FILED 10/22/2024
DOCUMENT NO. 09644-2024
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	DOCKET NO. 20240026-EI
Petition for approval of 2023 depreciation and dismantlement study, by Tampa Electric Company.	DOCKET No. 20230139-EI
In re: Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2022 stipulation and settlement agreement, by Tampa Electric Company.	DOCKET NO. 20230090-EI
	FILED: OCTOBER 22, 2024

FEDERAL EXECUTIVE AGENCIES POST-HEARING BRIEF (CORRECTED)

Federal Executive Agencies (FEA), through the undersigned counsel, pursuant to Prehearing Order, Order No. PSC-2024-0351-PHO-EI, issued August 14, 2024, hereby submits this Post-hearing Brief.

STATEMENT OF BASIC POSITION

On April 3, 2024, Tampa Electric Company ("TECO" or "Company") filed a petition seeking the Florida Public Service Commission's ("Commission") approval of a rate increase and associated depreciation rates, minimum filing requirements (MFRs), and testimony. TECO, a subsidiary of Emera, is an electricity local distribution company providing sales and transportation of electricity and is a public utility subject to our regulatory jurisdiction under Florida Statutes (F.S.) Section 366.02. TECO currently serves approximately 844,000 residential, commercial, and industrial electric customers in Hillsborough County, and portions of Polk, Pasco, and Pinellas counties, Florida.

TECO initially requested an increase of ~\$293.6 million in additional annual base rate revenues and ~\$2.9 million annual increase to its service charges for a total of ~\$296.6 million to be effective in January 2025. TECO also requested incremental Subsequent Year Adjustments (SYA) of ~$100 million and $71.8 million in January 2026 and January 2027 respectively. In rebuttal, TECO updated those figures to ~$295.5 million, ~$95.2 million, and ~$69 million for 2025, 2026, and 2027, respectively. On August 22, 2024, TECO filed updated revenue requirement documents, which reduced the 2025, 2026, and 2027 figures to ~$287.9 million, ~$92.3 million, and ~$65.4 million. Of those amounts, 1) $530.0 million is based on a depreciation and dismantlement study completed on December 27, 2023; 2) TECO's proposed addition of 488.7 Megawatts (MW) of Future Solar projects, Grid Reliability and Resilience Projects (GRR projects), 115 MW of Energy Storage Capacity projects, a new corporate headquarters building, the South Tampa Resilience project, the Polk 1 flexibility project, TECO's Future Environmental Compliance project (which would assess the viability of underground carbon storage at Polk Power Station); and 3) TECO's proposed Return on Equity is 11.5% with an equity ratio of 54% from investors.

On March 20, 2024, FEA intervened in this case because the Company's service and rates are critically important to the missions of MacDill Air Force Bace, among other federal customers. FEA presented the Testimony of Brian C. Andrews, Christopher C. Walters, and Michael P. Gorman in this proceeding. Mr. Andrews' testimony addresses TECO's depreciation rates. Specifically, that TECO's depreciation rates are overstated, that certain combined cycle plants lifespans are too short, the survivor curves for four Production Accounts should be lengthened, that the net salvage rates for several Transmission, Distribution, and General Plant ("TD&G") accounts have been overstated based on TECO's own data, and presents FEA's own depreciation rates, survivor curves, and net salvage rate adjustments resulting in a reduction of TECO's 2024 depreciation expense by $35.8 million.[1]

Mr. Walters' testimony addresses TECO's access to capital and economic environment, credit rating trends and outlooks, and recent trends concerning the authorized return on equity ("ROE") for utilities throughout the country. Mr. Walters also provided an overview of the market's perception of TECO's investment risk, commented on TECO's proposed capital structure, and presented the analyses he relied on to estimate an appropriate ROE for the Company. Based on the results of these analyses, Mr. Walters concludes that a fair and reasonable common equity ratio of 52.0 % is more consistent with the capital structures of the proxy group used to estimate the Company's ROE.[2] Additionally, based off Mr. Walters ROE estimation methods, he estimates that the Company's current market ROE is in the reasonable range of 9.20% to 10.0%, with a midpoint estimate of 9.60%.[3]

Mr. Gorman's testimony addresses the Company's proposed spread of its requested increase across rate classes and the reasonableness and accuracy of the Company's class cost of service study ("CCOSS"). Mr. Gorman recommends TECO's CCOSS be adopted as it properly allocates the costs of generation capacity and transmission capacity costs on the 4 Coincident Peak ("4 CP") methodology and properly reflects costs causation. Additionally, TECO's use of the Minimum Distribution System ("MDS") to determine customer costs associated with its distribution system is reasonable.

---

[1] *See*, CEL Exh. 111 and CEL Exh. 147, Document 2, p. 5.
[2] TR. Vol. 13, p. 2952, ln. 17-21 (Walters Direct).
[3] TR. Vol. 13, p. 2984, lns. 3-12 (Walters Direct).

ISSUES, POSITIONS, AND ARGUMENTS

2025 TEST PERIOD AND FORECASTING

ISSUE 1: **Is TECO's projected test period of the twelve months ending December 31, 2025, appropriate?**

FEA: No position.

ISSUE 2: **Are FCG's forecasts of customers, KWH, and KW by revenue and rate class appropriate?**

FEA: No position.

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

FEA: No position.

QUALITY OF SERVICE

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

FEA: No position.

DEPRECIATION STUDY

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

FEA: No position.

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

FEA: No position.

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

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

ARGUMENT

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing the service.[4] Capital recovery occurs over the Average Service Life ("ASL") of the investment or assets.[5] To determine the depreciation rates, companies use a depreciation system consisting of differing methods, procedures, and techniques.[6] FEA proposes several adjustments to the Company's proposed depreciation rates. These adjustments include a recommendation to: 1) increase the life of the Big Bend and Bayside combined cycle plant from a 35-year life to 40 years; 2) make adjustments to the interim retirement survivor curve for Production plant accounts 312, 341, 342 and 343; 3) maintain the Average Service Life ("ASL") of Account 367 at the current 45-year life; and 4) make adjustments to the net salvage rates for Transmission, Distribution and General Plant ("TD&G") accounts 356, 362, 364, 365, 367, 392.02, 392.03, 392. 12, and 392.13. These adjustments are captured in Comprehensive Exhibit List ("CEL") Exhibit 111 and updated and corrected in CEL Exhibit 147, Document 2, resulting in a decrease in TECO's 2024 depreciation expense by $35.8 million.[7]

In TECO witness Mr. Ned Allis' testimony, he states that a typical industry range for the life span of combined cycle plants is 35 to 40 years.[8] Mr. Andrews agrees with this range but more specifically, Mr. Andrews notes that Mr. Allis has recommended a 40-year life for combined plants in the recent rate cases of two other Florida utility companies, Duke Energy and Florida Power and Light ("FPL").[9] As a result, to be consistent with the other Florida utilities and remain in the

---

[4] TR. Vol. 13, p. 3026, lns. 4 – 5 (Andrews Direct).
[5] *Id.* at lns. 7 – 8.
[6] TR. Vol. 13, p. 3027, lns. 5 – 9 (Andrews Direct).
[7] *See,* CEL Exh. 111 & CEL Exh. 147, Document 2, p. 5.
[8] TR. Vol 8, p.1669, lns. 4 – 11 (Allis Rebuttal).
[9] TR. Vol 13, p. 3034, lns. 13 – 17 (Andrews Direct).

typical industry range Mr. Andrews suggests that TECO also have a 40-year life span for its combined cycle plants.

FEA recommends adjustments to the survivor curves of 4 of TECO's accounts. The adjustments recommended by Mr. Andrews result in interim retirement survivor curves that mathematically and statistically fit TECO's data better than those recommended by Mr. Allis. Specifically, the Sum of Squared Differences ("SSD") of the FEA proposal is significantly lower than the TECO proposal. Table 3 from Mr. Andrews' direct testimony shows the comparison between Mr. Andrews and Mr. Allis recommended survivor curves.[10]

TABLE 3

Goodness of Fit Statistics

	TECO		FEA		Delta		% Change
Account	**Curve**	**SSD**	**Curve**	**SSD**	**Life**	**SSD**	**SSD**
312	40-L0	1,622	60-O3	402	20	(1,220)	-75.2%
341	50-R3	3,562	74-R2	31	24	(3,531)	-99.1%
342	50-R0.5	55	55-R0.5	25	5	(29)	-53.6%
343	50-O1	1,085	75-O1	122	25	(963)	-88.7%

Source: Exhibit BCA-1 through Exhibit BCA-4

With Interim retirement curves, it is important to accurately reflect the company's data, as all the interim curves serve to do is shorten the remaining lives of the assets to recover interim retirements.[11] As shown in the Table above, the Commission should approve the survivor cures recommended by FEA.

FEA also recommends the survivor curve used for Account 367, which includes the cost of electric underground conductors and devices used for electric distribution, remain unchanged. Currently, this account has a 45-R1.5 survivor curve however, Mr. Allis recommends a 35-R1.5

[10] TR. Vol. 13, p. 3038, lns. 19 – 25.
[11] TR. Vol. 13, pp. 3038, ln. 25 – 3039 ln. 2

survivor curve, a 10-year reduction to the life of one of TECO's largest accounts.[12] As Mr. Andrews states, this 35-year recommendation comes from a reliance an actuarial analysis and the Simulated Plant Record ("SPR") method of analysis which almost always results in an understated Average Service Life ("ASL").[13] TECO's recommendation also proves to be uncommonly low when compared to the survivor curves Mr. Allis recommended for Account 367 in both Duke Energy and FPL's recent rate cases. For Duke Energy Mr. Allis recommended a 50-R1 survivor curve, and for FPL he recommended a 44-S0 (duct system) and a 40-S0.5 (direct buried cables) survivor curve.[14] Ultimately, when proper aged data is available and used instead of relying on simulated data, the lives for mass property assets like those in Account 367 tend to have longer lives.[15] TECOs current 45-R1.5 survivor curve for Account 367 is appropriate and FEA recommends the Commission maintain this survivor curve.

Lastly, FEA recommends adjustments to several TD&G net salvage rates. TECO's net salvage rates are based on an analysis of company data from 1982 through 2022.[16] The analysis compares the annual cost of removal and gross salvage to the retirements that occurred in each year of this 41-year period. For several accounts, Mr. Allis has overstated the net salvage rates, resulting in excessive depreciation rates and expense.[17] Specifically, Mr. Allis has recommended to increase the net salvage rate for Account 367 from the currently approved -5% up to -15%.[18] The table below captures FEA's recommended adjustments which result in net salvage rates that do not exceed TECO's experienced net salvage by more than 1% and have been rounded to the

---

[12] TR. Vol. 8, pp 1727, ln. 25 – 1728 ln. 10.
[13] TR. Vol. 13, pp. 3044, ln. 22 – 3045 ln. 8 (Andrews Direct).
[14] Docket No. 20210015-EL, Exh. NWA-1, pp. 761,763 & Docket No. 20240025-EL. Exh. NWA-4, p. 25.
[15] TR. Vol. 13, p. 3045, lns. 20 – 22 (Andrews Direct).
[16] TR. Vol. 13, p. 3047, lns. 7 – 8 (Andrews Direct).
[17] *Id.* at lns. 8 – 11.
[18] *Id.* at lns. 15 – 20.

nearest 5%. These are all reasonable adjustments resulting in a less burdensome level of net salvage to be recovered from TECO's customers through depreciation expense.

TABLE 4

Net Salvage Rate Comparison

Account	Experienced Net Salvage	TECO Proposal	FEA Proposal	Delta
356	(39)	(50)	(40)	10
362	(14)	(20)	(15)	5
364	(73)	(75)	(70)	5
365	(21)	(30)	(20)	10
367	(13)	(15)	(10)	5
392.02	29	20	25	5
392.03	29	20	25	5
392.12	29	20	25	5
392.13	29	20	25	5

Source: Exhibit BCA-5 and Exhibit BCA-7

On rebuttal Mr. Allis identified an error in Mr. Andrews' calculations but did not indicate that FEA's recommended depreciation rates were unreasonable; Mr. Allis merely provided a difference in expert opinion.[19] This correction increased Mr. Andrews' initial depreciation rate reduction from $31.38 million to $35.8 million.

Overall, the Commission should approve FEA's depreciation rates as explained in the paragraphs above and provided in CEL Exhibit 147, Document 2 containing the corrections to FEA's initial recommendation in CEL Exhibit 111 which results in a reduction in TECO's proposed depreciation expense by $35.8 million.

[19] TR. Vol. 8, p. 1715, lns. 7-15 (Allis Rebuttal)

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?**

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

<u>ISSUE 16:</u> **Should TECO's proposed Customer Experience Enhancement Projects be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

<u>ISSUE 17:</u> **Should TECO's proposed Information Technology Capital Projects be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

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

FEA: No position.

<u>ISSUE 19:</u> **Should TECO's proposed Grid Reliability and Resilience Projects be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

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

FEA: No position.

<u>ISSUE 21:</u> **Should TECO's proposed Corporate Headquarters project be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

<u>ISSUE 22:</u> **Should TECO's proposed South Tampa Resilience project be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

<u>ISSUE 23:</u> **Should TECO's proposed Bearss Operations Center project be included in the 2025 projected test year? What, if any, adjustments should be made?**

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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

FEA: No position.

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?**

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.

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?**

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.

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?**

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.

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?**

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.

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?**

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.

ISSUE 38: **What equity ratio should be approved for use in the capital structure for ratemaking purposes for the 2025 projected test year?**

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.

ARGUMENT

FEA recommends TECO's capital structure contain no higher than a 52.0% common equity ratio.[20] TECO is requesting a 54.0% common equity ratio.[21] However, the Company has not demonstrated the appropriateness for a common equity ratio over 52%. A 52.0% common equity ratio strikes a balance between financial stability and the cost of equity providing sufficient equity

[20] TR. Vol. 13, p. 2928, lns. 20-23 (Walters Direct)
[21] TR. Vol. 9, p. 1813, lns. 15-16 (D'Ascendis Direct)

to buffer against financial risks without excessively increasing the cost of capital, which can result from higher equity ratios.

Mr. Walters analyzed the proxy group that TECO witness Mr. Dylan D'Ascendis used to support TECO's request for a 54.0% equity ratio. The proxy group has an average of a BBB+ rating in the S&P and a Baa2 rating in Moody's.[22] TECO itself has a BBB+ in the S&P and a A3 in Moody's.[23] The proxy group has an average common equity ratio of 40.5% (including short-term debt) 43.8% (excluding short-term debt) while TECO is requesting a 54% (including short-term debt) which exceeds the proxy group by almost 14 percentage points.[24] It is also important to note that TECO's "negative" outlook is clearly being driven by the outlook of TECO's parent company, Emera Inc., rather than by cash flow or other credit concerns at TECO. In fact, TECO's Stand-Alone-Credit-Profile ("SACP") rating from S&P, the rating that would otherwise be assigned to TECO if not for its affiliation with Emera Inc., is 'a' compared to its published rating of BBB+.[25] In other words, TECO's credit rating is being hindered two notches as a result of its affiliation with Emera Inc.

Utilities have been able to access external capital to support their capital expenditure programs, with capital expenditures for utilities having increased considerably which was largely driven by federal legislation enacted in 2021 and 2022 supporting infrastructure investment.[26] Mr. Walters noted that in the Regulatory Research Associates' ("RRA") Utility Capital Expenditures April 2, 2024 report, a division of S&P Global Market Intelligence, the utility industry's capital investments remain at elevated levels and are anticipated to fuel the profit growth of utility

[22] TR. Vol. 13, p 2954, lns. 4 – 5 (Walters Direct).
[23] *Id.* at lns 5 – 11.
[24] *Id.* at lns 12 – 17.
[25] TR. Vol. 13, p. 2950, lns. 16 – 22 (Walters Direct).
[26] TR. Vol. 13, p. 2933, lns. 15 – 20 (Walters Direct).

companies into the foreseeable future.[27] Additionally, market valuations of utility stocks are strong, which Mr. Walters explains is an indication that utilities are able to access equity capital at lower costs and under reasonable terms.[28] Mr. Walters' overall assessment is that "[g]enerally, authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic."[29]

While capital markets embrace these profit driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates. If this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity. For these reasons, FEA recommends the Commission approve a capital structure with a common equity ratio no higher than 52.0% for TECO in this case.

<u>ISSUE 39:</u> **What authorized return on equity (ROE) should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year?**

FEA: The authorized ROE of 9.60% should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year.

<u>ARGUMENT:</u>

FEA recommends the Commission approve an ROE of 9.6% and reject TECO's request for an ROE of 11.5%. All intervenors in this case either agree that TECO's ROE should be below 9.8% or do not present a position on the ROE.[30] In Mr. Walters' testimony, he provides an overview of the observable market evidence regarding trends in authorized ROEs for utilities, credit standing, utilities' access to capital, and recent policy actions taken by the Federal Reserve,

---

[27] TR. Vol. 13, p. 2934, Figure CCW-2 (Walters Direct).
[28] TR. Vol. 13, p. 2935, lns. 23 - 24 (Walters Direct).
[29] TR. Vol. 13, p. 2936, lns. 4 – 6 (Walters Direct).
[30] Order No. PSC-2024-0351-PHO-EI, p. 52, Issue 39.

all of which should be considered when determining a fair return for TECO. With respect to trends in authorized ROEs, Mr. Walters observes that electric and gas utility ROEs have declined in the last 10 years and have been below 10.0% for approximately the past nine years.[31] Since 2016, the overall average of authorized ROEs for electric utilities is 9.57% with the median being 9.58%.[32] When looking more narrowly at only the utilities authorized an ROE below 10%, the average is 9.2%.[33] Mr. Walters' estimates the current market cost of equity range of 9.2% to 10%, with a midpoint estimate of 9.6%, for the Company is consistent with the standards set forth in these decisions for determining a utility's fair cost of common equity.[34]

Mr. Walters developed his reasonable ROE recommendation using a 1) constant growth Discounted Cash Flow ("DCF") model using consensus analyst's growth rate projections; 2) a constant grown DCF model using sustainable growth rate estimates; 3) a multi-stage grown DCF model; 4) Risk Premium model, and 5) Capital Asset Pricing Model ("CAPM").[35]

<u>The Discounted Cash Flow Model</u>

Mr. Walters performed three variations of the DCF model: (1) a constant growth DCF model based on analysts' growth rate data; (2) a constant growth DCF model based on sustainable growth rates; and (3) a multi-stage DCF model.[36] "The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital."[37]

---

[31] TR. Vol. 13, p. 2929, lns. 7 – 9 (Walters Direct).
[32] TR. Vol. 13, p. 2930, Table CCW-1 (Walters Direct).
[33] *See id.*
[34] TR. Vol. 13, pp. 2927, ln. 23 – 2928 ln. 7 (Walters Direct).
[35] TR. Vol. 13, p 2948, lns. 16 – 21 (Walters Direct).
[36] *Id.*
[37] TR. Vol. 13, p. 2955, lns. 3 – 5 (Walters Direct)

Relying on the same proxy group developed by TECO witness Mr. D'Ascendis, Mr. Walters first conducted a constant growth DCF model analysis using the average of the weekly high and low prices of the proxy group utilities over a period of 13 weeks ending on May 10, 2024 for the stock price and the most recently paid quarterly dividends reported in *Value Line Investment Survey*.[38] This dividend was annualized and adjusted for next year's growth. Mr. Walters used the consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' growth rate expectations. Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence to show whether a particular analyst has more influence on general market investors than others. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.[39]

Using this model on the proxy group, the average growth rate for the proxy group is 6.33% and the median growth rate is 6.20%.[40] The average and median constant growth DCF returns for the 13 week analysis are 10.98% and 10.50%, respectively.[41] However, Mr. Walters cautions that since the three-year to five-year growth rates this model relies on are almost 50% higher than the projected long-term Gross Domestic Product ("GDP") growth rate of 4.14%, these growth rates are not sustainable.[42]

[38] TR. Vol. 13, p. 2956, lns. 3 – 4; 11-12 (Walters Direct).
[39] TR. Vol. 13, p. 2957, lns. 7 – 21 (Walters Direct).
[40] TR. Vol. 13, p. 2958, lns. 1 – 3 (Walters Direct).
[41] *Id.* at lns. 6 – 8.
[42] *Id.* at lns. 11 – 16.

Next, Mr. Walters applied the sustainable growth DCF model. A sustainable growth rate, or internal growth rate, "is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment."[43] Mr. Walters calculated the proxy group's sustainable, or internal, growth rate as an average of 4.80% and median of 4.76%.[44] These average and median sustainable growth rates result in a sustainable growth DCF analysis and produces a proxy group average and median DCF results for the 13-week period of 9.37% and 9.28%, respectively.[45]

Lastly, Mr. Walters conducted a multi-stage growth DCF analysis that applies growth rates over three periods: (1) short-term (first five years); (2) transition period (years 6 to 10); and (3) long-term (year 11 and beyond).[46] The results of Mr. Walters' multi-stage DCF model are an average return estimate of 9.35% and median return estimate of 9.31%.[47] The table below provides each DCF result.

Table CCW-8

Summary of DCF Results

	Proxy Group	
Description	**Mean**	**Median**
Constant Growth DCF Model (Analysts' Growth)	10.98%	10.50%
Constant Growth DCF Model (Sustainable Growth)	9.37%	9.28%
Multi-Stage DCF Model	9.35%	9.31%

[43] TR. Vol 13, p. 2959, lns. 14 – 16 (Walters Direct).
[44] TR. Vol. 13, p. 2960 lns. 8 – 10 (Walters Direct).
[45] *Id*. at lns. 15-17.
[46] TR. Vol. 13, pp. 2961 ln 25 – 2962 ln. 3 (Walter Direct).
[47] TR. Vol. 13, p. 2966 lns 15-16 (Walters Direct).

The average and median of the three DCF models are 9.9% and 9.69% respectfully. Thus, the DCF models support FEA's recommended ROE of 9.6%.

<u>The Risk Premium Model</u>

Mr. Walters also used the Risk Premium model, which "is based on the principle that investors require a higher return to assume greater risk."[48] Common equity securities are considered to be higher risk than bond securities because "bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations."[49] The Risk Premium model uses two estimates of equity risk premium: (1) the difference between ROEs authorized by regulatory commissions and contemporary U.S. Treasury bond yields; and (2) the difference between ROEs authorized by regulatory commissions and Moody's contemporary "A" rated utility bond yields.[50] Mr. Walters used the period between 1986 and 2023, because public utility stocks traded consistently at a premium over book value during that period of time.[51]

Mr. Walters' analysis indicates an average equity risk premium over U.S. Treasury bond yields of 5.70%.[52] To account for variations in the risk premium over time due to changes in market conditions and investors' risk perceptions, Mr. Walters used an estimated range of risk premiums to measure the current return on equity based on the Risk Premium model.[53] Using this methodology, Mr. Walters calculates the average equity risk premium over contemporary "A" rated Moody's utility bond yields is 4.34% and the 5-year and 10-year rolling average risk

---

[48] TR. Vol. 13, p. 2967, lns. 4 – 11 (Walters Direct).
[49] *Id.*at lns. 7 – 9.
[50] TR. Vol. 13, p. 2968, lns. 4 – 15 (Walters Direct); CEL Exh. 99.
[51] *Id.* at lns. 10 – 11.
[52] TR. Vol. 13, p. 3011, lns. 16 – 17 (Walters Errata); CEL Exh. 100.
[53] *Id.* at lns. 17 -21.

premiums to range from 2.88% to 5.90% and 3.20% to 5.73%, respectively.[54] Additionally, Mr. Walters considered the yield spread between utility bonds and U.S. Treasury since 1980 and determined that, for this period of time, the average utility bond yield spreads over U.S. Treasury bonds for "A" rated and "Baa" rated utility bonds are 1.48% and 1.90%, respectively.[55] Mr. Walters concludes that these yield spreads indicate a more normalized equity risk premium is warranted.[56] Mr. Walters' Risk Premium analysis produces an ROE estimate in the range of 9.90% to 10.0%.[57]

The Capital Asset Pricing Model ("CAPM")

The final model Mr. Walters used to determine his ROE recommendation is the CAPM method, which "is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security."[58] For this model, Mr. Walters used the following inputs: (1) *Blue Chip Financial Forecasts'* projected 30-year Treasury bond yield of 4.20% as the market risk-free rate;[59] (2) the current proxy group average and median from *Value Line* beta estimates, historical average of the *Value line* betas and Market Intelligence's Beta Generator Model, as well as long-term historical average betas from *Value Line*;[60] and (3) market risk premium estimates derived from a risk premium and DCF approach.[61] However, with respect to the market risk premium estimates, Mr. Walters also

[54] TR. Vol. 13, p. 3012 lns. 4-7 (Walters Errata); CEL Exh. 101.
[55] TR. Vol. 13, pp. 3012, ln. 25 – 3013 ln. 4 (Walters Errata); CEL Exh. 102.
[56] TR. Vol. 13, p. 3013, lns 18-20 (Walters Errata).
[57] *See* TR. Vol. 13, pp 3013, ln. 21 - 3014, ln. 12; Table CCW-9 (Walters Errata).
[58] TR. Vol. 13, p. 2972, lns. 2 – 5 (Walters Direct).
[59] TR. Vol. 13, p. 2973, lns. 6 – 9 (Walters Direct); Blue Chip Financial Forecast, May 1, 2024; CEL Exh. 103.
[60] TR. Vol. 13, pp. 2974, ln. 5 – 2975, ln 16 (Walters Direct) The average and median beta estimates are 0.92, 0.93, and 0.76 for the *Value Line* (current), *Value Line* (historical average), and Market Intelligence's Beta Generator Model's average and median are .85 and .84, respectively; CEL Exh. 104.
[61] TR. Vol. 13, p. 2975, lns. 19 –20 (Walters Direct).

considered the normalized market risk premium of 5.50% with the normalized risk-free rate of 4.61% published by Kroll.[62] He presents several estimates of the CAPM that relied on different measures of the expected market return, market risk premium, and beta.[63] The results of the nine versions of the CAPM that Mr. Walters applied are captured in the table below.

Table CCW-11

CAPM Results Summary

Description	**Current VL Beta**	**Historical VL Beta**	**Current S&P Beta**
Kroll Normalized Method	9.68%	8.80%	9.29%
Risk Premium Method	11.02%	9.83%	10.50%
FERC DCF Method	12.03%	10.66%	11.43%

TECO's D'Ascendis' Inputs and Methodology Inflate his ROE Results

TECOwitness Mr. D'Ascendis recommends an ROE of 11.50%.[64] The Commission should reject Mr. D'Ascendis' recommendations because they are significantly overstated. As Mr. Walters explains, to reach these excessive results, Mr. D'Ascendis relied on inflated inputs and flawed applications of the DCF analysis, Risk Premium analysis, CAPM, and Empirical CAPM ("ECAPM") analysis.[65] Notably, the deficiencies in Mr. D'Ascendis' ROE analyses, as Mr. Walters identifies, led to his results being higher than the evidence supports.

First, Mr. D'Ascendis proposes an ROE in the upper half of his recommended range

[62] TR. Vol. 13, pp. 2975, ln. 20 – 2976 ln. 2 (Walters Direct).
[63] TR. Vol. 13, pp. 2981, ln. 16 – 2982, ln. 7 (Walters Direct); CEL Exh. 105
[64] TR. Vol. 9, p. 1811, lns. 14 – 15 (D'Ascendis Direct); CEL Exh. 28.
[65] TR. Vol. 13, pp. 2985, ln. 6 – 2986 ln. 2 (Walters Direct).

(11.50%) based on Tampa Electric's small service area, weather risks, high customer growth, and substantial capital expenditure program.[66] However, these factors are already accounted for in Tampa Electric's credit ratings, specifically by S&P's Stand-Alone-Credit-Profile ("SACP"), which is two notches higher than the proxy group's average rating.[67] While Mr. D'Ascendis acknowledges the need to adjust downward for credit risk differences, he offsets that adjustment by recommending a 30-basis point upward adjustment to ROE, which is unnecessary.[68] The upward adjustment is unwarranted because the risks have already been captured in the company's credit ratings, and making further adjustments would result in excessive returns.[69]

Second, Mr. D'Ascendis calculates a flotation cost adjustment of 0.10%, based on equity issuance costs due to Emera's acquisition of TECO in 2016.[70] However, Mr. D'Ascendis has not demonstrated that these costs were reasonably incurred or properly allocated to TECO. More importantly, the Commission typically does not allow for the recovery of flotation costs through ROE. Instead, any prudently incurred flotation costs should be recovered through TECO's cost of service, not through an ROE adjustment. Additionally, TECO being a subsidiary of a much larger entity, Emera, and not a standalone small company, provides greater access to equity markets, further negating the need for a flotation cost adjustment.[71]

Third, Mr. D'Ascendis' eliminated the results of IDACORP, Inc., from his results when running his DCF analysis, which inflates his proxy group with growth rate assumptions that are unsustainable.[72]

Fourth, D'Ascendis' equity risk premium results, 10.00% to 16.02%, are excessively high

---

[66] TR. Vol. 13, p. 2985, ln. 22 – 2986 ln 2 (Walters Direct).
[67] TR Vol. 13, p. 2988, lns. 15- 18 (Walters Direct).
[68] *Id.* at ln. 18 – 21.
[69] TR. Vol. 13, pp. 2988, ln. 21 – 2989 ln 2 (Walters Direct).
[70] TR. Vol. 13, p. 2985, lns. 8 – 12 (Walters Direct).
[71] TR. Vol. 13, pp. 2989, ln. 5 – 2990 ln. 4 (Walters Direct).
[72] TR. Vol. 13, pp. 2990, l.n 7 – 2991 ln. 12 (Walters Direct).

and far removed from reasonable estimates.[73]

Fifth, Mr. D'Ascendis' CAPM and ECAPM analyses rely on market risk premiums of 9.93% (excluding PRPM) and 10.02% (with PRPM), which are excessively high.[74] Additionally, Mr. D'Ascendis' expected market returns are based on unsustainable growth rates, making the derived market risk premiums unreliable. Mr. D'Ascendis' also used an adjusted beta in his ECAPM, which inflates the results. More importantly, this is a method this Commission has historically rejected and should continue to reject the ECAPM with adjusted beta method along with any evidence or testimony that is derived from it.[75]

Lastly, Mr. D'Ascendis use of certain non-price regulated proxy groups to estimate the ROE is not comparable to companies that are similarly situated to TECO. Mr. D'Ascendis uses the same cost of equity studies (DCF, Risk Premium, and CAPM models) as applied to a proxy group of non-price regulated companies.[76] His non-price regulated companies were selected based on whether they had betas within two standard deviations of the beta of his utility proxy group. However, Mr. D'Ascendis has not shown that these non-price regulated companies share the same or similar risk factors to TECO. The non-price regulated proxy group includes large technology firms, such as Cisco Systems and Oracle Corporation, which are not comparable in business or operating risk to regulated utilities. For a valid comparison, it is necessary to demonstrate that the proxy companies have similar risk factors, which Mr. D'Ascendis fails to do. Ultimately, the non-price regulated companies are not risk comparable to TECO, and as a result Mr. D'Ascendis' recommendations based on this proxy group are unreliable and should be disregarded when

[73] TR. Vol. 13, p. 2992, lns. 7 -15 (Walters Direct).
[74] *See* TR. Vol. 13, pp. 2993, ln. 5 – 2997, ln 5 (Walters Direct).
[75] *See* TR. Vol. 13, pp. 2997, ln. 9 – 3000 ln 11 (Walters Direct).
[76] TR. Vol. 13, p. 3001, lns. 4 – 11 (Walters Direct).

determining the appropriate ROE for TECO.[77]

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?**

FEA: The capital structure and weighted average cost of capital that should be approve 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%
	$9,798,150	100.00%		6.36%

ARGUMENT

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.

2025 NET OPERATING INCOME

ISSUE 41: **Has TECO correctly calculated the revenues at current rates for the 2025 projected test year?**

FEA: No position.

[77] TR. Vol. 13, p. 3000, ln. 13 – 3001 ln. 21(Walters Direct).

<u>ISSUE 42:</u> **What amount of Total Operating Revenues should be approved for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 43:</u> **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?**

FEA: No position.

<u>ISSUE 44:</u> **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?**

FEA: No position.

<u>ISSUE 45:</u> **What amount of generation O&M expense should be approved for the 2025 projected test year??**

FEA: No position.

<u>ISSUE 46:</u> **What amount of transmission O&M expense should be approved for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 47:</u> **What amount of distribution O&M expense should be approved for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 48:</u> **Has TECO made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Fuel Adjustment Clause?**

FEA: No position.

<u>ISSUE 49:</u> **Has TECO made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause?**

FEA: No position.

ISSUE 50: **Has TECO made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause?**

FEA: No position.

ISSUE 51: **Has TECO made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause?**

FEA: No position.

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?**

FEA: No position.

ISSUE 53: **What amount of salaries and benefits, including incentive compensation, should be approved for the 2025 projected test year?**

FEA: No position.

ISSUE 54: **Does TECO's pension and OPEB expense properly reflect capitalization credits in the 2025 projected test year? If not, what adjustments, if any, should be made?**

FEA: No position.

ISSUE 55: **What cost allocation methodologies and what amount of allocated costs and charges with TECO's affiliated companies should be approved for the 2025projected test year and what, if any, other measures should be taken?**

FEA: No position.

ISSUE 56: **What amount of Directors and Officers Liability Insurance and Board of Director expense for the 2025 projected test year should be approved?**

FEA: No position.

ISSUE 57: **What amount of Economic Development expense for the 2025 projected test year should be approved?**

FEA: No position.

<u>ISSUE 58:</u> **What amount and amortization period for TECO's rate case expense for the 2025 projected test year should be approved?**

FEA: No position.

<u>ISSUE 59:</u> **What amount of O&M Expense for the 2025 projected test year should be approved?**

FEA: No position.

<u>ISSUE 60:</u> **What amount of depreciation and dismantlement expense for the 2025 projected test year should be approved?**

FEA: No position.

<u>ISSUE 61:</u> **What amount of Taxes Other Than Income Taxes for the 2025 projected test year should be approved?**

FEA: No position.

<u>ISSUE 62:</u> **What amount of Parent Debt Adjustment is required by Rule 25-14.004, Florida Administrative Code, for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 63:</u> **What amount of Production Tax Credits should be approved and what is the proper accounting treatment for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 64:</u> **What treatment, amounts, and amortization period for the Production Tax Credits that were deferred in 2022-2024 should be approved for the 2025projected test year?**

FEA: No position.

<u>ISSUE 65:</u> **What treatment and amount of the Investment Tax Credits pursuant to the Inflation Reduction Act should be approved for the 2025 projected test year?**

FEA: No position.

<u>ISSUE 66:</u> **What amount of Income Tax expense should be approved for the 2025 projected test year?**

FEA: No position.

ISSUE 67: **What amount of Net Operating Income should be approved for the 2025 projected test year?**

FEA: No position.

2025 REVENUE REQUIREMENTS

ISSUE 68: **What revenue expansion factor and net operating income multiplier, including the appropriate elements and rates, should be approved for the2025 projected test year?**

FEA: No position.

ISSUE 69: **What amount of annual operating revenue increase for the 2025 projected test year should be approved?**

FEA: No position.

2025 COST OF SERVICE AND RATES

ISSUE 70: **TECO's proposed separation of costs and revenues between the wholesale and retail jurisdictions appropriate?**

FEA: FEA supports TECO's jurisdiction allocation study.

ARGUMENT

FEA supports TECO's jurisdictional in Class Cost of Service Study ("CCOSS"). The Company's proposed CCOSS reflects the continuation of the cost-of-service methodology which was approved by the Commission and all stakeholders in TECO's 2021 rate case settlement.[78]. The continuation of this CCOSS methodology in this case is supported by all parties in this case except for Florida Rising ("FL Rising") and the League of United Latin American Citizens in Florida ("LULAC").[79] The 2021 rate case, Order No. PSC-2021-0423-S-EL established the demand-related production and transmission costs using a 4 Coincident Peak ("4 CP") method using the test period months of January, June, July, and August. To separate distribution cost,

[78] Consolidated Docket Numbers 20210034-EL/20200264-EL.
[79]Order No. PSC-2024-0351-PHO-EI, pp. 80 - 84, Issue 70-74.

TECO recommends the Minimum Distribution System ("MDS"). FEA agrees with this methodology.

ISSUE 71: **What is the appropriate methodology to allocate production costs to the rate classes?**

FEA: FEA supports the use of 4CP methodology as proposed by TECO. See below.

ISSUE 72: **What is the appropriate methodology to allocate transmission costs to the rate classes?**

FEA: FEA supports the use of 4CP methodology as proposed by TECO.

ARGUMENT

The Commission should again approve the Company's CCOSS in this case, as it did in the 2021 rate case, because it remains the best and most accurate methodology to allocate costs across rate classes in line with TECO's costs of providing service to the various rate classes.

TECO's CCOSS in this case allocates production capacity, and transmission capacity across rate classes using a four coincident peak (4CP) methodology that accurately allocates Production and Transmission ("P&T") capacity cost in line with the customers' demands that require the Company to invest in P&T capacity to provide reliable firm service.[80] The 4CP production and transmission capacity allocator reasonably and accurately aligns the costs of providing firm service to TECO's rate classes.[81]

FL Rising/LULAC witness Mr. Rabago recommends the Commission reject the 4CP allocator for P&T capacity cost and instead use the 12CP allocator.[82] Mr. Rabago's main argument

[80] TECO Minimum Filing Requirements Schedule E Cost of Service Study: 4 CP-Present and Proposed Rate Structure.
[81] TR. Vol. 13, p. 3060, lns. 27 – 30 (Gorman Direct).
[82] TR. Vol. 11, pp. 2605, ln. 1 – 2609, ln. 11 (Rabago Direct).

is focused on the claim that the use of a 4CP allocates more cost to residential customers[83], which in turn impacts the affordability of residential rates.[84] Mr. Rabago does not offer any cost causation arguments that support his recommendation. Instead, Mr. Rabago's arguments against the continued use of the 4CP allocate are purely results oriented. He wants to allocate less cost to residential class regardless of the cost TECO incurs to provide firm service to this rate class. The record shows that the 4CP allocator is the most accurate gage of the amount of production and transmission capacity that TECO needs to provide reliable firm service to all of its rate classes. Mr. Rabago's results-oriented arguments should be rejected.

Consistent with the Commission's finding in the 2021 TECO rate case, the 4CP allocator is the most accurate and fair allocator to assign production and transmission capacity cost across rate classes based on the amount of capacity TECO has invested in to provide firm service to all of its rate classes and should be maintained and approved by the Commission.

ISSUE 73: **What is the appropriate methodology to allocate distribution costs to the rate classes?**

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.

ARGUMENT

TECO's distribution capacity CCOSS, consistent with the Commission approved CCOSS settlement in its 2021 rate case, first classifies distribution capacity cost as customer related and demand related and then allocates these classified distribution cost across rate classes. This distribution classification is reasonable and reflects cost-causation because distribution costs are

---

[83] TR. Vol. 11, pp. 2605, ln. 17 – 2606 ln 6 (Rabago Direct).
[84] TR. Vol. 11, p. 2606, lns. 15 – 25 (Rabago Direct).

incurred in order to connect customers to the system, and to serve customers demands. Connecting customers to the distribution system concerns the length of the distribution circuits that are needed to connect all customers to the system, regardless of the demands customers place on the circuits. The distribution circuits are also designed to serve the peak demands on the circuits so TECO can provide reliable firm service to customers. The classification of distribution costs as both customer related and demand related reflects how TECO incurs cost to provide distribution service to its customers, and the cost of that infrastructure is allocated across customer classes in line with TECO cost-causation.

The MDS has been accepted for decades as a valid consideration of numerous state public utility commissions.[85] While the Residential class may be receiving an increase, it would bring them closer to equaling out to the Rate of Return ("ROR") for the class.[86] Mr. Rabago takes issue with the use of the MDS approach in classifying distribution cost into demand and customer's cost.[87] Mr. Rabago argues that the MDS is not reasonable because 1) none of Emera other subsidiary uses MDS,[88] 2) distribution cost do not meet the definition of customers cost according to a book published in 1961 by James Bonbright,[89] and 3) the 2020 Regulatory Assistance Project ("RAP") report opines that shared distribution cost classified as customer related is unfair.[90]

However, Mr. Rabago's arguments are without merit and should be rejected. Mr. Rabago doesn't provide any evidence that disputes the clear evidence in this case that distribution costs are, in fact, incurred to connect customers to the electric system AND to meet the peak demands of the connected customers. He also provides no evidence that takes issue with the record evidence

---

[85] TR. Vol. 13 p. 3062, lns. 8 – 18 (Gorman Direct).
[86] TR. Vol. 13 p. 3065, lns. 1 – 2, Table 2 (Gorman Direct).
[87] TR. Vol. 11 p. 2567, ln. 1 – 25 (Rabago Direct).
[88] TR. Vol. 11 p. 258,2 ln. 6 (Rabago Direct).
[89] TR. Vol. 11 pp. 2584, ln. 25 – 2586 ln. 3 (Rabago Direct).
[90] TR. Vol. 11 pp. 2589, ln. 1 – 2590 ln. 11 (Rabago Direct).

that distribution system costs are incurred by both the length of distribution circuits required to connect customers to the system and the size of the circuit conductor needed to serve the peak demand on the distribution circuit. Mr. Rabago provides no cost causation arguments at all in disputing the reasonableness and fairness of the MDS approach of classifying and allocating distribution costs using the MDS. Rather, Mr. Rabago supports his argument to reject the MDS by simply asserting it is unfair and other studies do not accept MDS. The evidence in this case is clear, the MDS does reflect cost-causation of the distribution system, and consistent with the Commission's finding in TECO's 2021 rate case, it should continue to be used as the best and most fair method to apportion distribution cost across rate classes in this case.

ISSUE 74: **How should any change in the revenue requirement approved by the Commission be allocated among the customer classes?**

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.

ARGUMENT

TECO proposes to allocate its revenue deficiency across the rate classes primarily on the results of its CCOSS. Doing this results in a gradual movement to cost of service while preventing large increases to specific rate classes that are currently priced well below cost of service. The Company's proposed class allocation, at the Company's claimed revenue deficiency, is presented in Mr. Gorman's testimony in the table below.[91]

[91] TR. Vol. 13 p. 3065, ln. 1 (Gorman Direct).

TABLE 2

Allocation of Proposed Increase
($000)

Rate Class	Present Operating & Service Charge Revenue	Proposed Operating & Service Charge Revenue	Total Revenue Increase	Percent Increase
RS	$ 937,081	$ 1,119,008	$ 181,927	19.4%
GS	$ 96,812	$ 101,069	$ 4,257	4.4%
GSD	$ 310,873	$ 411,530	$ 100,657	32.4%
GSLDPR	$ 44,353	$ 47,903	$ 3,550	8.0%
GSLDSU	$ 23,795	$ 30,000	$ 6,205	26.1%
LS Energy	$ 3,570	$ 3,578	$ 8	0.2%
LS Facilities	$ 82,706	$ 82,708	$ 2	0.0%
Total	$ 1,499,190	$ 1,795,796	$ 296,606	19.8%

Source: MFR - E Schedules; Schedule E-8, pg. 17

As demonstrated in the table, in TECO's proposed spread no class gets an exorbitant increase above the system average increase of 19.8%. The General Service – Demand ("GSD") class has the highest present increase of 32.4% which is 1.66x the system average increase. TECO's proposed gradual movement of all rate classes to cost of service reduces inter-classes subsidies without placing too much of the rate increase burden on any specific rate class. As a result, the TECO's proposed class revenue increase spread is reasonable.

ISSUE 75: **Should the proposed modifications to the delivery voltage credit be approved?**

FEA: No position.

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)?**

FEA: No position.

<u>ISSUE 77:</u> **Should the modifications to the emergency relay power supply charge be approved?**

FEA: No position.

<u>ISSUE 78:</u> **What are the appropriate basic service charges?**

FEA: The GSLDPR demand charges should be increased, and the energy charges reduced.

ARGUMENT

FEA recommends one change to the Company's method used to recover the revenue deficiency in its proposed rate adjustment for the General Service – Large Demand – Primary ("GSLDPR") rate class. Currently, the Company's cost of service study clearly indicates that rates in this rate class should have a greater weight in demand charge, and less in nonfuel energy charges. However, the Company's proposed rate design increases demand charges by a greater weight than the increase in non-fuel energy charges and over-collects on the energy charge and under-collects on the demand charge. The table below, shows that 86% of the GSLDPR revenue requirement CCOSS costs are demand-related, while the proposed GSLDPR TOD rate collects approximately 68% through the demand rates. As a result, the GSLDPR demand charges should be increased and the energy charges reduced.[92]

[92] TR. Vol. 13 p. 3069, ln. 5 (Gorman Direct).

TABLE 6

GSLDPR Unit Cost Rev. Req.
($000)

	Revenue Requirement	Percent
Demand		
Production	$ 31,908	
Transmission	$ 1,960	
Subtranmission	$ 2,432	
Distribution	$ 4,870	
Subtotal	$ 41,170	86.3%
Energy		
Production	$ 6,047	12.7%
Customer		
MDS	$ 475	
Meter & Cust Srv	$ 8	
Subtotal	$ 483	1.0%
Total	$ 47,700	

ISSUE 79: **What are the appropriate demand charges?**

FEA: See Issue 78 concerning demand charge for GSLDPR rate class.

ISSUE 80: **What are the appropriate energy charges?**

FEA: See Issue 78 concerning energy charge for GSLDPR rate class.

ISSUE 81: **What are the appropriate Lighting Service rate schedule charges?**

FEA: No position.

ISSUE 82: **What are the appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges?**

FEA: No position.

ISSUE 83: **Should the proposed modifications to the time-of-day periods be approved?**

FEA: No position.

ISSUE 84: **Should the proposed modifications to the Non-Standard Meter Rider tariff (Tariff Sheet No. 3.280) be approved?**

FEA: No position.

ISSUE 85: **Should the proposed tariff modifications to the Budget Billing Program (Fifth Revised Tariff Sheet No. 3.020) be approved?**

FEA: No position.

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?**

FEA: No position.

ISSUE 87: **Should the proposed tariff modifications to Contribution in Aid of Construction (Fifth Revised Tariff Sheet No. 5.105) be approved?**

FEA: No position.

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?**

FEA: No position.

ISSUE 89: **Should the proposed modifications to LS-1 (Eleventh Revised Tariff Sheet No. 6.809) regarding lighting wattage variance be approved?**

FEA: No position.

ISSUE 90: **Should the proposed LS-2 Monthly Rental Factors (Original Tariff Sheet No. 6.845) be approved?**

FEA: No position.

ISSUE 91: **Should the proposed termination factors for long-term facilities (Fifth Revised Tariff Sheet No. 7.765) be approved?**

FEA: No position.

ISSUE 92: **Should the non-rate related tariff modifications be approved?**

FEA: No position.

ISSUE 93: **Should the Commission give staff administrative authority to approve tariffs reflecting Commission approved rates and charges?**

FEA: No position.

2026 AND 2027 SUBSEQUENT YEAR ADJUSTMENTS

ISSUE 94: **What are the considerations or factors that the Commission should evaluate in determining whether an SYA should be approved?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

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?**

FEA: No position.

ISSUE 103: **What overall rate of return should be used to calculate the 2026 and 2027 SYA?**

FEA: No position.

ISSUE 104: **Should the SYA for 2026 and 2027 reflect additional revenues due to customer growth? What, if any, adjustments should be made?**

FEA: No position.

ISSUE 105: **Should the Commission approve the inclusion of TECO's proposed incremental O&M expense associated with the SYA projects in the 2026 and2027 SYA?**

FEA: No position.

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 the2025 projected test year?**

FEA: No position.

ISSUE 107: **What annual amount of incremental revenues should be approved for recovery through the 2026 and 2027 SYA?**

FEA: No position.

ISSUE 108: **What rate design approach should be used to develop customer rates for the 2026 and 2027 SYA?**

FEA: No position.

ISSUE 109: **When should the 2026 and 2027 SYA become effective?**

FEA: No position.

<u>ISSUE 110:</u> **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?**

FEA: No position.

<u>ISSUE 111:</u> **Should TECO's proposed Corporate Income Tax Change Provision be approved?**

FEA: No position.

<u>ISSUE 112:</u> **Should TECO's proposed Storm Cost Recovery Provision be approved?**

FEA: No position.

<u>ISSUE 113:</u> **Should TECO's proposed Asset Optimization Mechanism be approved, and what, if any, modifications should be made?**

FEA: No position.

<u>ISSUE 114:</u> **What are the appropriate updated Clean Energy Transition Mechanism factors and when should they become effective?**

FEA: No position.

<u>ISSUE 115:</u> **Should the proposed Senior Care Program (Original Tariff Sheet No. 3.310) and associated cost recovery be approved?**

FEA: No position.

<u>ISSUE 116:</u> **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?**

FEA: No position.

<u>ISSUE 117:</u> **What is the appropriate effective date for TECO's revised 2025 rates and charges?**

FEA: No position.

<u>ISSUE 118:</u> **Has the Commission considered TECO's performance pursuant to Sections 366.80–366.83 and 403.519, Florida Statutes, when establishing rates?**

FEA: No position.

<u>ISSUE 119:</u> **What considerations should the Commission give the affordability of customer bills and how does TECO's rate increase impact ratepayers in this proceeding?**

FEA: Adopts the position of FIPUG.

<u>ISSUE 120:</u> **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?**

FEA: No position.

<u>ISSUE 121:</u> **Should this docket be closed?**

FEA: No position.

<u>CONTESTED ISSUES</u>

SC-2: **Should TECO recover O&M expense associated with keeping integrated gasification, steam turbine, and/or heat recovery steam generator components at Polk Unit 1 in long-term standby, and what adjustments should be made?**

FEA: No position.

SC-5: **Should TECO recover O&M expense associated with injecting wastewater into deep wells at Polk Unit 1 and Big Bend Unit 4, and what adjustments should be made?**

FEA: No position.

SC-6: **Should TECO recover any O&M expense associated with coal or petcoke combustion at Polk Unit 1 and/or Big Bend Unit 4, and what adjustments should be made?**

FEA: No position.

SC-12: **Should TECO be required to apply for the U.S. Department of Energy's Energy Infrastructure Reinvestment Program for Polk Unit 1 and/or Big Bend Unit 4?**

FEA: No position.

SC-13: **Should TECO be required to cease all coal combustion at Polk Unit 1 by 2024 and Big Bend Unit 4 by 2025?**

FEA: No position.

OPC-1: **What considerations should the Commission give the affordability of customer bills in this proceeding?**

FEA: No position.

OPC-2: **What impact will TECO's rate increase have on rate payers?**

FEA: No position.

OPC-3: **Should TECO continue to operate as the *de facto* centralized service provider, and if so, what additional measures should be taken, if any, to facilitate its operation as the centralized service provider?**

FEA: No position.

Dated this 22st day of October 2024

Respectfully Submitted,
Attorneys for Federal Executive Agencies

/s/ Ashley N. George

Ashley N. George, Capt, USAF
Michael A. Rivera, Capt, USAF
Leslie R. Newton, Maj, USAF
Mr. Thomas A. Jernigan
AF/JAOE-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403
ashley.george.4@us.af.mil
michael.rivera.51@us.af.mil
leslie.newton.1@us.af.mil
thomas.jernigan.3@us.af.mil
850-283-6289

CERTIFICATE OF SERVICE
Docket Nos. 20240026-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 22nd day of October, 2024, to the following:

Florida Public Service Commission **Office of the General Counsel** Adria Harper Carlos Marquez Timothy Sparks Daniel Dose 2540 Shumard Oak Boulevard Tallahassee, Florida 32399 aharper@psc.state.fl.us cmarquez@psc.state.fl.us tsparks@psc.state.fl.us discovery-gcl@psc.state.fl.us ddose@psc.state.fl.us	**Ausley & McMullen** J. Jeffry Wahlen Malcolm Means Virginia Ponder P.O. Box 391 Tallahassee, Florida 32302 jwahlen@ausley.com mmeans@ausley.com vponder@ausley.com
Tampa Electric Company Paula K. Brown P.O. Box 111 Tampa, FL 33601 Regdept@tecoenergy.com	**EarthJustice** Bradley Marshall Jordan Luebkemann Hema Lochan 111 S. Martin Luther King Jr. Blvd Tallahassee, Florida 32301 bmarshall@earthjustice.org jluebkemann@earthjustice.org hlochan@earthjustice.org flcaseupdates@earthjustic.org
Office of Public Counsel Patricia A. Christensen Walt Trierweiler Octavia Ponce Charles Rehwinkel 111 West Madison Street, Room 812 Tallahassee, FL 32399 Christensen.patty@leg.state.fl.us Trierweiler.walt@leg.state.fl.us Poce.octavia@leg.state.fl.us Rehwinkel.charles@leg.state.fl.ua	**Florida Industrial Power Users Group** **Moyle Law Firm** Jon C. Moyle Jr. Karen A. Putnal 118 North Gadsden Street Tallahassee, Florida 32301 jmoyle@moylelaw.com kputnal@moylelaw.com
Sierra Club Nihal Shrinath Sari Amiel 2101 Webster Street Suite 1300 Oakland CA 94612 nihal.shrinath@sierraclub.org sari.amiel@sierraclub.org	**Florida Retail Federation** Robert Scheffel Wright John T. LaVia, III 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com

Sierra Club Sari Amiel 50 F St. NW, Eighth Floor Washington DC 20001 Sari.Amiel@sierraclub.org	**Berger Singerman, LLP** Floyd R. Self, B.C.S. Ruth Vafek, Esq. 313 North Monroe Street, Suite 301 Tallahassee, FL 32301 fself@bergersingerman.com rvafek@bergersingerman.com
	Federal Executive Agencies Leslie Newton Ashley George Michael Rivera James Ely Thomas Jernigan Ebony M. Payton AFLOA/JAOE-ULFSC 139 Barnes Drive, Suite 1 Tyndall Air Force Base, FL 32403 Leslie.Newton.1@us.af.mil Ashley.George..4@us.af.mil Michael.Rivera.51@us.af.mil James.Ely@us.af.mil Thomas.Jernigan.3@us.af.mil Ebony.Payton.ctr@us.af.mil

/s/ Ebony M. Payton
Ebony M. Payton
Paralegal for FEA