BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

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

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.
___________________________________/

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, August 29, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 7:00 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

TRANSCRIBED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
91-105	As identified in the CEL		3019
106-112	As identified in the CEL		3053
133-137	As identified in the CEL		3107

P R O C E E D I N G S

(Transcript follows in sequence from Volume 12.)

CHAIRMAN LA ROSA: All right. So I am going to go down the list, and I know we are a little bit out of order, so I am going to come back to FEAs, is that okay?

CAPTAIN GEORGE: Yes, Mr. Chairman.

CHAIRMAN LA ROSA: Okay. We are ready for you if you are.

CAPTAIN GEORGE: Yes. So I would like to move -- I think we may have done this already. Did we -- never mind, I will just do it now.

CHAIRMAN LA ROSA: Yep.

CAPTAIN GEORGE: I would like to move our -- two of our excused witnesses, previously excused witnesses' testimony into the record, Mr. Walter's prefiled testimony, consisting of 83 pages filed on June 6th, along with his errata filed on August 23rd, consisting of 13 pages into the record as so read, and along with his exhibits, which are marked as Exhibits 91 through 105.

CHAIRMAN LA ROSA: Okay. Are there objections?

Seeing none, show them entered into the

record.

(Whereupon, prefiled direct testimony of Christopher C. Walters was inserted.)

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C29-2901

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	)	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	)	**DOCKET NO. 20230090-EI**

Direct Testimony and Exhibits of

Christopher C. Walters

On behalf of

Federal Executive Agencies

June 6, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11662

C29-2901

C29-2902

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	**DOCKET NO. 20230090-EI**

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<u>Direct Testimony of Christopher C. Walters</u>

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	**DOCKET NO. 20230090-EI**

<u>Direct Testimony of Christopher C. Walters</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

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Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q **ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH THIS TESTIMONY?**

A Yes. I am sponsoring Exhibit CCW-1 through Exhibit CCW-15.

Q **WHAT IS THE SUBJECT OF YOUR DIRECT TESTIMONY?**

A In my testimony I make several recommendations concerning Tampa Electric Company's ("Tampa Electric" or "Company") rate filing in this proceeding. These recommendations include the following:

I. SUMMARY

Q **PLEASE SUMMARIZE YOUR TESTIMONY.**

A In Section II of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends, and outlooks, as well as the overall trend in the authorized ROE for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% in more recent history. I also review the impact that the Federal Reserve's (the "Fed") monetary policy actions have had on the cost of capital.

In Section III of my testimony, I outline how a fair ROE should be established, provide an overview of the market's perception of the Company's investment risk, comment on the Company's proposed capital structure, and

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present the analyses I relied on to estimate an appropriate ROE for Tampa Electric. Based on the results of several cost of equity estimation methods performed on publicly traded utility companies, I estimate the current fair market ROE for the Company to fall within the range of 9.20% to 10.00%. Based on my assessment of the Company's overall risk profile and the results of the analytical methods, I recommend Tampa Electric be awarded an ROE of 9.60%, which is the mid-point of my estimated range.

In Section IV of my testimony, I respond to Company witness Mr. D'Ascendis' estimate of the current market cost of equity for Tampa Electric. Mr. D'Ascendis recommends the Company be authorized an ROE of 11.50%. I demonstrate that his ROE recommendations are excessive and should be rejected.

Based on all of the foregoing, I request this Commission adopt the following recommendations:

1. Reject Tampa Electric's proposed ROE of 11.50% and instead adopt my recommended ROE of 9.60%, which is based on my assessment of the current and expected capital market environment, the Company's overall risk profile, and the results of several analytical methods which I have analyzed, to determine a fair and reasonable ROE to be authorized for Tampa Electric.

2. Reject Tampa Electric's proposed permanent equity ratio of 54.00% and instead authorize Tampa Electric an equity ratio of 52.0%. Should an equity ratio higher than 52.0% be authorized, an ROE in the lower half of my range would be warranted.

3. My recommendations produce an overall ratemaking ROR of 6.36% and would reduce Tampa Electric's Florida electric retail revenue requirements by approximately $134.7 million.

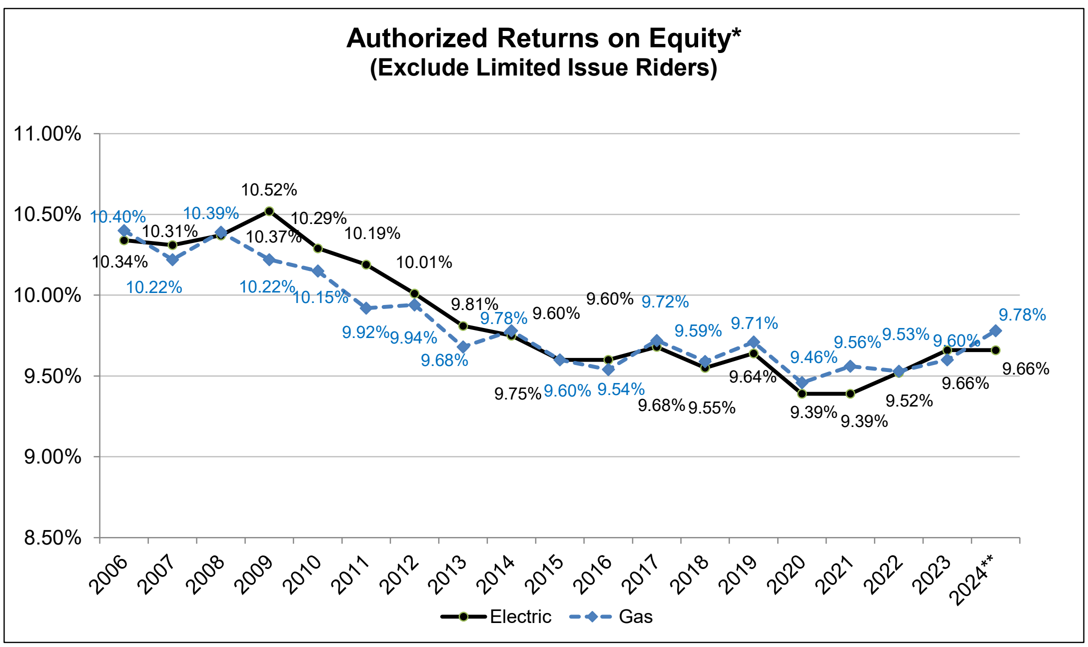
II. ACCESS TO CAPITAL AND ECONOMIC ENVIRONMENT

II.A. Regulated Utility Industry Authorized ROEs, Access to Capital, and Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROEs FOR ELECTRIC AND GAS UTILITIES.

A Authorized ROEs for both electric and gas utilities have declined over the last 10 years, as illustrated in Figure CCW-1, and have been below 10.0% for about the last nine years.

FIGURE CCW-1



Source and Notes:
* Electric Returns exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - March 2024, April 19, 2024 at page 3.

Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROEs FOR ELECTRIC UTILITIES FOR THE LAST FEW YEARS.

A The distribution of authorized returns, annually, since 2016 is summarized in Table CCW-1.

TABLE CCW-1

Distribution of Authorized ROEs
(All Electric Utilities)*

Line	Year (1)	Average (2)	Median (3)	Share of Decisions ≤ 9.5% (4)	Share of Decisions ≤ 9.7% (5)	Share of Decisions ≤ 10.0% (6)
1	2016	9.60%	9.60%	41%	53%	94%
2	2017[1]	9.67%	9.60%	42%	67%	81%
3	2018[2]	9.54%	9.57%	47%	63%	100%
4	2019	9.64%	9.65%	39%	58%	88%
5	2020[3]	9.38%	9.48%	64%	79%	100%
6	2021	9.39%	9.49%	58%	81%	97%
7	2022	9.52%	9.50%	53%	63%	84%
8	2023	9.66%	9.60%	38%	65%	85%
9	2024	9.70%	9.75%	9%	45%	100%
10	Average	9.57%	9.58%	44%	64%	92%
11	Median	9.60%	9.60%	42%	63%	94%

Source and Notes:
S&P Global Market Intelligence, data through May 10, 2024.
[1]Includes authorized base ROE of 9.4% for Nevada Power Company, which excludes incentives associated with the Lenzie facility.
[2]Includes authorized base ROE of 9.6% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
[3]Includes authorized base ROE of 9.8% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
*Excludes Limited Issue Rider Cases.

The distribution shows that over the last few years, the majority of authorized ROEs since 2016 have been below 9.7%, with many of those being below 9.5%.

Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A In general, the utility industry's common equity ratio has not really deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

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TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

Line	Year (1)	Electric[1] Average (2)	Electric[1] Median (3)
1	2016	49.70%	49.99%
2	2017	50.02%	49.85%
3	2018	50.60%	50.23%
4	2019	51.55%	51.37%
5	2020	50.94%	51.17%
6	2021	51.01%	52.00%
7	2022	51.57%	51.92%
8	2023	51.59%	52.27%
9	2024	50.62%	51.93%
10	Average	50.84%	51.19%
11	Median	50.94%	51.37%

Source and Notes:
[1] S&P Global Market Intelligence, data through May 10, 2024.
[2] Excludes Arkansas, Florida, Indiana, and Michigan, because they include non-investor capital.

Q HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN RELATIVELY STRONG CREDIT RATINGS DURING PERIODS OF DECLINING AUTHORIZED ROEs?

A Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved since 2009. In 2009, approximately 53% of the industry was rated BBB+ or higher. Currently, 83% of the industry has a rating of BBB+ or higher.

TABLE CCW-3

S&P Ratings by Category
Electric Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
A or higher	12%	12%	12%	11%	13%	13%	13%	10%	10%	8%	14%	14%	10%	10%	12%	13%
A-	18%	20%	19%	22%	26%	26%	34%	43%	52%	54%	54%	53%	37%	37%	37%	33%
BBB+	23%	24%	28%	28%	25%	28%	24%	32%	21%	22%	18%	19%	35%	36%	36%	42%
BBB	36%	26%	24%	22%	26%	23%	18%	4%	7%	13%	12%	3%	16%	16%	15%	12%
BBB-	9%	16%	15%	17%	11%	11%	11%	11%	11%	2%	1%	1%	0%	0%	0%	0%
Below BBB-	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	10%	1%	1%	1%	1%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Source: S&P CAPITAL IQ and Market Intelligence, downloaded 5/15/24.
Note: Subsidiary ratings used.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. In Regulatory Research Associates' ("RRA") April 2, 2024 Utility Capital Expenditures report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

- Multiple drivers are expected to elevate utility capital expenditures over the next several years. Pent-up demand to replace aging equipment continues to propel considerable utility investments in infrastructure, while artificial intelligence increases the power demands of datacenters daily.

- Projected 2024 capital expenditure for the 45 energy utilities included in the RRA representative sample of publicly traded, US-based utilities is $184 billion — an upswell of nearly 11% from the group's $166 billion of actual spending in 2023. The increase is largely driven by federal legislation enacted in 2021 and 2022 supporting infrastructure investment.

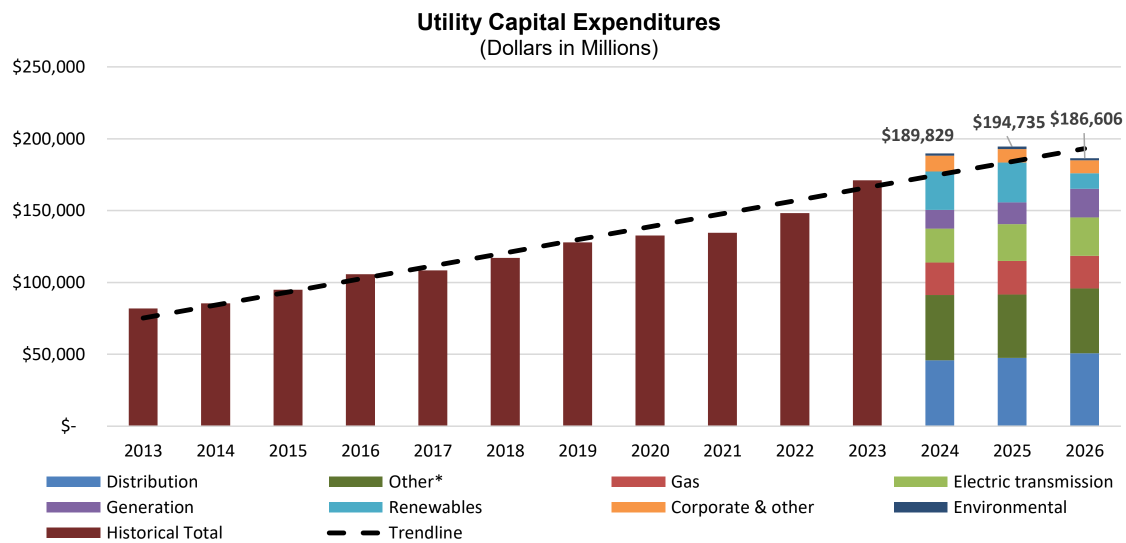
* * *

- Aggregated energy utility capex estimates for both 2024 and 2025 indicate successively higher spending levels, reaching $184 billion and $191 billion, respectively. Spending expectations for 2024 and beyond are likely to increase as the companies' plans for future projects continue to solidify around the new federal legislation supporting infrastructure investment.

- Utilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021. These pieces of legislation provide billions of dollars for power infrastructure investments, financial incentives for nuclear power plants and funding for battery storage technology, among other provisions.[1]

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025. The outlooks for electric and natural gas industries reasonably align with capital expenditure outlooks for water utilities as noted by RRA above.

FIGURE CCW-2



*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, March 27, 2024, Tables 1 and 3.

As demonstrated in Figure CCW-2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value and are attracting both

[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility capex primed for profusion in 2024 and beyond," April 2, 2024.

equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments. 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.

Q WHAT IS THE SIGNIFICANCE OF THESE FINDINGS?

A This is clear evidence that the capital investments are enhancing shareholder value, and are attracting both equity and debt capital to the utility industry in a manner that allows for these elevated capital investments.

Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?

A Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong signal that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit CCW-1, the historical valuation of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market price-to-book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA IN FORMING YOUR RECOMMENDED ROE AND OVERALL RATE OF RETURN?

A Generally, authorized ROEs, 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. It is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

<u>II.B. Federal Reserve Monetary Policy</u>

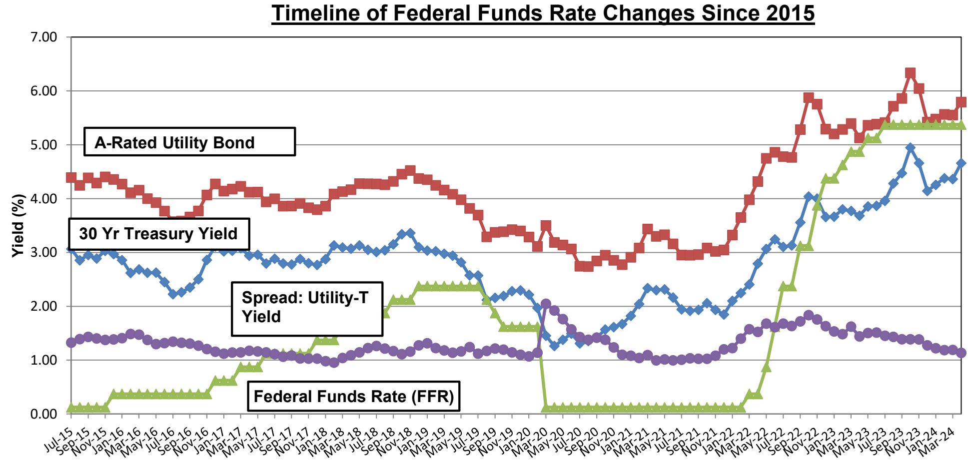
Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A Yes to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, on a monthly basis, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Such monetary policy actions include raising the target federal funds rate and allowing maturing bonds to roll off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below in Figure CCW-3.

FIGURE CCW-3

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	14	March 2020	0.00	→	0.25
2	December 2016	0.50	→	0.75	15	March 2022	0.25	→	0.50
3	March 2017	0.75	→	1.00	16	May 2022	0.75	→	1.00
4	June 2017	1.00	→	1.25	17	June 2022	1.50	→	1.75
5	December 2017	1.25	→	1.50	18	July 2022	2.25	→	2.50
6	March 2018	1.50	→	1.75	19	September 2022	3.00	→	3.25
7	June 2018	1.75	→	2.00	20	November 2022	3.75	→	4.00
8	September 2018	2.00	→	2.25	21	December 2022	4.25	→	4.50
9	December 2018	2.25	→	2.50	22	February 2023	4.50	→	4.75
10	August 2019	2.00	→	2.25	23	March 2023	4.75	→	5.00
11	September 2019	1.75	→	2.00	24	May 2023	5.00	→	5.25
12	October 2019	1.50	→	1.75	25	July 2023	5.25	→	5.50
13	March 2020	1.00	→	1.25					

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure CCW-3 above, the rise in the Federal Funds Rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.

Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?

A Yes. In its recent press release, the FOMC stated the following:

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> Recent indicators suggest that economic activity has continued to expand at a solid pace. Job gains have remained strong, and the unemployment rate has remained low. Inflation has eased over the past year but remains elevated. In recent months, there has been a lack of further progress toward the Committee's 2 percent inflation objective.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals have moved toward better balance over the past year. The economic outlook is uncertain, and the Committee remains highly attentive to inflation risks.
>
> In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Beginning in June, the Committee will slow the pace of decline of its securities holdings by reducing the monthly redemption cap on Treasury securities from $60 billion to $25 billion. The Committee will maintain the monthly redemption cap on agency debt and agency mortgage-backed securities at $35 billion and will reinvest any principal payments in excess of this cap into Treasury securities. The Committee is strongly committed to returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[2]

The above quotes suggest the FOMC has had some success in taming inflation over the last year, though not as much in recent months. It further reiterated its commitment to stabilizing consumer prices and promoting maximum employment through its monetary policy tools.

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[2]Found here: https://www.federalreserve.gov/newsevents/pressreleases/monetary20240501a.htm, May 1, 2024.

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Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?

A Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards. For example, independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of long-term interest rates as measured by the 30-year Treasury bond. Inflation, as measured through the Gross Domestic Product (GDP) price index, is expected to cool off in the near to intermediate term.

The consensus projections for the next several quarters are provided in Table CCW-4 below.

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TABLE CCW-4

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025	3Q 2025
Federal Funds Rate												
Jan-23	3.6	4.7	5.0	4.9	4.7	4.4	4.0					
Feb-23	3.7	4.7	5.0	4.9	4.7	4.3	4.0					
Mar-23	**3.7**	4.7	5.1	5.1	5.0	4.7	4.2					
Apr-23		4.5	5.0	5.1	4.9	4.6	4.2	3.8				
May-23		4.5	5.0	5.1	5.0	4.7	4.2	3.8				
Jun-23		**4.5**	5.0	5.1	5.0	4.6	4.2	3.9				
Jul-23			5.0	5.3	5.2	5.0	4.6	4.3	3.9			
Aug-23			5.0	5.4	5.4	5.2	4.9	4.4	4.0			
Sep-23			**5.0**	5.3	5.4	5.3	5.0	4.6	4.2			
Oct-23				5.3	5.4	5.4	5.1	4.7	4.3	4.0		
Nov-23				5.3	5.4	5.4	5.2	4.9	4.5	4.1		
Dec-23				**5.3**	5.4	5.4	5.2	4.9	4.6	4.2		
Jan-24					5.3	5.3	5.1	4.8	4.4	4.1	3.8	
Feb-24					5.3	5.3	5.1	4.7	4.4	4.1	3.8	
Mar-24					**5.3**	5.4	5.2	4.9	4.5	4.2	3.8	
Apr-24						5.3	5.2	5.0	4.6	4.2	3.9	3.7
May-24						5.3	5.4	5.2	4.9	4.6	4.3	4.0
T-Bond, 30 yr.												
Jan-23	3.9	4.0	4.0	3.9	3.9	3.8	3.8					
Feb-23	3.9	3.8	3.9	3.9	3.8	3.8	3.7					
Mar-23	**3.9**	3.9	4.0	3.9	3.9	3.8	3.8					
Apr-23		3.8	3.9	3.8	3.8	3.8	3.8	3.7				
May-23		3.7	3.8	3.8	3.8	3.8	3.7	3.7				
Jun-23		**3.7**	3.8	3.8	3.8	3.8	3.8	3.7				
Jul-23			3.8	3.9	3.9	3.9	3.8	3.8	3.8			
Aug-23			3.8	4.0	3.9	4.0	3.9	3.9	3.8			
Sep-23			**3.8**	4.1	4.2	4.1	4.0	4.0	3.9			
Oct-23				4.2	4.4	4.3	4.2	4.2	4.1	4.0		
Nov-23				4.2	4.8	4.7	4.5	4.5	4.3	4.2		
Dec-23				**4.2**	4.8	4.7	4.5	4.5	4.4	4.3		
Jan-24					4.6	4.3	4.3	4.2	4.1	4.0	4.0	
Feb-24					4.6	4.3	4.2	4.2	4.1	4.0	4.0	
Mar-24					**4.6**	4.4	4.3	4.2	4.2	4.1	4.1	
Apr-24						4.3	4.3	4.2	4.2	4.1	4.1	4.0
May-24						4.3	4.6	4.5	4.4	4.3	4.2	4.2
GDP Price Index												
Jan-23	4.3	3.6	3.0	2.7	2.5	2.3	2.2					
Feb-23	3.5	3.3	3.0	2.7	2.6	2.4	2.3					
Mar-23	**3.9**	3.2	2.8	2.6	2.5	2.5	2.3					
Apr-23		3.2	3.2	2.9	2.7	2.5	2.3	2.2				
May-23		4.0	3.2	2.9	2.7	2.5	2.3	2.2				
Jun-23		**4.2**	3.3	2.8	2.7	2.5	2.5	2.2				
Jul-23			3.3	2.9	2.8	2.5	2.4	2.2	2.2			
Aug-23			2.2	2.7	2.6	2.5	2.3	2.3	2.3			
Sep-23			**2.0**	2.7	2.6	2.4	2.3	2.2	2.2			
Oct-23				2.7	2.7	2.4	2.2	2.2	2.2	2.2		
Nov-23				3.5	2.7	2.4	2.3	2.2	2.2	2.3		
Dec-23				**3.6**	2.7	2.4	2.3	2.2	2.2	2.2		
Jan-24					2.7	2.3	2.3	2.3	2.2	2.2	2.1	
Feb-24					1.5	2.2	2.2	2.3	2.2	2.2	2.1	
Mar-24					**1.6**	2.2	2.3	2.2	2.2	2.1	2.1	
Apr-24						2.2	2.4	2.3	2.2	2.2	2.1	2.2
May-24						3.1	2.7	2.4	2.3	2.3	2.2	2.2

Source and Note:
Blue Chip Financial Forecasts, Jan 2022 through May 2024.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to long term is also impacted by the current Fed actions and the expectation that eventually the Fed's monetary actions will return to more-normal levels. Long-term interest rate projections are illustrated in Table CCW-5 below.

TABLE CCW-5

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	Near-Term Projected*	5- to 10-Year Projected
2019			
Q1	3.01%	3.50%	
Q2	2.78%	3.17%	3.6% - 3.8%
Q3	2.30%	2.70%	
Q4	2.30%	2.50%	3.2% - 3.7%
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
2022			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
2023			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%
Q3	4.24%	3.83%	
Q4	4.58%	4.17%	4.1% - 4.2%

Source and Note:
Blue Chip Financial Forecasts, January 2019 through March 2024.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-5 above, the outlook for increases in interest rates has jumped more recently relative to 2020 and part of 2021, but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. Indeed, relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. While there is potential for some upward movement in the cost of capital, that upward movement is uncertain. In fact, as shown on Figure CCW-3 above, increases in the federal funds rate do not necessarily translate into increases in longer-term yields.

<u>II.C. Market Sentiments and Utility Industry Outlook</u>

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as discussed below.

In 2024, S&P updated its industry outlook to "Negative," stating the following:

> **Key Takeaways**
>
> - We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
>
> - Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
>
> - The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
>
> - Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.

> - We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.[3]

Specifically, in S&P's utility report, it notes that the credit quality of the industry has changed to BBB+ from an A- rating over the last few years. It notes the recently increased interest rates, which are expected to stabilize and ease the pressure on utilities financial performance. S&P also comments on the narrowing spread between utilities authorized returns and the 10-year Treasury yield, which hinders the financial performance of the industry. The credit rating agency expects continued robust capital spending for utilities, projecting over $200 billion investment in 2025. S&P believes that the risks around the industry outlook include regulatory risks in responding to capital spending and the practice of many companies operating with minimal financial cushion from their downgrade thresholds.[4]

Q HAVE CREDIT AGENCIES NOTED CONCERN ABOUT RATE AFFORDABILITY AS A CREDIT RISK TO UTILITIES?

A Yes. Credit rating agencies have been emphasizing rate affordability, maintaining adequate financial coverages of debt obligations, and supporting utilities' overall investment grade bond ratings.

In a recent industry report, Moody's explained that the regulated electric and gas utilities' outlook remains "Negative" largely due to increased pricing pressures on customers. Moody's stated that it changed its outlook from "Positive" to "Negative" due to the following:

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[3] *S&P Global Ratings*: "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024 at 1.

[4] *Id*.

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> We have revised our outlook on the US regulated utilities sector to negative from stable. We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.[5]

Also, in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns.[6]

Finally, Fitch opined that the regulated electric and gas utilities' outlook is deteriorating due to elevated capex that put pressure on credit metrics. Fitch also notes the bill affordability concerns for ratepayers, and regulators' ability to balance the rate requests with increasing customer bills.

Specifically, Fitch states:

> Fitch Ratings' deteriorating outlook for the North American Utilities, Power & Gas sector reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment. Bill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures. Fitch expects utility capex to grow by double digits in 2024, underpinned by investments needed to make the electric infrastructure more resilient against extreme weather events and to accommodate renewable generation, including distributed sources. Rate case outcomes are key to watch as regulators balance more rate requests with increases in customer bills. Authorized ROEs could prove to be sticky despite an increase in cost of capital. Higher weather-normalized retail electricity sales, driven by datacenter growth and onshoring of manufacturing activities, and tax transferability provisions of the Inflation Reduction Act could somewhat offset headwinds to utilities. Ongoing management actions to sell assets and issue equity, in some cases, is supportive of parent companies' ratings. Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks. We expect limited rating movement in 2024. The number

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[5]*Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at 1. (emphasis added).

[6]*S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024, at 8.

> of upgrades in 2023 so far exceeds the number of downgrades, and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.[7]

As outlined by Moody's, S&P and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, 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.

III.D. Additional Remarks

Q IN LIGHT OF HIGHER LEVELS OF INFLATION, EXPECTATIONS OF HIGHER INTEREST RATES, AND GEOPOLITICAL EVENTS AROUND THE WORLD, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?

A In 2023, the utility sector underperformed the S&P 500 and has continued to do so in 2024. This is presented below in Figure CCW-4. However, it should be noted that the performance of the S&P 500 has largely been driven by a handful of "mega cap" companies. Because the S&P 500 is a market capitalization weighted index (meaning the higher the market capitalization a company has, the more influence it has on the index's performance). For example, in the S&P Dow Jones Indices report "U.S. Equity Market Attributes April 2024," it is noted that:

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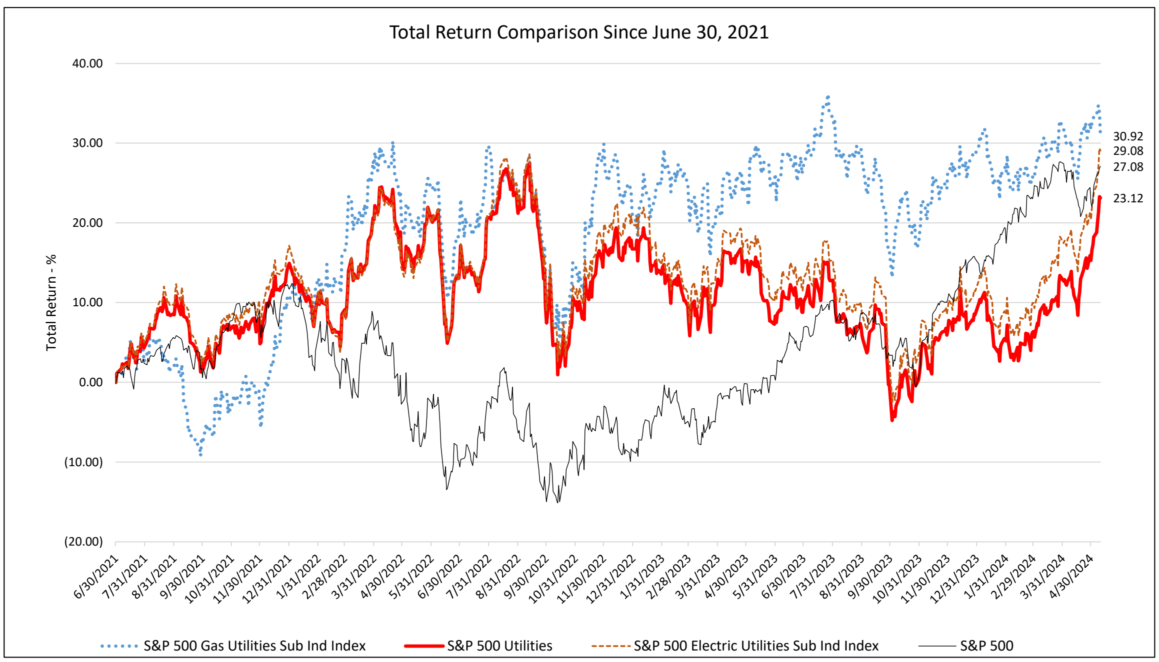
[7] *FitchRatings.* "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1. (emphasis added)

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[8]

Notwithstanding its recent underperformance relative to the S&P 500, the industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

Figure CCW-4



[8]https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202404.pdf

III. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[9] and 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

[9]*Bluefield,* 262 U.S. at 692-93.

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> credit and enable it to raise the money necessary for the proper discharge of its public duties.[10]

As such, a fair rate of return is based on the expectation that the utility 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. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE TAMPA ELECTRIC'S COST OF COMMON EQUITY.

A First, I assessed the market's assessment of Tampa Electric's risk. Then, I developed a proxy group of publicly-traded utility companies that have similar risks and characteristics to Tampa Electric and compared potential differences in risks. I then performed several models based on financial theory to estimate Tampa Electric's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM").

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[10] *Id*. at 693 (emphasis added).

III.A. Tampa Electric's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF TAMPA ELECTRIC'S INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. The current credit ratings for Tampa Electric are BBB+ and A3, from S&P and Moody's respectively.[11] The Company currently has a "negative" outlook from S&P and a "stable" outlook from Moody's. In its August 2023 report covering Tampa Electric, S&P stated as follows:

> *We expect Tampa Electric Co. (TEC) to maintain its financial performance through our two-year outlook period.* Our base-case scenario assumes the implementation of the utility's most recent rate-case proposals, annual capital spending averaging about $1.2 billion, and dividend payments averaging about $530 million over the forecast period. TEC continues to have large capital expenditures--nearly triple its depreciation expense. This will likely strain financial measures for a least the next year or so during the construction of renewable energy transition projects. Overall, we forecast that TEC will maintain funds from operations (FFO) to debt of about 20%-22% through the 2023-2025 outlook period.
>
> **Business Risk**
> Our assessment of TEC's business risk reflects its lower-risk, rate-regulated, and vertically integrated electric and gas utility operations, as well as its management of regulatory risk, which we view as consistent with that of its peers. TEC is regulated by the FPSC, which, in our view, has been constructive for credit quality. The FPSC tariff framework uses various cost-recovery riders to allow timely recovery of capital investments. In addition, the FPSC established equity returns that tend to exceed industry averages, and the commission uses forecast test years and frequently authorizes interim rate increases. Furthermore, TEC will likely continue to benefit from above-average economic growth in Florida. TEC's business risk is offset by the lack of regulatory or geographical diversity because it operates only in Florida. Additionally, TEC's generation capacity relies heavily on fossil-based energy, with about 86% and 7% from gas and coal-fired generation respectively, as of 2022. As a result, we view TEC's business risk profile at the lower end of the category compared to other utility peers

[11] S&P Capital IQ, accessed on May 10, 2024.

> **Financial Risk**
> We assess TEC's financial risk profile using our medial volatility financial benchmark tables rather than the financial benchmarks we use for a typical corporate issuer, which reflects its lower-risk regulated utility operations and effective management of regulatory risk. TEC has a very large capital program, about triple that of depreciation expense, that will likely result in negative discretionary cash flow, indicative of the company's external funding needs. TEC has recently received approval for increases in base rates of about $191 million, $90 million, and $21 million, for 2022, 2023, and 2024, respectively. The outcome of the rate case was helpful for TEC to maintain its financial measures. Furthermore, our analysis of TEC's financial measures also incorporates recent regulatory outcomes.[12]

The "negative" outlook is clearly being driven by the outlook of Tampa Electric's ultimate parent company, Emera Inc., rather than by cash flow or other credit concerns at Tampa Electric. In fact, Tampa Electric's Stand-Alone-Credit-Profile ("SACP") rating from S&P, the rating that would otherwise be assigned to Tampa Electric if not for its affiliation with Emera Inc., is 'a' compared to its published rating of BBB+. In other words, Tampa Electric's credit rating is being hindered by two notches directly as a result of its affiliation with Emera Inc.

<u>III.B. Tampa Electric's Proposed Capital Structure</u>

Q WHAT IS TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE?

A Tampa Electric's proposed capital structure is summarized in Table CCW-6 below:

[12] S&P Global Ratings, RatingsDirect, Oklahoma Gas & Electric Co, July 21, 2023.

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Table CCW-6

Investor-Supplied Capital Structure

Description	Weight
Debt	46.00%
Common Equity	54.00%
Total	100.00%

Q DO YOU HAVE ANY COMMENTS ON TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE?

A Yes. As I will discuss later, Tampa Electric's proposed equity ratio of 54.0% (including short-term debt) significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for Tampa Electric. As shown on Exhibit CCW-2, the proxy group has an average common equity ratio of 40.5% (including short-term debt) and 43.8% (excluding short-term debt).

Q ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?

A Yes. In a recent Order, the Arkansas Public Service Commission imputed the capital structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line with the comparable companies used to estimate the cost of equity.[13] The adjustment was to recognize that there must be *congruence* between the cost of equity and the capital structure. Specifically, the Order states as follows:

[13]APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the Commission holds that there should be congruence between the estimated cost of equity and the [debt-to-equity "Tampa Electric")] ratio, whereby a lower Tampa Electric ratio decreases financial risk and decreases the cost of equity. The evidence of record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[14]

As I described above, the proxy group has an average common equity ratio of 40.5% (including short-term debt) and 43.8% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. The Company's proposed equity ratio of 54.00% (including short-term debt) exceeds that of the proxy group's comparable equity ratio of 40.5%.

Q ARE YOU RECOMMENDING AN ADJUSTMENT BE MADE TO TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE?

A Yes. The Company has not reasonably demonstrated a need to be awarded a common equity ratio well in excess of 52.0%. A common equity ratio of 52.0% is consistent with what is being awarded around the country to other electric utilities. As such, I recommend this Commission authorize Tampa Electric an equity ratio of 52.0%.

[14] *Id*. at 25.

III.C. Development of Proxy Group

Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.

A There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other firms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Company's proposal under this standard.

Even if Tampa Electric were a publicly-traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases which would make the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by mitigating the potential for bias that may be introduced by measurement errors of model inputs.

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE TAMPA ELECTRIC'S CURRENT MARKET COST OF EQUITY.

A I relied on the same proxy group developed by Tampa Electric's witness, Mr. D'Ascendis.

Q HOW DOES THE INVESTMENT RISK OF TAMPA ELECTRIC COMPARE TO THAT OF THE PROXY GROUP?

A As shown on my Exhibit CCW-2, the proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. The proxy group's average rating of BBB+ from S&P is identical Tampa Electric's rating of BBB+ from S&P. However, as I discussed earlier, Tampa Electric's SACP is 'a', meaning its credit rating is being hindered by two notches directly as a result of its affiliation with Emera Inc. Compared to its SACP rating of 'a', the proxy group's average rating of BBB+ from S&P is two notches lower than Tampa Electric's SACP. The proxy group's average rating of Baa2 from Moody's is two notches lower than Tampa Electric's rating of A3.

As shown on the same exhibit, the proxy group has an average common equity ratio of 40.5% (including short-term debt) and 43.8% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. Tampa Electric's requested common equity ratio of 54.00% (including short-term debt) significantly exceeds the proxy group's equity ratio as described above.

Based on the two-notch difference in credit ratings, as well as the significant difference in equity ratios, the Company's cost of equity capital is most likely to be below the midpoint of the cost of equity range indicated for by the proxy group results. I will take these data into consideration in determining a fair and reasonable ROE for the Company.

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III.D. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A 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. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; . \; . \; . \; . \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

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Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on May 10, 2024. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[15] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate, will be, and not what an individual investor or analyst may use to make individual investment decisions.

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[15] *The Value Line Investment Survey*.

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As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[16] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Yahoo! Finance. All such projections were available on May 10, 2024, and all were reported online.[17]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. 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, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

[16] *See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

[17] www.zacks.com; https://finance.yahoo.com; and https://www.capitaliq.spglobal.com/.

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The growth rates I used in my DCF analysis are shown in Exhibit CCW-3. The average growth rate for my proxy group is 6.33% and a median growth rate of 6.20%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit CCW-4, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 10.98% and 10.50%, respectively.

Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.33%. The three- to five-year growth rates are approximately 50% higher than the long-term projected GDP growth rate of 4.14%, described below. As I explain in detail below, 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 DCF model.

Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy as a whole. *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%.[18] As such, the average nominal growth rate over the next 10 years is around 4.14%, which I believe is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment-practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Using the long-term GDP growth rate as a conservative projection for the maximum growth rate is logical, and is generally consistent with academic and economic-practitioner accepted practices.

III.E. Sustainable Growth DCF

Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A 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.

The internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as the company funds more investments using retained earnings.

[18]Blue Chip Economic Indicators, March 11, 2024 at page 14.

The payout ratios of the proxy group are shown in my Exhibit CCW-5. These dividend-payout ratios and earnings-retention ratios then can be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit CCW-6, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 4.80% and 4.76%, respectively.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit CCW-7. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 9.37% and 9.28%, respectively.

<u>III.F. Multi-Stage Growth DCF Model</u>

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I created is based on analyst growth-rate projections, providing a plausible representation of rational investment expectations over the next three-to-five years. The limitation of this constant growth DCF model is that it cannot

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reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns more with long-term sustainable growth. To accommodate changing growth expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A The growth rate projections by analysts for the next three-to-five years are subject to change as the outlook for utility earnings-growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings growth rate declines from an abnormally high three-to-five-year rate, to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth, as the utility has limited human and capital resources to expand its construction activities. Therefore, the three-to-five-year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three-to-five-year growth outlook is feasible and sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.

A The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1)

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a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[19]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[20]

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[19]*Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (emphasis added).

[20]Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.

Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?

A I relied on the consensus of long-term GDP growth projections as projected by independent economists. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.14% over the next 10 years.[21]

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Several projections are shown in Table CCW-7 below.

[21]Blue Chip Economic Indicators, March 11, 2024 at page 14.

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TABLE CCW-7

GDP Forecasts

Source	Projected Period	Real GDP	Inflation	Nominal GDP
Blue Chip Economic Indicators [1]	5-10 Yrs	1.9%	2.2%	4.1%
EIA - Annual Energy Outlook[2]	27 Yrs	1.9%	2.3%	4.3%
Congressional Budget Office[3]	30 Yrs	1.7%	2.0%	3.8%
Moody's Analytics[4]	31 Yrs	1.9%	2.1%	4.1%
Social Security Administration[5]	77 Yrs	1.6%	2.4%	4.1%
Economist Intelligence Unit[6]	31 Yrs	1.7%	2.2%	4.0%

Sources:
[1]Blue Chip Economic Indicators, March 11, 2024 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2023, September, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, June 28, 2023.
[4]Moody's Analytics Forecast, last updated March 11, 2024.
[5]Social Security Administration, "2023 OASDI Trustees Report," Table VI.G6. March 31, 2023.
[6]S&P MI, Economist Intelligence Unit, downloaded on April 26, 2024.

As shown in the table above, the real GDP and the inflation fall in the range of 1.6% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.8% to 4.3%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.14% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A As shown in Exhibit CCW-8, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 9.35% and 9.31%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-8 below. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.33%, which is approximately 50% higher than the long-term projected GDP growth rate of 4.14%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low-risk regulated utility. As such, it is my opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF.

Table CCW-8

Summary of DCF Results

Description	Proxy Group Mean	Proxy Group 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%

III.G. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit CCW-9, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit CCW-10, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.63%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit

CCW-10, the five-year rolling average risk premium over Treasury bonds ranged from 4.17% to 7.17%, while the ten-year rolling average risk premium ranged from 4.30% to 6.92%.

As shown on my Exhibit CCW-11, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.27%. The five-year and ten-year rolling average risk premiums ranged from 2.80% to 5.97% and 3.11% to 5.75%, respectively.

Q WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit

CCW-12, where I show the yield-spread between utility bonds and Treasury bonds since 1980. As shown in this schedule, the average utility bond yield-spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.90%, respectively.

A current 13-week average "A" rated utility bond yield of 5.66% when compared to the current Treasury bond yield of 4.50%, as shown in Exhibit CCW-13, page 1, implies a yield-spread of 1.16%. This current utility bond yield-spread is lower than the long-term average-spread for "A" rated utility bonds of 1.48%. The 13-week average yield on "Baa" rated utility bonds is 5.89%. This indicates a current spread for the "Baa" rated utility bond yield of 1.39%, which is lower than the long-term average of 1.90%.

Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?

A I give primary consideration to the Risk Premium results using Treasury bonds and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.63% is appropriate. Adding this risk premium to the projected Treasury yield of 4.20% produces an ROE of 9.63%.

Applying a similar methodology as described above, the average of the rolling five-year average risk premiums over A-rated utility bonds is 4.27%. The

A-rated utility bond yield has averaged 5.66% over the 13-week period ending May 10, 2024 while the Baa-rated utility bond yield has averaged 5.89% over the same period. Adding this risk premium to the 13-week A-rated utility bond yield of 5.66% produces an estimated cost of equity of 9.93%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.89% produces an estimated cost of equity of 10.16%.

The A-rated utility bond yield has averaged 5.60% over the 26-week period ending May 10, 2024 while the Baa-rated utility bond yield has averaged 5.84% over the same period. Adding the equity risk premium of 4.27% to the 26-week A-rated utility bond yield of 5.60% produces an estimated cost of equity of 9.87%. Adding the equity risk premium of 4.27% to the 26-week Baa-rated utility bond yield of 5.84% produces an estimated cost of equity of 10.11%.

The results of my risk premium analyses are summarized in Table CCW-9.

Table CCW-9

Summary of Risk Premium Results

Description	
Projected Treasury Yield	9.63%
13-Week Yields	
A-Rated Utility Bond	9.93%
Baa-Rated Utility Bond	10.16%
26-Week Yields	
A-Rated Utility Bond	9.87%
Baa-Rated Utility Bond	10.11%

III.H. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis 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. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

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Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.20%.[22] The current 30-year Treasury bond yield is 4.50%, as shown in Exhibit CCW-13 at page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.20% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to future inflation and liquidity. In this regard, a Treasury bond yield is not entirely risk-free. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for a company with a beta less than 1.0,

[22]Blue Chip Financial Forecast May 1, 2024.

using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit CCW-14, the current proxy group average and median *Value Line* beta estimates are 0.92 and 0.93, respectively. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.76 and has ranged from 0.54 to 0.90. Prior to the recent pandemic, the high end of this range was 0.73.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending May 10, 2024. The average and median Market Intelligence betas are 0.85 and 0.84, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta =

> 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[23]

Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment.[24] While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, the criticisms of the betas offered by S&P apply to both Bloomberg betas and *Value Line* betas.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATES?

A My market risk premium estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized market risk premium of 5.50% with the normalized risk-free rate of 4.61% as recommended by Kroll, formerly known as Duff & Phelps.[25] Based on this methodology and utilizing a "normalized" risk-free rate of 4.61%, Kroll concludes

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[23]S&P Market Intelligence, Beta Generator Model.

[24]The Blume adjustment is a tool used to refine a beta measurement in finance. In general, Beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

[25]Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 10.11%.[26]

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.

A The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Kroll *SBBI Yearbook* is no longer being published. As such, estimates of the historical, arithmetic-average, real-market return over the period 1926 to 2023 were calculated using data from Morningstar Direct. The arithmetic-average real return on the market since 1926 is 9.02%.[27] A current consensus for projected inflation, as measured by the Consumer Price Index ("CPI"), is 2.40%.[28] Using these estimates, the expected market return is 11.64%.[29] The market risk premium then is the difference between the 11.64% expected market return and the projected risk-free rate of 4.20%, or 7.44%.

[26]Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022. The current 20-year yield of 4.61% exceeds the "normalized" yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.61%.

[27]Morningstar Direct.

[28]Blue Chip Financial Forecast May 1, 2024.

[29]$[(1 + 9.02\%) * (1 + 2.40\%) - 1] * 100$.

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATES DERIVED USING THE DCF METHODOLOGY.

A I employed two versions of the constant growth DCF model to develop estimates of the market risk premium. I first employed the Federal Energy Regulatory Commission's ("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. 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 growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[30] The weighted average growth rate for the remaining companies is 11.50%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.90%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.70%. The market risk premium then is the expected market return of 12.70%, less the projected risk-free rate of 4.20%, or 8.50%.

My second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend-paying companies. The weighted average growth rate for these companies is 11.00%. After reflecting the FERC-prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.69%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.69%. The market risk

[30] Opinion No. 569-A, at 210.

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premium then is the expected market return of 12.69% less the projected risk-free rate of 4.20%, or 8.50%.

The average expected market return based on the DCF model is 12.70% and the average market risk premium based on the two DCF estimates is 8.50%.

Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?

A As shown in Table CCW-10, my average expected market return of 11.48%[31] exceeds long-term market expectations of several financial institutions.

TABLE CCW-10

Long-Term Expected Return on the Market

Source	Term	Expected Return Large Cap Equities
BlackRock Capital Management[1]	30 Years	7.00%
JP Morgan Chase[2]	10 - 15 Years	7.00%
Vanguard[3]	10 Years	4.2% - 6.2%
Research Affiliates[4]	10 Years	4.00%

Sources:
[1]BlackRock Investment Institute, November 2023 report.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2024 Report.
[3]Vanguard economic and market outlook for 2024: A Return to Sound Money.
[4]Research Affiliates, Asset Allocation Interactive. Retrieved 1/05/2024.

[31]11.48% = (10.11% + 12.70% + 11.64%) / 3.

When compared to the expected market returns of financial institutions above, my average expected market return of 11.48% is greater than all of them. For these reasons, my expected market returns, and the associated market risk premiums, should be considered reasonable, if not high-end estimates.

Q HOW DO YOUR ESTIMATED MARKET RISK PREMIUMS COMPARE TO THAT ESTIMATED BY KROLL?

A The Kroll analysis indicates a market risk premium falls somewhere in the range of 5.50% to 7.17% utilizing data through 2023. My market risk premium estimates are in the range of 5.50% to 8.50%.

Q HOW DOES KROLL MEASURE A MARKET RISK PREMIUM?

A Kroll's range is based on several methodologies. First, Kroll estimated a market risk premium of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2023 period.[32]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.22%.[33] Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

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[32]Kroll, *Cost of Capital Navigator*.
[33]*Id*.

Finally, Kroll developed its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.61%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 10.11%.[34]

Q DO YOU HAVE ANY COMMENTS ON THE EXPECTED MARKET RETURNS AND MARKET RISK PREMIUMS DESCRIBED ABOVE?

A Yes. As described above, the average expected market return based on the DCF model is 12.70% and the average market risk premium is 8.50%. The expected market return of 12.70% is based on a constant perpetual growth rate of 11.00%. This is simply unsustainable for the same reasons described in greater detail above.

It simply is not reasonable to believe individual companies can sustain growth rate of 11.00% into perpetuity. In fact, in the CFA curriculum textbooks, the CFA Institute notes as follows with regard to earnings growth rates for companies within the composite indices (i.e., S&P 500):

> Earnings growth for the overall national economy can differ from the growth of earnings per share in a country's equity market composites. This is due to the presence of new businesses that are not yet included in the equity indices and are typically growing at a faster rate than the mature companies that make up the composites. **Thus, the earnings growth rate of**

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[34] *Id.*

> **companies making up the composites should be lower than the earnings growth rate for the overall economy.**[35]

In addition, a market risk premium in excess of 8.0% is significantly outside the range supported by empirical evidence. For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the market risk premium have concluded that a market risk premium in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[36] The Duarte and Rosa study he cites concludes that the historical mean is "quite difficult to improve upon when considering out-of-sample performance measures."[37] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the market risk premium, and 60% of financial advisors used a market risk premium in the range of 7.0% to 7.4% (similar to a long-term arithmetic average market risk premium).[38]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit CCW-15, I have provided the results of nine different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.92. The results of the CAPM based on these inputs range from 9.68% to 12.03%.

[35]CFA Program Curriculum, 2014 Level II Vol. 1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, page 609, footnote 5 (emphasis added).

[36]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 pages 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

[37]See *Modern Regulatory Finance*¸ Dr. Roger A. Morin, at page 191, citing the Duarte and Rosa study.

[38]See *Modern Regulatory Finance*¸ Dr. Roger Morin, at page 190, footnote 35.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.76. The results of the CAPM based on these inputs range from 8.80% to 10.66%.

The last set of three results presented are based on the proxy group's current S&P Global Market Intelligence beta of 0.85. The results of the CAPM based on these inputs range from 9.29% to 11.43%. My CAPM results are summarized in Table CCW-11.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time. As such, I am giving less consideration to the results of my CAPM analyses that rely on current *Value Line* betas. Finally, for the reasons detailed above, I believe it is also reasonable to give less consideration to the CAPM results that rely on market risk premium estimates of 8.50%.

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%

III.I. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANY?

A The results of my analyses are summarized in Figure CCW-5. In this figure, I present the various measures of central tendency for each of my analytical models.

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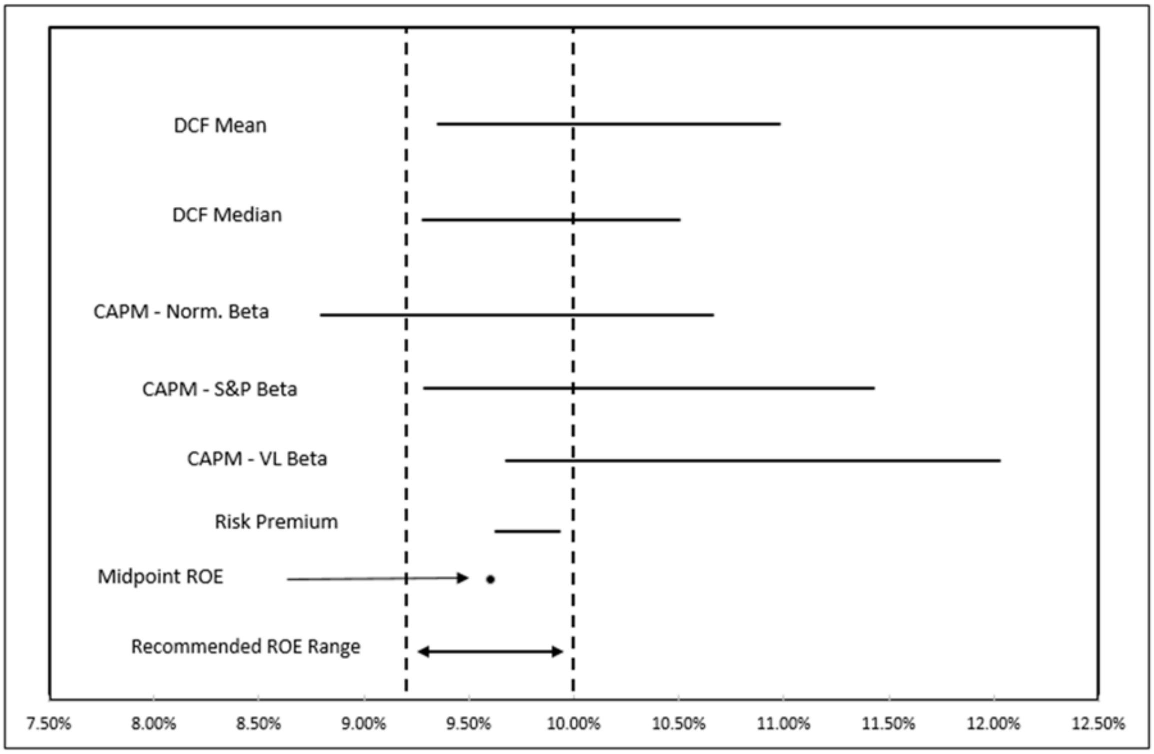
FIGURE CCW-5



Based on my analyses of the various methodologies described above, I estimate the Company's current market cost of equity to be in the reasonable range of 9.20% to 10.00%. My recommended range takes into consideration the unsustainable growth rates assumed in the constant growth DCF model, the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations, and the unsustainable growth rates assumed in the DCF-derived expected market return for the CAPM. Based on my assessment of Tampa Electric's overall risk profile and the results of these analytical methods, I would recommend that this Commission authorize Tampa Electric an ROE of 9.60%, which is the midpoint of my recommended range. Should the Commission authorize an equity ratio greater than my recommended level of 52.0%, an ROE in the lower half of my range would be warranted, particularly in light of the two-notch

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ratings differences Tampa Electric enjoys over that of the typical company in my proxy group.

IV. RESPONSE TO MR. D'ASCENDIS

IV.A. Summary of Rebuttal

Q WHAT RETURN ON COMMON EQUITY IS TAMPA ELECTRIC PROPOSING FOR THIS PROCEEDING?

A Mr. D'Ascendis estimates a market ROE in the range of 9.89% to 12.48% based on the results of various financial models applied to a utility proxy group, as well as the results of market models applied to a non-price regulated proxy group. He then increases his range by 0.01% after accounting for Tampa Electric's relative risk compared to the proxy group and flotation costs. He estimates a downward adjustment of approximately 0.08% to account for the difference in credit ratings for Tampa Electric relative to the proxy group and an upward adjustment for flotation costs of approximately 0.10%. As such, Mr. D'Ascendis' adjusted range is 9.90% to 12.49%. Mr. D'Ascendis recommends an ROE of 11.50%, which is in the upper-end of his adjusted range also considers the Company's small service area, weather risk, high customer growth, and its substantial capital expenditure program.[39]

Q IS MR. D'ASCENDIS' ESTIMATED ROE REASONABLE?

A No. Mr. D'Ascendis' unadjusted estimated market return in the range of 9.90% to 12.49% is significantly overstated. In addition, his conclusion to award an ROE in the upper-half of his range based on the Company's small service area, weather

[39] D'Ascendis Direct Testimony 90-91.

risk, high customer growth, and its substantial capital expenditure program is unwarranted and should be rejected.

Q PLEASE DESCRIBE MR. D'ASCENDIS' METHODOLOGIES USED TO SUPPORT HIS ESTIMATE OF THE MARKET COST OF COMMON EQUITY.

A Mr. D'Ascendis estimates a ROE for Tampa Electric based on the DCF model, a bond yield plus risk premium model, as well as the traditional and empirical forms of the CAPM. Mr. D'Ascendis applies these models to both a utility proxy group and a non-price regulated proxy group. The low-end (9.90%) of his range is based on his proxy group's DCF results and the high-end (12.49%) is based on the results of his CAPM. His recommended ROE of 11.50% is in the upper-half of this range.

Q PLEASE SUMMARIZE MR. D'ASCENDIS' RESULTS.

A Mr. D'Ascendis' results are summarized in Table CCW-12 below.

TABLE CCW-12

Summary of Mr. D'Ascendis'
Return on Equity Estimates

Model	**Proxy Group Estimate (1)**	**Estimate excl. PRPM (2)**
DCF	9.89%	9.89%
RP	11.47%	11.46%
CAPM	12.48%	12.41%
Non-Price Regulated Companies	12.95%	12.89%
Indicated Return on Equity	9.89%-12.48%	
Business Risk Adjustment	-0.083%	
Flotation Cost Adjustment	0.097%	
Total Adders	0.01%	
Return on Equity Range	9.90%-12.49%	
Recommended Return on Equity	11.50%	

For the reasons outlined below, several flaws and assumptions used by Mr. D'Ascendis' have led to a significant overstatement in the Company's cost of equity and demonstrate that my recommended ROE of 9.60% is within the range of reasonable outcomes.

IV.B. An ROE in the Upper-Half of the Range is Unsupported

Q PLEASE DESCRIBE MR. D'ASCENDIS' REASONING TO AWARD THE COMPANY AN ROE IN THE UPPER HALF OF HIS RANGE.

A Mr. D'Ascendis proposes an ROE in the upper-half of his recommended range after consideration of the Company's small service area, weather risk, high customer growth, and its substantial capital expenditure program.

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Q DO YOU BELIEVE AN ROE IN THE UPPER-HALF OF HIS RANGE IS WARRANTED GIVEN THOSE CONSIDERATIONS?

A No, I do not.

Q AS AN INITIAL MATTER, DO YOU BELIEVE THAT RATINGS AGENCIES CONSIDER A UTILITY'S GEOGRAPHIC SERVICE AREA, WEATHER RISK, CUSTOMER GROWTH, AND CAPITAL EXPENDITURES PROGRAM IN ASSESSING A COMPANY'S CREDIT RATINGS?

A Yes, they do. As shown below in Table CCW-13, S&P has identified multiple strengths and weaknesses of the Company that have been identified in S&P's most recent report, several of which are considerations that Mr. D'Ascendis has provided as his support for an ROE in the upper-half of his range.

Table CCW-13

Key strengths	Key risks
Tampa Electric Co. (TEC) is a low-risk, vertically integrated electric and gas distribution utility regulated by the Florida Public Service Commission (FPSC).	The company has limited geographic and regulatory diversity because the company only serves customers in the state of Florida.
TEC benefits from a supportive regulatory framework in Florida, which includes a cost-of-service methodology and a fuel adjustment mechanism to pass through commodity costs to customers.	TEC's high reliance on fossil fuel-based generation and higher-than-peers greenhouse gas emissions is considerable and exposes the company to potentially more stringent environmental regulations.
The company has a large residential customer base, which provides stable cash flows.	Very large capital programs over the next several years will pressure credit metrics, partially mitigated by cushion in the company's stand-alone financial measures.
Status as insulated subsidiary of Emera allows the utility to be rated higher than the group credit profile of Emera.	

In that same report, S&P also discusses the Company's exposure to hurricanes. Importantly, even after its consideration of these numerous strengths and weaknesses, S&P still awards Tampa Electric an SACP rating of 'a', which is two notches higher than the proxy group's credit rating from S&P. Even though Mr. D'Ascendis acknowledges the need to make a downward adjustment to reflect the differences in credit ratings, he more than offsets that credit risk adjustment by recommending an ROE that is 30 basis points above the midpoint. Because those risks are already accounted for in the Company's credit ratings, making an upward adjustment for such risks is completely unnecessary and should be rejected.

IV.C. D'Ascendis Proposed Flotation Cost Adjustment

Q PLEASE DESCRIBE THE FLOTATION COST ADJUSTMENT ROE ADDER PROPOSED BY MR. D'ASCENDIS.

A Mr. D'Ascendis calculates actual equity issuance costs for EU's since its acquisition of Tampa Electric in 2016 and estimates it to be 2.41% on average. He then adjusts the dividend yield within the DCF model for the proxy group and calculates an adjusted DCF result of 9.89% and compares it to his proxy group's average DCF result of 9.80%. His flotation cost adjustment of 0.09% is the difference between the two model results.

Q IS MR. D'ASCENDIS' PROPOSED FLOTATION COST ADDER FOR TAMPA ELECTRIC REASONABLE?

A As an initial matter, I am unaware of this Commission allowing for the recovery of flotation costs in the allowed ROE. Second, Mr. D'Ascendis has not shown the flotation costs have been reasonably incurred and allocated to Tampa Electric.

Should the Commission authorize recovery of flotation costs, it should be for the prudently incurred and allocated amount and recovered through its cost of service. However, Tampa Electric has not provided any evidence that flotation costs are part of its cost of service.

Mr. D'Ascendis' use of EU's common stock issuance cost justifies my reasons for rejecting the small company adder. Tampa Electric is not a stand-alone small company. Rather, it is a subsidiary of a much larger company, EU.

The importance of rejecting the small company adder is emphasized by reviewing Mr. D'Ascendis' proposed method for developing a flotation cost adder to arrive at his proposed return for Tampa Electric, it is based on EU's access to equity markets, not Tampa Electric's.

IV.D. D'Ascendis DCF

Q PLEASE DESCRIBE MR. D'ASCENDIS' DCF ANALYSIS.

A Mr. D'Ascendis performed his traditional constant growth DCF analyses on his proxy group. He relied on analysts' earnings growth rate projections from *Value Line*, Zack's, and Yahoo! Finance. The average growth rate for his proxy group is 5.27%.[40] However, Mr. D'Ascendis excludes the results of IDACORP, Inc. because he deemed the result to be too low. As such, the average growth rate his proxy group, excluding IDACORP, Inc., is 5.37%. He used an annualized dividend and a 60-day average stock price to calculate the proxy group's dividend yield. The mean and median results of his unadjusted DCF analysis are 9.71% and 9.78%, respectively. The mean and median results of his adjusted DCF analysis are both 9.89%.

Q DO YOU HAVE ANY CONCERNS WITH MR. D'ASCENDIS' DCF RETURN ESTIMATES?

A Yes, I have two concerns. First, Mr. D'Ascendis biases his proxy group's results by excluding the results of IDACORP, Inc. There is no reasonable basis to exclude its results. Rather than excluding the results for IDACORP, Inc., he should have simply relied on the median of his results as the median is a measure of central

[40]Exhibit 4.

tendency that mitigates the effect outlier results have. The median result of his DCF analysis is 9.78%. This would reduce the low-end of Mr. D'Ascendis' recommended range of 9.89% by 11 basis points.

Second, Mr. D'Ascendis' DCF model consists entirely of a Constant Growth DCF analysis based on analysts' projected growth. His proxy group's average DCF return is based on a growth rate of 5.37%, which is higher than the consensus economists' projected growth rate of 4.14% for the economy described above. In other words, Mr. D'Ascendis thinks it is reasonable for the proxy group to grow, on average, at a rate of 1.30x that of the economy in perpetuity. As explained above, it is unrealistic to expect utilities to maintain a growth rate that is well in excess of the anticipated growth in GDP. Accordingly, relying solely on a Constant Growth DCF tends to overstate the DCF result.

IV.E. D'Ascendis Risk Premium

Q PLEASE DESCRIBE MR. D'ASCENDIS' RISK PREMIUM ANALYSIS.

A Mr. D'Ascendis estimated a risk premium return of 11.47% based on the results including his Predictive Risk Premium Model ("PRPM") analysis and 11.46% excluding his PRPM analysis.[41] Mr. D'Ascendis' Risk Premium results are derived using estimates of the equity risk premium based on the adjusted total market approach (7.36%/7.32% with/without PRPM), the holding period return/projected market appreciation approach (4.80%), and regression derived equity risk premium of 4.85%. Based on the three general approaches, Mr. D'Ascendis estimates the proxy group's equity risk premium to be 5.67% including the results of his PRPM and 5.66% excluding his PRPM results. Adding his average equity

[41]Exhibit 5, page 1.

risk premiums of 5.67% and 5.66% to his estimate of the adjusted prospective proxy group bond yield (5.80%) produce Risk Premium results of 11.47% and 11.46%, respectively.

Q DO YOU HAVE ANY CONCERNS WITH MR. D'ASCENDIS' RISK PREMIUM METHODOLOGY?

A Yes, I do. Mr. D'Ascendis' average estimates of the equity risk premium under the prospective bond yield and spot yield approaches are the results of 12 individual estimates.[42] 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. For example, if we look at the 12 estimates of the equity risk premium, they would produce Risk Premium result in the range of 10.00% to 16.02%. Notably, 11 of the 12 individual equity risk premium estimates produce ROE results greater than 10.50%. When individual results are looked at in isolation, it is clear that they produce excessive results that are unreliable.

Q IN YOUR OPINION, WHAT ARE THE MOST EGREGIOUS ROE RESULTS PRODUCED BY HIS RISK PREMIUM ANALYSIS?

A Considering the floor estimate based on his Risk Premium analysis starts at 10.0% 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. However, when looking at what each of Mr. D'Ascendis' Risk Premium results would be in isolation, of the 12 individual estimates, there are five that range from 11.69% to

[42] His analysis including the PRPM is based on 12 individual estimates of the equity risk premium. His analysis excluding the PRPM is based on 10 of the same individual estimates, excluding two PRPM derived equity risk premiums.

16.02%. 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.

IV.F. D'Ascendis CAPM

Q HOW DID MR. D'ASCENDIS DERIVE HIS CAPM RETURN ESTIMATE FOR TAMPA ELECTRIC?

A Mr. D'Ascendis developed his CAPM return estimate on his Exhibit 6. As shown on that schedule, he relied on a proxy group beta of 0.81 which was the average of the mean and median beta published by Bloomberg and *Value Line* for his proxy companies, market risk premiums of 10.02% (w/ PRPM) and 9.93% (excluding PRPM), and a risk-free rate of 4.15%. These inputs produce traditional CAPM return estimates of 12.28% (w/ PRPM) and 12.21% (w/o PRPM). He relies on the same input data to perform an Empirical CAPM ("ECAPM") analysis as well. The results of his ECAPM are 12.75% (w/ PRPM) and 12.68% (w/o PRPM).

Q DO YOU HAVE ANY ISSUES WITH MR. D'ASCENDIS' CAPM STUDY?

A I disagree with several aspects of his methodology. First, his market risk premiums of 9.93% and 10.02% are excessive and unreliable due to unsustainable growth rates he used to develop an expected market return.

Second, his market risk premium estimates suffer from many of the same previously described flaws surrounding his equity risk premium estimates.

Finally, I disagree with his use of adjusted betas in the ECAPM.

Q PLEASE DESCRIBE MR. D'ASCENDIS' ESTIMATED MARKET RISK PREMIUMS, GENERALLY.

A Mr. D'Ascendis averages six market risk premium estimates to develop his recommended market risk premium of 10.02%.

His first market risk premium estimate is based on historical Ibbotson data. With this methodology, he estimates a market risk premium of 7.03%. His second market risk premium is based on a regression analysis and produced a risk premium of 8.27%. His third market risk premium is based on the application of his PRPM method using historical Ibbotson data. This method produces a market risk premium of 10.44%. His fourth market risk premium is based on a *Value Line* 3-5 year projected market return of 15.15% less his risk-free rate of 4.15% to derive an expected market risk premium on the *Value Line* index of 11.00%. His fifth market risk premium is based on a *Value Line* projected return on the S&P 500 of 14.14%, which produced a risk premium of 9.99% after his risk-free rate is subtracted. Finally, he uses Bloomberg growth rates to perform a DCF on the S&P 500. This method produces a return on the market of 17.52% from which he subtracts his projected risk-free rate of 4.15% to produce a market risk premium of 13.37%. The average of these six market risk premiums is 10.02%.[43] He performs a similar analysis excluding his PRPM results which produce an average market risk premium estimate of 9.93%.

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[43]Aqua Exhibit 5.04, page 2.

Q PLEASE COMMENT ON MR. D'ASCENDIS' MARKET RISK PREMIUM ESTIMATES.

A As an initial matter, his average market risk premiums of 9.93% and 10.02% fall well outside of the range 5.00% to 8.00% that is indicated by empirical evidence. I note that I agree with certain portions of his market risk premium estimates. It is the estimates that fall well outside of the range suggested by the empirical evidence that are a cause for concern.

In particular, his market risk premiums based on the application of the PRPM (10.44%), *Value Line*'s 3-5 year hence projections (11.00%), S&P 500 total return based on Value Line data (9.99%), and the S&P 500 total return based on Bloomberg data (13.37%). These market risk premium estimates exceed the high end of the empirical evidence by as much as 67%.[44] For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the market risk premium have concluded that a market risk premium in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[45] For example, the Duarte and Rosa study he cites concludes that the historical mean is "quite difficult to improve upon when considering out-of-sample performance measures."[46] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the market risk premium, and

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[44] 13.37% ÷ 8.00% = 67.1%

[45] 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%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

[46] See *Modern Regulatory Finance*¸ Dr. Roger A. Morin, at 191, citing the Duarte and Rosa study.

60% of financial advisors used a market risk premium in the range of 7.0% to 7.4% (similar to a long-term arithmetic average market risk premium).[47]

Q DO YOU HAVE ANY ADDITIONAL CONCERNS WITH MR. D'ASCENDIS' CAPM ANALYSIS?

A Yes. In addition to his market risk premiums generally falling well outside of the empirical range, Mr. D'Ascendis' expected market return derived using the DCF model with Bloomberg data of 17.52% assumes a perpetual weighted growth rate of the 15.98% for the S&P 500. Importantly, this analysis relies on individual company growth rates as high as 184.34% (Boeing Corporation). Both assumed growth rates are simply irrational and cannot be sustained.

The DCF model requires a long-term sustainable growth rate. Mr. D'Ascendis' sustainable market growth rate of 15.98% is far too high to be a rational outlook for sustainable long-term market growth. This growth rate is 3.9x the growth rate of the U.S. GDP long-term growth outlook of 4.14%. The assumed perpetual growth rate of 184.34% for Boeing is 44.5x that of the forecasted GDP growth rate.

It simply is not reasonable to believe individual companies can sustain growth rates as high as Mr. D'Ascendis has assumed into perpetuity. In fact, in the CFA curriculum textbooks, the CFA Institute notes as follows with regard to earnings growth rates for companies within the composite indices (i.e., S&P 500):

> Earnings growth for the overall national economy can differ from the growth of earnings per share in a country's equity market composites. This is due to the presence of new businesses that are not yet included in the equity indices and are typically growing at a faster rate than the mature companies that make up the composites. **<u>Thus, the earnings growth rate of companies</u>**

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[47]See *Modern Regulatory Finance*¸ Dr. Roger Morin, at 190, footnote 35.

<u>making up the composites should be lower than the earnings growth rate for the overall economy.</u>[48]

For these reasons, the overwhelming majority of Mr. D'Ascendis' traditional CAPM results are excessive and unreliable.

<u>IV.G. D'Ascendis Empirical CAPM ("ECAPM")</u>

Q PLEASE DESCRIBE MR. D'ASCENDIS' ECAPM ANALYSIS.

A Mr. D'Ascendis applies the same beta, market risk premium and risk-free rate that he used in his CAPM for his ECAPM. The ECAPM analysis modifies the traditional CAPM equation by including a risk premium weighted by the utility beta, and the overall market beta of 1.0. The original ECAPM analysis was designed to use raw, or unadjusted, regression betas. In Mr. D'Ascendis' ECAPM analysis, he adds two weighted risk premiums to a risk-free rate: a 75% weighted risk premium based on a 0.81 utility beta, and a 25% weighted risk premium based on a beta equal to the overall market beta of 1.0. The theory of the ECAPM is that a beta of less than 1.0 will increase toward the market beta of 1.0 over time, which is necessary because the risk of securities will be increasing over time. The ECAPM formula employed by Mr. D'Ascendis is as follows:

$$R_i = R_f + [(.75) \times B_i \times (R_m - R_f)] + [(.25) \times B_m \times (R_m - R_f)]$$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta coefficient for the stock (0.95)
B_m = Beta coefficient for the market (1.0)

[48]CFA Program Curriculum, 2014 Level II Vol. 1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, page 609, footnote 5 (emphasis added).

Q WHAT ISSUES DO YOU TAKE WITH MR. D'ASCENDIS' ECAPM ANALYSIS?

A The biggest issue I have with Mr. D'Ascendis' ECAPM analysis is his use of an adjusted beta as published by *Value Line*. The impact of Mr. D'Ascendis' ECAPM adjustment is to increase his beta estimate from 0.81 to 0.86.[49] The weighting adjustments applied in the ECAPM are mathematically consistent with the adjustments made to create the *Value Line* adjusted betas since the inputs are all multiplicative as shown in the formula above.

Mr. D'Ascendis' reliance on an adjusted *Value Line* beta in his ECAPM study is inconsistent with the academic research that I am aware of supporting the development of the ECAPM.[50] The *Value Line* adjusted betas are already adjusted for a stock's long-term tendency to converge to 1.00. Importantly, the timing of that convergence is not known, and therefore a constant weighting is applied when adjusting raw betas using the Blume method, as done by *Value Line* and Bloomberg. Thus, the end result of using the *Value Line* adjusted betas in the ECAPM is essentially an expected return line that has been flattened by two duplicative adjustments. In other words, the vertical intercept has been raised twice and the security market line has been flattened twice: once through the adjustments *Value Line* made to the raw beta, and again by weighting the risk-adjusted market risk premium as Mr. D'Ascendis has done.

Moreover, Mr. D'Ascendis further increases the intercept and flattens the security market line by using projected long-term Treasury yields that are at odds

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[49] 75% x 0.81 + 25% x 1 = 0.86.

[50] *See* Black, Fischer, "Beta and Return," *The Journal of Portfolio Management,* Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

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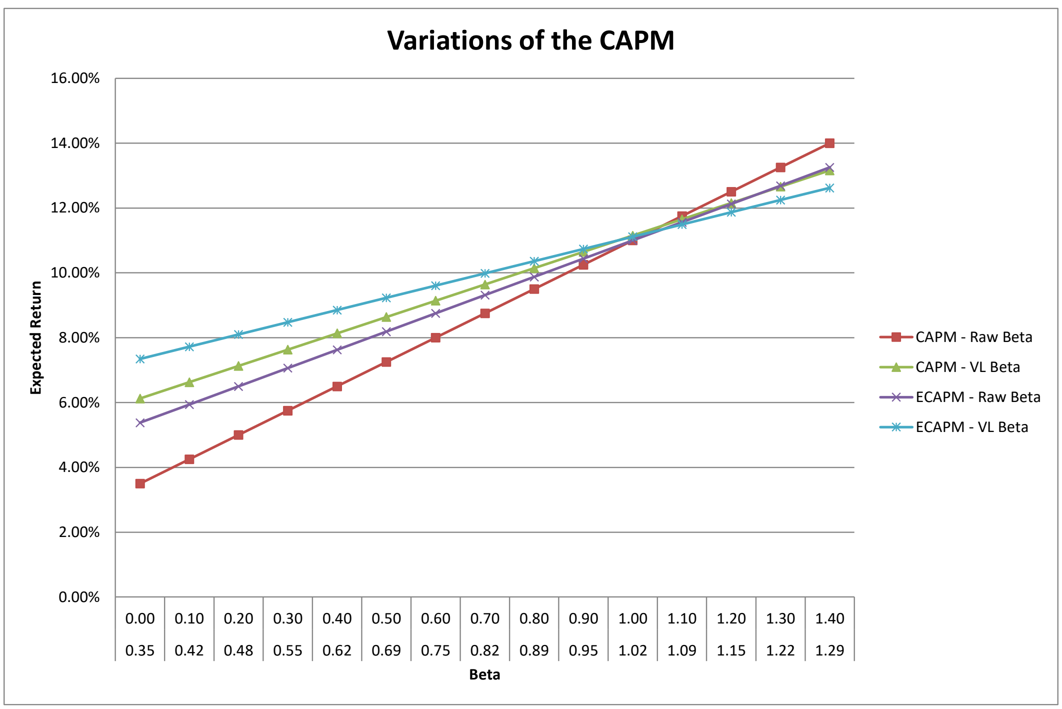
with current market expectations and inconsistent with the Federal Reserve's projections and monetary policy.

The ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. I have modeled the expected return line resulting from the application of the various forms of the CAPM/ECAPM below in Figure CCW-6.

FIGURE CCW-6



Along the horizontal axis in Figure CCW-6, I have provided the raw unadjusted beta (top row) and the corresponding adjusted *Value Line* beta (bottom row). As shown in Figure CCW-6, the CAPM using a *Value Line* beta compared to the CAPM using an unadjusted beta shows that the *Value Line* beta raises the intercept point and flattens the slope of the security market line. As shown in the figure above, the two variations with the most similar slope are the CAPM with the

Value Line beta, and the ECAPM with a raw beta. This evidence in shows that the ECAPM adjustment has a very similar impact on the expected return line as a *Value Line* adjusted beta. Another observation that can be made from the figure above is the magnifying effect that the ECAPM using a *Value Line* adjusted beta has on raising the vertical intercept and flattening the slope relative to all other variations. There is simply no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1.

Finally, this Commission has routinely rejected the ECAPM with an adjusted beta. As such, Mr. D'Ascendis' use of an adjusted beta in the ECAPM should be rejected.

IV.H. D'Ascendis Non-Regulated Company Analysis

Q PLEASE DESCRIBE MR. D'ASCENDIS' NON-PRICE REGULATED COMPANIES' EARNED ROE METHODOLOGY.

A Mr. D'Ascendis' non-price regulated ROE estimate is based on the results from the same cost of equity studies described above using a proxy group of non-price regulated companies that he chose based solely on whether they had betas within two standard deviations of the beta of his utility proxy group. His DCF, Risk Premium, and CAPM model results for the non-price regulated firms are 10.26%, 12.57%, and 11.75%, respectively. For his spot data analysis on the same non-price regulated companies, the financial models produce results of 10.32%, 12.70%, and 12.06%.[51]

[51]Exhibit 8.

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Q IS IT REASONABLE FOR MR. D'ASCENDIS TO USE HIS NON-PRICE REGULATED RISK PROXY GROUP TO ESTIMATE THE REQUIRED ROE FOR TAMPA ELECTRIC?

A No. Mr. D'Ascendis has not proven that these companies are risk-comparable to Tampa Electric. For example, Mr. D'Ascendis' non-price regulated proxy group includes large technology firms such as Cisco Systems and Oracle Corp. It is simply not credible to believe that these firms are comparable in business and operating risk to regulated utilities. To draw a valid comparison between Tampa Electric and any proxy group, it is necessary to show that these companies have comparable risk factors that are commonly used by investment professionals to compare investment risk between different investment alternatives. Because he has not shown that these companies are indeed risk comparable to Tampa Electric, his estimated return based on this proxy group is not reliable to estimate the cost of equity for Tampa Electric and should be disregarded.

Further, the RP and CAPM estimates on Mr. D'Ascendis' non-utility proxy group are flawed and biased for the same reasons described above concerning his utility proxy group. As such, his ROE estimates based on his non-utility proxy group do not reflect a reasonable risk proxy for Tampa Electric, and are based on flawed applications of DCF, the Risk Premium model and CAPM. Therefore, the Commission should reject the use of Mr. D'Ascendis' non-price regulated proxy group.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

C29-2979

Qualifications of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

C29-2981

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

C29-2982

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	**DOCKET NO. 20230090-EI**

STATE OF MISSOURI) SS
COUNTY OF ST. LOUIS)

Affidavit of Christopher C. Walters

Christopher C. Walters, being first duly sworn, on his oath states:

1. My name is Christopher C. Walters. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Florida Public Service Commission Docket Nos. 20240026-EI, 20230139-EI and 20230090-EI.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

C. Walters

Christopher C. Walters

Subscribed and sworn to before me this 6th day of June, 2024.

Sally D Wilhelms

Notary Public

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for rate increase by Duke Energy Florida, LLC	)	DOCKET NO. 20240025-EI
Petition for rate increase by Tampa Electric Company	)	DOCKET NO. 20240026-EI
	)	FILED: August 23, 2024

VIA ELECTRONIC FILING

August 23, 2024

Enclosed for filing on behalf of the Federal Executive Agencies' ("FEA") is the errata to the Direct testimony of Mr. Christopher Walters making the corrections identified in FEA's data responses to Staff's 1st data request.

If you should have any question about this filing, please do not hesitate to contact me.

Respectfully submitted this 23rd day of August, 2024.

Attorneys for Federal Executive Agencies

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
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III.A. Tampa Electric's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF TAMPA ELECTRIC'S INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. The current credit ratings for Tampa Electric are BBB+ and A3, from S&P and Moody's respectively.[11] The Company currently has a "negative" outlook from S&P and a "stable" outlook from Moody's. In its ~~August~~ June 2023 report covering Tampa Electric, S&P stated as follows:

> *We expect Tampa Electric Co. (TEC) to maintain its financial performance through our two-year outlook period.* Our base-case scenario assumes the implementation of the utility's most recent rate-case proposals, annual capital spending averaging about $1.2 billion, and dividend payments averaging about $530 million over the forecast period. TEC continues to have large capital expenditures--nearly triple its depreciation expense. This will likely strain financial measures for a least the next year or so during the construction of renewable energy transition projects. Overall, we forecast that TEC will maintain funds from operations (FFO) to debt of about 20%-22% through the 2023-2025 outlook period.
>
> **Business Risk**
> Our assessment of TEC's business risk reflects its lower-risk, rate-regulated, and vertically integrated electric and gas utility operations, as well as its management of regulatory risk, which we view as consistent with that of its peers. TEC is regulated by the FPSC, which, in our view, has been constructive for credit quality. The FPSC tariff framework uses various cost-recovery riders to allow timely recovery of capital investments. In addition, the FPSC established equity returns that tend to exceed industry averages, and the commission uses forecast test years and frequently authorizes interim rate increases. Furthermore, TEC will likely continue to benefit from above-average economic growth in Florida. TEC's business risk is offset by the lack of regulatory or geographical diversity because it operates only in Florida. Additionally, TEC's generation capacity relies heavily on fossil-based energy, with about 86% and 7% from gas and coal-fired generation respectively, as of 2022. As a result, we view TEC's business risk profile at the lower end of the category compared to other utility peers

[11] S&P Capital IQ, accessed on May 10, 2024.

> **Financial Risk**
> We assess TEC's financial risk profile using our medial volatility financial benchmark tables rather than the financial benchmarks we use for a typical corporate issuer, which reflects its lower-risk regulated utility operations and effective management of regulatory risk. TEC has a very large capital program, about triple that of depreciation expense, that will likely result in negative discretionary cash flow, indicative of the company's external funding needs. TEC has recently received approval for increases in base rates of about $191 million, $90 million, and $21 million, for 2022, 2023, and 2024, respectively. The outcome of the rate case was helpful for TEC to maintain its financial measures. Furthermore, our analysis of TEC's financial measures also incorporates recent regulatory outcomes.[12]

The "negative" outlook is clearly being driven by the outlook of Tampa Electric's ultimate parent company, Emera Inc., rather than by cash flow or other credit concerns at Tampa Electric. In fact, Tampa Electric's Stand-Alone-Credit-Profile ("SACP") rating from S&P, the rating that would otherwise be assigned to Tampa Electric if not for its affiliation with Emera Inc., is 'a' compared to its published rating of BBB+. In other words, Tampa Electric's credit rating is being hindered by two notches directly as a result of its affiliation with Emera Inc.

III.B. Tampa Electric's Proposed Capital Structure

Q WHAT IS TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE?

A Tampa Electric's proposed capital structure is summarized in Table CCW-6 below:

[12] S&P Global Ratings, RatingsDirect, ~~Oklahoma Gas & Electric~~Tampa Electric Co, ~~July~~ June ~~21~~15, 2023.

based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit CCW-9, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit CCW-10, the average indicated equity risk premium over U.S. Treasury bond yields has been ~~5.63~~5.70%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit

CCW-10, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 7.09%~~4.17% to 7.17%~~, while the ten-year rolling average risk premium ranged from 4.30% to 6.~~92~~91%.

As shown on my Exhibit CCW-11, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was ~~4.27~~4.34%. The five-year and ten-year rolling average risk premiums ranged from 2.~~80~~88% to 5.~~97~~90% and 3.~~11~~20% to 5.~~75~~73%, respectively.

Q WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit

CCW-12, where I show the yield-spread between utility bonds and Treasury bonds since 1980. As shown in this schedule, the average utility bond yield-spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.90%, respectively.

A current 13-week average "A" rated utility bond yield of 5.66% when compared to the current Treasury bond yield of 4.50%, as shown in Exhibit CCW-13, page 1, implies a yield-spread of 1.16%. This current utility bond yield-spread is lower than the long-term average-spread for "A" rated utility bonds of 1.48%. The 13-week average yield on "Baa" rated utility bonds is 5.89%. This indicates a current spread for the "Baa" rated utility bond yield of 1.39%, which is lower than the long-term average of 1.90%.

Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?

A I give primary consideration to the Risk Premium results using Treasury bonds and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.~~63~~70% is appropriate. Adding this risk premium to the projected Treasury yield of 4.20% produces an ROE of 9.~~63~~90%.

Applying a similar methodology as described above, the average ~~of the rolling five-year average~~ risk premiums over A-rated utility bonds is 4.~~27~~34%. The

A-rated utility bond yield has averaged 5.66% over the 13-week period ending May 10, 2024 while the Baa-rated utility bond yield has averaged 5.89% over the same period. Adding this risk premium to the 13-week A-rated utility bond yield of 5.66% produces an estimated cost of equity of ~~9.93~~10.00%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.89% produces an estimated cost of equity of 10.~~16~~23%.

The A-rated utility bond yield has averaged 5.60% over the 26-week period ending May 10, 2024 while the Baa-rated utility bond yield has averaged 5.84% over the same period. Adding the equity risk premium of 4.~~27~~34% to the 26-week A-rated utility bond yield of 5.60% produces an estimated cost of equity of 9.~~87~~94%. Adding the equity risk premium of 4.34~~27~~% to the 26-week Baa-rated utility bond yield of 5.84% produces an estimated cost of equity of 10.~~11~~18%.

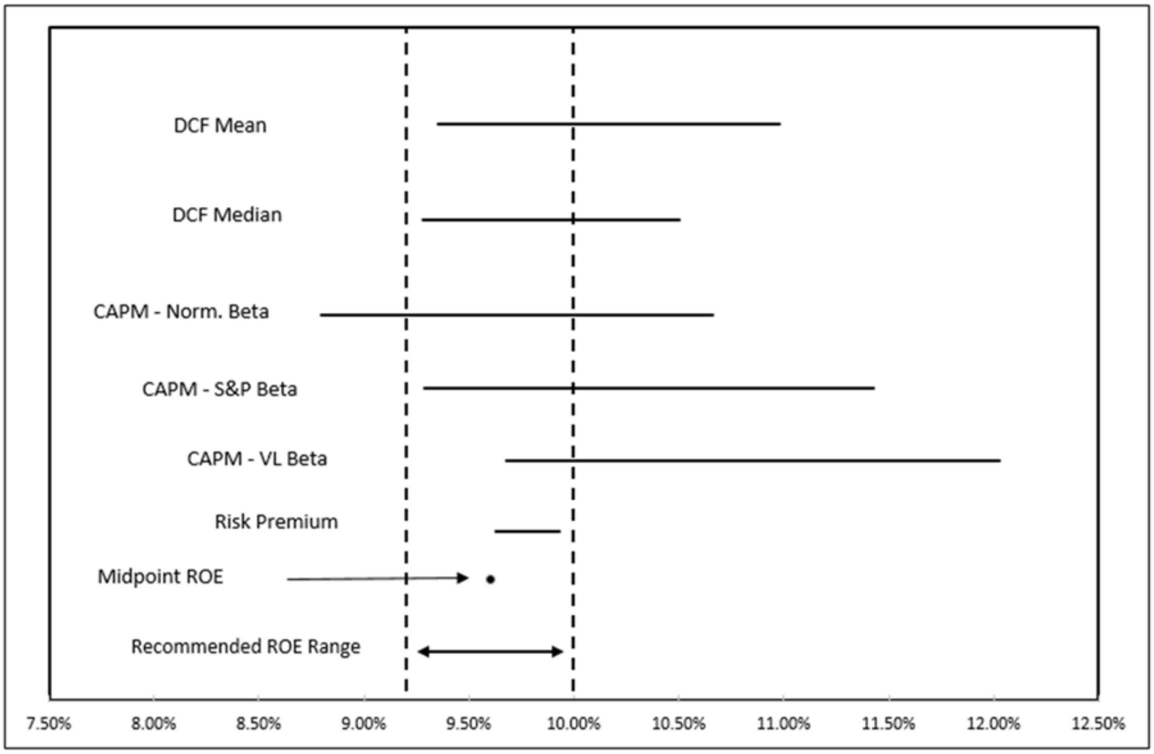
The results of my risk premium analyses are summarized in Table CCW-9.

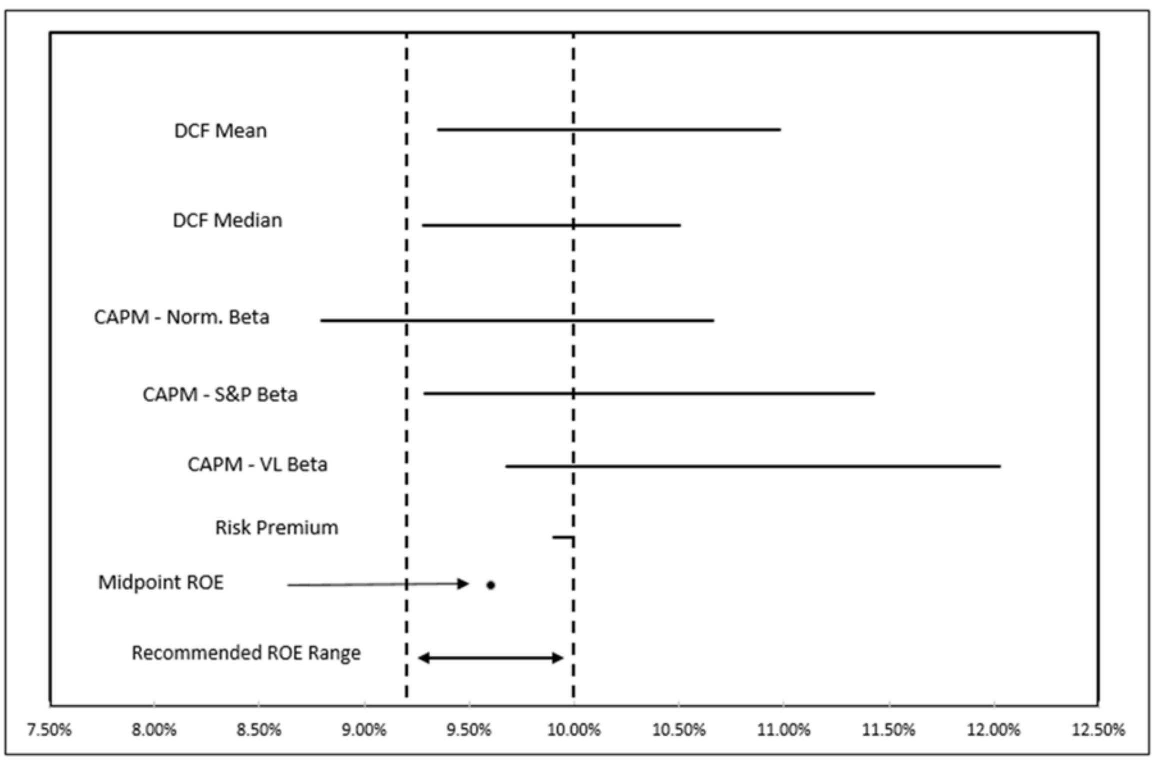
Table CCW-9

Summary of Risk Premium Results

Description	
Projected Treasury Yield	9.~~63~~90%
13-Week Yields	
A-Rated Utility Bond	~~9.93~~10.00%
Baa-Rated Utility Bond	10.23~~16~~%
26-Week Yields	
A-Rated Utility Bond	9.~~87~~94%
Baa-Rated Utility Bond	10.~~11~~18%

FIGURE CCW-5


DCF Mean
DCF Median
CAPM - Norm. Beta
CAPM - S&P Beta
CAPM - VL Beta
Risk Premium
Midpoint ROE
Recommended ROE Range
7.50%
8.00%
8.50%
9.00%
9.50%
10.00%
10.50%
11.00%
11.50%
12.00%
12.50%


DCF Mean
DCF Median
CAPM - Norm. Beta
CAPM - S&P Beta
CAPM - VL Beta
Risk Premium
Midpoint ROE
Recommended ROE Range
7.50%
8.00%
8.50%
9.00%
9.50%
10.00%
10.50%
11.00%
11.50%
12.00%
12.50%

Finally, this Commission has ~~routinely~~ rejected the ECAPM with an adjusted beta. As such, Mr. D'Ascendis' use of an adjusted beta in the ECAPM should be rejected.

IV.H. D'Ascendis Non-Regulated Company Analysis

Q PLEASE DESCRIBE MR. D'ASCENDIS' NON-PRICE REGULATED COMPANIES' EARNED ROE METHODOLOGY.

A Mr. D'Ascendis' non-price regulated ROE estimate is based on the results from the same cost of equity studies described above using a proxy group of non-price regulated companies that he chose based solely on whether they had betas within two standard deviations of the beta of his utility proxy group. His DCF, Risk Premium, and CAPM model results for the non-price regulated firms are 10.26%, 12.57%, and 11.75%, respectively. For his spot data analysis on the same non-price regulated companies, the financial models produce results of 10.32%, 12.70%, and 12.06%.[51]

Q IS IT REASONABLE FOR MR. D'ASCENDIS TO USE HIS NON-PRICE REGULATED RISK PROXY GROUP TO ESTIMATE THE REQUIRED ROE FOR TAMPA ELECTRIC?

A No. Mr. D'Ascendis has not proven that these companies are risk-comparable to Tampa Electric. For example, Mr. D'Ascendis' non-price regulated proxy group includes large technology firms such as Cisco Systems and Oracle Corp. It is simply not credible to believe that these firms are comparable in business and operating risk to regulated utilities. To draw a valid comparison between Tampa

[51] Exhibit 8.

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 23rd day of August, 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

<u>/s/ Ebony M. Payton</u>
Ebony M. Payton
Paralegal for FEA

(Whereupon, Exhibit Nos. 91-105 were received into evidence.)

CAPTAIN GEORGE: And then additionally, I would like to have Mr. Andrews' prefiled testimony filed on June 6th, consisting of 33 pages, into the record as though read, along with his exhibits, Exhibit Nos. 106 through 112.

CHAIRMAN LA ROSA: Are there objections?

Seeing none, show them entered into the record as well.

(Whereupon, prefiled direct testimony of Brian C. Andrews was inserted.)

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FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
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Direct Testimony and Exhibits of

Brian C. Andrews

On behalf of

Federal Executive Agencies

June 6, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11662

**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
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STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

<u>Affidavit of Brian C. Andrews</u>

Brian C. Andrews, being first duly sworn, on his oath states:

1. My name is Brian C. Andrews. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Florida Public Service Commission Docket Nos. 20240026-EI, 20230139-EI and 20230090-EI.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Brian C. Andrews

Brian C. Andrews

Subscribed and sworn to before me this 6th day of June, 2024.

ADRIENNE JEAN NAVARRO
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: Mar. 22, 2025
Commission # 21989987

Adrienne S Navarro

Notary Public

BEFORE THE
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Direct Testimony of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

C30-3036

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony addresses Tampa Electric Company's ("TECO") proposed depreciation rates.

To the extent my testimony does not address any particular issue does not indicate tacit agreement with the Company's or another party's position on that issue.

Q HAVE YOU FILED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION") REGARDING DEPRECIATION ISSUES?

A Yes. I filed testimony in the Florida Power & Light Company rate case (Docket No. 160021-EI) in 2016 and the Gulf Power Company's 2017 rate case (Docket No. 160170-EI) on depreciation issues. In addition, I have filed depreciation-related testimony in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

Q PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are summarized as follows:

1. TECO has proposed a new set of depreciation rates which would result in a $40.73 million increase to its depreciation expense based on plant balances as of December 31, 2024.[1] This increase is based on overstated depreciation rates. These rates produce an excessive amount of depreciation expense, thus, overstating the test year revenue requirement.

2. TECO's proposal to assume a 35-year life for the Big Bend and Bayside combined cycle plants is too short. 40 years is a more appropriate basis for the depreciation rates for TECO's combined cycle plants and is consistent with both Duke Energy Florida and Florida Power & Light.

3. The interim survivor curves that TECO, through its witness Mr. Ned Allis, is recommending for four Production Accounts should be lengthened. Statistical

[1]Exhibit NA-1, Document No. 2, Table 2.

fitting methods indicate that survivor curves with longer Average Service Lives ("ASL") fit TECO's historic retirement data better than what is being proposed by Mr. Allis.

4. The ASL that TECO, through its witness Mr. Allis, is recommending for Distribution Account 367 – Underground Conductors and Devices should be lengthened. Mr. Allis' use of simulated data results in an understated life for this account. No change to the currently approved 45-year life for this account should be used to develop the depreciation rates for this account.

5. The net salvage rates for several Transmission, Distribution, and General Plant ("TD&G") accounts have been overstated based on TECO's historical data. I proposed reasonable adjustments to keep net salvage recoveries for these accounts at a level more in line with historical experience.

6. I present FEA's recommended depreciation rates in Exhibit BCA-6. These rates include all adjustments I propose regarding the combined cycle plant lifespan and the Production plant interim survivor cures, Account 367 ASL, and the net salvage rate adjustments. These depreciation rates should be approved by the Commission.

7. My recommended adjustments to TECO's depreciation rates reduces TECO's 2024 depreciation expense by $31.38 million. I provide a comparison of my proposed test year depreciation expense with TECO's in Exhibit BCA-7.

I. BOOK DEPRECIATION CONCEPTS

Q PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

The basic underlying principle of utility depreciation accounting is intergenerational equity, where the customers/ratepayers who benefit from the generated service of assets pay all the costs for those assets during the benefit period, which is over the life of those assets.[2] This concept of intergenerational equity can be

[2]Edison Electric Institute, Introduction to Depreciation for Public Utilities and Other Industries, April 2013, page viii.

achieved through depreciation by allocating costs to customers in a systematic and rational manner that is consistent with the period of time in which customers receive the service value.[3]

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of current investment. Generally, this capital recovery occurs over the ASL of the investment or assets. As a result, it is critical that appropriate ASLs be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is simply the scrap or reuse value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

Q ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?

A Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."[4]

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[3] *Id.* at 22.
[4] Electronic Code of Federal Regulations, Title 18, Chapter 1, Subchapter C, Part 101.

Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Q HOW ARE DEPRECIATION RATES DETERMINED?

A Depreciation rates are determined using a depreciation system. There are three components, each with a number of variations, used to determine a depreciation system, which is then used to estimate depreciation rates. The three basic components are methods, procedures, and techniques. The choice of a depreciation system can significantly affect the resulting depreciation rates.

Q PLEASE FURTHER DESCRIBE THE METHODS THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A There generally are three types of methods of spreading the depreciation expense over the life of property. These are the Straight Line Method, Accelerated Methods, and Deferred Methods. The Straight Line Method is the method most widely used by utility companies for accounting and ratemaking purposes as it is easy to apply and does not create intergenerational inequities because it spreads an equal portion of the plant cost across each accounting period. Accelerated Methods result in higher depreciation rates earlier in an asset's life, and lower depreciation rates later. Deferred Methods have increasing rates over an asset's life.

Q PLEASE FURTHER DESCRIBE THE GROUPING PROCEDURES THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A There are three main grouping procedures used within a depreciation system. These four procedures are the Broad Group (more commonly known as the Average Life Group ("ALG")), the Vintage Group, and the Equal Life Group ("ELG").

In the ALG Procedure, all units within a particular account or category are assumed to be part of a single group that exhibits the same life and retirement characteristics. This is the most common utilized procedure.

The Vintage Group and the ELG Procedure assume that sub-groups within a particular account or category may exhibit unique life characteristics. As an example of the Vintage Group Procedure, it may assume that all poles installed in 1985 have a 50-year life, while all poles installed in year 1995 have a 45-year life. With the ELG Procedure, it may assume that all poles that are expected to have a life of 50 years should have one depreciation rate, while poles that are expected to only attain life spans of 45 years would have a different depreciation rate. The overall group depreciation rate would be a composite of the ELG depreciation rates.

Q PLEASE FURTHER DESCRIBE THE TECHNIQUES THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A There are two techniques used to calculate depreciation rates: Whole Life and Remaining Life. The Whole Life Technique spreads the original cost less net salvage of the account over the average life of the account. This technique requires that separate amortizations be made to correct for over- and under-accumulations due to changes in an account's ASL.

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The Remaining Life Technique spreads the unrecovered cost less net salvage over the remaining life of the account. The Remaining Life Technique is the most common technique used and it has a self-correcting nature that spreads any over- or under-accumulations over the remaining life.

Q IN YOUR EXPERIENCE, WHAT DEPRECIATION SYSTEM IS MOST COMMONLY UTILIZED TO DETERMINE UTILITY DEPRECIATION RATES FOR RATEMAKING PURPOSES?

A The most common depreciation system is one that consists of the Straight Line Method, the ALG Procedure, and the Remaining Life Technique.

Q PLEASE DESCRIBE THE ACTUARIAL LIFE ANALYSIS THAT IS PERFORMED TO EVALUATE HISTORICAL ASSET RETIREMENT DATA.

A I will first provide the description of actuarial life analysis (retirement rate method) that is contained in the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices Manual ("NARUC Manual"):

> "Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.
>
> Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical; **it is a powerful analytical tool and, therefore, is generally considered the preferred approach**.
>
> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or, capital budgets."

(NARUC Manual, 1996, Page 111, Emphasis Added).

As explained by the NARUC Manual, when the required data exists, a database that contains the year of installation and the year of retirements for each vintage of property, actuarial life analysis is the preferred method of determining the life, and thus, retirement characteristics of a group of property. In this type of analysis, there are three major steps. The first step is to gather and use available aged data from the Company's continuing plant records to create an observed life table. The observed life table provides the percent surviving for each age interval of property.

The second step is to conduct a fitting analysis to match the actual survivor data from the observed life table to a standard set of mortality or survivor curves. Typically, the observed life table data is matched to Iowa Curves. The fitting process is a mathematical fitting process, which minimizes the Sum of Squared Differences ("SSD") between the actual data and the Iowa Curves.

The third step is to select the best fitting curve while using informed judgment to determine the curve that best represents the property being studied. This includes the use of a visual matching process. Although the mathematical fitting process provides a curve that is theoretically possible, the visual matching process will allow the trained depreciation professional to use informed judgment in the determination of the best fitting survivor curve.

Q PLEASE PROVIDE FURTHER EXPLANATION OF THE SSD STATISTICAL MEASUREMENT.

A In the Actuarial Life Analysis section of the NARUC Manual, it describes SSD as follows:

> "Generally, the goodness of fit criterion is the least sum of squared deviations. The difference between the observed and projected data is

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> calculated for each data point in the observed data. This difference is squared, and the resulting amounts are summed to provide a single statistic that represents the quality of the fit between the observed and projected curves.
>
> The difference between the observed and projected data points is squared for two reasons: (1) the importance of large differences is increased, and (2) the result is a positive number, hence the squared differences can be summed to generate a measure of the total absolute difference between the two curves. The curves with the least sum of squared deviations are considered the best fits."
>
> (NARUC Manual, 1996, Pages 124-125).

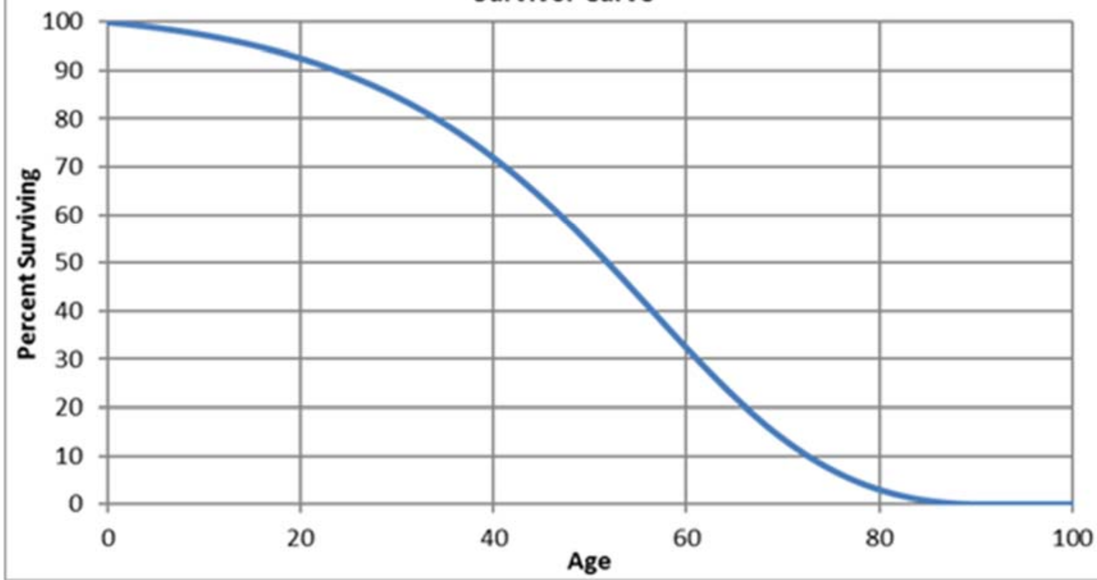
Q PLEASE EXPLAIN SURVIVOR CURVES AND THE NOTATION USED TO REFERENCE THEM.

A The selection of the survivor curve is one of the most important aspects in conducting a depreciation study. A survivor curve is a visual representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the ASL of the group of property and the composite remaining life. For assets with an assumed lifespan or retirement date, the survivor curve is used to estimate the interim retirements that will occur between the study date and the estimated year of final retirement. These parameters directly affect the depreciation rate calculations, therefore, informed judgment should be used in their selection.

In this proceeding, as well as the majority of utility regulatory rate case proceedings throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of a group of property. There are four types of Iowa Curves: right-moded, left-moded, symmetrical-moded, and origin-moded. Each type describes where the greatest frequency of retirements occur relative to the ASL.

A survivor curve consists of an ASL and Iowa Curve type combination. For example, when describing property with a 50-year ASL that has mortality characteristics of the R2 Iowa Curve, the survivor curve would simply be notated as "50-R2." I present the 50-R2 survivor curve in Figure 1.

Figure 1
50-R2
Survivor Curve



II. TECO DEPRECIATION STUDY RESULTS

Q HAS TECO FILED A NEW DEPRECIATION STUDY IN THIS CASE?

A Yes. TECO filed a depreciation study as Exhibit No. NA-1, Document No. 2. TECO's witness, Mr. Allis of Gannett Fleming, supports this study which was conducted on plant balances as of December 31, 2024. The resulting depreciation rates presented in Exhibit No NA-1, Document No. 2 provide the basis for TECO's depreciation expense component of its revenue requirement.

Q WHAT DEPRECIATION SYSTEM DID TECO UTILIZE IN THE CALCULATION OF DEPRECIATION RATES PRESENTED IN EXHIBIT NA-1, DOCUMENT NO. 2?

A TECO used a depreciation system consisting of the Straight Line Method, the ALG Procedure, and the Remaining Life Technique[5] to calculate its proposed depreciation rates.

Q HOW DO TECO'S PROPOSED DEPRECIATION RATES IMPACT THE 2024 DEPRECIATION EXPENSE?

A TECO's proposed depreciation rates significantly increase its depreciation expense over that calculated using the currently approved depreciation rates. In Table 1 below, I provide the increase by group. This increase totals $40.73 million, a significant component of TECO's proposed revenue requirement increase.

TABLE 1

Impact of TECO's Proposed Depreciation Rates and Expense for Electric Plant as of December 31, 2024

	Depreciation Expense ($ Millions)				Depreciation Rates		
			Difference				
Depreciable Group	**Present**	**Proposed**	**Amount**	**Percent**	**Present**	**Proposed**	**Difference**
Steam	$ 48.63	$ 59.33	$ 10.71	22.02%	3.34%	4.07%	0.73%
Other Production	$ 140.94	$ 142.40	$ 1.46	1.04%	3.87%	3.91%	0.04%
Solar	$ 54.21	$ 62.81	$ 8.60	15.87%	2.90%	3.50%	0.60%
DC Micro Grid	$ 0.03	$ 0.03	$ 0.00	2.54%	2.90%	3.48%	0.58%
MacDill AFB	$ -	$ -	$ -	0.00%	0.00%	0.00%	0.00%
Transmission	$ 32.91	$ 33.43	$ 0.52	1.58%	2.57%	2.61%	0.04%
Distribution	$ 130.81	$ 150.66	$ 19.85	15.18%	3.20%	3.68%	0.48%
General	$ 10.7	$ 10.24	$ (0.42)	-3.91%	3.08%	2.96%	-0.12%
Total	**$ 418.18**	**$ 458.91**	**$ 40.73**	**9.74%**	**3.32%**	**3.64%**	**0.32%**

Sources: Exhibit NA-1, Document No. 2, Table 2

TECO's proposed $40.73 million increase is a 9.74% increase over depreciation expense based on the currently approved depreciation rates.

[5]Direct Testimony of Ned Allis at page 9, lines 1-3.

Q HOW DOES TECO EXPLAIN THE NEED FOR SUCH AN INCREASE?

A Mr. Allis provides a figure on page 39 of his Direct Testimony that details the drivers of the $41 million increase. The largest driver is the increased plant investment, with more investment needed to be recovered over the remaining lives of the assets. This accounts for $37 million. Some of the production plants have extended lifespans, resulting in a $15 million reduction to the depreciation expense, as the unrecovered investment is spread over a longer remaining life. Finally, changes to TD&G service lives and net salvage rates accounts for $19 million of the increase.

Q PLEASE SUMMARIZE THE PROPOSED CHANGES THAT YOU ARE RECOMMENDING TO TECO'S DEPRECIATION RATES.

A For the Big Bend and Bayside combined cycle plants, I proposed to increase the lifespan of these plants to 40-years. TECO has assumed that the Big Bend and Bayside combined cycle plants will only have a service life of 35 years. This is a low end assumption and is not consistent with Mr. Allis' recommendations for both Duke Energy Florida and Florida Power & Light, nor is it consistent with the lifespan for the Polk combined cycle plants.

I will also propose to adjust the interim survivor curves for four of TECO's production accounts. My life analysis demonstrates that TECO has overstated the level of interim retirements that will occur in these accounts.

The TD&G book depreciation rates should be reduced for several accounts. For Distribution Account 367, Mr. Allis has proposed one of the shortest lives I have seen, based on an analysis of simulated data. Their currently approved 45-year life should be maintained.

Additionally, the net salvage rates for several TD&G accounts has been overstated.

The depreciation rates proposed by TECO would depreciate the assets in these accounts too quickly, which is a burden on current customers.

III. COMBINED CYCLE PLANT LIFESPAN

Q WHAT LIFESPAN DOES MR. ALLIS PROPOSE TO USE FOR THE BIG BEND AND BAYSIDE COMBINED CYCLE PLANTS?

A Mr. Allis states in his testimony that he used a 35-year life for the combined cycle plants.[6] However, inspection of his depreciation study shows that the lives for these plants vary. Figure 2 below is a recreation of a table from the depreciation study.

Figure 2

DEPRECIABLE GROUP	MAJOR YEAR IN SERVICE	PROBABLE RETIREMENT YEAR	LIFE SPAN
STEAM PRODUCTION			
Big Bend Common	1970	2057	87
Big Bend Unit 4	1985	2040	55
OTHER PRODUCTION			
Big Bend Unit 1	2022	2057	35
Big Bend Unit 4	2009	2049	40
Big Bend Unit 5	2021	2057	36
Big Bend Unit 6	2021	2057	36
Polk Common	1996	2052	56
Polk Unit 1 Gasifier	1996	2036	40
Polk Unit 2	2000	2052	52
Polk Unit 3	2002	2052	50
Polk Unit 4	2007	2052	45
Polk Unit 5	2007	2052	45
Polk Unit 6	2017	2052	35
Bayside Common	2003	2049	46
Bayside Unit 1	2003	2038	35
Bayside Unit 2	2004	2038	34
Bayside Unit 3	2009	2049	40
Bayside Unit 4	2009	2049	40
Bayside Unit 5	2009	2049	40
Bayside Unit 6	2009	2049	40
MacDill Air Force Base	2025	2055	30

[6] Direct Testimony of Ned Allis at page 25, line 22 through page 26, line 2.

As can be seen, 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. The Polk Power Station has two combined cycle plants and the lives of these units range from 35 to 52 years. I will not propose any adjustments to the Polk lifespan.

Q DOES MR. ALLIS PROVIDE A TYPICAL RANGE FOR THE LIFE SPAN OF COMBINED CYCLE PLANTS?

A Yes. Mr. Allis states that the typical industry range for the lifespan of these plants is 35 to 40 years.

Q WHAT LIFESPAN FOR COMBINED CYCLE PLANTS DOES MR. ALLIS USE FOR OTHER ELECTRIC UTILITY COMPANIES IN FLORIDA?

A In the current Duke Energy Florida rate case, Docket No. 20240025-EI, Mr. Allis recommends the use of a 40-year life for combined plants.[7] Similarly, in Florida Power and Light's 2021 rate case, Docket No. 20210015-EI, Mr. Allis also recommend a 40-year life for the combined cycle plants.[8]

Q WHAT LIFESPAN FOR THE BIG BEND AND BAYSIDE COMBINED CYCLE PLANTS DO YOU RECOMMEND?

A In 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. The specific retirement dates are shown in Table 2. Big Bend should retire in 2062 and Bayside should retire in 2043.

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[7] Docket No. 20240025-EI, Direct Testimony of Ned Allis at page 22, lines 15-17.
[8] Docket No. 20210015-EI, Direct Testimony of Ned Allis at page 29, lines 10-12.

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TABLE 2			
Comparison of Production Plant Retirement Dates			
Plant	**TECO**	**FEA**	**Delta**
Big Bend Common	2057	2062	5
Big Bend Unit 1	2057	2062	5
Big Bend Unit 5	2057	2062	5
Big Bend Unit 6	2057	2062	5
Bayside Unit 1	2038	2043	5
Bayside Unit 2	2038	2043	5

Source: Exhibit BCA-7

IV. PRODUCTION PLANT INTERIM SURVIVOR CURVES

Q WHAT ARE INTERIM RETIREMENT SURVIVOR CURVES?

A Interim retirement survivor curves are Iowa Type survivor curves that are used to estimate the amount of property at a production plant that will retire at a plant prior to its final retirement date. In short, the use of an interim retirement curve shortens the remaining life of a plant such that recovery of all recovered investment can occur through the plant's actual final retirement date.

Q PLEASE PROVIDE ADDITIONAL DETAIL ON THE PROCESS USED FOR THE LIFE ANALYSIS YOU CONDUCTED FOR THE INTERIM RETIREMENT CURVES FOR THE PRODUCTION PLANT ACCOUNTS.

A The first step in my analysis was a thorough review of the TECO depreciation study and of Mr. Allis' workpapers. I conducted my own actuarial analysis based on the observed life tables created by Mr. Allis for his actuarial analysis. I utilized an Excel-based model to determine the Iowa Curve and ASL combination that best fits the significant points of the observed life table created by Mr. Allis. I then used a statistical and visual analysis to select Iowa Curves and ASLs that resulted in a better statistical fit (lower SSD) than the survivor curves being recommended by Mr. Allis. Again, the SSD is the sum of the squared differences between the Iowa Curves and the significant data points from the observed life tables. See Exhibit BCA-1 through BCA-4.

In each of the exhibits, Exhibits BCA-1 through BCA-4, I provide a table and a graph. The table contains the results of the fitting analysis. This table shows for each Iowa Curve type, the ASL that minimizes the SSD. In addition, the table contains the SSD of the TECO and FEA proposals. For each account to which an adjustment is proposed, the FEA proposal has a lower SSD, which indicates a better statistical fit than both TECO's proposal and the currently approved curve. The graph shows the actual TECO retirement data (blue triangles), the TECO proposed curve (green long-dashed line), the FEA proposed curve (purple dotted line), and the best fit curve (orange short-dash-dotted line). The best-fit curve shown on the graph is the curve determined by the statistical fitting analysis to have the lowest SSD.

Q DO THE SURVIVOR CURVES THAT YOU ARE RECOMMENDING PRODUCE A BETTER FIT TO TECO'S DATA THAN THOSE BEING RECOMMENDED BY MR. ALLIS?

A Yes. For each of the 4 accounts where I am proposing an interim retirement survivor curve that differs from Mr. Allis' recommendation, the SSD is lower. That is, all of my recommendations result in survivor curves that mathematically and statistically fit TECO's data better than those recommended by Mr. Allis. The SSDs of my recommendations compared to the recommendations of Mr. Allis are shown in Table 3. For each account, the SSD of the FEA proposal is significantly lower than the TECO proposal. With Interim retirement curves, it is important to accurately reflect the company's data, as all they serve to do is shorten the remaining lives of the assets to recover interim retirements.

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	(30)	-54.5%
343	50-O1	1,085	75-O1	122	25	(963)	-88.8%

Source: Exhibit BCA-1 through Exhibit BCA-4

Q PLEASE DISCUSS YOUR INTERIM RETIREMENT SURVIVOR CURVE ADJUSTMENT FOR ACCOUNT 312.

A The life analysis for this account is presented in Exhibit BCA-1. Account 312 is for Boiler Plant Equipment. Per the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, "This account shall include the cost installed of furnaces, boilers, coal and ash handling and coal preparing equipment, steam and feed water piping, boiler apparatus and accessories used in the production of steam, mercury, or other vapor, to be used primarily for generating electricity." TECO's depreciation study states, "Some of the assets in this account, such as stacks, are likely to be in service for the full life of the plant. Other equipment, such as pumps, motors, and piping, will be retired as interim retirements."[9]

TECO recommends using the 40-L0 survivor curve which results in just 20% of the original cost surviving at a full lifespan of 60-years. This is not supported by TECO's retirement data. I recommend moving to the 60-O3 curve, which is the best-fit

[9] Exhibit No. NA-1, Document No. 2 at page 376.

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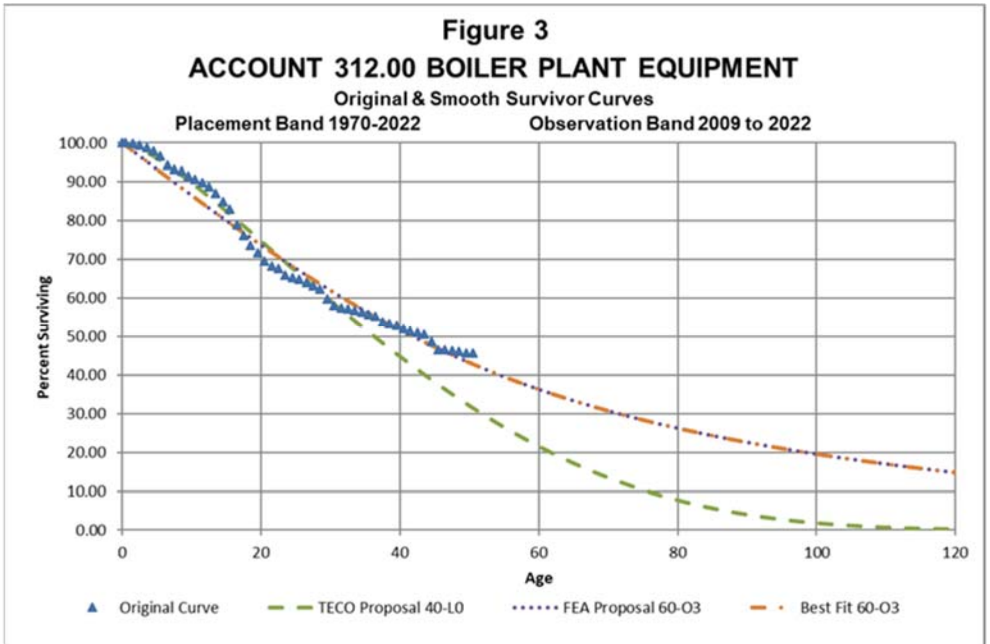
of the data. This curve produces a much better fit for the data, with an SSD of 402, a decrease of 75.2% relative to TECO's proposed curve. Figure 3 is a scaled down version of the full size graph contained in Exhibit BCA-1. As can be seen, the 60-O3 is a much better fit.



Q PLEASE DISCUSS YOUR INTERIM RETIREMENT SURVIVOR CURVE ADJUSTMENT FOR ACCOUNT 341.

A The life analysis for this account is presented in Exhibit BCA-2. Account 341 is for Other Production Structures and Improvements. Per the FERC's Uniform System of Accounts, "This account includes the cost of structures and improvements for other power generation." TECO's depreciation study states, "The assets in this account include all structures located at the Company's steam power plants, including steel and concrete superstructures, foundations, and roads."[10]

[10]Exhibit No. NA-1, Document No. 2 at page 392.

TECO recommends using the 50-R3 survivor curve which results in just 78% of the original cost surviving at a full lifespan of 40-years. The 50-R3 produces an SSD of 3,562, clearly it is not supported by TECO's retirement data. I recommend moving to the 74-R2 curve, which is very near the best-fit curve (113-L0.5) through 40 years and is the best-fitting R2 curve type. The 74-R2 curve produces a much better fit for the data, with an SSD of 31, a decrease of 99.1% relative to TECO's proposed curve. Figure 4 below is a scaled down version of the full size graph contained in Exhibit BCA-2. As can be seen, the 74-R2 is a much better fit.

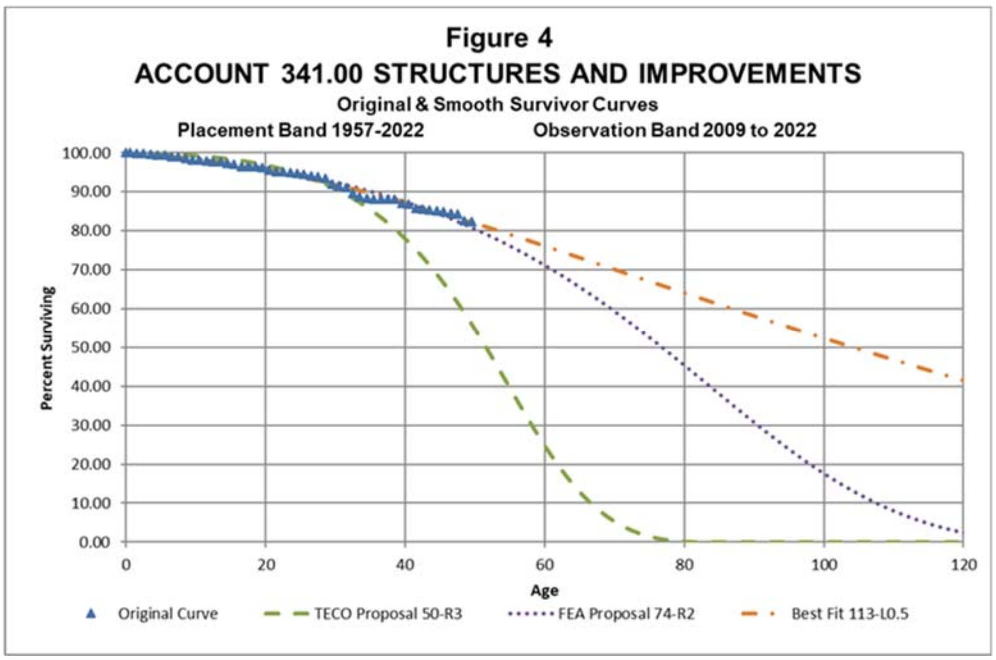
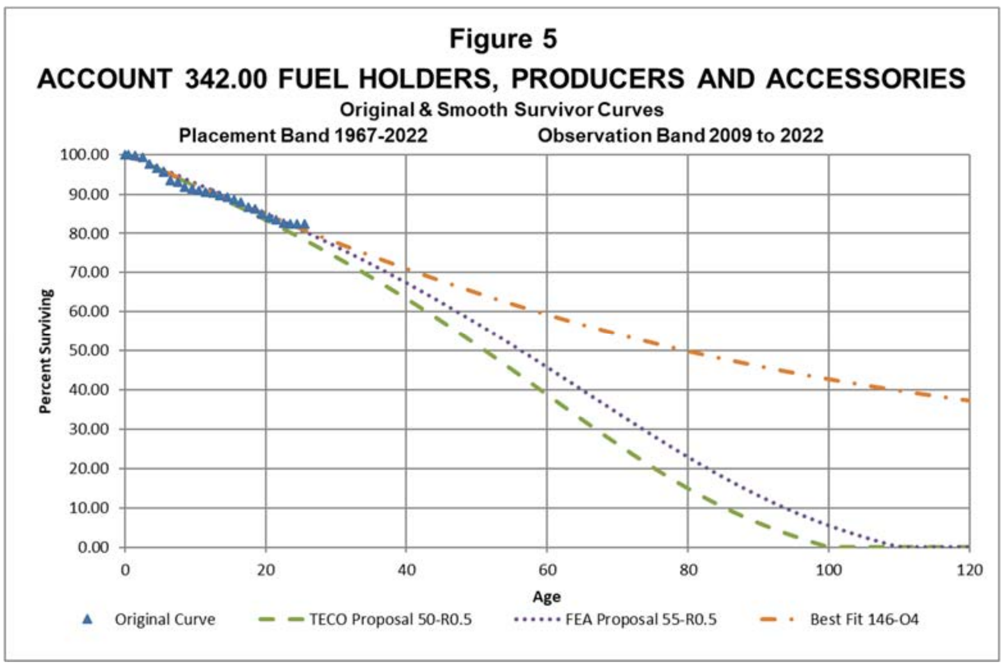


Figure 4
ACCOUNT 341.00 STRUCTURES AND IMPROVEMENTS
Original & Smooth Survivor Curves
Placement Band 1957-2022 Observation Band 2009 to 2022

Q PLEASE DISCUSS YOUR INTERIM RETIREMENT SURVIVOR CURVE ADJUSTMENT FOR ACCOUNT 342.

A The life analysis for this account is presented in Exhibit BCA-3. Account 342 is for Other Production Fuel Holders. Per the FERC's Uniform System of Accounts, "This account includes the installed cost of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine as well as the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators."

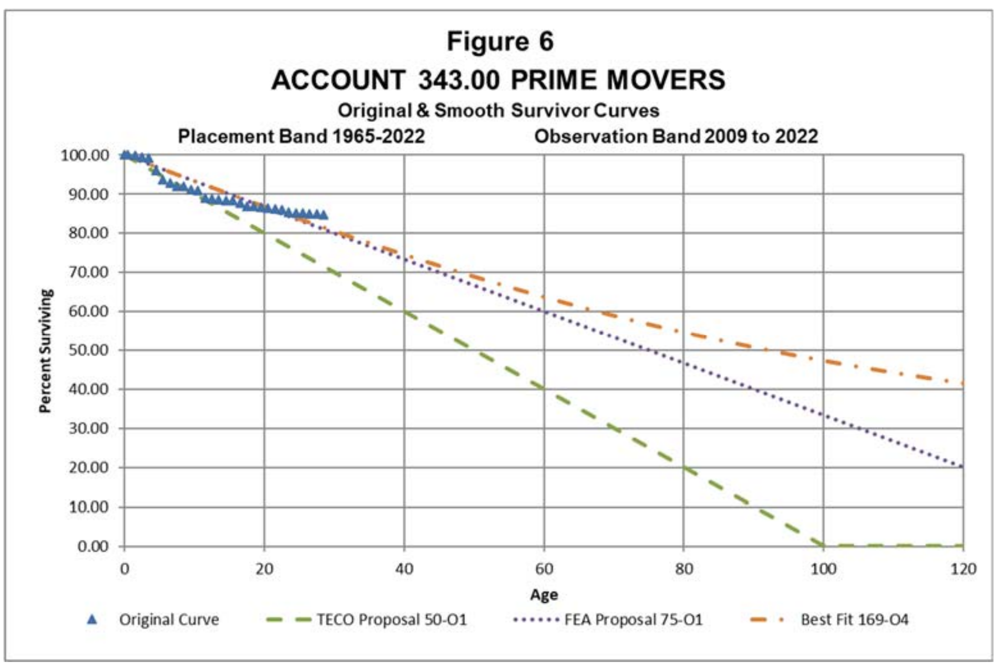
TECO recommends using the 50-R0.5 survivor curve which results in just 63% of the original cost surviving at a full lifespan of 40-years. The 50-R0.5 produces an SSD of 55. I recommend moving to the 55-R0.5 curve, which is a better fitting R0.5 curve type. The best-fit curve is the 146-O4. A longer life is supported by the data. The 55-R0.5 curve produces a much better fit for the data, with an SSD of 25, a decrease of 54.5% relative to TECO's proposed curve. Figure 5 is a scaled down version of the full size graph contained in Exhibit BCA-3. As can be seen, the 55-R0.5 is a much better fit.



Q PLEASE DISCUSS YOUR INTERIM RETIREMENT SURVIVOR CURVE ADJUSTMENT FOR ACCOUNT 343.

A The life analysis for this account is presented in Exhibit BCA-4. Account 343 is for Other Production Prime Movers. Per the FERC's Uniform System of Accounts, "This account includes the installed cost of prime movers, including their auxiliaries, devoted to the generation of electric energy."

TECO recommends using the 50-O1 survivor curve which results in just 60% of the original cost surviving at a full lifespan of 40-years. The 50-O1 produces an SSD of 1,085, clearly it is not supported by TECO's retirement data. I recommend moving to the 75-O1, which very near the SSD of the best-fit curve (169-O4). The 75-O1 curve produces a much better fit for the data, with an SSD of 122, a decrease of 88.8% relative to TECO's proposed curve. Figure 6 below is a scaled down version of the full size graph contained in Exhibit BCA-4. As can be seen, the 75-O1 is a much better fit.



Q WILL ANY OF YOUR INTERIM SURVIVOR CURVE ADJUSTMENTS PREVENT TECO FROM RECOVERING ITS ENTIRE UNRECOVERED INVESTMENT OVER THE REMAINING LIVES OF ITS PRODUCTION ASSETS?

A No. TECO will still recover all of its unrecovered production plant investment through the retirement dates of its plants.

V. <u>ACCOUNT 367 SURVIVOR CURVE</u>

Q WHAT IS ACCOUNT 367?

A This account includes the cost of electric underground conductors and devices used for electric distribution. The assets in this account include cable (95% aluminum, 5% copper), enclosed switchgears and potheads.

Q WHAT IS THE CURRENTLY APPROVED AND TECO PROPOSED SURVIVOR CURVE FOR ACCOUNT 367?

A The currently approved survivor curve for Account 367 is 45-R1.5, which was adopted in the Settlement Agreement outlined in Order No. PSC-2021-0423-S-EI. TECO proposes to move to 35-R1.5 survivor curve, a 10-year reduction to the life of one of TECO's largest accounts.

Q HOW DOES MR. ALLIS JUSTIFY HIS SELECTION OF A THE 35-R1.5 CURVE FOR ACCOUNT 367?

A Mr. Allis states, "Bands analyzed for this account include the overall historic band, as well as the most recent twenty- and forty year experience bands. All historic retirements were statistically aged for the actuarial analysis. In addition to the actuarial analysis, the Simulated Plant Record ("SPR") method of analysis was also employed.

The actuarial and SPR analyses both support average service lives in the 35 year range. The 35-R1.5 life estimate is on the shorter end of the industry range but is consistent with TECO's historic experience as well as the operating environment in Florida."[11]

Q DO YOU TAKE ISSUE WITH MR. ALLIS' RECOMMENDATION?

A Yes. 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. A 35-year life for Account 367 would be one of the shortest lives I have ever seen for underground conductors.

Q WHAT SERVICE LIFE DOES MR. ALLIS PROPOSE FOR ACCOUNT 367 FOR DUKE ENERGY FLORIDA AND FLORIDA POWER AND LIGHT?

A Both of these utilities appear to have the proper aged data to conduct an actuarial life analysis and Mr. Allis proposed significantly higher lives. In the current Duke Energy Florida rate case, Mr. Allis proposed a 50-R1 survivor curve. In the 2021 Florida Power and Light rate case, Mr. Allis proposed a 44-S0 survivor curve for the Account 367 – Duct System and 40-S0.5 survivor for Account 367 – Direct Buried Cable.[12] When proper aged data is available, the lives for mass property assets like those in Account 367 tend to have longer lives.

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[11]Exhibit No. NA-1, Document No. 2 at page 424.
[12]Docket No. 20210015-EI, Exhibit NWA-1, pages 761 and 763.

C30-3058

Q WHAT IS THE TYPICAL RANGE OF LIVES RECOMMENDED BY GANNETT FLEMING (MR. ALLIS' FIRM) FOR ACCOUNT 367?

A Gannett Fleming maintains a database that tracks the life and net salvage parameters for all accounts for all the depreciation studies that it conducts. This database contains depreciation parameters for over 100 electric utility companies. According to Gannett Fleming's own data, the typical range for Account 367 is a minimum of 40-years and a maximum of 65-years. The average ASL used for Account 367 is 50 years.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that the currently approved 45-R1.5 survivor curve be maintained for Account 367. A 45-year life is more in line with other Florida utilities and is in the range of reasonableness based on Gannett Fleming's own depreciation studies.

VI. TD&G NET SALVAGE RATES

Q WHAT ARE NET SALVAGE RATES?

A Net salvage rates are the portion of depreciation rates that are intended to recover the gross salvage cost less the cost of removal. A negative net salvage rate indicates that the cost of removal exceeds any gross salvage proceeds. Negative net salvage is a significant component of TECO's overall depreciation expense. As an example, a -20% net salvage rate for an account would mean that TECO would recover $120 for every $100 invested in the account.

Q WHAT PORTION OF THE PROPOSED DEPRECIATION EXPENSE INCREASE IS DUE TO CHANGES TO TD&G NET SALVAGE RATES?

A Mr. Allis shows that the TD&G net salvage rates account for $14 million of the $40.7 million increase.

Q WHAT ARE THE NET SALVAGE RATE RECOMMENDATIONS BASED ON?

A The net salvage rates are based on an analysis of company data from 1982 through 2022. 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.

Q WHAT IS YOUR GENERAL RECOMMENDATION FOR NET SALVAGE RATES?

A The retirement data analyzed typically represents a very small sample size of TECO's plant in-service. For example, Account 367, one of the largest accounts to which I will propose an adjustment has experienced just $81.6 million of retirements and $10.9 million of net salvage over the 41-year study period, for an overall net salvage rate of -13%. This represents just 11% of the 2024 plant in-service for this account. Mr. Allis recommends to increase the net salvage rate from the currently approved -5% up to -15%. 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%.

Q WHAT ARE YOUR RECOMMENDATIONS FOR THE NET SALVAGE RATE ADJUSTMENTS?

A Table 4 shows my recommended adjustments for 9 of TECO's TD&G accounts. The net salvage analysis was conducted by Mr. Allis. For convenience I have included the relevant pages from TECO's depreciation study in Exhibit BCA-5.

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

As can be seen, all of my adjustments result in net salvage rates that do not exceed TECO's experienced net salvage by more than 1% and have been rounded to the 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.

VII. FEA'S PROPOSED DEPRECIATION RATES

Q HAVE YOU CALCULATED THE DEPRECIATION RATES CONSISTENT WITH YOUR RECOMMENDATIONS TO USE A 40-YEAR LIFE FOR THE BIG BEND AND BAYSIDE COMBINED CYCLE PLANTS, THE INTERIM RETIREMENT SURVIVOR CURVE ADJUSTMENTS FOR THE PRODUCTION ACCOUNTS, THE USE OF A 45-R1.5 SURVIVOR CURVE FOR ACCOUNT 367 AND THE NINE NET SALVAGE RATE ADJUSTMENTS PROPOSED FOR VARIOUS TRANSMISSION AND DISTRIBUTION ACCOUNTS?

A Yes. I have calculated all of TECO's depreciation rates consistent with the adjustments recommended in this testimony. The resulting depreciation rates are shown in Exhibit BCA-6. I provide a comparison of FEA's depreciation rates and expense to those proposed by TECO in Exhibit BCA-7. Table 5 below summarizes the impact by functional group.

TABLE 5

Impact of FEA's Proposed Depreciation Rates and Expense for Electric Plant as of December 31, 2024

	Depreciation Expense ($ Millions)				Depreciation Rates		
			Difference				
Depreciable Group	**TECO**	**FEA**	**Amount**	**Percent**	**TECO**	**FEA**	**Difference**
Steam	$ 59.33	$ 55.75	$ (3.58)	-6.03%	4.07%	3.83%	-0.24%
Other Production	$ 142.40	$ 125.23	$ (17.17)	-12.06%	3.91%	3.44%	-0.47%
Solar	$ 62.81	$ 62.87	$ 0.06	0.10%	3.50%	3.50%	0.00%
DC Micro Grid	$ 0.03	$ 0.03	$ 0.00	0.11%	3.48%	3.48%	0.00%
MacDill AFB	$ -	$ 0.00	$ 0.00	0.00%	0.00%	0.00%	0.00%
Transmission	$ 33.43	$ 33.02	$ (0.42)	-1.25%	2.61%	2.58%	-0.03%
Distribution	$ 150.66	$ 141.01	$ (9.65)	-6.41%	3.68%	3.45%	-0.23%
General	$ 10.2	$ 9.62	$ (0.62)	-6.06%	2.96%	2.78%	-0.18%
Total	**$ 458.91**	**$ 427.53**	**$ (31.38)**	**-6.84%**	**3.64%**	**3.39%**	**-0.25%**

Sources: Exhibit BCA-7

Q WHAT IS YOUR ULTIMATE RECOMMENDATION TO THE COMMISSION WITH RESPECT TO DEPRECIATION RATES?

A I recommend that the Commission reject the depreciation rates proposed by TECO in its Exhibit No. NA-1, Document No. 2 and instead approve the rates that I have calculated in Exhibit BCA-6. These rates are the result of reasonable adjustments, alleviating the burden of excessive depreciation expense, all the while allowing TECO the full opportunity to recover its investment over the remaining lives of its assets.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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C30-3063

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As an Principal at BAI, and as an Associate, Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

C30-3065

(Whereupon, Exhibit Nos. 106-112 were received into evidence.)

CHAIRMAN LA ROSA: I believe you have a witness.

CAPTAIN GEORGE: Yes, Mr. Chairman. FEA would call Mr. Michael Gorman to --

CHAIRMAN LA ROSA: Mr. Gorman, welcome, and if you don't mind administering the oath before you sit down.

Please raise your right hand.

Whereupon,

MICHAEL P. GORMAN

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do.

CHAIRMAN LA ROSA: Thank you.

You are free to get settled in, and in your hands when you are ready.

CAPTAIN GEORGE: Thank you, Mr. Chairman.

EXAMINATION

BY CAPTAIN GEORGE:

Q Good morning, Mr. Gorman. Could you please state your full name for the record please?

A My name is Michael Gorman.

Q And by whom are you employed and in what capacity?

A By Brubaker & Associates as a Managing Principal.

Q And what is your business address?

A 16690 Swingley Ridge Road, Chesterfield, Missouri.

Q And on whose behalf are you testifying?

A Federal Executive Agency.

Q And did you prepare and cause to be filed direct testimony on June 6th, 2024, consisting of 19 pages?

A Yes.

Q And though I know the answer to this question, just for clarification, did you have any attachments or exhibits?

A I did not.

Q Okay. Do you have any changes or corrections to your testimony?

A I do not.

Q And if you were asked those same questions today, would your answers be the same?

A Yes.

CAPTAIN GEORGE: At this time, FEA moves to enter Mr. Gorman's prefiled testimony into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Michael P. Gorman was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	**DOCKET NO. 20230090-EI**

Direct Testimony of

Michael P. Gorman

On behalf of

Federal Executive Agencies

June 6, 2024

Brubaker & Associates, Inc.

Project 11662

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
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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.	**DOCKET NO. 20230090-EI**

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Direct Testimony of Michael P. Gorman

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	)	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	)	**DOCKET NO. 20230090-EI**

Direct Testimony of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Federal Executive Agencies ("FEA"). FEA, including MacDill Air Force Base, is a large customer of Tampa Electric Company ("TECO" or "Company").

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony addresses cost of service, revenue allocation and rate design. To the extent my testimony does not address any particular issue does not indicate tacit agreement with the Company's or another party's position on that issue.

Q PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A My testimony addresses the following items:

1. The Company's Class Cost of Service Study ("CCOSS") reflects the 2021 Stipulation and Settlement Agreement ("2021 Agreement") approved by the Florida Public Service Commission ("FPSC" or "Commission") in Order No. PSC-2021-0423-S-EI. The results of this CCOSS should be utilized to assign costs to the studied rate classes.

2. The spread of the proposed revenue increase across tariff rate classes is reasonable and moves rates much closer to cost of service.

3. The Company's proposed rate design for the time-of-day rates has been revised to reflect different energy charges during the Peak, Off-Peak and Super Off-Peak periods.

I. CLASS COST OF SERVICE STUDY

Q DID THE COMPANY OFFER A CCOSS IN THIS CASE?

A Yes. The Company's CCOSS is offered by TECO witness Jordan Williams. As outlined in Mr. Williams' testimony, he developed a CCOSS in the following steps:

1. First, he functionalized costs into specific functions necessary to provide service to retail customers. Those functions include production, transmission, distribution,

and customer components. The distribution costs were functionalized to the primary and secondary level.

2. After the costs were functionalized, Mr. Williams then classified costs into demand, energy, and customer cost-related components. To enhance the development of the customer costs associated with the distribution system, a Minimum Distribution System ("MDS") was performed

3. After functionalizing and classifying the costs, the costs were assigned to the various rate classes utilizing developed demand, energy and customer cost allocators.

4. As per the 2021 Agreement, the demand-related production and transmission costs were allocated using a 4 Coincident Peak ("4 CP") methodology. As stated in Mr. Williams' Direct Testimony on pages 23 and 24:

    > The proposed 4 CP methodology allocates costs to 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.

5. For distribution costs, TECO uses the MDS to separate distribution costs into two classifications – customer and demand. For the customer classified distribution costs, the Company allocates those costs on the number of customers in each rate class. For primary distribution classified as demand costs, the Company allocates the costs across rate classes based on non-coincident demands and for the secondary distribution classified as demand costs, the costs are allocated based on maximum demands.[1]

Q DO YOU BELIEVE THE COMPANY'S COST OF SERVICE STUDY IS REASONABLE?

A Yes. The Company's CCOSS allocation of generation capacity and transmission capacity costs on the 4 CP methodology reflects cost causation. The Company's proposal to use the MDS to classify distribution costs into demand and customer components is reasonable.

---

[1]Minimum Filing Requirements Schedule E Cost of Service Study: 4 CP-Present and Proposed Rate Structure.

C31-3105

Q DID THE COMPANY FILE AN ADDITIONAL COST OF SERVICE STUDY?

A Yes. Volume III of TECO's filing contains a CCOSS that uses the 12 Coincident Peak and One Thirteenth Average Demand ("12 CP and 1/13th AD") cost allocation methodology and excludes the implementation of the MDS. It is my understanding that this CCOSS was prepared and filed as a Minimum Filing Requirement but is not recommended by the Company for this case.

Q SHOULD THE COMMISSION UTILIZE THE RESULTS OF THE 12 CP AND 1/13th AD CCOSS FOR DEVELOPING THE RATE CLASSES' REVENUE REQUIREMENTS?

A No. The use of the 4 CP to allocate demand-related production and transmission costs and employing the MDS to develop the demand and customer-related functionalized costs properly reflect cost-causation. Mr. Williams supports utilizing the 2021 Agreement CCOSS to establish the rate classes' revenue responsibility.

Q DO YOU SUPPORT THE USE OF THE 4 CP TO ALLOCATE PRODUCTION AND TRANSMISSION DEMAND-RELATED COSTS?

A Yes. As stated in Mr. Williams' Direct Testimony, the 4 CP methodology reflects cost causation in relation to TECO's peak demands. TECO's peak demands are driven by energy consumption that is related to the weather in the coldest and hottest months. The 2021 Settlement identified those months as January, June, July and August. Mr. Williams states the reasons for using the 4 CP in his Direct Testimony on pages 25 and 26.

Q DO YOU SUPPORT THE USE OF THE MDS TO FUNCTIONALIZE DISTRIBUTION COSTS?

A Yes. The MDS separates distribution costs into both customer-related and demand-related categories. After these costs are separated, the customer costs are allocated to the rate classes based on the number of customers in each rate class and the demand costs are allocated to the rate classes based on class demands.

Q IS AN MDS A NEW COST OF SERVICE CONCEPT?

A No. The MDS has been accepted for decades as a valid consideration of numerous state public utility commissions. The MDS was presented in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual") in January 1992.[2] The central idea behind the MDS is that there is a minimum cost incurred by a utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the MDS comprises every distribution component necessary to provide service (i.e., meters, services, secondary and primary wires, poles, substations, etc.). A certain portion of the costs of the distribution system is required just to connect customers to the system regardless of the demand or energy requirements.

Q WHAT ARE THE RESULTS OF TECO'S CCOSS THAT UTILIZE THE 4 CP METHODOLOGY AND INCLUDE THE MDS?

A Table MPG-1 below shows the result of the Company's 4 CP and full MDS CCOSS at present rates.

[2]Electric Utility Cost Manual, National Association of Regulatory Utility Commissioners, January 1992, at 86-96.

C31-3107

TABLE 1

Cost of Service Results - Present Rates
($000)

Rate Class	Rate Base	Net Operating Income	ROR	ROR Index
RS	$6,080,302	$ 301,653	4.96%	0.97
GS	$ 520,092	$ 35,123	6.75%	1.32
GSD	$2,379,537	$ 98,676	4.15%	0.81
GSLDPR	$ 274,056	$ 17,556	6.41%	1.25
GSLDSU	$ 176,440	$ 7,542	4.27%	0.84
LS Energy	$ 12,808	$ 1,789	13.97%	2.73
LS Facilities	$ 354,915	$ 39,034	11.00%	2.15
Total	$9,798,150	$ 501,373	5.12%	1.00

Source: MFR - E Schedules - Volume II of IV, pg. 2

The rate classes are Residential Service ("RS"), General Service - Non-Demand ("GS"), General Service - Demand ("GSD"), General Service - Large Demand - Primary ("GSLDPR"), General Service - Large Demand - Subtransmission ("GSLDSU"), Lighting Service Energy ("LS Energy") and Lighting Service Facilities ("LS Facilities"). Table 1 shows the two largest rate classes' (RS and GSD) current rates provide revenues that produce a Rate of Return ("ROR") below the system average ROR. That means those rate classes are being subsidized by the rate classes that provide an ROR above the system average of 5.12%.

C31-3108

II. CLASS REVENUE ALLOCATION

Q HOW IS TECO PROPOSING TO RECOVER ITS CLAIMED REVENUE DEFICIENCY FROM ITS RATE CLASSES?

A As stated on page 27 of Mr. Williams' Direct Testimony, TECO is proposing a revenue increase for its retail customer classes of $293.6 million. The current projected retail billed electric revenues for 2025 are $1.480 million.

The first step in allocating the increase was to determine the rate changes in the service charge revenues and other operating revenues. Those changes were used to offset a portion of the proposed base rate revenue deficiency. In the second step, the rates for the rate classes were developed to recover the remaining revenue deficiency.

Q HOW DID TECO ALLOCATE THE PROPOSED BASE RATE REVENUE DEFICIENCY TO THE VARIOUS RATE CLASSES?

A The remaining revenue deficiency balance was used to bring rates closer to the CCOSS results. The 2021 Agreement requires TECO to "substantially and materially improve the position of all above-parity customer classes towards parity, such that costs are allocated and revenue is collected consistent with 4 CP and full MDS method.[3]" No rate class received a rate reduction.

Table 2 shows the Company's proposed increase in operating and service charge revenues by rate class, relative to current operating and service charge revenues by rate classes.

[3]Williams Direct at 33-36.

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

Table 2 shows that those rate classes that were below cost to serve received the largest rate increases.

Q WHAT IS THE IMPACT ON EACH RATE CLASS'S ROR OF THE COMPANY'S ALLOCATION OF THE PROPOSED RATE INCREASES?

A The Company's allocation of the proposed revenue increase significantly moves rates closer to cost of service. Table 3 shows the results of the Company's 4 CP and full MDS CCOSS at their proposed rates.

C31-3110

TABLE 3

Cost of Service Results - Proposed Rates
($000)

Rate Class	Rate Base	Net Operating Income	ROR	ROR Index
RS	$6,080,302	$ 437,365	7.19%	0.98
GS	$ 520,092	$ 38,327	7.37%	1.00
GSD	$2,379,537	$ 173,660	7.30%	0.99
GSLDPR	$ 274,056	$ 20,210	7.37%	1.00
GSLDSU	$ 176,440	$ 12,166	6.90%	0.93
LS Energy	$ 12,808	$ 1,793	14.00%	1.90
LS Facilities	$ 354,915	$ 39,075	11.01%	1.49
Total	$9,798,150	$ 722,596	7.37%	1.00

Source: MFR - E Schedules - Volume II of IV, pg. 45

The Company's proposed revenue spread makes a substantial movement toward cost of service for all rate classes. The Lighting rate classes did not receive a base rate increase.

III. GSLDPR RATE DESIGN

Q WHAT REVISIONS WERE MADE TO THE GSLDPR RATES?

A TECO has two GSLDPR rates. The first GSLDPR is a standard rate that contains a Daily Basic Service Charge, Demand Charge and Energy Charge. The Demand and Energy Charges are constant throughout the year. Table 4 below shows the current and proposed changes for the standard rate.

TABLE 4

Standard GSLDPR Rates

Charges	Unit	Present Rate	Proposed Rate	Percent Increase
Daily Basic Service	$/day	$19.52	$21.42	9.7%
Demand	$/kW	$11.88	$13.00	9.4%
Energy	¢/kWh	1.0421¢	1.063¢	2.0%

Source: MFR - E Schedules; Schedule E-8, pg. 109

The second GSLDPR is an optional Time-of-Day ("TOD") rate. Approximately 80% of the GSLDPR energy is consumed on the TOD rate.[4]

The proposed rate contains energy rates for three time periods. TECO is proposing to add a Super Off-Peak period and to remove the seasonality rates from its TOD periods.[5] For the Super Off-Peak period, TECO is proposing an energy charge that is significantly below both the peak and off-peak energy charges.[6] TECO has increased both during the peak and off-peak energy charges. TECO contends that the recent and continued investment in renewable generation assets has resulted in a change in TECO's hourly cost profile.[7]

For the demand charge, TECO has increased the per-kilowatt ("kW") billing charges for the peak periods from $8.08/kW to $10.07/kW, and reduced the charge for the overall peak demand from $3.77/kW to $2.93/kW.[8]

[4] MFR – E Schedules, Schedule E-13C, page 12.
[5] *Id*. at 29-31, and MFR – E Schedules, Schedule E-8.
[6] MFR – E Schedules, Schedule E-8, pages 123-125.
[7] Williams Direct at 31.
[8] MFR – E Schedules, Schedule E-8, page 123.

Q DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY'S PROPOSED ADJUSTMENTS TO THE GSLDPR RATE?

A Yes. In general, I concur with TECO's proposed revisions to the rates. However it appears that TECO's rate design over-collects on the energy charge and under-collects on the demand charge.

Table 5 below shows the proposed percent revenues that TECO will collect from the Standard and TOD GSLDPR proposed Basic Service, Energy and Demand charges.

TABLE 5

GSLDPR Revenue by Charges
($000)

Charges	Standard Rate Cost	Percent	TOD Rate Cost	Percent
Service	$ 184	1.6%	$ 287	0.8%
Energy	$ 2,742	24.3%	$ 10,941	31.5%
Demand	$ 8,362	74.1%	$ 23,454	67.6%
Total	$ 11,288	100.0%	$ 34,682	100.0%

Table MPG-5 shows that for the TOD revenues approximately 68% are collected through demand charges. A review of the CCOSS shows that the GSLDPR revenue requirement is made up of a larger portion of demand-related costs.

Q HOW DOES THE COLLECTION OF THE REVENUES COMPARE WITH THE CUSTOMER, ENERGY AND DEMAND UNIT COSTS THAT RESULT FROM THE 4 CP CCOSS FOR GSLDPR?

A TECO's Minimum Filing Requirements - E Schedules - Cost of Service Study - Volume II of IV, page 77 provides a "Derivation of Unit Costs" ("UNTCST") for

GSLDPR. The UNTCST provides the GSLDPR costs by functional revenue requirement, production, transmission, subtransmission and distribution, along with the demand, energy and customer classifications for each. Table 6 shows a summary of the GSLDPR revenue requirement unit costs that are related to demand, energy and customer.

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	

Table 6 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. The GSLDPR demand charges should be increased and the energy charges reduced.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate

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design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

497956

C31-3118

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	**DOCKET NO. 20240026-EI**
In re: 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 2021 Stipulation and Settlement Agreement, by Tampa Electric Company.	**DOCKET NO. 20230090-EI**

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of Michael P. Gorman

Michael P. Gorman, being first duly sworn, on his oath states:

1. My name is Michael P. Gorman. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony which was prepared in written form for introduction into evidence in the Florida Public Service Commission Docket Nos. 20240026-EI, 20230139-EI and 20230090-EI.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

Michael Gorman

Michael P. Gorman

Subscribed and sworn to before me this 6th day of June, 2024.

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

Sally D Wilhelms

Notary Public

BY CAPTAIN GEORGE:

Q And do you have a summary of your testimony prepared?

A I do, yes.

Good morning, Commissioners. My testimony addresses the development of class cost of service study. I supported the company's use of the class cost of service study that aligned with the 2021 stipulation in its previous rate case. That class cost of service study allocated production and transmission costs based on a four coincident peak methodology. That allocation aligns with the amount of capacity the utility has to invest for production and transmission resources in order to serve customers -- reliably serve customers throughout the year.

That capacity that is used to provide service during peak periods can be operated at less than 100 percent load factor to serve their demands during non-peak periods. But the 4CP at the allocation of production and transmission capacity cost that aligns with system peak aligns also with the company's cost of investing in capacity necessary to provide firm and reliable service to its customers.

I also support the company's classification of distribution cost based on demand and customer components. Distribution costs are incurred not only to serve the demands on the distribution circuits, but the costs are also incurred to ensure that all customers are connected to the distribution system. Consequently, distribution costs are incurred based on both demands and number of customers on the system.

The company's proposed spread of the increase generally aligns with this proposed class cost of service study, but it did gradually move the rate classes towards cost of service while eliminating rate subsidies between various rate classes.

Finally, on the allocation of the rate cost for the large general service demand rate, I believe the company's class cost of service study supports increasing the demand charge more than the energy charge is a significant amount of the cost allocated to that specific rate class is demand related, and a larger increase in demand charge than energy charge would better align with designing that rate to reflect cost of service.

That summarizes my, my testimony in this case.

Q Thank you.

CAPTAIN GEORGE: Mr. Gorman is free for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

OPC.

MS. CHRISTENSEN: No questions.

CHAIRMAN LA ROSA: Florida Rising/LULAC.

MR. MARSHALL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MARSHALL:

Q Good morning.

A Good morning.

Q You would agree that a class cost of service study should reflect cost causation?

A Yes.

Q And the 4CP methodology you believe reflects cost causation because peak demands are driven by energy consumption, and that the 2021 settlement identifies those months as January, June, July and August?

A There is a lot in that question.

I believe that peak demand drives the need to invest in capacity for production and transmission resources in order to provide classes firm service -- reliable firm service. So 4CP is the load characteristic the utility observes when determining how to invest, and how much to invest in production and transmission capacity.

Q And the 2021 settlement identified the months used for that 4CP as January, June, July and August?

A Yes.
Q Has January actually been a peaking month?
A Not historically, but the company is projecting that it will.
Q Can the 2021 settlement itself change when TECO's system actually peaks?
A Well, the 4CP methodology, the appropriate methodology, can change based on changes in load characteristics. But the settlement that was outlined in the 2021 settlement is still reflective of load characteristics in this case.
Q So can the 2021 settlement actually determine whether TECO's system will peak in January?
A The settlement can't determine, but the load characteristics in the rate case can determine, and the projected load characteristics in the effective rate period are relevant in determining the peak periods used to design the 4CP allocators in this case.
Q And this cost causation presumption based on system peaks assumes implicitly, doesn't it, that generation is being added to address those peaks?
A It implicitly assumes that there has to be adequate reliable generating and transmission capacity to serve those peaks. Yes.
Q And so, as a corollary to that, it assumes

that generation is being -- that the reason generation investments are being made is to address those peaks?

A Production and transmission investments are made to address system peak. Yes.

Q And it also assumes, doesn't it, that generation that is actually being added to the system is actually capable of addressing those peaks?

A Well, there is complications in revaluating the accredited capacity of production resources to serve peak demands, particularly with the introduction of invercory (PH) resources, such as wind and solar resources, which are non-dispatchable. But the accredited capacity of the various resources that go into their production resource portfolio is designed to allow the utility to serve -- to reliably serve peak demands on the system.

Q And so I think you are going where I am going. You didn't actually conduct an analysis of TECO's generation investments as part of your direct testimony?

A I reviewed the load characteristics of the system and whether or not a 4CP methodology reasonably allocated the cost of the production resources across the various rate classes.

Q But you didn't actually look at the kinds of generation investments that TECO is making as part of

your direct testimony?

A That I did not, because the allocation was generally based on how you allocate the existing production resource that is used to provide service to customers that aligns without that generation portfolio.

Cost was incurred in order to provide service to customers. And that analysis led me to conclude that a 4CP allocator is the most reasonable way to assign that production of resource portfolio cost across the various rate classes.

Q So you didn't conduct an analysis of the firm capacity values of the solar that TECO is adding to its system?

A Not specifically, but other than to understand that TECO had adequate accredited capacity to serve its peak demands.

Q On page six of your testimony, you point out that under TECO's 4CP with MDS cost of service methodology, the RRS class and GSE class are below this average system rate of return, and are, therefore, being subsidized by the other rate classes?

A That's correct.

Q And that assumes, doesn't it, that the four peaks in TECO's cost of service study are the actual peaks driving TECO's generation investments, and that

TECO's generation investments are being made to address those peaks?

A Well, it, in part, allocates the cost of the various infrastructure used to provide service to the various rate classes, including the amount of production capacity necessary to provide reliable service to those rate classes.

Q And so I think in your answer there, you said that it is assuming that it's making those generation investments for that production capacity?

A Well, the generating -- the resource portfolio, production resource portfolio of the utility is designed to meet the demands of the system so all customers can receive firm service to the extent they want firm service. And the 4CP allocator is used to apportion that resource portfolio cost to the various rate classes based on that cost causation principle.

Q So is it your testimony that TECO is only investing in its solar power plants for its production capacity value?

A It's one element of the justification for choosing to invest in the solar generating resource, is the accredited capacity of the solar resource, plus the operating benefits of that resource in serving both demand and energy in the system.

Q Have you conducted an analysis showing a different capacity credit for that solar than TECO has put forward in this case?

A No, that -- part of any integrated resource plan, I would look at that to determine whether or not they are designing the resource production portfolio in the least cost manner. The purpose of this case --

Q But my question is, no, you have not conducted an analysis that's contrary to TECO's on the capacity credit of the solar TECO is investing in in this case?

A I have not evaluated this case based on an integrated resource planning asset to evaluate the specific resources that are included in its production resources.

Rather, my analysis in this case was based on determining in a methodology that reasonably out apportioned those -- that production resource portfolio cost across the various rate classes, in line with the cost the utility incurred to provide service to each of those rate classes.

Q Was that a no?

A It was an explanation of what I did in this case. I did not --

Q So did you do that analysis? It should be a yes or a no.

A Let me be clear. The analysis you are asking is whether or not I looked at the accredited capacity of each of the portfolio resources within the resource portfolio. The answer to that is no.

Q Thank you.

A And I believe I did say I didn't do that at the beginning of my last answer.

Q If you did, I missed it, and I apologize.

You also have -- include in your testimony an analysis comparing the various rate classes to the system average rate of return. And I believe that is what's up on the screen right now, is that right?

A Yes.

Q And it shows residential class on -- and this is based on the 4CP with MDS methodology?

A Yeah, the company's proposed class cost of service study.

Q And it shows the -- that the class RS is 0.03 points below the system rate of return?

A Which class did you refer to?

Q RS. That's residential.

A It's a 4.96 percent rate of return, or 97 percent relative rate of return.

Q Right, and so that would be 0.03 points below that 1.0 relative rate of return, is that right?

A Can you repeat those numbers?

Q 1.00 minus 0.97 is 0.03.

A I am not sure what calculation you are making.

Q In the right column there, you have a rate of return index, is that right?

A Yes.

Q And the system average, of course, is going to be 1.0?

A Yes.

Q And so the rate of return index on that column for residential customers is 0.97?

A Correct.

Q And that is 0.03 below 1.0?

A That's correct.

Q And class GSD is 0.19 below that system rate of return?

A It's 0.19 percent the one times relative rate of return index.

Q And isn't that six times more below that index?

A Six times more than the residentials?

Q Yes.

A It's pretty close, yes.

Q And class GSLDSU is also 0.16 points below that index?

A Yes.

Q And so even under TECO's 4CP with MDS cost of service methodology and your terminology, once accounting for size, aren't classes GSD and GSLDSU being subsidized relatively more than RS?

A Well, there are further below cost of service based on this cost of service study, then yes.

Q Thank you.

MR. MARSHALL: That's all my questions, Mr. Chairman.

CHAIRMAN LA ROSA: Great. Thank you.

FIPUG.

EXAMINATION

BY MR. MOYLE:

Q I just have a question with respect to that chart up there, you were asked some questions about the relative contribution that the GSLDPR. That's above parity, is it not?

A It is, yes.

Q And those are our large commercial --

MR. MARSHALL: Mr. Chairman, I am going to object to friendly cross.

CHAIRMAN LA ROSA: Are you looking for clarification, or --

MR. MOYLE: I am just trying to understand the follow-up on the question he just asked with respect to the impacts. He has maintained, oh, that the commercials are getting subsidized by the residential --

CHAIRMAN LA ROSA: I am going to allow the question. I understand where -- I can understand where you are coming from, but I am going to allow the question. Maybe restate the question.

BY MR. MOYLE:

Q So --

A Yes. That rate class is priced above cost of service at current rates.

Q And do you know what that rate class looks like in terms of -- is it large users of electricity?

A Yeah. General service, large demand, primary delivery voltage customers.

Q So based on that, they would be subsidizing residential?

MR. MARSHALL: Mr. Chairman, I am going to renew my objection. This is basically redirect.

CHAIRMAN LA ROSA: Okay. I am going to --

MR. MOYLE: That's my -- I mean, that's the last question I have, is just, you know, if you are going to put it up there, you got to be able to stand by it.

CHAIRMAN LA ROSA: I am going to go to my Advisor on this, from a legal perspective.

MS. HELTON: Mr. Chairman, it does appear to be friendly cross, which is prohibited by our Prehearing Order.

CHAIRMAN LA ROSA: Sure. I understand, then I sustain the objection.

Any further questions?

MR. MOYLE: No, sir.

CHAIRMAN LA ROSA: Okay. So we will then go to Florida Retail.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.

CHAIRMAN LA ROSA: Staff.

MR. SPARKS: No questions.

CHAIRMAN LA ROSA: Commissioners, do we have questions?

Seeing none, FEA for redirect.

CAPTAIN GEORGE: Briefly.

FURTHER EXAMINATION

BY CAPTAIN GEORGE:

Q Mr. Gorman, ultimately, your analysis and your

testimony covers cost of service and rate design based on the cost causation principles, correct?

A It does. Yes.

Q And generally speaking, this just means that working towards the best allocation methodology and cost of service for people -- for customers to pay for the service that they are demanding?

A It allows for the development of efficient price signals to customers. It reflects the utility's true cost to providing them service, which, in turns, provides economic incentive to customers to make economic consumption decisions, and to pursue conservation of energy where economically possible.

Q And then to go back to this chart, asking the question in regards to the GSLDPR rate class, it is at 1.25 ROR index, correct?

A Yeah. That indicates it's priced above cost of service at current rates.

Q So as of right now, the current rates, it is subsidizing the residential class?

A Yes, it does.

CAPTAIN GEORGE: I have no further questions.

CHAIRMAN LA ROSA: Great. Thank you.

Are there exhibits to move into the record?

CAPTAIN GEORGE: None from FEA.

CHAIRMAN LA ROSA: Any other exhibits to move in?

Okay. Seeing none, Mr. Gorman, I believe you are excused.

THE WITNESS: Thank you.

CHAIRMAN LA ROSA: Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: Okay. I just want to go to Florida Retail real quick. You have a witness, but I believe the witness is not here, right?

MR. LAVIA: He has been excused. Yes, sir.

CHAIRMAN LA ROSA: Okay. Do we need to move testimony to the record?

MR. LAVIA: Yes, sir. There was a stipulation approved, I believe, concerning his testimony during preliminary matters; is that accurate, staff?

MS. HELTON: That is correct.

MR. LAVIA: Thank you.

Mr. Chriss did prefile testimony on June 6th, consisting of 15 pages, and we would ask that be moved into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Steve W. Chriss was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	**DOCKET NO. 20240026-EI**

DIRECT TESTIMONY AND EXHIBITS OF

STEVE W. CHRISS

ON BEHALF OF

FLORIDA RETAIL FEDERATION

JUNE 6, 2024

Contents

Exhibits

Exhibit SWC-1: Witness Qualifications Statement

Exhibit SWC-2: Impact of TECO's Proposed Increase in Return on Equity ($000) vs. Originally Approved

Exhibit SWC-3: Impact of TECO's Proposed Increase in Return on Equity ($000) vs. ROE Trigger

Exhibit SWC-4: Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2021 to Present

Exhibit SWC-5: Impact of TECO's Proposed Increase in Return on Equity ($000) vs. National Average, Vertically Integrated

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72716-0550. I am employed by Walmart Inc. ("Walmart") as Senior Director, Utility Partnerships.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Florida Retail Federation ("FRF"), a statewide trade association of more than 8,000 of Florida's retailers, many of whom are retail customers of Tampa Electric Company ("TECO" or "Company"). As an example, Walmart has 36 stores and clubs, one distribution center, and related facilities that take service from TECO. Our facilities primarily take service on the Company's Time-of-Day General Service – Demand rate schedule.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to

Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to Director, Energy and Strategy Analysis in October 2016 and the position was re-titled in October 2018. I was promoted to my current position in July 2023. My Witness Qualifications Statement is attached as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I testified in Docket Nos. 20110138-EI, 20120015-EI, 20130140-EI, 20130040-EI, 20140002-EI, 20160021-EI, 20160186-EI, 20190061-EI, 20200067-EI, 20200069-EI, 20200070-EI, 20200071, 20200092, 20200176, 20210015, 20240012-EG, 20240013-EG, 20240014-EG, 20240015-EG, 20240016-EG, and 20240017-EG.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 270 proceedings before 42 other utility regulatory commissions. I have also submitted testimony before legislative committees in six states. My testimony has addressed topics including, but not limited to, cost of service and rate design, return on equity, revenue requirements, ratemaking policy, net metering, community solar, large customer renewable programs, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

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Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT TECO'S PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are TECO's residential and small business customers. Given current economic conditions, a rate increase is a serious concern for retailers and their customers, and the Commission should consider these impacts thoroughly and carefully in ensuring that any increase in TECO's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to TECO's rate case filing and to provide recommendations to assist the Commission in its thorough and careful consideration of the customer impact of the Company's proposed rate increases.

Q. PLEASE SUMMARIZE FRF'S RECOMMENDATIONS TO THE COMMISSION.

A. FRF's recommendations to the Commission are as follows:

1) 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. Specifically, the Commission should closely examine TECO's proposed revenue requirement increase and the associated ROE in light of:

   a. The customer impact of the resulting revenue requirement increases;
   b. The use of a future test year, which reduces regulatory lag by allowing the utility to include projected costs in its rates at the time they will be in effect;
   c. The high degree of revenue certainty realized by TECO through recovery of a substantial proportion of total retail revenues through cost recovery clauses;
   d. Recent rate case ROEs approved by the Commission; and
   e. Recent rate case ROEs approved by other state regulatory commissions nationwide.

2) For the purposes of this docket, FRF does not oppose the Company's proposed cost of service study.

3) For the purposes of this docket, FRF does not oppose the Company's proposed revenue allocation methodology.

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Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE FRF'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

Return on Equity

Q. WHAT IS YOUR UNDERSTANDING OF TECO'S PROPOSED REVENUE REQUIREMENT INCREASE IN THIS DOCKET?

A. My understanding is that TECO is requesting a general base rate increase for the 2025 test year of $296.6 million to be effective January 1, 2025, and additional subsequent year adjustments ("SYA") of $100.1 million to be effective January 1, 2026 and $71.8 million to be effective January 1, 2027. See Direct Testimony of Archie Collins, page 35, line 12 to page 36, line 9. In total, TECO is requesting a total increase over four years of $468.5 million.

Q. WHAT IS THE COMPANIES' PROPOSED ROE IN THIS DOCKET?

A. The Company proposes an ROE of 11.50 percent, based on a range of 9.90 percent to 12.49 percent. See Direct Testimony of Dylan D'Ascendis, page 7, line 1 to line 11.

Q. IS TECO'S PROPOSED ROE HIGHER THAN THEIR LAST APPROVED MIDPOINT ROE?

A. Yes. The Company's proposed ROE represents an increase of 155 basis points from TECO's last approved midpoint ROE of 9.95 percent. *See* Direct Testimony of Archie Collins, page 12, line 24. The proposed ROE is also 130 basis points higher than the ROE trigger result of 10.20 percent approved in 2022. *Id.*, page 14, line 2 to line 9.

Q. IS FRF CONCERNED ABOUT THE REASONABLENESS OF TAMPA ELECTRIC'S PROPOSED ROE?

A. Yes, especially when viewed in light of:

1) The customer impact of the resulting revenue requirement increases;

2) The use of a future test year, which reduces regulatory lag by allowing the utility to include projected costs in its rates at the time they will be in effect;

3) The high degree of revenue certainty that TECO realizes through the use of pass-through type cost recovery clauses;

4) Recent rate case ROEs approved by the Commission; and

5) Recent rate case ROEs approved by other state regulatory commissions nationwide.

Q. WHAT IS YOUR CONCERN WITH TECO'S ROE RELATIVE TO ITS USE OF COST RECOVERY CLAUSES?

A. Through the use of cost recovery clauses and charges, such as the Fuel and Purchased Power Cost Recovery Clause, the Environmental Cost Recovery Clause, the Energy Conservation Cost Recovery Clause, and other such clauses, TECO realizes great revenue certainty. For example, TECO's March 2024 Earnings Surveillance Report shows that TECO recovered nearly 39 percent of its total retail operating revenues through cost recovery clauses. This great degree of revenue certainty demonstrates correspondingly great reductions in risk, which should be

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reflected in the ROE approved for the Company.

Customer Impact

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT FOR THE 2025 TEST YEAR OF TECO'S PROPOSED INCREASE IN ROE FROM THE COMPANY'S LAST APPROVED MIDPOINT ROE OF 9.95 PERCENT?

A. The proposed increase in ROE from TECO's last approved midpoint ROE has an annual revenue requirement impact on the Company's rates of approximately $94.4 million for 2025. This constitutes about 32 percent of the Companies' overall increase request for the 2025 test year. *See* Exhibit SWC-2.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT FOR THE 2025 TEST YEAR OF TECO'S PROPOSED INCREASE IN ROE FROM THE COMPANY'S ROE TRIGGER MIDPOINT ROE OF 10.20 PERCENT?

A. When the approved ROE trigger midpoint is considered, the annual revenue requirement impact on TECO's rates is approximately $78.9 million for 2025. This constitutes about 27 percent of the Companies' overall increase request for the 2025 test year. *See* Exhibit SWC-3.

Future Test Year

Q. HAS THE COMMISSION RECOGNIZED THAT THE USE OF A FUTURE TEST YEAR IMPACTS THE UTILITY'S EXPOSURE TO REGULATORY LAG?

A. Yes. The use of a projected test year reduces the utility's financial risk due to regulatory lag because, as the Commission has previously stated, "the main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect."[1] As such, the Commission should carefully consider the level of ROE required in light of the Company's reduced exposure to regulatory lag.

Recent ROEs Approved by the Commission

Q. IS TECO'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN ROEs RECENTLY APPROVED BY THE COMMISSION?

A. Yes. In 2021, in addition to the TECO ROE discussed above, the Commission approved Duke Energy Florida, LLC's 2021 Settlement Agreement for its base rate case in Docket 20210016-EI, which included approval of an ROE midpoint of 9.85 percent.[2] Additionally, the Commission approved Florida Power & Light Company's 2021 Settlement Agreement of its base rate case in Docket 20210015-EI, which included approval of an ROE midpoint of 10.6 percent.[3]

As such, the Companies' proposed 11.5 percent ROE midpoint is excessive as compared to recent Commission actions regarding ROE.

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[1] *In re: Request for rate increase by Gulf Power Company*, Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI, Order Granting in Part and Denying in Part Gulf Power Company's Petition for Rate Increase (issued June 10, 2002), page 9.
[2] *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC*, Docket No. 20210016-EI, Order No. PSC-2021-0202-AS-EI, Final Order Approving 2021 Settlement Agreement (issued June 4, 2021).
[3] In re: Petition for rate increase by Florida Power & Light Company, Docket No. 20210015-EI, Order No. PSC-2021-0446-S-EI Approving 2021 Stipulation and Settlement Agreement (issued December 2, 2021).

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National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROEs APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS IN 2021, 2022, 2023, AND SO FAR IN 2024?

A. Yes. According to data from S&P Global Market Intelligence ("S&P Global"), a financial news and reporting company, the average of the 118 reported electric utility rate case ROEs authorized by regulatory commissions for investor-owned utilities in 2021, 2022, 2023, and so far in 2024, is 9.50 percent. The range of reported authorized ROEs for the period is 7.36 percent to 11.45 percent, and the median authorized ROE is 9.50 percent. The average and median values are significantly below the Company's proposed ROE of 11.5 percent. As such, TECO's proposed 11.5 percent midpoint ROE is excessive when compared to broader electric industry trends. *See* Exhibit SWC-4.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROEs ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by S&P Global, the average ROE for vertically integrated utilities authorized from 2021 through present is 9.62 percent. The average ROE authorized for vertically integrated utilities in 2021 was 9.54 percent; in 2022, it was 9.60 percent; in 2023, it was 9.71 percent; and thus far in 2024, it is 9.72

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percent. *Id.* As such, the Company's proposed 11.5 percent ROE is excessive in light of broader electric industry trends and, in fact, as shown in Figure 1, would be the highest approved ROE (out of 84) for a vertically integrated utility from 2021 to present, if approved by the Commission.

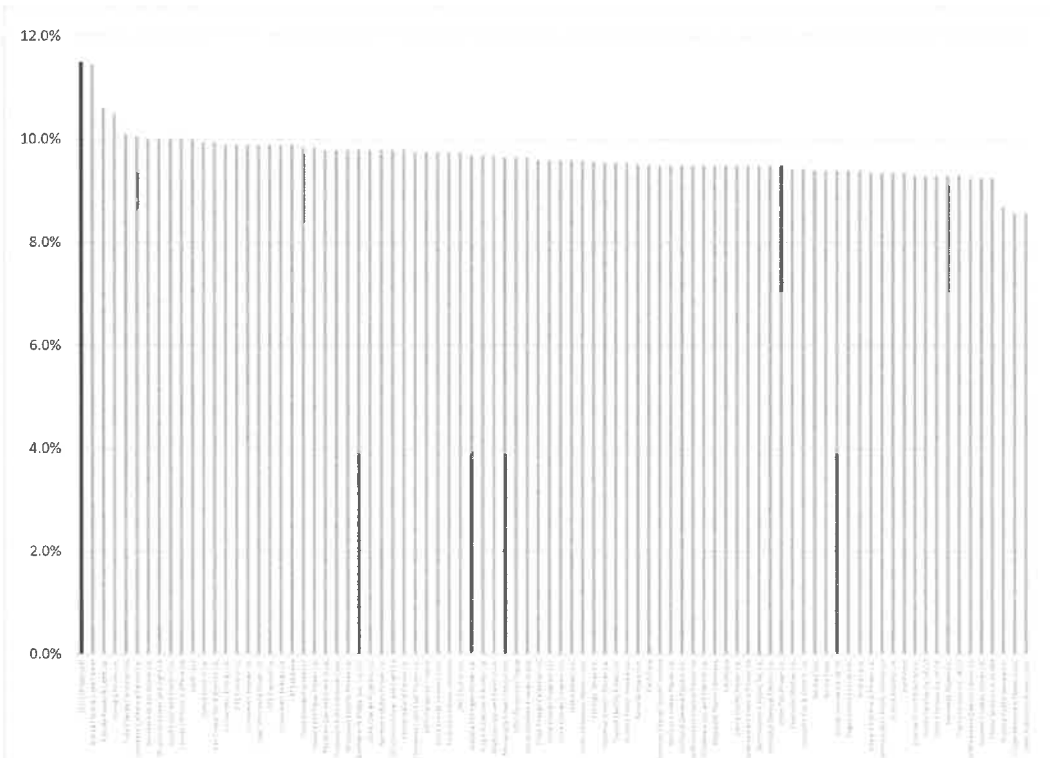

Figure 1. TECO's Proposed ROE Versus Authorized ROEs for Vertically Integrated Utilities, 2021 to present. Source: Exhibit SWC-4.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT WERE THE COMMISSION TO APPROVE AN ROE FOR TECO EQUIVALENT TO 9.72 PERCENT, THE AVERAGE AUTHORIZED ROE NATIONWIDE FOR VERTICALLY INTEGRATED UTILITIES IN 2024?

A. If the Commission were to approve an ROE for TECO of 9.72 percent, versus the Company's proposal of 11.5 percent, it would result in a reduction in the Company's

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proposed revenue requirement of $108.6 million, or 36.6 percent. *See* Exhibit SWC-5.

Q. IS FRF RECOMMENDING THAT THE COMMISSION BE BOUND BY ROEs AUTHORIZED BY OTHER STATE REGULATORY COMMISSIONS?

A. No. Decisions of other state regulatory commissions are not binding on the Commission. Additionally, each state regulatory commission considers the specific circumstances in each case in its determination of the proper ROE. FRF is providing this information to illustrate a national customer perspective on industry trends in authorized ROE.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN REGARD TO THE COMPANY'S PROPOSED ROE?

A. 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.

Cost of Service and Revenue Allocation

Q. GENERALLY, WHAT IS FRF'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. FRF advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, sends proper price

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signals, and minimizes price distortions.

Q. WHAT IS FRF'S UNDERSTANDING OF THE COMPANY'S PROPOSED COST OF SERVICE STUDY IN THIS DOCKET?

A. It is FRF's understanding that the Company's proposed cost of service study in this docket has been filed in compliance with the 2021 unanimous Stipulation and Settlement Agreement ("2021 Agreement") approved by the Commission in Order No. PSC-2021-0423-S-EI. Both FRF and Walmart were parties to the settlement, though 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 a settlement. The 2021 Agreement required that for retail-related costs, the Company implement the minimum distribution system and 4 CP cost allocation methodologies. *See* Direct Testimony of Jordan Williams, page 4, line 20 to line 23.

Q. WHAT IS FRF'S POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE STUDY?

A. For the purposes of this docket, FRF does not oppose the Company's proposed cost of service study.

Q. DOES THE 2021 AGREEMENT CONTAIN PROVISIONS REGARDING REVENUE ALLOCATION?

A. Yes. The 2021 Agreement also requires the Company to "substantially and materially improve the position of all above-parity customer classes toward parity." *Id.*, page 4, line 24 to line 25.

Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST OF SERVICE?

A. The Company represents this relationship in its cost of service study results through a comparison of class-specific rates of return. *See* Schedule E-8. These rates of return can be converted into a rate of return index ("RRI"), which is an indexed measure of the relationship of the rate of return for an individual rate class to the total system rate of return. An RRI greater than 1.0 means that the rate class is paying rates in excess of the costs incurred to serve that class, and an RRI less than 1.0 means that the rate class is paying rates less than the costs incurred to serve that class. As such, those rate classes with an RRI greater than 1.0 shoulder some of the revenue responsibility for the classes with an RRI less than 1.0.

Q. HAS THE COMPANY CALCULATED A RRI FOR EACH CUSTOMER CLASS BASED ON TECO'S COST OF SERVICE RESULTS AT PRESENT RATES?

A. Yes, as shown in Table 1 below.

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Table 1. Rate of Return Index, TECO Proposed Cost of Service Study Results, Present Rates.		
Customer Class	**Rate of Return (%)**	**RRI**
RS	4.96	0.97
GS	6.75	1.32
GSD	4.15	0.81
GSLDPR	6.41	1.25
GSLDSU	4.27	0.84
LS – Energy Service	13.97	2.73
LS – Facilities	11.00	2.15
Total Company	5.12	1.00
Sources: Schedule E-8.		

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S REVENUE ALLOCATION PROPOSAL?

A. As shown in Table 2, my understanding is that the Company proposes a revenue allocation that, with the exception of the LS class, brings classes much closer to their respective cost-based revenue requirements.

Table 2. Proposed Revenue Increases and Rate of Return Index.		
Customer Class	**Revenue Increase (%)**	**RRI**
RS	19.42	0.98
GS	4.40	1.00
GSD	32.37	0.99
GSLDPR	8.00	1.00
GSLDSU	26.07	0.93
LS – Energy Service	0.11	1.90
LS – Facilities	0.00	1.49
Total Company	5.12	1.00
Sources: Schedule E-8.		

The RS, GSD, GSLDSU, and LS classes were not set strictly at cost as the LS class, by application of Commission-approved rate transition policy, is not allowed to receive a rate decrease when the utility is receiving an overall revenue increase. *See* MFR Schedule E-8.

Q. WHAT IS FRF'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. For the purposes of this docket, FRF does not oppose the Company's proposed revenue allocation methodology.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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MR. WRIGHT: And Mr. Chriss' testimony included five exhibits, SWC-1 through SWC-5. That's 133 to 137 on the CEL. We also ask that they be moved into the record.

CHAIRMAN LA ROSA: Is there objection?

MR. WAHLEN: No objection.

CHAIRMAN LA ROSA: Seeing none -- yeah, I am sorry. Show them entered into the record.

(Whereupon, Exhibit Nos. 133-137 were received into evidence.)

MR. LAVIA: Thank you so much.

CHAIRMAN LA ROSA: Okay. So it's 12 o'clock. So we are going to move to a lunch break.

I believe all we have left are TECO's witnesses, so --

MR. WAHLEN: We will be prepared with Mr. Heisey when we return from the break.

CHAIRMAN LA ROSA: Okay. So let's plan for one o'clock. We are at a good pace. Let's see how the afternoon goes. If we have got to go a little bit late tonight, we will, but let's break and we will reconvene here at one o'clock.

Thank you.

(Lunch recess.)

(Transcript continues in sequence in Volume

14.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said videotaped proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 5th day of October, 2024.

Debbie R. Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028