AOM Sharing Thresholds and Percentages***

As previously discussed, TECO's 2017 Settlement AOM initial customer sharing threshold was established using a historic four-year average plus a \$1 million adder, while the second threshold was set at double the initial savings, with no changes in the 2021 Settlement AOM. In this proceeding, TECO proposed to continue its existing 2021 Settlement negotiated initial \$4.5 million and second \$8.0 million sharing thresholds with the additional allowable optimization activities. (TR 3123) Staff notes that no intervening parties provided testimony in regards to TECO's proposed AOM. In response to discovery, TECO asserted that it was not opposed to changing the sharing thresholds or percentages as long as an appropriate incentive mechanism exists for the Company. (EXH 199 MPN E6041) Staff believes that it is improper to add more revenue generating activities into the AOM without a corresponding increase to the sharing thresholds for the ratepayers and Company, alike. Therefore, staff recommends that TECO's currently established \$4.5 million and \$8.0 million sharing thresholds be maintained.

Staff recognizes the dissonance between the various AOMs for each IOU that would occur with the disallowance of TECO's proposed modifications to its allowable optimization activities. Therefore, if the Commission wishes to provide parity for all IOUs, staff believes that TECO's revenue-sharing thresholds should be modified with the addition of the allowable optimization activities. Using TECO's original methodology for establishing the initial value from its 2016 petition, and excluding the \$1 million adder in the 2017 Settlement, the historic four-year average (2020-2023) of wholesale power purchase savings & power sales gains rounded upward, the initial customer sharing threshold would be \$12.5 million, with the second threshold set at \$25 million. (EXH 158 MPN E1923)

### **Generic Proceeding**

Although the Commission has approved AOMs with similar modifications for the other IOUs, the recommendation provided by staff would maintain the status quo of TECO's AOM. However, staff notes that the current AOMs were produced as terms of settlement agreements and have not undergone independent Commission approval. Staff believes that, similar to the Commission approved shareholder incentive program from 2000, the asset optimization activities the IOUs are engaging in apply to all electric IOUs. In response to discovery, TECO stated that it believed that a separate docket to address the continuation of the AOM to be appropriate. (EXH 199 MPN E6042) Staff recommends that a generic proceeding be established to allow the Commission to both consolidate the various AOMs and equally establish the



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allowable optimization activities and revenue-sharing thresholds for all IOUs. A staff workshop could be the first step in this process to allow IOUs and interested parties to provide input for an all-encompassing AOM.

No party provided testimony regarding this Issue, however in its brief OPC maintained that the program should not be authorized because it is improper to use a settlement agreement as precedent for the program. (OPC BR 85) OPC further argued that no AOM has been authorized by the Commission as all AOM's are products of settlements. (OPC BR 86) OPC maintained that there was no established procedure for determining sharing thresholds for the AOM. (OPC BR 87) However, the Commission's jurisdiction and authority for electric rate cases rests in Chapter 366, F.S., whether in approving a settlement agreement or ordering rates after a full hearing. The mere existence of a settlement agreement does not permit the Commission to grant something it otherwise could not, absent the settlement agreement. As discussed above, staff believes that there is a value to mechanisms that incentivize companies to seek additional activities to produce savings for ratepayers. Staff is recommending the AOM continue, not merely because it was part of the 2021 Settlement Agreement. Rather, it is the benefits that TECO's customers have derived over the past six years (over \$45 million dollars) that warrants continuation of the AOM at this time. (TR 3127) Allowing the AOM to continue in its current form until the program is terminated or modified by the Commission, in a future proceeding, benefits TECO's ratepayers. OPC's arguments further support the staff's recommended generic proceeding regarding a broadly applied AOM. FEA and Fuel Retailers took no position on this Issue with all other intervenors adopting OPC's position.

## **CONCLUSION**

The proposed AOM should be approved, effective January 1, 2025, with modifications. As the customer-sharing threshold has not been increased, the requested REC sales and natural gas sales should not be added to the allowable optimization activities. In addition, staff recommends a docket should be opened to establish a generic proceeding to address incentives for all investor-owned utilities.

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**Issue 114:** What are the appropriate updated Clean Energy Transition Mechanism factors and when should they become effective?

**Recommendation:** The Clean Energy Transition Mechanism (CETM) factors have been approved by the Commission in the 2021 Settlement Agreement; however, the final calculation of the CETM factors, are dependent on the Commission's vote on ROE and cost of service. TECO should provide revised CETM factors and associated tariff for the December 19, 2024 Commission Conference. (McClelland, J. Wu, O. Wooten)

**Position of the Parties:**

**TECO:** The Commission should approve the proposed Clean Energy Transition Mechanism ("CETM") factors shown on pages 10 and 11 of the prepared direct testimony of Ashley Sizemore as updated to reflect the overall rate of return approved by the Commission in Issue 40 to be effective with the first billing cycle in January 2025.

**OPC:** The CETM should be reduced by \$1.828 million in 2025 to reflect OPC's positions on ROE of 9.5% and inclusion of the battery storage related ITCs as zero cost of capital.

**FL RISING/**

**LULAC:** The Clean Energy Transition Mechanism should be discontinued, but at the very least, there is no basis for allocating it using a 4CP cost of service methodology (it obviously does not increase capacity) and at the very least should use a 12CP and 50% methodology to calculate the factors.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The CETM revenues should be reduced by \$1.828 million in 2025 to reflect OPC's positions on ROE of 9.5% and inclusion of the battery storage related ITCs at a zero cost of capital.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart adopts OPC's positions and incorporates herein OPC's arguments and references to record evidence as to the following Issues: 2, 4-12, 15-17, 19, 22, 25-27, 29-38, 40-45, 52, 58-60, 62-67, 87, 94-106, 111, 113, 114.

**Staff Analysis:**

**ANALYSIS**

TECO witness Sizemore addressed the CETM factors in her direct testimony. Witness Sizemore explained that per the 2021 Settlement Agreement, TECO removed the costs associated with the undepreciated net book value of retired Automatic Meter Reading assets, the undepreciated net book value of Big Bend Units 1 through 3, and the dismantlement reserve deficiency associated with Big Bend Units 1 through 3. (TR 3265) The 2021 Settlement Agreement specifies that recovery of these costs will be over 15 years through a separate charge on customers' bills. (TR 3265)

Per the 2021 Settlement Agreement, TECO is required to modify the CETM factors every 3 years and completed a final true-up at the end of the 15-year period. (TR 3266-3268). Witness Sizemore explained that the 2021 Settlement Agreement specifically requires that TECO adjust the CETM factors to reflect changes to TECO's overall rate of return each time TECO's midpoint ROE is reset. (TR 3266)

TECO proposed revised CETM factors for the period beginning in January 2025 which reflect TECO's requested ROE of 11.5 percent. (TR 3721) Witness Sizemore further explained that the CETM factors were developed based on the cost of service study utilized in the 2021 rate case. (TR 3272). Therefore, the Commission's vote on cost of service would also affect the calculation of the CETM factors.

FL Rising/LULAC took the position that the CETM factors should be discontinued, but at the very least, should be allocated based on FL Rising/LULAC's proposed cost of service. (FL Rising/LULAC BR 26) The CETM factors have been approved in the 2021 Settlement Agreement and there is no record evidence to support discontinuance of the factors; however, TECO should calculate CETM factors based on the Commission's vote on cost of service.

**CONCLUSION**

The CETM factors have been approved by the Commission in the 2021 Settlement Agreement; however, the final calculation of the CETM factors, are dependent on the Commission's vote on ROE and cost of service. TECO should provide revised CETM factors and associated tariff for the December 19, 2024 Commission Conference.

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**Issue 115:** Should the proposed Senior Care Program (Original Tariff Sheet No. 3.310) and associated cost recovery be approved?

**Recommendation:** No. The proposed Senior Care Program (Original Tariff Sheet No. 3.310) and associated cost recovery should not be approved as proposed. If TECO wishes to offer the proposed program which offers a fixed \$10 monthly bill credit to TECO's low-income customers 65 and older, the program should be funded through voluntary rate payer donations and/or by TECO employees and TECO shareholders. (Guffey)

**Position of the Parties:**

**TECO:** Yes. The proposed new Senior Care Program assists a small population of financially challenged customers and should be approved.

**OPC:** No position.

**FL RISING/**

**LULAC:** No. TECO does need to care for its seniors and low-income customers, but this program is not the way to do it. A reasonable cost of service and revenue requirement would lower electric bills for these customers (and all customers) far more than \$10, without then having even higher bills for all residential customers to provide a credit to a small-slice of the customers that need relief.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** The FRF does not oppose the proposed Senior Care program tariff. However, the Commission must note that this offering is simply a vehicle for Tampa Electric's customers to contribute to lower rates for senior citizens with a demonstrable need, as the program is funded from base rates. Other than serving as a collection and distribution agent, TECO is not contributing financially to the benefitted customers.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

The proposed Senior Care Program offers a fixed \$10 monthly bill credit to TECO's low-income customers 65 and older. (TR 3696) TECO witness Williams stated that to qualify for the Senior Care Program, a customer of record must provide a copy of their State of Florida Agency of Healthcare Administration's Medicaid Program enrollment letter (Medicaid Eligibility Letter), or an alternative form of proof of enrollment acceptable to the Company, and proof of their date of birth. (TR 3698) Witness Williams explained that since Medicaid is only open to low-income Florida residents, enrollment in Medicaid serves as proof of low-income status. (TR 3696-3697) Using the Medicaid Eligibility Letter and Medicaid income thresholds as eligibility criteria for the Senior Care Program avoids the need for TECO to income-qualify customers in-house. (TR 3697) During cross examination by FL Rising/LULAC, TECO witness Williams stated that in Hillsborough county over 26 percent of the population is on Medicaid, and 15 percent of the population is over the age of 65. (TR 3727-3728)

To explain why TECO chose that a customer must be 65 years old or older to qualify for the Senior Care Program, witness Williams testified that TECO needed an accurate metric for the potentially eligible population to forecast the number of potential participants and design the program. U.S. Census Bureau data is available for the percentage of the population in Hillsborough County that is 65 years old or older, while other senior citizen age data was not available. (TR 3697). TECO explained that the proposed Senior Care Program targets a particular subset of low-income households; furthermore, TECO stated that customers indicated that assisting low-income senior citizens were the two most important causes that they would like to see TECO support. (EXH 212, MPN E8213)

TECO is proposing to fund the program via base rates and all customers would fund the program. (TR 3698; EXH 208, MPN E7775) MFR Schedule E-13c demonstrates the proposed program funding. MFR Schedule E-13c, line 17, shows the estimated costs to be \$3,653,880. (EXH 164)

Regarding the proposal to provide a \$10 monthly bill credit, TECO considered programs offered by other utilities and different basic design approaches, i.e., fixed dollar credit versus per kWh credits. (EXH 165, MPN E2203) After reviewing options, TECO explained that it applied its judgment and determined that a \$10 credit would assist participants by lowering their monthly bills which while keeping the impact to non-participants reasonable. (EXH 165, MPN E2203)

Table 115-1 shows each rate class' estimated contribution. (EXH 208, MPN E7776)

**Table 115-1**  
**Senior Care Program Contributions by Rate Class**

Rate Class	Senior Care Program Contribution
RS	\$2,295,521
GS	\$204,393
GSD	\$851,563
GSLDPR	\$98,648
GSLDSU	\$64,120
LS Energy	\$5,011
LS Facilities	\$134,625
<b>Total</b>	<b>\$3,653,880</b>

Source: (EXH 208, MPN E7776)

TECO offers another program to assist customers called the Share program. However, that donation program is funded by TECO shareholders, TECO employees, and customers *voluntarily* willing to donate. (EXH 199, MPN E6022; EXH 212, MPN E8212-8213) TECO shareholders match donations dollar-for-dollar up to \$500,000. (EXH 212, MPN E8212) TECO employees are also encouraged to assist their neighbors through donations to the Share program but are not obligated to donate, and any customer of TECO's general body of ratepayers can voluntarily donate to TECO's Share program. No customer is obligated to donate to the Share program, unlike the proposed Senior Care Program. TECO explained that customers in need of financial assistance can apply for help through one of the Share administrators, which are the Salvation Army or Catholic Charities Diocese of St. Petersburg. The maximum amount of assistance provided is \$450 per year, per customer. (EXH 199, MPN E6022)

If a customer meets the criteria for both the Share program and the Senior Care Program, they would be eligible for and could receive assistance under each program at the same time. (EXH 212, MPN E8213) Though not every customer that is eligible for the Share program receives funding from the Share program, because that program's financial resources are limited. With that said, if a Senior Care Program eligible customer were to receive the \$450 annual allotment from the Share program, they would still be incentivized to receive an additional \$10 monthly bill credit via the Senior Care Program. (EXH 212, MPN E8213)

FL Rising/LULAC took the position that TECO does need to care for its seniors and low-income customers; however, a reasonable cost of service and revenue requirement would lower bills for customers far more than \$10, without having higher bills for all residential customers to provide a credit to a small group of customers. (FL Rising/LULAC BR 24)

As proposed, TECO's stockholders would not contribute to the Senior Care Program. However, TECO stockholders do assist low-income customers by contributing to TECO's Share program. Staff believes that if TECO wishes to assist a subset of customers with their energy bills, the program should be funded by voluntary ratepayer and/or TECO employees and shareholder

donations, similar to TECO's Share program. Staff does not believe it is appropriate for the general body of ratepayers to be required to subsidize TECO's proposed Senior Care Program. If the Commission agrees with staff's recommendation, TECO should make the necessary adjustments to remove the estimated costs and bill credits from the cost of service study.

### **CONCLUSION**

The proposed Senior Care Program (Original Tariff Sheet No. 3.310) and associated cost recovery should not be approved as proposed. If TECO wishes to offer the proposed program which offers a fixed \$10 monthly bill credit to TECO's low-income customers 65 and older, the program should be funded through voluntary ratepayer donations and/or by TECO employees and TECO shareholders.

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**Issue 116:** Should TECO be required to perform any studies or analysis relating to the retirement of Polk Unit 1 and/or Big Bend Unit 4, including early retirement dates, environmental compliance costs, and/or procurement of alternative resources?

**Recommendation:** No. TECO is responsible for continuously evaluating its generating fleet for reliability, economics, and compliance with applicable regulations. Based on the record, TECO has performed reasonable analysis in regards to the early retirement of Polk Unit 1 and Big Bend Unit 4 and no further studies are needed at this time. (O. Wooten)

**Position of the Parties:**

**TECO:** No. The company's testimony and exhibits demonstrate that Polk Unit 1 and Big Bend Unit 4 provide important fuel diversity, reliability, and flexibility benefits to customers. The company evaluates the roles these units play in its generating portfolio every year as part of the 10-Year Site Planning process, so no further studies or actions like early retirement and loan applications are needed or should be ordered at this time.

**OPC:** No position.

**FL RISING/**

**LULAC:** Yes. Florida Rising and LULAC adopt Sierra Club's arguments on this issue.

**FIPUG:** Not unless ordered to do by the Commission.

**FEA:** No position.

**SIERRA**

**CLUB:** Given TECO is summer-peaking and overshooting capacity needs, Sierra Club recommends retiring both Polk 1 and Big Bend 4 by 2030. If the Commission does not order 2030 retirements, TECO should be required to study earlier retirement dates, including by 2028, 2030 and 2032. In the study, TECO should (a) demonstrate the units' needs as reliability resources and (b) measure the cost-effectiveness of retiring each unit early against the cost of acquiring replacement resources.

**FRF:** Regardless whether the PSC requires TECO to perform any studies or analyses relating to potential early retirements of Polk Unit 1 or Big Bend Unit 4, in the current regulatory environment, it would be imprudent for TECO not to be conducting such studies and analyses on a regular basis far enough in advance to enable it to make prudent retirement decisions based on regulatory and market developments.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.



**Staff Analysis:**

**ANALYSIS**

As discussed in Issue 24, TECO has requested to convert Polk from an IGCC unit to a simple cycle CT unit, but retaining the equipment that would let the unit to be converted back to an IGCC unit. (TR 652-653) This would allow the Company the opportunity to operate the unit using natural gas currently and potentially convert to unit to utilize petcoke in the case of future natural gas price increases. (TR 654, 696) TECO has also stated its intent to continue the operation of Big Bend as a dual-fuel unit with coal-burning capacity. (EXH 114 MPN C32-3257)

Sierra Club witness Glick testified that TECO should study the economics of maintaining an adequate, but not excessive, capacity position to serve its customers. The witness further testified that TECO should proactively test the market with request for proposals to evaluate the replacement resource options. (TR 2546-2547) However, as discussed in Issue 24, staff is recommending the retirement of Polk's gasifier, HRSG, and steam turbine - thereby eliminating fuel-switching as an option for Polk in the future.

Witness Glick asserted that TECO did not consider early retirements for the Polk and Big Bend units. The witness further asserted that Polk did not undergo analysis that demonstrated that the Polk conversion was the most cost-effective option relative to retirement. (TR 2548) The witness also asserted that Big Bend should be evaluated to be retired and replaced with renewable resources or use an alternative fuel source. (TR 2541-2542) In rebuttal, witness Aldazabal stated that TECO performed a CPVRR analysis that showed a savings of \$24.6 million of the Polk conversion compared to a 2028 retirement date. (TR 700) Staff notes that in Issue 24, staff reviewed TECO's requested conversion of Polk and recommends approval of the conversion. In regards to Big Bend, witness Aldazabal asserted that the Company had not performed an early retirement analysis of the unit as the fuel diversity and resiliency provided by the unit was necessary to mitigate natural gas fuel prices and supply interruption risk. (TR 716) The witness further explained that because Big Bend has at least 15 years of remaining useful life, it would be premature to incur the costs associated with developing cost estimates and system impacts of repowering the unit. (EXH 189, MPN E5323)

Sierra Club was the only party that proffered testimony regarding this Issue; and, in its brief reiterated its argument that TECO should be required to perform the additional studies for the units in this Issue. (Sierra Club BR 63) In its brief, FRF argued that in the current regulatory environment TECO should be pursuing evaluations of its unit's ability to be retired early. (FRF BR 51) FL Rising/LULAC and Walmart adopted OPC's and FRF's positions, respectively. All other intervenors took no position on this Issue.

Staff believes that it is important for utilities to continually evaluate the factors surrounding the retirement and addition of generating units, such as reliability, economic, and regulatory impacts. Staff recommends that the evidence in the record shows that TECO has given reasonable consideration of these factors in its continued operation. Therefore, the economic resource evaluation proposed by Sierra Club witness Glick would be duplicative of normal business

operations. Because of this, staff recommends that no additional analysis of early retirement dates for Polk and Big Bend are necessary.

### **CONCLUSION**

TECO is responsible for continuously evaluating its generating fleet for reliability, economics, and compliance with applicable regulations. Based on the record, TECO has performed reasonable analysis in regards to the early retirement of Polk Unit 1 and Big Bend Unit 4 and no further studies are needed at this time.

**Issue 117:** What is the appropriate effective date for TECO's revised 2025 rates and charges?

**Recommendation:** This is a fall-out issue and will be decided at the December 19, 2024 Commission Conference. (Guffey)

**Position of the Parties:**

**TECO:** The company's revised 2025 rates and charges should be approved to be effective with the first billing cycle in January 2025.

**OPC:** The 2025 rates and charges should not become effective any sooner than the first billing cycle in 2026.

**FL RISING/**

**LULAC:** No effective date should be applicable because the Commission should deny TECO's petition for rate increase. If the Commission does not outright deny the petition, then January 1, 2025.

**FIPUG:** Adopt position of OPC.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Any change in rates for the 2025 test year should be effective for service rendered on the first day of the first billing cycle of January 2025.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

This is fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**CONCLUSION**

This is fall-out issue and will be decided at the December 19, 2024 Commission Conference.

**Issue 118:** Has the Commission considered TECO’s performance pursuant to Sections 366.80–366.83 and 403.519, F.S., when establishing rates?

**Recommendation:** Yes. The Commission has considered TECO’s performance pursuant to Sections 366.80-366.83 and 403.519, F.S., when establishing rates. (Prewett)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, not at this time. However, the Commission has a duty to consider these statutes. The Commission should consider TECO’s performance adequate, but since TECO does minimal energy efficiency as compared to national standards, no adjustments are warranted.

**FIPUG:** No position at this time.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** No position.

**FUEL**

**RETAILERS:** No Position.

**WALMART:** Walmart takes no position on the following Issues in this Docket: 13, 14, 21, 23, 24, 28, 46-51, 53-57, 61, 75-77, 84-86, 88-93, 115, 118.

**Staff Analysis:**

**ANALYSIS**

In 1980, the Florida Legislature approved the Florida Energy and Efficiency Conservation Act (FEECA), which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Collectively, these statutes are referenced as the “FEECA statutes.”

In its brief, TECO asserts that since the FEECA statutes were enacted in 1980, its goal achievement performance has saved the equivalent of over seven 180 MW power generating stations. (TECO BR 96)

FL Rising/LULAC believe the Commission should consider TECO’s goal achievement performance when establishing rates. It contends that the Commission has not done so to date, but has a duty to do so in this case. (FL Rising/LULAC BR 7) FL Rising/LULAC state that

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TECO's FEECA performance is adequate when compared to other utilities across the United States or to national standards. (FL Rising/LULAC BR 7) No other parties offered a position on this Issue.

Under FEECA, the Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, including TECO. Staff notes that TECO submits periodic (annual) reports to the Commission, pursuant to the obligation set forth in Section 366.82(10), F.S. The annual filing summarizes its goal achievement performance from the prior year.<sup>95</sup> In addition, TECO participates in the FEECA demand side management goalsetting proceeding every five years, the most recent of which concluded earlier in 2024.<sup>96</sup>

Staff believes the Commission reviews the FEECA Report on an annual basis, and TECO has consistently met its goals. Since 2020, TECO has only fell short of its goal achievements in 2021 and 2022, years when COVID-related concerns prompted constraints on TECO and other utilities' ability to offer all programs throughout the year.<sup>97</sup>

## CONCLUSION

Staff recommends that the Commission has considered TECO's performance pursuant to Sections 366.80-366.83 and 403.519, F.S., when establishing rates.

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<sup>95</sup> Data from TECO and other utilities is published in the Commission's Annual Report on Activities Pursuant to the Florida Energy and Efficiency Conservation Act (FEECA Report). Current and historic FEECA Reports are accessible via the Commission's website, and hearing exhibit 220 (MPN E8333-E8562) is a composite of FEECA Reports from 2021, 2022, and 2023.

<sup>96</sup> TECO was an active participant in the goal-setting proceeding, which concluded earlier in 2024. See Docket No. 20240014-EG, *In re: Commission review of numeric conservation goals (Tampa Electric Company)*.

<sup>97</sup> In 2021, TECO did not achieve its performance goal for Residential Summer MW reduction and Residential Winter MW reduction, but achieved all others in that review period. In 2022, TECO did not achieve its performance goal for Residential Winter MW reduction and Total Winter MW reduction, but achieved all others in that review period. Full goal achievement results are in the archived FEECA Reports accessible via [floridapsc.com](http://floridapsc.com).

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**Issue 119:** What considerations should the Commission give the affordability of customer bills and how does TECO's rate increase impact ratepayers in this proceeding?

**Recommendation:** The Commission has broad discretion to carry out its legislative mandate of ensuring rates are fair, just, and reasonable. To the extent the Commission can consider the "affordability" of customer bills, it must do so within the context of its governing statutes in Chapter 366, F.S., which require the Commission to set rates that are fair, just, and reasonable. OPC and FL Rising/LULAC offered tests to gauge affordability, but staff is persuaded by the law, which is supported by the evidence presented by TECO regarding how it kept affordability in mind while making business decisions that would result in "affordable" rates. Moreover, if staff's adjustments are approved by the Commission, the rate impact on customers will be lower and thus even more affordable for ratepayers. (Marquez, Sparks, Harper)

**Position of the Parties:**

**TECO:** The Commission should consider "affordability" by recognizing that the company promotes affordability by operating in an efficient and cost-effective manner, and by making cost-effective investments that provide moderate fuel and operating costs over the long-term. Florida's recently changed energy policy does not expressly add "affordability" to the list of factors for the Commission to consider or authorize or direct the Commission to depart from traditional cost of service ratemaking.

**OPC:** Tampa Electric's excessive rate increase request is contrary to the State's goal of providing affordable electric rates and will have a negative impact on ratepayers. Now, more than ever, the Commission must consider affordability of the customer's bills when evaluating Tampa Electric's rate request. Ultimately, the Commission must hold Tampa Electric to its burden and only approve the portions of Tampa Electric's rate request which are fair, just, and reasonable.

**FL RISING/**

**LULAC:** Pursuant to section 377.601(2)(a), Florida Statutes, the state's energy policy must be guided by the goal of "[e]nsuring a cost-effective and affordable energy supply." As shown at the hearing and service hearings, TECO's customers are facing an affordability crisis caused by their skyrocketing electricity bills. All investments TECO is making must be carefully weighed against the harm they will cause via higher bills.

**FIPUG:** FIPUG did not provide a summary of their position on this issue as was required under Section XIII of the Prehearing Order.

**FEA:** Adopts the position of FIPUG.

**SIERRA**

**CLUB:** Given that TECO customers face the third-highest electricity bills in the nation, the Commission should favor measures to reduce ratepayers' bills when making policy choices regarding TECO's proposed expenses. Wherever the Commission can reduce costs to ratepayers, especially for investments with unproven benefits, the Commission should favor such cutbacks.

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Finally, the Commission should scrutinize TECO's reserve margin and reliability planning assumptions, with an eye toward reducing overbuild and costs to ratepayers.

**FRF:** The Commission should give serious consideration and accord great weight to the affordability of TECO's service to its residential and business customers. In the public interest, the only reasonable balancing of affordability and service reliability is that TECO, and any public utility, should provide safe and reliable service at the lowest possible cost to its customers.

## **FUEL**

**RETAILERS:** No Position.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

## **Staff Analysis:**

### **ANALYSIS**

#### **Affordability**

The Commission can consider the "affordability" of rates in this docket, but it may do so only within the confines of its "fair, just, and reasonable" rates standard in Section 366.06(1), F.S.<sup>98</sup> "Affordable rates" are therefore those rates that allow a utility to recover all of its necessary costs incurred to provide safe and reliable service and to earn a reasonable—but not excessive—return on its used and useful investment. Sections 366.06(2) and 366.07, F.S.

In order to effectuate a determination of fair, just, and reasonable, the Commission considers a number of factors (which may vary slightly from case to case). These could include, for example, whether:

- Projects proposed by a utility are truly needed.<sup>99</sup>
- Costs are reasonably and prudently incurred.<sup>100</sup>
- Plans of action appear to be cost-effective.<sup>101</sup>
- Projects will be used and useful in the time rates are charged.<sup>102</sup>
- Activities contribute to the security and reliability of Florida's energy grid.<sup>103</sup>

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<sup>98</sup> OPC, FRF, and Walmart appear to agree that "affordability," to the extent it can be considered, must be looked at within the "fair, just, and reasonable" rates standard. (OPC BR 90, 93–94; FRF BR 18–20, 51–52; Walmart BR 9–10). Contrary to the insinuations of OPC and FL Rising/LULAC, Florida's energy policy goals in Section 377.601, F.S., do not expand the Commission's traditional cost of service ratemaking authority. Goals are generally aspirational in nature—things that can be worked toward when practicable and legally permissible to do so within existing statutory frameworks.

<sup>99</sup> See Section 366.06(1)–(2), F.S.; Section 366.07, F.S.

<sup>100</sup> Section 366.06(1), F.S.

<sup>101</sup> See *id.*

<sup>102</sup> *Id.*

<sup>103</sup> See Section 366.04(2)(c), F.S.; Section 366.055(1), F.S.

- A utility’s Florida Energy Efficiency and Conservation Act performance is adequate.<sup>104</sup>
- The rate of return is reasonable in light of legal standards and all the evidence presented.<sup>105</sup>
- The cost of providing service to the rate class.<sup>106</sup>
- Value of service.<sup>107</sup>

Furthermore, pursuant to Section 366.041(1), F.S., the Commission has discretion to consider the “efficiency, sufficiency, and adequacy of the facilities provided and the services rendered,” the ability of the utility to improve service and facilities, energy conservation, and the efficient use of alternative energy resources. The aforementioned factors are typically discrete issues supported by testimony and evidence. Looking at base rate changes through this lens results in rates that are fair, just, and reasonable for both the public utility and for TECO’s general body of ratepayers.

In this case, OPC, FL Rising/LULAC, FRF, Walmart, and FIPUG argue that the Commission’s decision should rest on whether customers’ utility bills are affordable. OPC and FL Rising/LULAC (hereinafter Proponents) would have the Commission evaluate whether an individual household has enough money to pay their utility bill given the proposed rate increase. In essence, this type of analysis would require a case-by-case analysis of a customer’s utility bill and would require consideration of factors invented by the Commission, and not authorized by law. In fact, the evidence shows that Proponents’ definitions of affordability varies from person to person and household to household. (TR 3717–18) For example, two families with the same income and utility bill amount may view affordability of electricity differently based on their different circumstances. (TR 3717-18) “Affordability” is therefore a subjective term. (TR 178, 192-93, 2181, 3717)

TECO’s customers expressed a broad range of experiences and concerns regarding the affordability of electric bills. (SH1-TR; SH2-TR; SH3-TR; EXH 832) Many customers pointed to how inflation has impacted them. (SH1-TR 46, 56; SH2-TR 18–19). Other customers expressed that higher bills might cause them to shift their spending priorities. (SH1-TR 29–30, 38) Customers pointed to the lack of universal healthcare and high prices for food, medicine, and housing as budget-stressors. (SH1-TR 39–40; SH2-TR 25). One customer suggested that while solar energy development may not fix everything, it could help alleviate the burden of customer bills. (SH2-TR 25)

Affordability of utility bills depends on many factors beyond the control of a utility or the Commission, such as: idiosyncratic perceptions, personal electricity usage choices, income levels, inflation, financial obligations, housing, transportation choices, spending priorities, and spending decisions. (TR 1442, 3717–18) Overall, customers seemed to ask the Commission to

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<sup>104</sup> Section 366.82(10), F.S.

<sup>105</sup> Section 366.06(2), F.S.

<sup>106</sup> Section 366.06(1), F.S.

<sup>107</sup> *Id.*



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scrutinize TECO's proposed rate increase on the basis of fairness, reasonableness, and need. (SH1-TR 28, 39–40, 44–45, 56; SH2-TR 21, 27, 43; SH3-TR 34–35, 38)

Notwithstanding that the word “affordable” is not defined, nor is the term even referenced in Chapter 366, F.S., there does not appear to be any universally accepted definition of affordability either. (TR 2181, 3717) TECO witness Williams, (TR 3713–16, 3719–20; EXH 152), OPC witness Dismukes, (TR 2182, 2184; EXH 41), and FL Rising/LULAC witness Rábago, (TR 2570–72), each approached and analyzed the topic differently. Essentially, as noted previously, Proponents argue for an individual budget-type, household analysis that is not contained in Chapter 366, F.S. TECO disagrees with the metrics proposed by the Proponents. To demonstrate the shortcomings of the Proponents' analyses, TECO witness Williams assumed for sake of argument a 6 percent energy burden proxy and used over two decades of data (in addition to the 2025 projected test year) to conclude the energy burden for a low-income, two-person household on TECO's proposed rates would be 4.5 percent. (TR 3719–20; EXH 152) This falls below the energy burden standard adopted by OPC witness Dismukes. (TR 2182) Furthermore, FL Rising/LULAC witness Rábago failed to account for differences in other states' average customer bills where customers rely on natural gas or oil for winter heating, rather than electricity, thereby contributing to lower overall electricity bills in other states. (TR 3713–16) This apples to oranges comparison is thus flawed.

Furthermore, OPC witness Dismukes testified that other jurisdictions have addressed the concept of energy “affordability,” like Pennsylvania and California, but those states have different enabling legislation than Florida and can be distinguished. (TR 2183–84) For example, Pennsylvania has a mandate that low-income customers have access to affordable electricity, including through low-income assistance programs funded through a universal statewide charge on all non-program participants.<sup>108</sup> Meanwhile, California law expressly authorizes the California Public Utilities Commission to consider the affordability of electricity, gas, water, and telecommunications rates,<sup>109</sup> unlike our existing laws in Florida.<sup>110</sup> California, like Pennsylvania, has expressly authorized its utility commission to establish assistance programs that subsidize low-income electric customers.<sup>111</sup> For these reasons, the Commission should find OPC witness

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<sup>108</sup> *Retail Energy Supply Ass'n v. Penn. Public Utility Comm'n*, 185 A.3d 1206, 1210 (Pa. Commw. Ct. 2018); see also 66 Pa. C.S. §§ 2801–2815 (codifying Pennsylvania's Electricity Generation Customer Choice and Competition Act).

<sup>109</sup> CA Pub. Util. Code § 739(d)(2) (“In establishing residential electric and gas rates, including baseline rates, the commission shall ensure that the rates are sufficient to enable the electrical corporation or gas corporation to recover a just and reasonable amount of revenue from residential customers as a class, while observing the principle that electricity and gas services are necessities, for which a low *affordable rate* is desirable and while observing the principle that conservation is desirable in order to maintain and *affordable bill*.”) (emphasis added); CA Pub. Util. Code § 739.8(a)–(b) (“Access to an adequate supply of healthful water is a basic necessity of human life, and shall be made available to all residents of California at an *affordable cost*. The commission shall consider and *may implement programs* to provide rate relief for low-income ratepayers.”) (emphasis added); CA Pub. Util. Code § 871.5(a) (“The offering of high-quality basic telephone service at *affordable rates* to the greatest number of citizens has been a longstanding goal of the state. The Moore Universal Telephone Service Act has been, and continues to be, an important means for achieving universal service by making basic telephone service *affordable* to low-income households through the creation of a lifeline class of service.”) (emphasis added).

<sup>110</sup> Although Florida facilitates the provision of Lifeline service in the State, pursuant to Section 364.10, F.S., it has not had ratemaking authority over telecommunications companies for many years.

<sup>111</sup> CA Pub. Util. Code § 739.1.

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Dismukes’ attempted analogies to how other jurisdictions have addressed “affordability” unpersuasive.

TECO gave affordability consideration in its operating and planning decisions. The record is replete with its efforts to do so in a manner rooted in traditional factors of cost-effectiveness, reliability, and reasonableness. The Board of Directors was informed about ways that high utility bills place financial and social pressures on customers. (TR 230, 293–97; EXH 245; EXH 837) The Board was presented with many ways to keep customer costs down, like leveraging tax credits. (TR 308-310, EXH 780) TECO took concrete steps to create fuel savings for customers. (TR 3491) It made infrastructure decisions that promoted reliability so operating costs passed along to customers would be reduced. (TR 3491) TECO also invests in technology to drive down costs. (TR 3491) These are but a few of the ways TECO witness Chronister testified the Company takes affordability into consideration. (TR 3491–93) While Proponents characterize TECO’s proposed rates as being “unaffordable,” as they would define that term, (OPC BR 90–94; FL Rising/LULAC BR 2–3, 6, 27, 28, 30), TECO provides more persuasive testimony and evidence that its proposed rates are “affordable” because it does so within the context of the Commission’s existing fair, just, and reasonable statutory standard.

### **Rate Impact**

The term “rate impact” appears in our statutes and rules, albeit in the context of Storm Protection Plans.<sup>112</sup> It is a final calculated number that shows the change in rates. Each individual customer may feel the effect differently, depending upon their individual circumstances, but the rate impact is the same for all customers within a class.

TECO provided typical bill comparisons for its major rate schedules in MFR Schedule A-2. (EXH 3, MPN J2–J8) By way of illustrative example, for a residential customer using 1,000 kWh (a benchmark commonly used to compare bills), TECO’s proposed revenue increase would increase the base rate portion of monthly bills in 2025 from \$87.80 to \$107.01—a rate impact of \$19.20. If, however, the Commission approves all of staff’s recommended adjustments, staff estimates that the rate impact on customers will be less.<sup>113</sup> Regardless, to the extent the Commission considers affordability, it should be within the scope of its statutory mandate to consider whether proposed rates are fair, just, and reasonable. In evaluating this statutory mandate the Commission may consider affordability from the perspective of analyzing rate impact across-the-board, i.e. the impact of the proposed rate increase on the average base rate portion of the monthly bills.

## **CONCLUSION**

The Commission has broad discretion to carry out its legislative mandate of ensuring rates are fair, just, and reasonable. However, there exists no statutory authority to infer a specific definition of affordability absent express legislative authorization.<sup>114</sup> To the extent the Commission can consider the “affordability” of customer bills, it must do so within the context

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<sup>112</sup> Section 366.96(4)(d), F.S.; Rule 25-6.030(3)(h), F.A.C.

<sup>113</sup> A customer’s total bill includes various adjustment clauses, such as fuel, storm hardening, and storm restoration, in addition to base rates. Those clause factors are established by the Commission in other proceedings.

<sup>114</sup> See Section 120.52(8), F.S.

of its governing statutes in Chapter 366, F.S. OPC and FL Rising/LULAC offered standards/tests for affordability that appear to be beyond the Commission's statutorily delegated authority. Staff is persuaded, however, by the evidence TECO offered that TECO's proposed requests are affordable to the extent that the Commission finds those rates to be fair, just, and reasonable. Staff further notes that if the Commission approves all of staff's recommended adjustments, customers are estimated to experience a smaller rate impact by comparison. Final rates will ultimately be approved at a subsequent Special Agenda conference.

**Issue 120:** Should TECO 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. TECO 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. (Vogel)

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No position.

**FL RISING/**

**LULAC:** No, because TECO's petition for rate increase should be denied. If the Commission does not outright deny the petition, then yes.

**FIPUG:** Yes.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** Yes.

**FUEL**

**RETAILERS:** Yes.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

Consistent with Commission practice, TECO 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, TECO 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 121:** Should this docket be closed?

**Recommendation:** This docket should remain open for the Commission to determine the final rates at a subsequent Special Agenda. (Marquez, Sparks, Harper).

**Position of the Parties:**

**TECO:** Yes.

**OPC:** No position.

**FL RISING/**

**LULAC:** Yes, after the Commission denies TECO's petition for rate increase.

**FIPUG:** Yes, after the Commission takes final agency action.

**FEA:** No position.

**SIERRA**

**CLUB:** Sierra Club has no position on this issue.

**FRF:** When a final Commission order has been issued and either (a) all appeals of such order (or orders) have been finally resolved, or (b) the time for filing any further appeal has passed, this docket should be closed.

**FUEL**

**RETAILERS:** Not until all actions are concluded, including any appeals.

**WALMART:** [. . .] Walmart adopts and incorporates herein FRF's positions and incorporates herein FRF's arguments and references to record evidence as to the following Issues: 1, 3, 68-74, 78-83, 107-110, 116, 117, 119, 120, 121.

**Staff Analysis:**

**ANALYSIS**

This docket should remain open for the Commission to determine the final rates at a subsequent Special Agenda.

**CONCLUSION**

This docket should remain open for the Commission to determine the final rates at a subsequent Special Agenda.

SCHEDULE 1 - 2025 TEST YEAR

Tampa Electric Company  
 DOCKET NO. 20240026-EI  
 13-MONTH AVERAGE RATE BASE  
 DECEMBER 2025 TEST YEAR

Issue	Adjusted per Company	Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
		13,418,078	4,004,807	9,413,271	230,175	68,034	9,711,480	86,671	9,798,150,000
<u>No.</u>	<u>Staff Adjustments:</u>								
15	Remove Customer Experience Projects	(13,400)	(893)	(12,507)	-		(12,507)		(12,507)
16	Remove Microgrid Project	(2,800)	(97)	(2,703)	-		(2,703)		(2,703)
22	Remove South Tampa RP	(76,818)	(558)	(76,260)	-		(76,260)	-	(76,260)
24	Retire Portions of Polk 1 Flexibility	(456,823)	(314,571)	(142,252)	-		(142,252)	-	(142,252)
24	Early Retirement of Polk 1 Flexibility	-	-	-	-		-	129,320	129,320
31	To reflect amortization of Generation O&M	-	-	-	-		-	8,200	8,200
64	PTC Amortization adjustment	-	-	-	-		-	(220)	(220)
7	35-yr Solar, 20-yr Energy Stor., 40-yr 367	-	(8,744)	8,744	-		8,744	-	8,744
11	Solar accrual (35-yr) and Inflation factors	-	(836)	836	-		836	-	836
---	Total Staff Adjustments	(549,841)	(325,701)	(224,141)	-	-	(224,141)	137,300	(86,840)
	Fall Out - Staff Adjusted Rate Base	12,868,237	3,679,106	9,189,130	230,175	68,034	9,487,339	223,971	9,711,310

SCHEDULE 2 - 2025 TEST YEAR

Tampa Electric Company  
 DOCKET NO. 20240026-EI  
 13-MONTH AVERAGE CAPITAL STRUCTURE  
DECEMBER 2025 TEST YEAR

<u>Company As Filed</u>	<u>(\$)</u> <u>Amount</u>	<u>Ratio</u>	<u>Cost</u> <u>Rate</u>	<u>Weighted</u> <u>Cost</u>
Long Term Debt	3,536,333	36.09%	4.53%	1.63%
Short Term Debt	376,625	3.84%	3.90%	0.15%
Customer Deposits	99,195	1.01%	2.41%	0.02%
Preferred Stock	-	0.00%	0.00%	0.00%
Common Equity	4,593,473	46.88%	11.50%	5.39%
Deferred Income Taxes	980,855	10.01%	0.00%	0.00%
Tax Credits - Zero Cost	-	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	211,669	2.16%	8.26%	0.18%
<b>Total</b>	<b>9,798,150</b>	<b>100.00%</b>		<b>7.38%</b>
 Equity Ratio	 <u>54.00%</u>			

<u>Staff Adjusted</u>	<u>(\$)</u> <u>Company As</u> <u>Filed Amount</u>	<u>(\$)</u> <u>Specific</u> <u>Adjustments</u>	<u>(\$)</u> <u>Adjusted</u> <u>Total</u>	<u>Ratio</u>	<u>(\$)</u> <u>Pro Rata</u> <u>Adjustments</u>	<u>(\$)</u> <u>Staff</u> <u>Adjusted</u>	<u>Ratio</u>	<u>Cost</u> <u>Rate</u>	<u>Weighted</u> <u>Cost</u>
Long Term Debt	3,536,333		3,536,333	36.10%	(30,662)	3,505,671	36.10%	4.53%	1.64%
Short Term Debt	376,625		376,625	3.84%	(3,266)	373,359	3.84%	3.90%	0.15%
Customer Deposits	99,195		99,195	1.01%	(860)	98,335	1.01%	2.41%	0.02%
Preferred Stock	-		-	0.00%	-	-	0.00%	0.00%	0.00%
Common Equity	4,593,473		4,593,473	46.89%	(39,828)	4,553,645	46.89%	10.30%	4.83%
Deferred Income Taxes	980,855	(259)	980,596	10.01%	(8,502)	972,094	10.01%	0.00%	0.00%
Tax Credits - Zero Cost	-		-	0.00%	-	-	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	211,669	(1,643)	210,026	2.14%	(1,821)	208,205	2.14%	7.90%	0.17%
<b>Total</b>	<b>9,798,150</b>	<b>(1,902)</b>	<b>9,796,248</b>	<b>100.00%</b>	<b>(84,938)</b>	<b>9,711,310</b>	<b>100.00%</b>		<b>6.81%</b>



SCHEDULE 3 - 2025 TEST YEAR

Tampa Electric Company  
 DOCKET NO. 20240026-EI  
 NET OPERATING INCOME  
DECEMBER 2025 TEST YEAR

Issue No.	Adjusted per Company Staff Adjustments:	Operating Revenues	O&M Other	O&M - Fuel	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
		1,518,472	391,771	626	531,436	101,592	(8,327)	-	1,017,099	501,372
7	35-yr Solar, 20-yr Energy Stor., 40-yr 367				(18,937)		4,800		(14,137)	14,137
11	Solar accrual (35-yr) and Inflation factors				(1,672)		424		(1,248)	1,248
15	Customer Experience Projects		(3,140)		(893)		1,022		(3,011)	3,011
16	Microgrid Project				(97)		25		(73)	73
22	South Tampa		(1,169)		(558)		438		(1,290)	1,290
24/43	Polk 1 Flexibility Retirement		11,432		(2,010)		(2,388)		7,034	(7,034)
45	Generation O&M Reduction		(8,270)				2,096		(6,174)	6,174
41	Adjust Forecasted Sales	11,985					3,038		3,038	8,947
53	Remove SERP		(107)				27		(80)	80
55	Remove 1/2 Corp Resp.		(3,810)				966		(2,844)	2,844
56	Reduce D&O Liab Insurance (50%)		(151)				38		(113)	113
64	PTC Amortization adjustment		(11,636)				2,949		(8,687)	8,687
65	ITC 10-yr Amort.						(2,883)		(2,883)	2,883
62	Fallout Adj. - Parent Debt						(481)		(481)	481
63	PTC Rate						(3,217)		(3,217)	3,217
	Interest Synchronization						464		464	(464)
	Total Staff Adjustments	11,985	(16,851)	-	(24,168)	-	7,316	-	(33,703)	45,688
	Fall Out - Staff Adjusted NOI	1,530,457	374,920	626	507,268	101,592	(1,011)	-	983,396	547,060

**SCHEDULE 4 - 2025**

Tampa Electric Company  
 DOCKET NO. 20240026-EI  
NET OPERATING INCOME MULTIPLIER

Line No.		2025	
		(%) <u>As Filed</u>	(%) Staff <u>Adjusted</u>
1	Revenue Requirement	100.000	100.000
2	Regulatory Assessment Fee	(0.085)	(0.0848)
3	Bad Debt Rate	<u>(0.224)</u>	<u>(0.224)</u>
4	Net Before State Income Taxes (L1 + L2 +L3)	99.691	99.691
5	State Income Tax (L17)	<u>5.483</u>	<u>5.483</u>
6	Net Before Federal Income Taxes (L4 - L5)	94.208	94.208
7	Federal Income Tax (L25)	<u>19.784</u>	<u>19.784</u>
8	Revenue Expansion Factor (L6 - L7)	<u>74.424</u>	<u>74.424</u>
9	Net Operating Income Multiplier (100% / L8)	<u>1.34365</u>	<u>1.34364</u>

**SCHEDULE 5 - 2025**

Tampa Electric Company  
 DOCKET NO. 20240026-EI  
 DECEMBER 2025 PROJECTED TEST YEAR  
OPERATING REVENUE REQUIREMENT INCREASE CALCULATION

Line No.		<u>As Filed</u>	<u>Staff Adjusted</u>
1	Rate Base	\$9,798,150	\$9,711,310
2	Overall Rate of Return	<u>7.38%</u>	<u>6.81%</u>
3	Required Net Operating Income (1)x(2)	723,008	661,211
4	Achieved Net Operating Income	<u>501,372</u>	<u>547,060</u>
5	Net Operating Income Deficiency (3)-(4)	221,636	114,152
6	Net Operating Income Multiplier	<u>1.34365</u>	<u>1.34364</u>
7	Operating Revenue Increase (5)x(6)	<u>\$297,802</u>	<u>\$153,379</u>
8	Difference		<u>(\$144,423)</u>