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
	FILED: October 21, 2024

POST-HEARING BRIEF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL

The Citizens of the State of Florida, through the Office of Public Counsel ("Citizens" or "OPC"), submit this Post-Hearing Brief pursuant to the Orders Establishing Procedure in this docket issued on April 16, 2024, and October 17, 2024.

STATEMENT OF BASIC POSITION

Introduction

This case is about overreach and excess to rescue the parent company.

The Office of Public Counsel ("OPC") joins the other intervenors in this case united in the assessment that Tampa Electric Company[1] has presented a vastly overstated request for rate relief. With the egregiously excessive profit request of an 11.5% return on equity ("ROE") leading the way, followed by accelerated cost recovery of solar and combined cycle generation units, glacial flowback of customer-provided tax credits, and overstated major generation unit maintenance expense, among others, it is difficult to fathom how the revenue "requirements" could be any more inflated. For 2025, the Company's ask is for (a slightly revised) $287 million revenue increase. For a company the size of Florida Power & Light ("FPL"), this would equate to an approximate annual revenue increase of over $2 billion. To rub salt into the customer wounds, Tampa Electric is asking for the Florida Public Service Commission ("PSC" or "Commission") to tack on two

[1] In this brief, OPC uses Tampa Electric Company, Tampa Electric, TECO, TEC or Company interchangeably unless the specific context indicates otherwise.

very large and unprecedented rate increases of $92 million and $65 million for the years 2026 and 2027, respectively. For a hypothetical, FPL-sized company, this would roughly equal additional customer revenues of $657 and $464 million, respectively.[2] These comparative numbers should give the observer a perspective on the breathtaking size of the ask that Tampa Electric is making of its customers. Only the Commission stands between the utility and the infliction of severe economic pain on its customers. The Public Counsel urges the Commission to pull its own available levers to rein in the proposed runaway rate increase to a level that meets the Company's actual requirements to provide safe and reliable electric service and plug in an opportunity to earn a reasonable profit. Anything more would be unfair, unjust, and unreasonable and not in the public interest.

OPC has serious concerns about the three primary drivers of Tampa Electric's excessive rate requests. On one end of the rate case spectrum, there is a strong external force fueling the vast majority of the ask: Emera. Tampa Electric's ailing parent company's ongoing struggles to raise cash to avoid being downgraded to junk bond status[3] is clearly a driver of the excessive rate increase. On the other end, an affordability crisis looms for a very large percentage of Tampa Electric customers. Sandwiched in between is a rate case that is overloaded with large capital expenditures ("CapEx"), an eye-popping profit request, and significant cash flow generators (benefiting the ailing parent company) like accelerated capital recovery (depreciation), molasses-like flowback of tax benefits provided by customers, and two gratuitous extra rate increases in 2026 and 2027. In the balance hangs the fate of many customers who are clinging desperately to the hope for rescue from this manmade perfect storm. As their advocate, OPC submits this record-based roadmap that would provide Tampa Electric with everything that they need, but spare customers from the pain of excessive rates sought by Emera.

Public utilities are granted a monopoly by the state in return for providing essential, life-sustaining services to customers. Periodically, a rate case is necessary to establish new fair, just,

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[2] Over the three-year rate setting period, the cumulative incremental revenue that Tampa Electric wants to extract from its customers would total $1,110,000,000 in total cash. Using the FPL comparative size factor of 7.14 (TR 137), purely for illustrative purposes this would be the equivalent of extracting an extra $7.9 billion from the customers of a company the size of FPL over the same period.

[3] TR167-168; EXH 434, BSP 10887, 10888, 10915, 10917; EXH 445, BSP 16097. *See also*, EXH 242 MPN F2.1-4044. [S&P debt rating of "BBB$^-$ (negative outlook)," which is commonly understood as the lowest investment grade bond rating by S&P.]

and reasonable rates.[4] OPC acknowledges that a public utility is constitutionally authorized and entitled to earn a fair return on its investment and to recover the reasonable, prudent, and necessary costs of providing safe and reliable service to all qualified customers on a non-discriminatory basis. This principle was established in two landmark U.S. Supreme Court cases, *Federal Power Commission et al v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923). On this point, OPC and Tampa Electric Company are in agreement. However, neither case guarantees or requires an 11.5% ROE or expenses to be recovered in a way that gratuitously generates cash flow for the benefit of shareholders.

The elephant in the room in this case is the degree to which Tampa Electric loaded-up the 2025 test year and the 2026 and 2027 subsequent years with discretionary and avoidable costs at a time when a substantial portion of their customer base is struggling to make ends meet and to pay their bills. The warning signs and red flags are everywhere and were known to management before and during the preparation of the filing. TR 213-214, 185-190, 308-309, 192-193; EXH 245; EXH 446, BSP 7023-7026. Federal help was expiring or had already dried up in 2022 and 2023. TR 289; EXH 438, BSP 7106. Bad debt expense was increasing and was evidence of a lack of affordability that the Company acknowledged and then ignored in their "need cash now" filings. TR 289; TR 296; EXH 245, BSP 3; EXH 5, MPN J258. Internal Company data indicated a looming affordability crisis, while investors and rating agencies likewise began expressing concerns about affordability. TR 192, 214-215. The United States Census Bureau data was interpreted by the Company as indicating that a sizable portion of the core customer base was in energy poverty trouble. EXH 446, BSP 7025; EXH 831, MPN F16-102. The signs were everywhere.

The Company professed awareness of these red flags and discussed identifying and using what it termed "levers of affordability" to address the looming crisis. TR 294, 309-310; EXH 245. Other parties identified Tampa Electric as having one of the highest residential bills in the country among similar utilities – even before the case was filed. TR 360, 2656. Tampa Electric had an opportunity to seek rates that would be reasonable, prudent, necessary, and sufficient to provide safe and reliable electric service.[5] However, on April 2, 2024, Tampa Electric filed a case that was clearly

[4] § 366.06(1), Fla. Stat. (2024).
[5] Section 366.06(1), Fla. Stat., provides that "the commission shall have the authority to determine and fix fair, just, and reasonable rates that may be requested, demanded, charged, or collected by any public utility for its service."

outside the fundamentals of this standard. This departure was not minimal, inconsequential, or fairly debatable. Instead, it was breathtaking and epic. Tampa Electric sought only the best, the biggest, and the most rewarding profits and financial benefits for itself and shareholders. Calling it gold-plating would be an understatement. Necessity and moderation could have been the guiding principle for framing needed relief. It would have shown the sincerity of creating and pulling the "levers of affordability." Instead, Tampa Electric replaced the "levers of affordability" with a crowbar to extract the maximum cash from Tampa Electric's customers.

Excess, maximized profits, and cash flow were the clear motivations for Tampa Electric's requested rate increase. Emera and Tampa Electric CFO Greg Blunden called the request a "fairly significant ask" when touting the $293 million initial revenue proposal to investors. TR 167-168, 177-178; EXH 249, MPN F2.1-4283-4284. This phrase is an understatement because the terms "overwhelming," "crushing," and "excessive" customer bill impacts do not look good in an investor presentation. Instead, this well-coiffed phraseology communicates to investors the essential message: your investment will be well treated by the significant sacrifices of Tampa Electric's 840,000 customers, **a significant, "highly confidential" percentage**[6] of whom are mired in energy poverty and struggling to pay their current bills even before the first slug of the "fairly significant ask" hits the mailbox in January 2025.

Tale of Two Cities

It is interesting to note that Emera's pursuit of cash from Tampa Electric's sister company, Nova Scotia Power ("NSP"), was effectively quashed by Bill 212 (amending the Public Utilities Act) as passed by the Novia Scotia Legislature. EXH 445, BSP 16086. NSP is comparable in many ways to Tampa Electric in size, population, and coastal territories: however, Emera plans to invest 59.6% of its capital in Tampa Electric and derives 54% of its net income from Tampa Electric. EXH 242, MPN F2.1-4040; 4028. Why? In 2022, the Nova Scotia Legislature passed Bill 212 essentially limiting any rate increase and ROE increase for NSP. EXH 164, MPN E2113 –

[6] Curiously, Tampa Electric sought and received confidential treatment of this number while adamantly asserting that it was wrong and that the document in which it was found (though presented to the Board) should "be taken with a grain of salt" and was "wrong." TR 219; EXH 446, BSP 7025. Also of interest is that the cited source of the United States Census Bureau can be consulted and a fairly consistent number derived. Additionally, a public document that contains a fairly consistent, corroborative number is in the record. EXH 831, MPN, F16-102.

E2114; EXH 445, BSP 19086.[7] Just before this rate case preparation began in earnest, Emera CEO Balfour advised the Tampa Electric Board of this legislation and its impact on the Emera companies. TR 284-285. So, having already saddled its local utility with carbon tax mandates, (EXH 242, MPN 2.1-4042) the Nova Scotia government acted to shield its residents from NSP's rate case. Therefore, if Emera was going to remain profitable and quickly secure much needed cash to stave off a downgrade, then those funds would have to come from the already beleaguered customers of NSP's Florida-based sister company. Accordingly, Tampa Electric customers became the unwilling recipients of a classic balloon squeeze.

Meanwhile, back home in Florida, investor-owned utilities are not constricted by carbon mandates or direct rate case intervention by the Legislature. Instead, the responsibility for determining fair, just, and reasonable utility rates are placed in the Commission's capable hands. We respectfully request that even though this is a cost-based, revenue requirement-oriented proceeding, the Commission should take specific note of the bill impacts that the Tampa Electric customers face. Beginning in April of 2023, the typical Tampa Electric customer faced an average bill of $161. TR 143, 178, 179. This bill included the fuel surcharge spike related to the war in Ukraine and a large storm cost recovery surcharge. Mr. Collins acknowledged that this bill level was likely the highest ever in nominal terms and caused a virtual meltdown in customer service levels. TR 188-189. Mr. Collins further acknowledged that the significant ask that the Company carefully designed in 2023 and folded into the Minimum Filing Requirements ("MFRs"), Petition, and testimony filed exactly one year later would take the average customer bill right back to the $161 level[8] – without ***any*** extraordinary fuel surcharge or ***any*** storm surcharge. TR 128-129, 133-135; EXH 249, MPN F2.1-4283-4284.

The point of illustration here is that whatever amount of base rate increase the Commission authorizes should be considered for affordability purposes alongside the extremely likely potential for additional storm cost surcharges and potential fuel spikes that could occur in an increasingly

[7] The evidence shows Emera's willingness to restrict investment of capital in Nova Scotia due to the passage of Bill 212 (which limited rate increases to 1.8%). EXH 434, BSP 10896 (redacted public version), 10905; EXH 12, MPN J1100; J1148,

[8] Tampa Electric Witness Jordan Williams presents an average residential bill impact of $160.93 based on the "as-filed" case. TR 3687, 3793-3794. This testimony and the supporting MFR schedule A-2 shows that the projected average residential customer 2025 bill impact under the primary methodology holds the current (low/normal) fuel surcharge amount of $35.36 constant and zeros out the $2.19 residual storm surcharge that was on the March 2024 bill. TR 133-135, 3687.

war-prone environment. Tampa Electric's CEO conceded that management considered the "all-in rate" as the significant element of managing the business. TR 135,352. The affordability discussion conducted with the Tampa Electric Board before and after the filing of the case in June 2023 and 2024 only considered this all-in rate. TR 296-297; EXH 446, BSP 7024, EXH 245, BSP 000001. The customer impact of the 2023 $161 average bill to Florida's customers was somewhat ameliorated by the return to normal fuel cost levels and the storm charges from Isaias, Ian and Idalia dropping off. Given the severe impact registered in 2023, these lessened bill impacts are not a green light to turn right back around in 2025 and backfill the rate increases into the "all-in" bill rate. In addition to the severe impacts on affordability and energy poverty, as the evidence demonstrated, the revenue requirements underlying this incremental increase in the bill predominantly provides unwarranted, additional surplus cash flow for poor credit metric improvement at the Emera level.

Emera seeks an inequitable distribution of cost recovery and cash flow responsibility that falls squarely upon the shoulders of its Florida-based customers, while NSP's customers have been shielded from this burden. In response, the Commission should refuse to be painted into this box and rely upon its statutory authority to craft an equitable outcome for Florida.

Tone-deafness on Affordability

Much of the hearing involved a focus on the concept of affordability. Throughout the hearing, Tampa Electric made an effort to downplay the importance of this concept. That level of bravado is undercut by the gravity that senior management has assigned to this issue at the highest level. TR 293; EXH 245; EXH 434, BSP 10963-10964, 10993 (even outside Florida); EXH 446, BSP 7009-7010, 7020; EXH 449, BSP 6036. Mr. Collins acknowledged that at least one rating agency indicated that the agency deemed the issue of "affordability" to be "paramount." TR 214-215. This shows that investors are increasingly concerned about the pace and level of rate increases and the stress they impart on the customer. The Commission should share this concern.

The evidence was overwhelming that, like investors, Tampa Electric recognized that the Company has had an affordability crisis on its hands even before it began preparing the case. The Company recognized this while it was putting its MFRs together. TR 229-231; EXH 837. Tampa Electric also recognized the looming crisis while it was presenting its case to the Commission between the filing on April 2nd and the hearing on August 26th. The Company held a Board session on affordability smack in the middle of this case in early June 2024. TR 292-

293; EXH 245. At any point following that, and up to the hearing, Tampa Electric could have sharpened the contrast between what it needed and what it included purely for cash flow to Emera and moderated its request to a “need-to-have” level. But Emera insisted on the “nice-to-have” level. Sure, some tweaks were made to the filing on the eve of hearing. TR 24; EXH 835. However, these adjustments were largely error corrections. Only one correction (the recognition that a 10-year life for the batteries was too short) was a scant nod to the fact of the overreach of the original filing.

At the end of the day, Tampa Electric has only backed out $7.5 million of the proposed 2025 requirement, and $2.9 million and $3.5 million for the 2026 and 2027 subsequent year adjustment (”SYA”) revenue requirements, respectively. Together these adjustments shaved a mere $32 million off the cumulative three-year original new revenue ask of $1.1 billion. Notably, not a cent that was removed came from the $82 million revenue requirement representing the abyss between the 11.5% ROE and the current 10.2% or the $76 million related to the revenue requirement excess above the recently approved Duke Energy Florida (“DEF”) 10.3% ROE. This does not address affordability: it only deepens the crisis without even considering potential fuel price spikes or storm surcharges.

In the face of such an affordability crisis, shareholder profits would have been a good place to have started sharpening the pencil. However, since every penny above 10.2% or 10.3% ROE appears to be earmarked to rescue the flagging Emera financial measures, this failure to act for customer benefit is not surprising. The evidence instead revealed that the Company brushed aside customer concerns and plowed ahead with a massive three-year revenue increase request. Furthermore, the evidence resoundingly demonstrates that the cash flow needs of a financially struggling parent company preempted the willingness to moderate their ask. There is no evidence that the proverbial foot was taken off the revenue production accelerator.

The Public Counsel recognizes that base rate regulation of electric utilities in Florida is explicitly grounded in the concept of cost-based recovery, and that the word “affordability” is not found in Chapter 366, Florida Statutes. However, the 2024 Florida Legislature weighed in on the looming crisis by decreeing that the state’s energy policy in Chapter 377, Florida Statutes, must be guided by a goal of ensuring a cost-effective and ***affordable*** energy supply.[9] Rather than

[9] § 377.601(2)(a), Fla Stat. (2024); § 377.601(3)(k), Fla Stat. (2024).

constraining Florida utility companies, the Legislature provided relief from constraining language regarding renewables and instead promoted a common-sense based approach to secure diverse energy sources. The remaining language in Florida's new energy bill constructively facilitates and safeguards the effective operation of Florida's grid. Not only does the policy recognize the importance of Florida's energy infrastructure to Florida's economy, but for the first time it highlights cost-effectiveness and affordability as Florida's top energy goals. Florida's new energy policy empowers rather than constrains the Commission, who armed with both quasi-judicial and quasi-legislative authority, can establish rates that are cost-effective, affordable, and in the public interest. We therefore enthusiastically encourage the Commission to implement the clear direction of the State's energy policy. That policy recognizes what the Company has demonstrated: an inability to constrain itself from promoting runaway ratebase growth and seeking rapidly rising rates and bills with little consideration of affordability.

On November 9, 2023, the Commission awarded the Tampa Electric's sister company, Peoples Gas System, Inc. ("PGS"), over 85% of its base rate case ask (TR 169, 173; EXH 249, MPN F2.1-4030), ostensibly giving the Company approximately four months to tailor its request to optimize the outcome to take advantage of the perceived generosity manifest in the PGS order. To accomplish this, Tampa Electric appears to have ignored the levers of affordability at its fingertips and instead decided to: (1) seek an exorbitant 11.50% ROE that would generate $82 million more annually than the current authorized 10.20% (TR 401);[10] (2) accelerate the depreciation on the increasing solar investment being added; (3) accelerate the recovery of the proposed $156.1 million in battery/storage investments (TR 841); (4) cram an extra $12.4 million of expense, representing three-to-five years of major plant maintenance expense, into a single test year: (5) use out-of-model revenue forecast adjustments to deflate projected test year revenues by $12.4 million; and (6) fail to pull the levers at its disposal to flow back Investment tax credits or ITC and Production tax credit or PTC benefits to fight the affordability markers of economic distress and energy poverty, thereby increasing cash flow and revenue requirements by $26 million. These initiatives, individually and collectively, represent a callous and purposeful effort to inflate the revenue requirement, customer bills, and cash flow to save parent company Emera from a dire

[10] 1.30 times $63.19 million (TR 401) = $ 82.1 million.

financial crisis. Perhaps a better way to look at the 2025 test year impact of this phenomenon is in a table:

Inflated ROE	$ 82.1 million	*See Issue 39*
Accelerated Depreciation	$ 15.5 million	*See Issue 7*
Accelerated Maintenance Expense	$ 10.0 million	*See Issue 45*
Underforecasted Revenue	$ 12.4 million	*See Issue 2*
ITC & PTC Slowdown	$ 26.4 million	*See Issues 63-65*
Total	**$ 146.4 million**	

These categories of grossly overstated claims of revenue requirements added nearly $150 million to the 2025 test year and represent over 50% of the $293 million in the increased annual revenue originally demanded. These elements of the Tampa Electric ask each relate solely to extra cash desperately needed by the parent company. They are simply gravy. Not one penny of this revenue requirement is essential to providing safe, reliable, and affordable electric service.

These high-level examples of revenue requirement inflation are not the only pressures on affordability. Other more subtle mechanisms to inflate rate base, enhance earnings, and increase cash flow to the parent company exist. For example, Tampa Electric engages in an activity called "reprofiling" capital.[11] This self-serving financial maneuver benefits the parent company. TR 125-126, 272-273; EXH 350, BSP 16425; EXH 445, BSP, 16099. It holds the potential of harming customers by delaying the deployment of sustaining capital (TR 270: EXH 350; EXH 445, BSP 16093); it risks abrogation of a settlement agreement (Order No. PSC-2021-0433-S-EI, at pp. 49-50); and it contributes to inflating ratebase in a test year by stalling the accumulation of depreciation and/or pulling a future-planned capital deployment forward into a ratesetting test year. TR 267; EXH 350; TR 3513-3514. These activities evince a disregard of the principles designed to provide objectivity and transparency in the accounting that supports the integrity of the test year concept. Reprofiling capital skews ratebase in one direction - up! Its use undermines Tampa Electric's assertions of independence from the needs of Emera and a sensitivity to the customers' energy poverty, economic distress, and affordability plight.

[11] One acknowledged definition is when one moves budgeted or forecasted capital into a period different than the period originally designated for the spending or placement into service of that same capital or capital asset. TR 125-126.

Central to the enormous revenue requirement ask is the combination of Emera's control over the fundamental financial levers of Tampa Electric and the needs of Emera. It is obvious to even the most casual observer that, absent significant parent company-level financial distress, it seems unlikely there would be such an overreaching rate hike request. The hearing testimony revealed a tension between the entire body of evidence and Mr. Collins' assertion that Tampa Electric is operated independently and without interference from Emera. TR 185-186, 188, 203, 204, 262-263, 291-292, 408-409, 412-413; EXH 445, BSP 16099. The CEO can be applauded for the hands-on approach demonstrated at the hearing, for taking responsibility and ownership of the case, and for supporting the Company's filing prepared by his team. Even so, many contrary indicators demonstrating close control by Emera of the key financial drivers sit elephant-like in the center of the room that is the record. TR 257, 259-261, 262, 264-265, 267-269; EXH 350, BSP 16412, 16420, 16425; EXH 444, BSP 7551; EXH 445, BSP 16099.

For example, Emera's CEO is the Chairman of the Board for both Emera and Tampa Electric. Emera CFO Greg Blunden performs this role at both companies and is also Treasurer at Tampa Electric. TR 166; EXH 13, MPN J1277, J1280-J1281; EXH 449, BSP 6040;[12] EXH 370, MPN F2.2-7215.[13] Dan Muldoon is a Tampa Electric Director and is also Emera's Executive Vice-President, Project Development and Operations Support. TR 291-292, 407; EXH 449, BSP 6040. Similarly, Emera General Counsel Mike Barrett sits in on the Tampa Electric Board meetings via teleconference. TR 291-292; EXH 449, BSP 6040. The regular and consistent presence at the Tampa Electric Board of these members of Emera senior leadership cannot be brushed aside. The parent company is both chaperoning and participating. The very fact of the Emera CEO chairing the Board meetings is a constant reminder that control of the purse strings can never be outside of the parent company's control.

There is perhaps an earnest and sincere initiative by the leadership in Tampa to take maximum responsibility for the day-to-day operations at Tampa Electric. The Emera documents produced in the hearing tell a vastly different story about the control wielded over the financial fundamentals. Emera has an aggressive rate base growth strategy established for Tampa Electric in Florida that

[12] The minutes refer to Mr. Blunden as Treasurer and CFO, but do not indicate that he is with Emera as they do for Emera General Counsel Mike Barrett. The signatures on the Securities & Exchange Commission filings show him as an officer of Tampa Electric. EXH 13, MPN J1277.
[13] On this CLT approval document Mr. Blunden is also shown as "SVP Finance & Accounting and CFO TECO Energy."

is outstripping customer growth and inflation. TR 177, 194-195, 330-335; EXH 242, MPN F2.1-4037, EXH 242, MPN F2.1-4037; EXH 542, MPN F3.1-2498, 2505; EXH 543, MPN F3.1-2515; EXH 658, MPN F3.3-6489, 6492. This strategy is clearly pushed down to Tampa Electric by the parent company. Tampa Electric and Emera Board documents show that CapEx is controlled fundamentally for the benefit of the parent corporation and that customer costs and even customer benefits can take a back seat to this objective. This corporate strategy executed by Tampa Electric [and incented through Emera directives (TR 1458-1459;[14] EXH 267, MPN F2.1-5530)] drives earnings per share ("EPS") and the vital cash flow needed to prop up Emera's sagging credit metrics, ratings, and flagging stock price. TR 266. The evidence shows that Emera has dictated that a significant amount of its rate base growth is driven by 75% of its capital spending being focused in Florida - primarily at Tampa Electric. TR 177; EXH 242, MPN F2.1-4037.

The Commission should not ignore these facts when evaluating what Tampa Electric actually needs to provide safe and reliable electric service. Emera's needs, motivation, and degree of control over the cost drivers affecting customer rates are palpable and cannot be ignored or dismissed. The Commission has the final say in the level of rates. Despite the overwhelming evidence that Emera is pushing the very ratebase growth that Tampa Electric's own internal and high-level documents warn will outstrip customer growth and the rate of inflation, OPC is ***not*** seeking any material specific ratebase disallowance.[15]

The customers ***are*** urging the Commission to exercise maximum regulatory oversight to toss out the excess cash-flow generators shown on the table above. The hardships faced by a broad cross-section of the customer base require nothing less. None of these profit and cash flow items are necessary to provide safe and reliable electric service. The revenue requirements for them only

[14] On re-direct examination, Tampa Electric Witness Cacciatore was asked a short series of leading questions suggesting that company executives were not incented to grow rate base. TR 1480. Company documents undermine this rehabilitation effort as the largest segment (30%) of executive long-term incentive compensation is based on achieving net income ***and*** cash flow goals. TR 1469; EXH 267, F2.1-5530; EXH 700, MPN F3.4-14971. Other Tampa Electric and Emera documents draw a direct link between rate base, net income, earnings per share ("EPS"), and cash flow. TR 177, EXH 242, MPN F2.1-4033. It is also worth noting that growing rate base timed for recovery in a test year drives increased supporting revenues authorized by the regulator which directly supports increased ***net income***. Tampa Electric and Emera were shown to have timed capital (rate base) items to minimize regulatory lag (via test year inclusion) and increase achieved earnings (TR 266, 269-272; EXH 350, BSP 16412, 16420), which meets the incentive goals established by Emera. Non-achievement of the net income goals limits overall incentive compensation to 110% of the entire scorecard amount. EXH 267, MPN F2.1-5530. This represents an enhanced incentive for Tampa Electric executives to grow rate base and grow revenue requirements and grow cash flow for Emera.

[15] As further demonstrated in Issue 16, customers specifically stated that they do not want certain Customer Experience Enhancements in the amount of $9.3 million.

serve two purposes: (1) they will further inflate already high customer base rates; and (2) they will only serve to enhance cash flow that Emera needs for reasons unrelated to Tampa Electric. Taking the action to dial back the excessive elements of the case is a win-win solution for the Commission: customer impacts are minimized while Tampa Electric still is able to make the investments it asserts are needed to serve customers.

It should be noted that Tampa Electric is also not averse to situationally understating ratebase for the sake of enhanced revenue requirements. OPC expert Witness Lane Kollen documented that Tampa Electric undercapitalized certain benefit costs by inflating expenses that are subject to being capitalized. By failing to properly capitalize the expense ***in the test year,*** net revenue requirements are overstated. (TR 2271-2272, 2289; EXH 44). To the extent expenses are later reclassified as capital, actual revenue requirements would be overstated, and customers would be subject to paying again for the same dollars in a future test year ratebase.

The Commission adjusted the PGS revenue requirement in the 2023 rate case where the Tampa Electric affiliate failed to justify the amount of expense it was capitalizing from Accounts 921 and 922. Order No. PSC-2023-0388-FOF-GU at p. 92. A similar failure to justify this initial over-expensing and undercapitalization is consistent with several Emera needs that were documented influences on the size of the requested revenue requirement – rate base growth, earnings, and cash flow. In this case, cash flow is increased by the failure to capitalize the requisite cost. This benefits the parent company's needs. TR 165-168. By retaining the ability to later adjust (increase) the amount of these A&G costs (pensions and OPEB) that are capitalized, Tampa Electric's potential further achievement of the Emera goal of increasing earnings (net income), cash flow, and rate base in Florida is enhanced.

ADI/GRR Creation and Additional Reprofiling

In the context of the issues of affordability, economic distress, and energy poverty, Tampa Electric went to extraordinary lengths to create a project out of dozens of existing distribution upgrades, updates, and obsolescence replacements. The creation of the project is a process documented in the Board materials in June and August of 2023, and in certain approval documentation in May and June of 2024. The effect of this process was that the company stitched together or "packaged" a disparate group of software-related distribution network components into something to support additional post-test year relief. TR 240-242, 243, 255-256, 1288-1289; EXH 370, MPN F2.2-7211; EXH 439, BSP 7275, ("aggregating"), 7276 ("packaged"). The concern this raises is that it is inconsistent with the notion that Tampa Electric is pulling the affordability lever for the reason it claims. Instead, the ADI/GRR initiative seems clearly designed to enhance 2026 and 2027 cash flow for the benefit of the parent company.

The Commission should also be aware that there was evidence received at hearing demonstrating that during the three-year term of the current settlement, Emera and Tampa Electric worked in concert to defer CapEx planned for 2023 and 2024 and move the dollars into the test year. TR 287-288; EXH 445, BSP 16099. These operational and accounting decisions appear to be inconsistent with the spirit – if not the letter – of the 2021 Agreement approved by Commission order. Specifically, page 35, Paragraph 7 of that Agreement states in relevant part that:

> As a part of the base rate freeze agreed to herein, the company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred (such as those which have been litigated[16] before the Commission (e.g. pandemic costs)), from the effective Date through and including December 31, 2024, which are of the type which historically or traditionally been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to in a writing signed by each of the Parties.

The Company acknowledged that this reprofiling of capital was made for the benefit of the parent company and to increase achieved ROE in the 2023 and 2024 accounting periods. *Id*. The clear accumulated intent of the provision, as the intervenor signatories view it, is that for the base rate freeze to have meaning, there should be no debits "mined" out of the freeze period and pushed into future test years. It creates a presumption that customers are effectively double paying to the degree that the deferral just generates benefits to the shareholder bottom line (enhanced achieved earnings) and rate base is increased in the next test year. At a minimum, rate base is inflated because accumulated depreciation is understated by the delay in the in-service date. TR 3513-3514.

In another series of actions inconsistent with the 2021 Agreement, Tampa Electric seeks to cherry-pick from the document and ask the Commission to adopt whole provisions of the Agreement even though the Company committed to refrain from doing so. *See* Issues 111-113.

[16] In Docket No. 20170123 (*In re: Petition for approval of arrangement to mitigate unfavorable impact of St. Johns River Power Park, by Florida Power & Light Company*), OPC litigated the issue of deferring costs during the term of the FPL 2016 Settlement Agreement. Evidence of the litigation of the dispute is shown in the prehearing order at Order No. PSC-2017-0352-PHO-EI at p. 6. This issue was resolved in a compromise stipulation in Order No. PSC-2017- 0415-AS-EI.

The Commission approved that Agreement and adopted it *in toto* as its own order. Specifically, the parties, including Tampa Electric, agreed that "[n]o party will assert in any proceeding before the Commission or before court that the 2021 Agreement of any of the term in the 2021 Agreement shall have any precedential value."[17] Despite this express language, Tampa Electric has succumbed to the temptation to entice the Commission to commit reversable error and to ignore the policies and prior practices contained in its orders. The Florida Supreme Court reversed the Commission in 2017 when it blatantly ignored the plain language of a settlement.[18] Allowing the Company to waltz in and cherry-pick a few negotiated items that were the product of value and consideration exchanged, would explicitly run afoul the plain language of Paragraph 16. The effort to exploit the 2021 Agreement curiously runs afoul of the very arguments that were (incorrectly) advanced to stiff-arm the intervenor efforts to compare the resolution of two simultaneously filed cases.

At the end of the day, this case is about the revenue requirement and the impact on the customers. Accordingly, attached to this brief as Appendix 1, are two sets of schedules. Appendix 1A are the schedules originally included in OPC Expert Witness Lane Kollen's testimony at TR 2282-2283, revised to reflect changes made prior to the hearing by the Company. Also included in the schedules are revisions related to revised OPC positions on Issues 16 (Customer Experience rate base additions) and 55 (major generation maintenance). The result is that OPC recommended maximum revenue requirement is $68.083 million for 2025, $54.651 million for 2026 and $20.890 million for 2027. If an SYA is allowed over OPC objection, Appendix 1B is included for illustration to show what the same revenue requirements would be if the Commission determined that the Company's authorized ROE mid-point should remain unchanged at 10.20%.

In sum, OPC urges the Commission to consider the significant backdrop of this case in evaluating the Tampa Electric rate increase request and responsibly discharging its mandate to achieve fair, just, and reasonable rates. By approving projects that are both needed and cost-effective, the regulated rates should be affordable and in the public interest of all Florida customers, today and tomorrow. It is essential that there is a separation between the genuine need for rate relief and the callous indifference to the genuine needs of the customers in seeking to aid

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[17] Order No. PSC-2021-0423-S-EI at p. 50.
[18] *Citizens of Fla. V. Graham*, 213 So. 3d 703, at 710-711 (Fla. 2017). ("[T]he Commission departed from the essential requirements of law by failing to adequately address application of the settlement agreement to the FPL transmission interconnection costs.")

the shaky finances of the parent company. As the ratepayers see it, this case is really about the stark contrast in these two elements of Tampa Electric's petition.

STATEMENT OF FACTUAL ISSUES AND POSITIONS

VIII. ISSUES AND POSITIONS

2025 TEST PERIOD AND FORECASTING

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

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

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

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

ARGUMENT:

Tampa Electric served an average of 834,144 retail customers in 2023. TR 1500. The Company projects customer growth to increase at an average annual growth rate ("AAGR") of 1.4 percent over the next ten years, from 2024-2033. TR 1489. Despite this customer AAGR increase, the Company nonetheless predicts average customer use during this period to decline at an AAGR of 0.5 percent. TR 1489. Based on these projections, Tampa Electric expects retail energy sales to increase at an AAGR of 0.9 percent during the forecast horizon. TR 1489. Comparing the last year for which there is full data, 2023, and Tampa Electric's projected 2025 test year, Tampa Electric projects an approximately 2 percent sales decrease in gigawatt hours from 2023 to 2025 (TR 2177; EXH 25, C10-611) while customers increase by approximately three percent. TR 2177; EXH 25, C10-609.

The divergence between Tampa Electric's customer growth and customer use forecasts is contradictory. TR 2177. This contradiction arises from the failure of Tampa Electric's forecasting to conform to historic trends and by Tampa Electric's usage of out-of-model adjustments. TR 2180. This issue is not just academic because customer growth and per-customer consumption growth are the primary causes for growth in energy sales. TR 1493. If Tampa Electric's actual sales are above expected total sales, then the Company could potentially over-recover if rates are set in reliance on the Company's sales projection. TR 1619-1620. Therefore, how the Commission resolves this contradiction has real-life implications for the affordability of Tampa Electric's bills. TR 2184.

The record demonstrates that Tampa is one of the fastest-growing regions in the country within one of the fastest growing states in the country. TR 1529. Despite this historic development, Tampa Electric's forecasts consistently understate sales, customer, and usage per customer projections. TR 1892. For example, with regard to customer growth, Tampa Electric's percent forecasting variance when compared to actuals from 2013-2023 ranged from -.03% to -2.2% per year; always understated. EXH 40, MPN C20-1983. The same is true for MWh sales, where Tampa Electric's variance in the same period ranges from -.08% to -3.9%; again, always understated. EXH 40, MPN C20-1983. The Company's accuracy has not improved when measuring the time period from May 2023 to April 2024; in that time period, the Company's forecasting underestimated customers by -.03%, average use by -.20%, and energy sales by -.23%. EXH 580, MPN F3.2-3815. Measuring the accuracy of Tampa Electric's total customer forecasts results in an average 0-3 year error percentage of -.5%. EXH 193, MPN E5462. Using the same measure for the accuracy of Tampa Electric's total retail sales forecasts yields an average 0-3 year error percentage of -2.3%. EXH 193, MPN E5462.

These consistent forecasting errors are in defiance of historic trends. For example, the Company is projecting a sales decrease in its 2025 test year despite the fact that sales have steadily increased at an annualized rate of 1.2 percent from 2013 to 2023. TR 2178. The difference between the Company's current forecast and a historic trend-based projection of 10 year sales is substantial. TR 2178; EXH 38. The forecast for 2024 shows the large decreases in usage per customer from existing customers are forecasted to be over two times larger in absolute value than usage changes attributable to new customer growth. TR 2177; EXH 37, MPN C20-1979. Such an outcome has not happened since 2011 when the state was still reeling from the aftermath of the 2008 to 2009 recession. TR 2177; EXH 37, MPN C20-1979.

All of the above percentages may seem small at first glance. However, applying the average test year forecast variance between Tampa Electric's 2013 and 2021 rate proceedings of 2.1% to the instant proceeding results in retail revenue increases of $31 million in 2025, $37 million in 2026, and $39 million in 2027. TR 2168. This gamesmanship results in a high payoff for the company at a time when Tampa Electric's customers are already experiencing affordability issues. TR 2169. The Commission should find that the variances in Tampa Electric's forecasting are consistently in favor of underforecasting, which raises serious questions about the forecasts' reliability and integrity. TR 2180.

Tampa Electric asserts that the disruption in the historical UPC trend is due to the transition from actual data for years when weather was hotter than normal to years where the energy sales and UPC are based on normal weather. TR 1516. Because load forecasters are not able to predict future weather, they rely on what is referred to as "normal" or "expected" weather in terms of degree-days. Accordingly, projections for 2024 and beyond are based on normal degree-days. TR 1516. With regard to underforecasting, in order to assess the accuracy and reliability of the forecasting models and the resulting energy sales forecasts, the variances should be calculated using weather-normalized sales. TR 1518.

However, it is inappropriate to dismiss OPC Witness Dismukes' observation as being due to a fluke of the weather because 9 of the past 10 years in the 20-year time period used by Tampa Electric for forecasting have been anomalously hot. TR 1532, 1599-1600; EXH 216. Although Tampa Electric notes that it cannot anticipate temperatures returning to lower baselines (TR 1600-1601), Tampa Electric nonetheless dismisses using a 10-year historical period for its forecasts because there is "more instability" in that time period. TR 1599. However, the industry has already largely moved past using a 30-year historical time period despite that doing so must have also added instability to forecasts. TR 1532. Tampa Electric's reliance on a 20-year time period to determine normal weather for its forecasts is itself therefore biasing results towards a cooler time period. With regards to normalization in general, if the Company's energy sales forecast always understates results when compared to actuals but does not always understate results when compared to weather normalized actuals, that would suggest that the Company's weather normalization adjustment is understating forecast results.

On top of issues with underforecasting, the Company's forecasts are also called into doubt by the Company's reliance on out-of-model adjustments, or exogenous forecasts. TR 2167. The

Company relies on three major out-of-model adjustments to its sales forecast: revisions for what can broadly be categorized as changes in energy efficiency; revisions for increases in electric vehicle adoption; and revisions for increases in behind-the-meter solar installations. TR 2171; EXH 14, MPN J1325. Collectively, these out-of-model adjustments reduce the Company's test year energy sales by 169,457 megawatt-hours. TR 2176; EXH 36.

The Company defends its use of the out-of-model adjustments by asserting that they are necessary for the accuracy of the Company's forecasting, which is used for purposes other than rate case proceedings, and all Florida utilities make similar adjustments. TR 1512-1513. The issue, however, is not whether the Company uses out-of-model adjustments at all, but rather the Company's lack of supporting evidence for how the Company made its calculations. TR 2172-2176. The out-of-model adjustments rely on assumptions such as the penetration levels and impacts of solar installations (TR 2175) and electric vehicles (TR 1528) which are not supported by the record. The Company has the burden of proof in this proceeding, and by failing to justify these assumptions, the Company has failed to meet that burden. TR 2172-2176.

All things being equal, it is possible that if Tampa Electric's load were actually much higher than the forecast, Tampa Electric could over-recover versus the revenue requirement that Tampa Electric anticipated for 2025. TR 1543. With potentially tens of millions of dollars at stake in this issue alone, the Commission should act with the knowledge that energy affordability remains a challenging issue in the Company's service territory. TR 2187. The most commonly accepted threshold at which utilities, and thus energy, becomes unaffordable or burdensome is when the percentage of income spent on energy exceeds six percent. TR 2182. The Company's own internal analysis of United States Census Bureau indicated that the percentage of its customers could be significant. TR 219; EXH 446, BSP 7025. See also EXH 831, MPN, F16-102. Under this analysis, Tampa Electric's rates are already burdensome for Tampa Electric's low-income customers. TR 2184. The burden is especially pronounced for lower income households because lower income households spend a larger share of their income on electricity. TR 2184.

The Commission should address the Company's forecasting deficiencies by rejecting the Company's out-of-model adjustments. The removal of out-of-model adjustments will increase the Company's test year sales forecast resulting in a 2025 sales projection of 20,635,457 megawatt-hours. TR 2186. This recommendation, if applied to the subsequent years, would support forecasted megawatt-hour sales of 20,886,730 in 2026, and 21,128,190 in 2027. TR 2186. This will result in an increase of 2025 test year retail revenues by $12 million, and, if applied to the subsequent years, would support retail revenue increases of $20 million in 2026 and $26 million in 2027. TR 2186. These moderate sales and revenue adjustments, which simply exclude several proposed but unsupported out-of-model adjustments, are reasonable and supported by the record.

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

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

ARGUMENT: *See Issue 2.*

QUALITY OF SERVICE

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

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

ARGUMENT:

When making findings of fact on this issue, the Commission should, as promised, consider the customer testimony at the customer service hearings, the approximately 840 written customer comments submitted in this docket, and the customer service complaints received by the Commission from January 1, 2022, to date. SH1-TR, SH2-TR, SH3-TR, EXH 832, EXH 833. Each contain a variety of complaints about the service provided by Tampa Electric, which should all be factored into the Commission's decision. Additionally, the Commission should also consider the affordability of Tampa Electric's rates (as argued further in the Introduction *supra* and within Issue 119) when determining the quality of Tampa Electric's service because if customers cannot afford their electric bill, then the quality of service is a moot point.

DEPRECIATION AND DISMANTLEMENT STUDY

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

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

ARGUMENT:

The presently approved 35-year service life for solar assets should be retained. The service life for battery energy storage assets should be revised to reflect a 20-year average service life. The combined cycle plants as well as changes to service life and net salvage estimates should be revised to reflect FEA Witness Andrew's proposal. TR 3035-37. The provisions for dismantlement should be revised to reflect OPC Witness Kollen's recommendation. TR 2282.

Battery Energy Storage Systems

The Commission should adopt a 20-year service life for battery energy storage assets. TR 2301. In his depreciation study, Tampa Electric Witness Allis, provided calculations for the currently approved 10-year service life and stated, "The recommendation is for a 10-s3 survivor curve and zero net salvage, although this latter estimate may be revised upward in future studies as more data becomes available." EXH 26, MPN C11-1052. On August 22, 2024, the Company filed an update to their revenue requirement in which they departed from their initial proposal of a 10-year service life for the battery storage asset and proposed that the new depreciation life of its energy storage assets be 20 years.[19] OPC agrees with a 20-year service life for solar facilities.

Solar Facility Service Life

The Commission should approve and maintain a 35-year service life for solar facilities and reject Tampa Electric's proposal of shortening the service life by five years to reflect a 30-year service life. A 35-year service life for solar facilities is consistent with Florida's currently approved practice. Currently, FPL, DEF, and Tampa Electric all have Commission-approved service lives for solar sites of 35 years.[20] One day prior to filing for a rate increase, Tampa Electric filed its 10-year site plan with solar facilities reflecting an expected 35- year life for solar facilities, as well as solar leases lasting for 35 years. TR 875; EXH 300, MPN F2.1-5863; EXH 408, MPN F2.2-7767, F2.2-7768, F2.2-7774, F2.2-7775, F2.2-7776, F2.2-7777, F2.2-7778, F2.2-7779. Maintaining the

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[19] EXH 835; Document No. 08609-2024, PSC Docket No. 20240026-EI, *In Re: Petition for rate increase by Tampa Electric Company.*

[20] Order No. PSC-2024-0078-FOF-EI, Docket No. 20210015-EI, *In Re: Petition for rate increase by Florida Power & Light Company.; See also*, Document No. 008846-2024, PSC Docket No. 20240025-EI, *In Re; Petition for rate increase by Duke Energy Florida*.; Order No. PSC-2021-0423-S-EI, PSC Docket No. 20210034-EI, 20200264-EI *In Re: Petition for rate increase by Tampa Electric Company.*

current 35-year service life would not conflict with current policies or create inconsistencies within Tampa Electric's future planning.

Witness Allis provided revised calculations using OPC Witness Kollen's proposed estimates stating those would be ". . . the correct rates to use if a 35-year average service life were to be used . . . ." TR 1719. Witness Allis conceded that a 35-year life is within a range of reasonable possibilities. TR 1719, 1742. The Commission should maintain a 35-year service life and rely on the revised calculations provided by Mr. Allis.

<u>Dismantlement</u>

The provisions for dismantlement should be revised to reduce estimated solar site dismantlement costs. A lease agreement typically states the requirements for the leased land on which a solar facility is located. TR 1792. Those leases affect decommissioning obligations, environmental remediation, and site restoration. TR 1792. Tampa Electric Witness Kopp estimated the dismantlement costs and site restoration for those solar facilities. TR 1670. Tampa Electric Witness Kopp did not review the leases of 25 of 32 solar sites and does not know the environmental remediation or site restoration requirements for those 25 sites. TR 1792-93.

Neither the Commission nor Witness Kopp know whether the solar sites will be abandoned or remain in use 35 years into the future. TR 1792-93. These facilities were assumed to be returned to an industrial state by Mr. Kopp. TR 1761-62. However, OPC Witness Kollen states the sites are just as likely to remain in use and be refitted with new equipment, so neither site restoration nor environmental costs will be incurred or will be incurred at a lower cost than what has been proposed. TR 2309. The costs are not known and measurable and should therefore be excluded. If not excluded, there is a permanent tax penalty: asset-accumulated deferred income tax, which reduces the cost-free liability of accumulated deferred tax assets reflected in the cost of capital and increases the base revenue requirement, SYA revenue requirements, and the other rider revenue requirements that include a return on rate base. TR 2309-10. Due to the lack of specificity in the record about the extent of dismantlement actions that will be necessary, the Commission should exclude the environmental and site restoration components of the dismantlement costs for solar sites.

A 20-year life for battery energy storage assets is feasible, as admitted to by the company in their updated revenue requirement. EXH 835. All other large electric IOU's have solar asset service lives of 35 years. The commission should not depart from its standard and maintain the currently approved 35-year life. The Commission should reduce the estimated solar site dismantlement and restoration costs because these costs are not known and measurable and, if recovered, would impose a permanent penalty on Tampa Electric's customers.

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

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

ARGUMENT:

Depreciation and dismantlement rates should be implemented with the change in base rates upon approval of the Commission.

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

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

ARGUMENT:

Solar Facility

The Commission should reduce Tampa Electric's requested depreciation expense by $9.519 million by using the currently approved 35-year service life for solar assets. As addressed above in Issue 5, the presently approved 35-year service life for solar assets should be retained. There is no evidence that solar assets will not operate for 35 years, and Tampa Electric will not be harmed by operation at the current Commission approved service life.

Battery Energy Storage System

The Commission should reduce Tampa Electric's requested depreciation expense by $4.9 million for the 2025 test year, and $1.35 million and $.091 million for its proposed 2026 and 2027 SYAs respectively as indicated in Tampa Electric's August 22, 2024, updated revenue requirement.[21] Tampa Electric reflected various in-service date delays to the proposed test year and SYA battery storage projects. As addressed above in Issue 5, the battery storage assets should

[21] EXH 835; *See* Document No. 08609-2024, PSC Docket No. 20240026-EI, *In Re: Petition for rate increase by Tampa Electric Company.*

reflect a 20-year service life. However, Tampa Electric improperly applied the net operating income (NOI) multiplier to the entirety of the weighted average cost of capital for the increase in rate base for the 20-year service life on the battery assets. Tampa Electric corrected the NOI in 2026 and 2027 SYAs but incorrectly introduced the error in the 2025 test year. This requires a further reduction for the 2025 test year of $.593 million.

<u>Combined Cycle Plant</u>

OPC agrees that the approved combined cycle plants life spans should be revised to reflect FEA Witness Andrew's expert recommendation. TR 3035-37.

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

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

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

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

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

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

ARGUMENT:

Tampa Electric Witness Strickland identified three items that impact the income tax expense: (1) the flow back of the net excess deferred taxes; (2) the amortization of ITC; and (3) tax credits. TR 3195. The flow back of the net excessive deferred taxes of $26.8 million, as a result of the TCJA and state income tax rate reductions enacted in 2019 and 2021 and reduced by the deficient state taxes ($4.2 million revenue requirement), was calculated at $21 million to be flowed back over 5 years. TR 3196-97.

Issues 63 and 64 relate to the production tax credit ("PTC") treatment of the current solar assets and solar assets added from 2022 through 2024. For the deferred PTCs from 2022 through 2024, Witness Kollen recommends they be amortized over a three-year amortization period. TR 2320.

In its filing on August 22, 2024, Tampa Electric changed from a 10-year battery life proposed in its depreciation study to adopting a 20-year battery life which OPC Witness Kollen recommended in his testimony. TR 2356; EXH 835. Prior to the August 22, 2024, filing, Tampa Electric was proposing to defer these energy storage ITCs and amortized them over the regulatory life of the asset, which was 10 years. TR 3188. On August 16, 2022, the Inflation Reduction Act ("IRA") was signed into law. TR 2311. ITCs arise or are earned only in the year the qualifying asset goes into service. TR 3183. Pre-IRA, energy storage related ITCs would be deferred and then flowed back to customers over the life of the assets under the IRS normalization rule. TR 2313-2314, 3239. However, as Witness Strickland acknowledged, the IRA has a provision allowing a utility to elect out of IRS normalization rules for energy storage technology, but said the Company chose to not to elect out of "normalization" blaming the language in the 2021 settlement. TR 3187-88. As discussed in detail in Issue 65, Witness Kollen recommends Tampa Electric elect out of ITC "normalization" for the battery storage. TR 2317-2321. Additionally, Mr. Kollen testified that the IRA allowed the utility's regulator to separately specify the amortization period for the ITC untethered to the service life of the asset used for depreciation purposes. TR 2312. He recommends that the associated battery storage ITCs are amortized over a three-year amortization period. TR 2334.

Even though the Company stuck to its position on "normalization" for ITCs, Tampa Electric Witness Chronister suggested an alternative five-year amortization period for the deferred solar PTCs. TR 3454. Under the Company's filed position, the "normalized" life period for battery storage would have been 10 years, rather than the 20-year life adopted shortly before hearing. EXH 835. Regardless, given the change in Tampa Electric's position, the testimony supports electing out of "normalization," deferring ITCs, and amortizing the ITC over a shorter period than 20 years. Given the affordability issues recognized by Tampa Electric, and in order to benefit customers, the Commission should require the ITCs for energy storage be deferred and amortized over a three-year period as well as utilize a three-year amortization period for solar PTCs. Tampa Electric stated that if the Commission believes that the Company should opt out of normalization for energy storage that it will do so. TR 3257. The Commission should send that signal to the Company in this case.

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

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

ARGUMENT:

The annual accrual for dismantlement should exclude the cost and expense escalations after the end of the test year for dismantlement. The Company has failed to satisfy its burden of proof regarding the annual accrual for dismantlement cost and expense escalations. Tampa Electric's Witness Kopp developed an estimate of costs in 2023 dollars and excluded any potential contingency costs in the dismantlement. TR 2304. However, no Tampa Electric witnesses (Chronister, Kopp, and Allis) addressed the dismantlement expense calculation.[22] Because of the failure to meet its burden of proof, and as discussed in Issue 5, dismantlement expense should be reduced by $2.614 million to remove solar site restoration environmental costs. Dismantlement costs should be reduced by $0.955 million with the continuation of the currently approved 35-year service life for solar, as addressed by OPC Witness Kollen. TR 2282.

ISSUE 12: What, if any, corrective dismantlement reserve measures should be approved?
OPC: ***** All imbalances should be flowed back over the useful lives of the assets in this case.*

<u>2025 RATE BASE</u>

ISSUE 13: No position.
ISSUE 14: No position.

[22] Witness Chronister stated "The increases in new depreciation rates results in a 2025 expense increase of 46.9 million and the increase in the new dismantlement accrual results in a 2025 expense increase of $9.4 million. These changes are discussed further by Tampa Electric Witnesses Ned Allis and Jeff Kopp in their direct testimony." TR. 3319. Witness Allis stated "However, for Tampa Electric these [accrual for dismantlement costs and expense escalations] were not included in my recommended depreciation rates." TR. 1727.; Witness Chronister when asked "Did you perform the escalation of dismantlement expense in this proceeding?", he responded with "No. the Company performs the dismantlement accrual model calculation, and consistent with previous filings, applies a 15% contingency factor to the decommissioning cost estimates." TR. 1774-75.

ISSUE 15: No position.

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

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

ARGUMENT:

Tampa Electric has included in rate base $4.4 million[23] in the 2025 test year for "customer digitalization" enhancements, and an additional $4.9 million[24] of so-called "optional customer programs," the costs of which will be charged to all customers although not all customers will benefit. The Commission must deny these and not allow Tampa Electric to recover these unnecessary, platinum-plated investments from customers.

Tampa Electric filed testimony on April 2, 2024, claiming that "our customers live in a digital world and expect an experience from their electric utility that is similar to what they receive from companies like Amazon and Uber." TR 432. However, Tampa Electric conducted surveys of their own customers in August and December of 2023 that proves the exact opposite. EXH 237. A group comprised of over 2,000 Tampa Electric customers from all ages and backgrounds[25] were asked, "[w]ould you be willing to pay a little more, a lot more, or no additional cost" for 14 different items, including "digital service options (such as mobile apps, billing, and website)." EXH 237, MPN F2.1-1381. Of those who responded, an overwhelming majority (86%) said they were not willing to pay any more for the "digital service options." In fact, of all 14 items that customers were asked to evaluate, the "digital service option" was the item that customers were the least willing to pay additional money for. Then, in December 2023, all Tampa Electric customers were surveyed and asked what they believed were the most important elements of service. EXH 237, MPN F2.1-1382. Of all of the options listed, the least important element of service was "providing self-service digital offerings." These two survey results stand in sharp

[23] TR 464.
[24] TR 466.
[25] TR 603.

contrast to Tampa Electric's claim that customers want the Company to spend $4.4 million on "customer digitalization" enhancements. Tampa Electric knew or should have known how customers felt shortly before the rate case was filed and yet still chose to stuff $4.4 million of additional cost in their rate case and incorrectly claim that customers want these investments. These investments are without justification in the record.

The Company's purported need for $4.9 million of capital cost for "optional customer programs" is also unsupported by the evidence. If approved, all Tampa Electric customers will be charged for these programs; however, not all customers will benefit from all programs. TR 498-501. Examples of these programs include a HART Bus Charging Program, Commercial & Industrial Rooftop Solar, Fleet EV Charging, and Residential EV Charging. EXH 640, MPN F3.3-5864. When asked specifically about the benefits that the Fleet EV Charging program would provide to all customers, the Company stated that it had not yet decided which rate classes it will be made available to. EXH 238, MPN F2.1-1401. If the Company has to pick and choose which rate classes that programs will be made available to, then by definition it is not going to be available to all customers. Tampa Electric even tacitly conceded that at least one of these optional customer programs, the Residential EV Charging Program, will not be available to all customers. TR 501-502. Although not all customers can benefit from all of these optional programs, Tampa Electric intends to charge all customers for their development. This violates the basic tenet of cost-based ratemaking that the cost-causer should pay for the costs associated with providing the service.

The Company has failed to satisfy its burden of proof regarding the customer digitalization and optional customer programs elements of their requested rate increase. The evidence provided by the Company for these $4.4 million and $4.9 million of rate base costs was contradicted by other evidence and testimony; yet another affordability lever left unpulled. At a time when affordability of even the current Tampa Electric rates is an issue for many customers, the Commission must deny these unnecessary and unwanted investments, especially when they are not supported by the evidence.

ISSUE 17: No position.

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

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

ARGUMENT:

As further demonstrated in Issue 7, a 35-year depreciable life for solar facilities should be maintained by the Commission for several reasons, including that the leases for each of the proposed solar facilities are for a minimum of 35 years and because Tampa Electric listed the book life for all eight solar projects as 35 years in the 2024 Ten Year Site Plan. TR 875; EXH 300, MPN F2.1-5863; EXH 408, MPN F2.2-7767, F2.2-7768, F2.2-7774, F2.2-7775, F2.2-7776, F2.2-7777, F2.2-7778, F2.2-7779. Allowing depreciation expense to be calculated based on a 30-year life would result in unreasonable rates since the record evidence supports a 35-year life rather than a 30-year life.

Additionally, OPC recommends that the Commission seriously consider separating the solar investment costs from base rates initially and have the Company bear the risk of the solar investments going into service on time. The Commission should consider requiring Tampa Electric to petition to recover those investments as the solar facilities go into service through a limited proceeding where both the need for and the prudence of those investments can be challenged. This would incentivize Tampa Electric to put these projects into service on time. Adding such a requirement within the overall revenue requirement will allow Tampa Electric to meet its commitment to serve customers, and shareholders will have an opportunity to earn a full (yet windfall-free) return on their prudent investments without making customers bear the risk of supply chain and permitting delays and other obstacles.

Otherwise, customers will begin paying for all of these investments beginning on January 1, 2025, regardless of when, or even if, these investments ultimately go into service. Tampa Electric admitted that the Company has more control than the customers do over whether the solar facilities are put into service on time. TR 869. Under this approach, Tampa Electric shareholders should reasonably bear the risk of these investments not going into service as expected. If the Commission approves the revenue requirements for these solar investments as requested, this could result in a windfall of cash flow for Emera through the “reprofiling” danger that Tampa Electric admits to engaging in. TR 125. This same rationale applies to the solar projects that are the subject of Issue 95.

ISSUE 19: No position.

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

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

ISSUE 21: No position.

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

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

ARGUMENT:

OPC has not proposed to eliminate this cost. However, OPC takes this opportunity to note that Tampa Electric was aware that the affordability struggles of a sizable percentage of its customers base that by its own and external numbers likely extends into the six figures. TR 216-217. Nevertheless, the capital associated with Phase 2 of this project was pulled forward or reprofiled into the test year. According to documents delivered to the Emera CEO and considered at the November 7, 2023, Tampa Electric Board of Directors meeting, the Company made the decision to accelerate this capital into the test year. TR 266-267; EXH 444, BSP 7551. This reprofiling of capital is consistent with evidence that such a fairly widespread policy exists at the corporate level that is designed to maximize regulatory recovery for the benefit of the parent company's financial needs and goals. Not surprisingly, these goals and needs were subject to increasing the rewards to the executives at Tampa Electric who can earn incentive compensation in the form of stock options, the value of which is tied to the Emera stock price. TR 1452-1453.

Another element of concern about this project is the absence of sufficient federal government funding that recognizes the benefits being provided to the Air Force Base. TR 2611. This indicates that Tampa Electric has not sufficiently demonstrated that the entire cost of the project is prudent.

The absence of such an equitable contribution is an indicator that the Company rushed to reprofile capital to maximize revenue requirements without adequate due diligence in seeking a federal contribution and has not demonstrated that it met its burden of proof that the project is reasonable and prudent, apart from the fact that the capital for the second phase of the project was reprofiled by accelerating it by 3 years. TR 266-267: EXH 444, BSP 7551.

Rather than seek to disallow recovery of this cost based on the reprofiling, OPC asks that this evidence be considered in the determination of the profit (ROE) is allowed (Issue 39), and in deciding the other costs related to accelerated capital recovery (Issue 7), "bunched" major maintenance expense overhaul expense (Issue 45), underforecasted revenues (Issue 2), excessive executive incentive compensation (Issue 53) and unreasonable withholding of tax credits (Issues 10, 34, 54, and 65). Consideration of these elements of the case and this example should help the Commission to recognize that Tampa Electric has attempted to stuff its own Christmas stocking in contemplation of a very merry 85% holiday gift. The Commission should not dole out shareholder gifts at the expense of creating a bleak holiday season and an unhappy New Year for customers.

ISSUE 23: No position.
ISSUE 24: No position.

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

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

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

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

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

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

ISSUE 28: No position.

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

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

ARGUMENT:

The $1.209 million undercapitalized amount would be appropriate to add to rate base if the expense adjustment supported by Mr. Kollen is made in Issue 54.

ISSUE 30: No position.

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

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

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

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

<u>2025 COST OF CAPITAL</u>

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

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

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

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

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

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

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

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

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

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

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

OPC: *Tampa Electric’s requested equity ratio of 54% should only be accepted if the ROE is accordingly established taking into consideration the high level of the equity ratio; otherwise, the proposed equity ratio is excessive.*

ARGUMENT:

Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of dollars than it could raise with just equity. Debt is, therefore, a means of “leveraging” capital dollars. However, as the amount of debt in the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors, also increases. A high equity component can amplify the overall impact of a relatively low ROE while a low equity component can mitigate the overall impact of a relatively high ROE. As the equity ratio increases, the utility's revenue requirement increases, and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. TR 2822-2824.

Tampa Electric has proposed a capital structure from investor-provided capital of 41.57% long term debt, 3.90% short-term debt, and 54.00% common equity and long-term and short-term debt cost rates of 4.53% and 3.90%. TR 2819. The average common equity ratios of the proxy groups selected by OPC Witness Woolridge and Tampa Electric Witness D'Ascendis are 40.9% and 40.1%, respectively. As such, Tampa Electric's proposed capitalization from investor-provided capital and as proposed for rate setting purposes has much more equity and much less financial risk than the average current capitalizations of the electric utility companies in the proxy groups. TR 2819.

Dr. Woolridge did not offer testimony contesting Tampa Electric's proposed capital structure. He chose to do so because Tampa Electric's capitalization with a 54.00% common equity ratio was adopted in a settlement in Tampa Electric's last rate case and because this ratio is consistent with how the Company has financed itself since that ratio's adoption. TR 2826. Dr. Woolridge accordingly opted to account for Tampa Electric's high common equity ratio and lower financial risk in his ROE recommendation discussed below. TR 2826. Should the Commission reject Dr. Woolridge's ROE recommendation, then the Commission should, as discussed above, exercise the affordability levers at its disposal and choose an ROE that accounts for Tampa Electric's high equity ratio to avoid rates that will be higher than they need to be. TR 2823-2824

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

OPC: *The Commission should approve a 9.50% ROE.*

ARGUMENT:

Tampa Electric Witness D'Ascendis is recommending an ROE of 11.50%. TR 2039. This recommended ROE is 155 basis points higher than Tampa Electric's last approved ROE of 9.95%, and 130 basis points higher than the ROE trigger-adjusted authorized ROE of 10.2% that this Commission approved in 2022. TR 84-85. By itself, increasing Tampa Electric's ROE from the trigger-adjusted level of 10.2% to 11.5% represents about $78 million a year of revenue requirement. TR 149. An ROE as high as 11.5% makes little sense considering: (1) Tampa Electric's below average risk when compared to the proxy groups used by both Mr. D'Ascendis and Dr. Woolridge in determining Tampa Electric's fair rate of return; and (2) Tampa Electric's capital structure, which has more common equity and less financial risk. TR 2907. Mr. D'Ascendis can only suggest what would be a historically absurd result through his manipulation of risk premium and other factors in several of his models in a way that upwardly biases his results. Instead, the Commission should find that Dr. Woolridge's recommended ROE of 9.50% from within a 9.25% to 9.75% range is more reasonable than Mr. D'Ascendis' 11.50% ROE recommendation. This is because a 9.50% ROE more accurately reflects Tampa Electric's relatively smaller investor risk and is closely aligned with the national average. TR 3100-3101.

Both Dr. Woolridge and Mr. D'Ascendis used the Discounted Cash Flow ("DCF") and Capital Asset Pricing Models ("CAPM") in reaching their ROE recommendations. TR 2798. Both of these models are widely used and widely accepted financial models for calculating the cost of equity in utility rate proceedings. TR 1833. However, as explained below, despite using the same models, both experts applied different approaches to come to different ROE results; Dr. Woolridge's being in-line with the national average of ROEs while Mr. D'Ascendis' number is wildly out of alignment with reality. In addition, Mr. D'Ascendis also employed a Risk Premium Model and a Predictive Risk Premium. TR 2094.

I. Legal Standard

Due to the capital requirements needed to provide services to the public and the need to avoid duplication of these services, most regulated public utilities are monopolies for whom it is not appropriate to set their own prices. TR 2826-2827. Therefore, for regulated public utilities such as Tampa Electric, regulation must act as a substitute for marketplace competition. TR 1814. In *Bluefield Water Work & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923), the United States Supreme Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

In *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944), the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses *but also for the capital costs of the business*. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

(Emphasis added). Both the DCF and CAPM models employed by Dr. Woolridge and Mr. D'Ascendis are market-based approaches to calculating a regulated public utility's fair rate of return. TR 1833. As such, the methodologies are generally recognized as being consistent with the market-based standards of a fair return contemplated by *Hope* and *Bluefield*. TR 1833.

In his testimony, Mr. D'Ascendis asserts that Dr. Woolridge's ROE recommendation is "far below" recent authorized ROEs in Florida. TR 1910. Dr. Woolridge, while acknowledging that his recommendation is slightly below the average authorized ROEs for electric utility companies nationally, nonetheless demonstrated that his recommendation complies with *Hope* and *Bluefield*. TR 2813-2814.[26] In recent years, nationally electric utility companies have been earning ROEs in the range of 9.0% to 10.0%. TR 2184. Such utilities still have strong investment-grade credit ratings, have stocks that sell over book value, and raise abundant amounts of capital. TR 2184. Further, Dr. Woolridge cites to a 2022 study that concluded that, over the past four decades, authorized ROEs have not declined in line with capital costs over time and therefore have overstated the actual cost of equity capital. TR 2814. Tampa Electric represents a low investment risk thanks to its standalone credit ratings and relatively high equity ratio, plus its ability to recover costs not just from rate proceedings, but also from the various clause dockets that the Commission annually entertains. Finally, as conceded by Archie Collins, Tampa Electric is not constitutionally required to have an 11.5% ROE. TR 198. Therefore, the Commission should not be concerned that a 9.5% ROE will violate the principals of *Hope* and *Bluefield* and should address Tampa Electric's affordability issues by issuing an appropriate ROE along the lines of Dr. Woolridge's recommendation.

II. <u>The Impact of Tampa Electric's Parent Company</u>

[26] Walmart expert Witness Chriss testified that for 2021-2024 (year-to-date) the average awarded ROEs have ranged from 9.54% to 9.72%. TR 3100-3101.

In deciding an ROE for Tampa Electric, the Commission cannot ignore the position of Emera, Tampa Electric's parent company. A June 15, 2023, S&P Global Ratings Score Snapshot, while describing Tampa Electric as "low-risk," still noted that one of Tampa Electric's key risks included pressure on credit metrics from capital programs over the next several years. TR 2074; EXH 177, MPN E3443. This negative outlook reflected the negative outlook of Emera, which itself had a minimal financial cushion from its downgrade threshold and the possibility that financial measures could weaken further due to regulatory risks. TR 2074-2075; EXH 177, MPN E3445. Similarly, a Moody's Investment Report dated December 20, 2023, concluded that Tampa Electric's credit rating is constrained due to Emera's weak credit profile and high debt load. TR 2075; EXH 177, MPN E3454. That same report concluded that Emera's high debt put financial pressure on Tampa Electric and that Emera will potentially need Tampa Electric to upstream dividends to service Emera's debt. TR 2075; EXH 177, MPN E3454.[27] In a later report dated May 10, 2024, Moody's Investor's Service noted that Emera issued a significant amount of debt and subordinated hybrid notes to finance its acquisition of Tampa Electric in 2016, and has since been trying to reduce holding company leverage. TR 2076; EXH 177, MPN E3459.

Considering Emera's weakened financial position, it should not be surprising that there is significant risk that every excessive Florida ratepayer dollar that the Commission approves for Tampa Electric could inexorably flow to its parent company Emera in Canada. Mr. D'Ascendis himself touted Emera investing in American utilities because they provide an opportunity for a higher rate of return as simply being a basic financial precept followed by Emera. TR 2077. In a 2023 presentation, Emera flaunted to investors that PGS, another Emera company, had been awarded 85% of their ask in their own rate case. TR 173; EXH 242, MPN F2.1-4030. Later, in an analyst call subsequent to the DEF settling its rate case earlier this year, Greg Blunden, the CFO of Emera, indicated to investors that Tampa Electric's pending rate case would be a contributor to giving Emera a cushion towards their cash flow metric issues. TR 166-167; EXH 249, MPN F2.1-4283. It is incumbent upon the Commission to decide whether customers must reward Emera's shareholders within the reasonable range of FEA Witness Andrews' 9.45% ROE to Dr. Woolridge's recommended national average centered 9.50% ROE, or if customers must be

[27] These external observations are consistent with Emera's own hyper-sensitivity to subsidiary ratemaking and its resulting impacts on cash flow and credit metrics as it teeters on the brink of a downgrade below investment grade. The evidence shows that the parent company's concerns take precedent over the existing and increasing affordability impacts on customers. TR167-168; EXH 434, BSP 10887, 10888, 10915, 10917; EXH 445, BSP 16097.

required to reward Emera's shareholders with Mr. D'Ascendis' patently absurd 11.50% ROE. It must do this along with awareness that Tampa Electric's "thick" equity ratio determines what portion of the increased rate base dollars Emera will earn and upstream to the parent company. TR 175-176.

III. Credibility of Tampa Electric ROE Witness

Mr. D'Ascendis has previously provided expert testimony concerning utility regulation. EXH 28, MPN C13-1316. However, certain issues and his demeanor during the proceeding itself should give the Commission pause when deciding how to weigh his testimony in this case. The testimony listing attached to Mr. D'Ascendis' resume shows that Mr. D'Ascendis only testifies on ROE on behalf of utilities. EXH 28, MPN C13-1316-1322. Despite testifying in over 150 occasions regarding ROE, cost of service, rate design, and valuation (EXH 28, MPN C13-1316), Mr. D'Ascendis admitted that he was unaware of a single instance in which he recommended a lower ROE compared to a company's existing ROE. TR 2076; EXH 164, MPN E2135. Tellingly, in describing how he and the other witnesses in this matter came to their respective ROE recommendations, Mr. D'Ascendis stated: "I have my number, Dr. Woolridge has his number, Mr. Walters has his number, and it's up for the Commission and the Commission staff to kind of balance those interests" (TR 2081), as though ROE witnesses are mercenaries who bend the numbers to defend their employer's goals.

The most disturbing incident impeaching Mr. D'Ascendis' credibility occurred when counsel for OPC sought to introduce evidence indicating that the witness was closely associated with ROE Witness Paul Moul by asking if he had adopted the testimony of Mr. Moul in a Kentucky rate case. Mr. D'Ascendis emphatically and expressly denied adopting the testimony. TR 2062.[28] Then, Kentucky Order in Case No. 2021-00185 was introduced and accepted into evidence. TR 2065-2072; EXH 839. Mr. D'Ascendis was forced to admit he *had* adopted Mr. Moul's testimony – thus exposing his previous lack of candor. TR 2071-2072. When questioned about a cluster of Pennsylvania electric IOU rate case filings contemporaneous with the filing of this case, Mr. D'Ascendis denied knowing that Mr. Moul contemporaneously filed testimony supporting an 11.5% ROE at a time when Mr. D'Ascendis had shortly thereafter followed up by filing testimony for a group of affiliated electric utilities supporting an 11.3% ROE. TR 2061, 2072; EXH 321,

[28] Witness D'Ascendis' impeached testimony can be viewed beginning at the 10 hour and 28 minute mark at the following link: https://psc-fl.granicus.com/player/clip/4224?view_id=2&redirect=true.

MPN F2.1-6132. The Commission can decide for itself whether it is credible for an ROE witness to be unaware of a known, fellow ROE witness' requested ROE (a central issue in all rate cases) filed in the same jurisdiction just thirteen days earlier. The Commission should bear in mind Mr. D'Ascendis' lack of candor with the tribunal and implausible statements when reviewing and assigning weight to his testimony.

IV. Proxy Groups

To develop an appropriate ROE for Tampa Electric, both Dr. Woolridge and Mr. D'Ascendis evaluated the return requirements of investors in the common stock of a proxy group of publicly held utility companies. TR 1818, 2816. Dr. Woolridge selected 24 companies, while Mr. D'Ascendis selected 14. TR 2817-2818. The average S&P and Moody's ratings for the two groups was BBB+ and Baa2. Tampa Electric's credit rating is BBB+ according to S&P and A3 according to Moody's. As such, Tampa Electric's S&P credit rating is equal to the average of the two proxy groups (BBB+ vs. BBB+), and Tampa Electric's Moody's rating is two notches above the average of the two proxy groups (A3 vs. Baa2). This evidence demonstrates that Tampa Electric is a little less risky than the average of the two proxy groups.

V. DCF Model

The DCF model employed by Dr. Woolridge is a traditional constant-growth model that estimates ROE by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. TR 2800, 2937. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. TR 2832-2833. Therefore, this discount rate represents the cost of common equity. TR 2834.

In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity-cost rates entails estimating investors' expected dividend growth rate. TR 2837. Dr. Woolridge calculated the dividend yields for the companies in the proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. For Dr. Woolridge's proxy group, the mean and median dividend yields using the 30-day, 90-day, and 180-day average stock prices ranged from 4.00% to 4.20%. TR 2838. Dr. Woolridge therefore opted to use 4.10% as the dividend yield for his proxy group. TR 2838. Dr. Woolridge then adjusted the dividend yield by one-half of the expected growth to reflect growth over the coming year. TR 2839. The result for Dr. Woolridge's proxy group is the 4.10% dividend yield, times the 1 + ½ growth adjustment of 1.02725, plus the DCF growth rate of which results in an equity cost rate of 9.70%. TR 2850.

In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. In contrast, Mr. D'Ascendis computed his dividend yield using the 60-day average stock price for the proxy companies. For the DCF growth rate, Mr. D'Ascendis used three measures of projected EPS growth: the projected EPS growth of Wall Street analysts as compiled by Yahoo Finance, Zack's, *Value Line*. TR 2870. However, despite to the inaccuracy of analysts' long-term-earnings growth-rate forecasts, the weight given to projected EPS growth rates should have been limited, but was not. TR 2872. Plowing through and relying on EPS growth rates in his DCF formula enabled Mr. D'Ascendis to rely exclusively on the overly optimistic and upwardly-biased EPS growth-rate forecasts of Wall Street analysts and *Value Line*. Further, after calculating his DCF, Mr. D'Ascendis then inexplicably gave it little weight in his ROE recommendation. TR 2871.

VI. <u>CAPM</u>

The CAPM is a risk premium approach to gauging a firm's ROE. TR 2851. To estimate the required ROE using the CAPM requires three inputs: the risk-free rate of interest (Rf), the beta (ß), and the expected equity or market risk premium [E(Rm) – (Rf)]. TR 2852. The yield on a long-term U.S. Treasury security normally stands in for the interest rate of a risk-free bond. TR 2851. Systematic risk and market risk premium are more difficult to measure. TR 2852. Dr. Woolridge traditionally used beta as provided in the *Value Line Investment Survey*. TR 2855. However, Dr. Woolridge found various issue with these betas post-2020, and so now also uses betas published by S&P Capital IQ. TR 2856-2857. Risk premium, on the other hand, is equal to the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets. TR 2857. It is therefore difficult to measure because it requires an estimate of the expected return on the market. TR 2857.

Expected return on the market can be measured in different ways. TR 2857. The three approaches to estimating mark risk premium are: historic stock and bond returns; *ex ante* or expected returns models; and surveys. TR 2861. In his testimony, Dr. Woolridge discusses the various approaches and provides a summary of the results of the market risk premium studies that he reviewed. TR 2857-2860; EXH 68. Based on his overview, Dr. Woolridge opined that the appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range. TR 2865. As interest rates declined, so too have estimates of market risk premium declined. TR 2865-2866. Giving more weight to certain surveys listed in his testimony, Dr. Woolridge ultimately settles on a market risk premium of 5.25% for his CAPM. This leads Dr. Woolridge to a CAPM ROE result of 8.85%. TR 2866.

Mr. D'Ascendis also developed an ROE recommendation using the CAPM approach. Mr. D'Ascendis used both the CAPM and the empirical CAPM approaches ("ECAPM"). Mr. D'Ascendis' reports CAPM and ECAPM results of 12.48% for his electric group and a projected rate of 4.15% for the long-term Treasury bond, betas from *Value Line* and Bloomberg, and a market-risk premium of 10.02%. TR 2901.

There are two primary flaws with Mr. D'Ascendis' CAPM analyses: the use of ECAPM and the use of a market-risk premium of 10.02%. TR 2901. The ECAPM is an *ad hoc* version of the CAPM and has not been theoretically or empirically validated in reference journals. TR 2902. The ECAPM provides for weights which are used to adjust the risk-free rate and market-risk premium in applying the ECAPM. TR 2902. Mr. D'Ascendis uses 0.25 and 0.75 factors to boost the equity risk premium measure but provides no empirical justification for those figures. TR 2902. Dr. Woolridge is also not aware of any tests of the CAPM that use adjusted beta such as those used by Mr. D'Ascendis. TR 2902. With regards to risk premium, a 10.02% market-risk premium is much higher than published market-risk premiums and is developed using highly unrealistic assumptions of future earnings growth and stock-market returns along with other issues discussed below. The Commission should therefore give no credence to this view this element of Mr. D'Ascendis' testimony.

VII. <u>Other Models and Costs</u>

In addition to DCF and CAPM models, Mr. D'Ascendis also attempted to calculate an appropriate ROE for Tampa Electric using the Risk Premium Model ("RPM") and Predictive Risk Premium Model ("PRPM"). TR 2874. Mr. D'Ascendis' primary errors in these analyses are the excessive magnitude of the risk premiums that he developed using six different approaches. TR 2875. The first three of these approaches use historic stock and bond returns to develop a risk premium while the latter three use projected stock returns and risk premiums. TR 2875. Dr. Woolridge details in his testimony the myriad of issues associated with computing an expected equity risk premium using historical stock and bond returns, essentially empirical problems which produce inflated estimates of expected risk premiums. TR 2877-2881.

With regards to projected stock returns, Mr. D'Ascendis uses three methods: *Value Line's* projected stock returns for a certain term, calculating an expected return by applying the DCF model to the S&P 500 using projected EPS growth rates from Bloomberg, and doing likewise but using projected EPS growth rates from *Value Line*. TR 2881. These approached results in market risk premiums well in excess of those found in studies by leading academic scholars, produced by analyses of historic stock and bond returns, and found in surveys of financial professionals. TR 2882-2883. Historic stock and bond returns suggest a market-risk premium in the 4.40% to 6.80% range. Studies using *ex ante* models give results varying from 2.61% to 6.00%. Finally, market-risk premiums developed from financial professionals give results ranging from 3.40% to 5.70%. In contrast, Mr. D'Ascendis' average projected market risk premium is 11.45%. This shows that Mr. D'Ascendis' results are excessive and not credible since they are based on unrealistic, long-term, EPS growth rates. TR 2882-2891; EXH 68.

Mr. D'Ascendis also includes in his ROE analysis an adjustment for flotation costs. TR 2050. Flotation costs are those costs associated with the sale of new issuances of common stock. TR 1875. However, while Emera issues stock at Emera's level (TR 2053), Tampa Electric does not issue stock. TR 2052. There is no evidence in Tampa Electric's application or testimony that Tampa Electric has paid any flotation costs. TR 2904. Therefore, Tampa Electric should not receive higher revenues in the form of a higher ROE for flotation costs that Tampa Electric does not incur. TR 2904.

VIII. <u>ROE Comparison</u>

Exhibits 82 and 321 demonstrate that an 11.50% ROE is also outrageous in the context of historical ROE awards from across the nation. The only comparable ROE was awarded to a utility in Alaska. TR 2077. Although Mr. D'Ascendis attempts to rebut comparison to these ROEs as being based on lagging indicators (TR 1911), he nonetheless concedes that the Commission could consider and evaluate recent rate cases approved by other commissions nationally. TR 2110. The Commission should take note that Florida has made ROE awards in the last two to three years that are higher than the national average. TR 2063. With this case, the Commission has a chance to accept an ROE that satisfies *Hope* and *Bluefield* while addressing the affordability crisis faced by Tampa Electric's customers.

IX. Conclusion

The Commission should reject Mr. D'Ascendis' exorbitant ROE recommendation of 11.50%. Dr. Woolridge's more reasonable analysis indicates an equity cost rate in the range of 8.85% to 10.00% is appropriate for the Company. Given that Dr. Woolridge primarily relies on the DCF model and the results for his selected proxy group, Dr. Woolridge's recommendation that the appropriate ROE range for the Company is in the 9.25% - 9.75% range is reasonable. Given further that Tampa Electric's investment risk is below the average of the two groups, and since Dr. Woolridge has employed a capital structure that has much more common equity and less financial risk than the average of the two proxy groups as well as Tampa Electric's parent, Emera, the Commission should adopt Dr. Woolridge's ROE recommendation of 9.50% for the Company.

OPC notes that Dr. Woolridge's expert recommendation is highly consistent with the recent historical national average which gives his number credibility, especially when compared to the nearly 178 basis point departure from the national average that Mr. D'Ascendis touts. Keep in mind that that 178 basis points (11.5 to 9.72) above the most recent national average number in the record (TR 3100-3101) represents a revenue requirement of $112 million. Despite this, OPC would note that the Commission recently voted on August 21, 2024, to award a negotiated ROE of 10.3% for DEF. TR 141; EXH 243 (proffered). Tampa Electric's currently authorized ROE midpoint is 10.2%. Given the totality of the circumstances, including the recent historical national average and the fact that the Company is relatively less risky, it would not be unreasonable for the Commission to leave the Tampa Electric ROE unchanged. Setting aside the numerous other credibility issues that arose at the hearing, the Company forfeited its credibility when it offered Mr. D'Ascendis' outlandish 11.5% ROE, which is almost 200 basis points above the national average. Ultimately, the Company failed to meet its burden to show why its current ROE should be increased. The facts of this case, combined with the darkening clouds of affordability and energy poverty, provide the Commission with ample basis for awarding no more than a 10.2% ROE without needing to reference or rely on the Commission-approved DEF ROE of 10.3%.

ISSUE 40: What capital structure and weighted average cost of capital should be approved for use in establishing TECO's revenue requirement for the 2025 projected test year?

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

2025 NET OPERATING INCOME

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

OPC: *No. Tampa Electric's energy sales forecast should be rejected as inconsistent with historic trends and is biased due to subjective out-of-model adjustments. A conservative, modified version of Tampa Electric's forecast that removes subjective out-of-model adjustments should be approved. Removal of out-of-model adjustments will increase Tampa Electric's test year sales forecast, resulting in a 2025 sales projection of 20,635,457 MW-hours, and a $12.3 million increase in test year projected retail revenues.*

ARGUMENT: *See Issue 2.*

ISSUE 42: What amount of Total Operating Revenues should be approved for the 2025 projected test year?

OPC: *This is a largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness of its forecast of test year revenues. The Total Operating Revenues for the 2025 projected test year should reflect all of OPC's recommended adjustments, the adjustments for Issue 7 and should be no more than $43.8 million.*

ISSUE 43: No position.
ISSUE 44: No position.

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

OPC: *The Commission should only include in the test year a "normalized" level of major maintenance expense. Tampa Electric's filing overstated the level of regular recurring major maintenance expense in the test year. The level of O&M should be reduced by $12.4 million for purposes of setting rates that are fair, just, reasonable, and affordable.*

ARGUMENT:

OPC Expert Witness Lane Kollen testified that Tampa Electric's generation maintenance expense is abnormally high in the test year compared to actual expenses in prior years, due, in significant part, to the number and scope of outages in the test year compared to the prior years. He noted that Company delayed the planned maintenance beyond the original equipment manufacturer ("OEM") recommended run hours. Regardless of the motivations, this had the effect of bunching the outages in the test year and resulted in a significantly greater level of expense into the test year compared to prior years. TR 2286. Mr. Kollen testified that the level of the test year expense included in the revenue requirement should represent the recurring level of expense to ensure that abnormally high expense in the test year is not embedded into the base revenues as if it were recurring. TR 2287. He also pointed out that making no adjustment to recognize a normal or "normalized" level of this O&M expense in the test year for rate setting will generate a windfall for the Company's shareholders. *Id.*

It is significant to note that Tampa Electric did not propose any type of normalization adjustment for this situation. Had this not been spotted, the windfall scenarios would have been enhanced. Tampa Electric Vice President Energy Supply Carlos Aldazabal tacitly acknowledged that this windfall related to this specific expense could occur. TR 730-731 (lines 20-10). The witness acknowledged that the test year level of major outage O&M expense was higher than historical levels and higher than projected levels. TR 730. Mr. Kollen testified that Tampa Electric provided no evidence that the abnormally high level of expense will recur in the years subsequent to the test year for the generating assets that were in-service in the test year. TR 2287. Mr. Aldazabal agreed. TR 729-730. He also effectively conceded that an adjustment to reduce the expense was in order, but did not agree to the amount and methodology for determining the adjustment. TR 731-732.

After the issue was called out by OPC and its expert, Tampa Electric Vice President of Finance Jeff Chronister sought to minimize the impact of the required adjustment by proposing a baseline plus deferral approach that would effectively allow the Company to still collect a cherry-picked level of this expense. In his rebuttal, Mr. Chronister proposed a shareholder-friendly approach that would create a baseline amount of expense, then a deferral of the test year amount above that level and a three-year amortization of the deferred piece. TR 3437-3438. This approach would reduce the filed $25.2 million projected expense by $8.27 million. OPC contends that this is inadequate. A better compromise might be found in Mr. Chronister's rebuttal in the same manner that the Tampa Electric "defer-and-amortize" approach was borrowed from Mr. Kollen's testimony. Mr. Chronister concedes that a five-year amortization period after deferral would be proper.[29] TR 3437.

[29] Mr. Chronister suggests that the 5-year amortization be paired with a 2021 average and the three-year amortization should be paired with the $12.8 million average calculated in OPC Expert Witness Kollen's testimony. The rationale for the limited pairing of the five-year period is not explained.

Mr. Aldazabal, a CPA like Mr. Chronister and very experienced in regulatory affairs and ratemaking, agreed that a five-year amortization period would not be inappropriate. TR 732-733.

A five-year amortization period utilized in lieu of Mr. Kollen's primary amortization approach may make sense and represent a reasonable compromise. The "defer-and-amortize" method upon which Witnesses Kollen, Chronister and Aldazabal seemed to find common ground, coupled with Company experts' acknowledgement that a five-year amortization is appropriate, would yield an adjustment of a $10 million reduction to test year O&M expense.[30]

ISSUE 46: No position.
ISSUE 47: No position.
ISSUE 48: No position.
ISSUE 49: No position.
ISSUE 50: No position.
ISSUE 51: No position.
ISSUE 52: No position.

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

OPC: *Tampa Electric customers should not be forced to pay any of the stock-based long term incentive compensation that is designed to incentivize financial performance to motivate Tampa Electric executive management to increase costs and rates for the benefit of shareholders. Instead, all $7.170 million of compensation expense should be assigned to shareholders for recovery.*

ARGUMENT:

As noted by Mr. Kollen, the Commission has a long-standing practice of disallowing such expenses. In its order in the 2009 Progress Energy Florida, Inc. (now DEF) rate case, the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals such as EPS. He noted that in its discussion related to the disallowance, the Commission stated:

> Accordingly, we believe that incentive compensation tied to EPS should not be passed on to ratepayers. [31]

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[30] If the $12.4 million amount above the average is divided by 5, the result of $2.48 million added to the $12.8 million average would yield an adjusted major generation outage amount of $15.28. Subtracted from the test year amount of $25.2 million yields an adjustment to O&M expense of $9.92 million.
[31] Order No. PSC-2010-0131-FOF-EI at p. 114.

Likewise, in its order in an FPL rate case, the Commission specifically disallowed incentive compensation expense tied to EPS or other earnings measures. In its discussion related to the disallowance, the Commission stated:

> We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder value. We find that the executive incentive compensation program is designed to place the interests of executives in the same light as that of shareholders, thus creating incentive to increase the value of FPL Group's shares. Because these programs are designed for the benefit of shareholders, those costs shall be borne exclusively by shareholders.[32]

Finally, in its order in a Tampa Electric Company rate case, Mr. Kollen pointed out that the Commission specifically disallowed incentive compensation expense tied to the financial goals of its parent company at that time, TECO Energy. In its discussion related to the disallowance, the Commission stated:

> We also find, however, that the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy. Therefore, jurisdictional operating expenses shall be reduced by $540,000 ($560,000 system) for that portion of incentive compensation pay tied directly to TECO Energy's results as recalculated by Witness Chronister.[33]

TR 2292-2293.

OPC expert Kollen testified that the LTIP expense projected in the test year is designed to incentivize the achievement of financial metrics that benefit shareholders; it was not incurred to incentivize the achievement of metrics that benefit customers and/or otherwise achieve other strategic and societal goals, such as safety. His observations were borne out by the evidence in the hearing. Emera has significant credit metric problems that it seeks to shore up through an enormous rate increase on the backs of customers. Increased rate base and associated revenues yielding increased net income, cash flow and EPS are all outcomes that Tampa Electric seeks. TR 167; EXH 242; EXH 434, BSP 10887-10888, 10915, 10917; EXH 445, BSP 16097. *See also* Introduction discussion *supra.*

In this case, Tampa Electric management under the direction of Emera pulled out all the stops to support an outcome favorable to Emera. The addition of disproportionate levels of CapEx, the reprofiling of capital, the pursuit of peak maintenance expense recovery, the slow-down of tax

[32] Order No. PSC-2010-0153-FOF-EI at p. 149.
[33] Order No. PSC-2009-0283-FOF-EI at p. 58.

benefit flow-through, and the acceleration of depreciation recovery are all measures designed for the benefit of Emera and are incented by the LTIP. Witness Cacciatore testified that the LTIP goals are established exclusively by Emera. TR 1454. She agreed that the financial goals of net income and cash flow together made up the largest segment of incentive compensation. Ms. Cacciatore further agreed that "100 percent of the long-term incentive compensation is tied to reaching financial performance goals that include the Emera stock price." TR 1455. The LTIP goal documents also demonstrated that failure to reach the financial goals would limit the overall incentive compensation. TR 1469; EXH 267; EXH 700, MPN F3.4-14971. This enhancement to the incentive merely increases the customer exposure to the pressures that are designed to aid shareholders.

Tampa Electric asserted that the Commission should look at this as a "total compensation" issue. TR 1432-1433. The theory behind this approach would be that this is a competitive issue. However, the Company's expert witness conceded that the benchmarking survey that the Company relies on indicated that 53% of companies surveyed do not offer long-term incentive plans. TR 1462-1463: EXH 513, MPN F3.1-1267. Witness Cacciatore, hired as Vice President Human Resources, herself moved to Tampa Electric from her previous job but not because the incentive compensation plans were better. TR 1374, 1459. This is certainly an anecdotal example but it should be examined along with the fact that most benchmarked companies do not offer any incentive plan. This evidence provides significant evidence that the total compensation approach is not as meaningful as the Company claims. What is a concern is that Tampa Electric is asking the customers to pay extra just so the shareholders can benefit from a higher stock price as a result of increasing rate base and cash flow.

OPC asks that these LTIP expenses be assigned to shareholders.

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

OPC: *The Commission should reduce the pension and OPEB cost to reflect the credit for the portions of the costs that will be capitalized. The effect is a reduction of $0.489 million in the revenue requirement for the reduction in pension expense and a reduction of $0.806 million in the revenue requirement for the reduction in OPEB expense to reduce the requested amounts for the capitalized portions.*

ARGUMENT:

OPC Witness Kollen testified that Tampa Electric's request for recovery includes the total pension cost and total Other Post-Employment Benefits ("OPEB") cost without reductions for the amounts that will be capitalized. TR 2289. He explained that the amounts the Company included for total pensions and total OPEB costs reflected the actuarial reports for 2025, meaning the total costs were not reduced for the amounts that would be capitalized. TR 2289.

Tampa Electric Witness Chronister testified that the pension and OPEB costs are capitalized through the fringe rate. TR 3438-3439. He noted that all benefit costs are initially posted to FERC Account 926 and then the fringe rate follows the allocation of labor and FERC Account 926 is subsequently credited to reflect the capitalized portion. TR 3438-3439. Crucially, he did not testify that this capitalization was reflected in the MFRs. Mr. Kollen agrees that the Company uses the "fringe rate" methodology to load its pension and OPEB costs for accounting purposes but did not do so in this case. TR 2289-2290.

Witness Chronister claimed that Mr. Kollen's adjustment was unnecessary because the amount of the pension and OPEB cost to be capitalized was already deducted from the Company's forecasted benefits expense. TR 3439. However, OPC requested the breakdown between expense and capital of the test year total pension and total OPEB costs several times. TR 2290, EXH 44, EXH 843. Every discovery response provided by the Company simply provided the total pension and total OPEB cost with no breakdown. TR 2290. EXH 44, 843. The problem is the pension "expense" and the OPEB "expense" matched the Mercer actuarial report for 2025 before any reductions for the capitalized portions of the costs. TR 2290. As Mr. Kollen testified, the actuarial reports provide only pension and OPEB costs; they do not breakdown these costs between expense and capital because that is a function of the Company's account for payroll and related costs. TR 2290.

Witness Chronister's rebuttal testimony reflects an unexplained inconsistency with the historical recording of these costs and the filing. He just claims that the payroll allocation is picked up in the fringe rate in the future periods of 2024 and 2025. TR 3439. Mr. Kollen points out that this is not the historical way these costs are reflected in the budget (which is the basis in the MFRs for the projected test year). TR 2289 (Footnote 16). From 2016–2023, the budget showed the credit to expense and the allocation the capital portion. Inexplicably this accounting does not show up in the evidence that the Company presented, nor is the anomaly explained. TR 2289-2290; EXH 44; EXH 45; EXH 843. At hearing, the testimony of Mr. Chronister did not demonstrate that the amount capitalized was reflected in the MRFs. TR 3522-3527. For ratemaking purposes, the Company has failed to meet its burden to demonstrate the capitalization has been incorporates in the revenue requirement.

For these reasons, the Commission should reduce the pension and OPEB cost to reflect the credit for the portions of the costs that will be capitalized. The effect is a reduction of $0.489 million in the revenue requirement for the reduction in pension expense and a reduction of $0.806 million in the revenue requirement for the reduction in OPEB expense to reduce the requested amounts for the capitalized portions. TR 2290-2291.

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

OPC: *The Commission should reduce the Corporate Support Allocations from Emera to Tampa Electric by $0.858 million related to the dissolved TSI and the shared service allocation from Tampa Electric to TECO by $5.457 million to reflect unsupported corporate overhead. Tampa Electric should change its MMM allocation factor by substituting a Headcount allocation factor in place of the Net Income allocation factor. Tampa Electric should discontinue its central service provider responsibilities or in the alternative implement steps to ensuring transparency.*

ARGUMENT:

As OPC Witness Ostrander testified, prior to 2019, TECO Services, Inc. ("TSI") was providing central service functions to Tampa Electric and its affiliates. TR 2461. TSI will be legally dissolved in 2024 (TR 2461-2462), and its functions will have been transferred to Tampa Electric which now operates as the central service provider ("CSP"). TR 2461-2462. Witness Ostrander testified that $0.858 million related to the seconded employees that work for Emera affiliates moved to Tampa Electric from TSI. TR 2461. Witness Chronister claims that Tampa Electric was previously charged some shared services with that description in the years prior to 2024 but did not budget these charges in the same manner in 2024 or 2025. TR 3473-3474. Tampa Electric claimed these are direct charges that will not impact Tampa Electric, but Witness Ostrander disagreed. Mr. Ostrander testified that these are allocated costs that will result in a change to expense amounts to Tampa Electric, so he removed them. TR 2461. The Commission should reduce the Corporate Support Allocations from Emera to Tampa Electric by $0.858 million related to expenses of a dissolved affiliate that is proposed to be transferred to Tampa Electric. TR 2461.

Witness Ostrander testified that Tampa Electric should change its Modified Massachusetts Method, or MMM allocation factor, substituting Headcount for the Net Income allocation factor. TR 2275. Despite exhibiting confusion about who has the burden of proof on matters of prudence, Witness Chronister claims that this change will cause inconsistency without proof that this change will be prudent for cost distribution. TR 3475. Mr. Ostrander recommends the change from Net Income as an allocation factor because it is not causative, measurable, objective, stable, or predictive and is not consistent and applicable, as required by the Tampa Electric cost allocation manual ("CAM"). TR 2474-2475.

Witness Ostrander also recommends disallowing 50% of the Corporate Responsibility expense. TR 2477-78. Witness Chronister suggested that the documentation filed annually with the Commission is sufficient to justify these costs along with the fact of A&G costs being lower than the benchmark. TR 3475-76. However, Mr. Ostrander testified that Tampa Electric had not provided supporting documentation that these broad and undefined corporate responsibility expenses are not duplicative of other corporate-type expenses or excessive even though justification was requested via discovery. TR 2468-69.

Witness Ostrander also testified that the procurement expense increases were unsupported. TR 2479. Witness Chronister argued that procurement activities and expenses grew from 2020 to 2023 for Tampa Electric, so the 2025 procurement costs were reasonable. TR 3477-3478. However, Witness Ostrander testified that the procurement allocation factor for Tampa Electric appears excessive when compared to almost any other allocation factor. He also stated that Tampa Electric failed to control its excessive procurement costs or justify the increasing levels of centralized service expense. TR 2479. Accordingly, the Commission should also reduce the shared service allocated expense to TECO by $5.5 million to reflect Witness Ostrander's recommended revision of the allocation factors for various shared services and the disallowing of one half of significant unsupported corporate overhead. TR 2466-2468.

The Commission should consider requiring Tampa Electric to discontinue its CSP responsibilities or, in the alternative, require Tampa Electric to implement the steps outlined in Witness Ostrander's testimony. OPC Witness Ostrander testified that the Commission should require Tampa Electric to discontinue its role as the CSP or require the nine measures outlined more fully in his testimony. These are summarized as follows: (1) implement a plan for achieving recommendations; (2) identify costs saving as CSP and flow back to customers; (3) document and explain when an affiliate takes back share service in-house; (4) change accounting to track and audit affiliate transactions easily; (5) reconcile accounting [in (4) above] to the FERC Form 1; (6) require an external audit of the CSP role and affiliate transactions; (7) require monthly invoices for CSP services; (8) Emera and Tampa Electric should have written internal controls regarding its role as CSP; and (9) Emera should perform an internal audit of Tampa Electric as CSP. TR 2450-54. Witness Chronister claims that Tampa Electric items five, seven, eight, and nine are already in place, but the other requirements would be burdensome or redundant. TR 3480. The Commission should consider requiring Tampa Electric to implement the additional measures to the extent necessary to assure that the reasonableness and prudence of the affiliate transactions are demonstrated, supported, and justified. However, most importantly, the Commission should address the conspicuous absence of a parent-level CAM.

Witness Chronister acknowledged that Emera does not have its own CAM and relies on its Canadian affiliate, Nova Scotia Power's CAM. TR 3470-71. As Mr. Ostrander identified, the NSP CAM is not specifically named or mentioned as an Emera CAM and does not specifically address the allocation or direct assignment of service expenses from Emera to Tampa Electric and other U.S. affiliates. TR 2417. He also identified that there was no supporting documentation, Emera Corporate Support Services Agreement (to the extent it existed) for the direct expenses from Emera, or Emera's Asset Management Agreement, were provided. TR 2418. Witness Chronister had no reasonable explanation why Emera should not be required to have their own CAM for transactions with Tampa Electric and U.S. affiliates, other than suggesting that a Canadian-approved CAM for an affiliate and the forms provided annually to the Commission is sufficient. TR 3470-72. Furthermore, there is no evidence provided by the Company that the Nova Scotia CAM has been reviewed and approved by the FERC or this Commission. Thus, the Commission should require that Emera, through Tampa Electric, provide an Emera CAM that specifically governs transactions with Tampa Electric.

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

OPC: *OPC recommends that shareholders bear half the cost of, or $0.151 million, for the Directors & Officers Liability Insurance premium costs and half, or $0.376

million, of the cost of the Board of Directors expense. This will properly allocate the benefits provided by these elements of the shareholders and the regulated utility.*

ARGUMENT:

As DOL insurance protects the Company's officers and directors from lawsuits that arise from their own questionable decisions, and the lawsuits are generally brought by shareholders, the ratepayers receive no benefit from this insurance. Since the ratepayers are not receiving the benefit, they should not bear the costs. OPC historically recommends a complete disallowance of this cost since attribution of the cost should follow benefit. However, recognizing that recovery of 50% has been allowed in prior dockets, OPC recommends at least 50% should be removed consistent with prior decisions. *See* Order No. PSC-2012-0179-FOF-EI, issued April 3, 2012, Docket No. 20110138-EI, *In re: Petition for increase in rates by Gulf Power Company*, at p. 101; Order No. PSC-2010-0131-FOF-EI, issued March 5, 2010, in Docket No. 20090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc*. at p. 99.

In the current case, the Company projects to incur Directors & Officers ("D&O") liability insurance expense of $0.303 million (total Company) during the test year. As Mr. Kollen testifies, D&O insurance is designed to protect the individual directors and officers of an organization from personal liability and potential losses arising from their service and decisions made while serving in those roles. D&O insurance also may defray the legal and other costs incurred to defend against corporate liability and potential losses related arising from decisions made by directors and officers on behalf of an organization. TR 2297-2298.

In addition, the Company included Board of Directors expenses of $0.753 million during the test year, consisting of expenses the Company incurred directly and expenses incurred by Emera and charged to the Company. Emera maintains an investor relations organization to interact with present and potential investors. Mr. Kollen testified that the Emera website details the communications supplied to investors. The communications include such things as news releases, investor presentations, regulatory filings, analyst reports, and other statistical and reporting information. The evidence in this case demonstrates that the Emera presence and benefits gained from that presence on the Tampa Electric Board leans significantly in the shareholder's direction. For example, Emera's CEO is the chair of the Boards of both Emera and Tampa Electric. Emera Chief Financial Officer Greg Blunden performs this role at both companies and is also Treasurer at Tampa Electric. TR 166, 291-292; EXH 13, MPN J1277, J1280-J1281; EXH 449, BSP 6040;[34] EXH 370 at MPN, F2.2-7215.[35] Dan Muldoon is a Tampa Electric director and is also Emera's Executive Vice-President, Project Development and Operations Support. TR 291-292, 407; EXH 449, BSP 6040. Similarly, Emera General Counsel Mike Barrett sits in on the Tampa Electric Board meetings via teleconference. TR 291-292; EXH 449, BSP 6040.

The evidence and precedent abundantly supports an equal sharing between shareholders and customers of the D&O Liability premiums. Based on the facts and circumstances that indicate that the Tampa Electric Company Board functions significantly as an arm of Emera for the advancement of Emera-benefiting actions, a 50% allocation of those costs is conservative.

ISSUE 57: No position.

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

OPC: *Rate case expense should be amortized over at least a three-year period.*

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

OPC: *This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The O&M expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.*

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

OPC: *This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The depreciation and dismantlement expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.*

ARGUMENT: *See Issue 7.*

ISSUE 61: No position.

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[34] The minutes refer to Mr. Blunden as Treasurer and CFO, but do not indicate that he is with Emera as they do for Emera General Counsel Mike Barrett. The signatures on the Securities & Exchange Commission filings show him as an officer of Tampa Electric. EXH 13, MPN J1277.

[35] On the CLT approval document, Mr. Blunden is also shown as "SVP Finance & Accounting and CFO TECO Energy."

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

OPC: *The requirements of rule 25-14.004, F.A.C., must be applied to all test years and ratemaking periods in this case. Apart from the differences in the proper equity ratio, OPC and Tampa Electric are in agreement on the application and calculation of the adjustment.*

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

OPC: *The amount of PTC credits should be updated to reflect the increase in the 2025 PTC rate from $2.75 per kilowatt-hour to $3.00 per kilowatt-hour which was effective January 1, 2024. Tampa Electric included $35.4 million in PTCs as a reduction to income tax expense for the 2025 projected test year, grossed-up, the PTCs reduced the revenue requirement by $47.5 million. The 2025 PTC rate change further decreases Tampa Electric's proposed revenue requirement by $4,917,948.*

ARGUMENT:

On August 16, 2022, the Inflation Reduction Act ("IRA") was signed into law, creating a new PTC for solar generating facilities. TR 2311-2312. The PTC is a tax credit that reduces income tax expense by an amount per kWh of solar energy produced by a qualifying facility during a tax year. TR 3183. In its filing on August 22, 2024, Tampa Electric filed an update which included a change to the PTC rate. EXH 835. In its original filing, Tampa Electric used a PTC rate of $2.75 per kilowatt-hour. TR 3183, EXH 835. In that letter, Tampa Electric wrote that the IRS in July announced an increase to the PTC rate from $2.75 per kilowatt-hour to $3.00 per kilowatt-hour, effective January 1, 2024. EXH 835. This change affects the following items: (1) lowers rate base due to the increase in the December 31, 2024 regulatory liability balance for deferred PTC benefit, net of the new amortization of the balance; (2) lowers O&M expense due to the change in the 10-year amortization of the increased December 31, 2024, projected balance of the regulatory liability for the deferred PTC benefit; and (3) lowers income tax expense due to the change in the flow-through for the PTCs to be earned in 2025. EXH 835. Tampa Electric included $35.4 million in PTCs as a reduction to income tax expense for the 2025 projected test year; grossed-up, the PTCs reduced the revenue requirement by $47.5 million. TR 3186. The 2025 PTC rate change further decreases Tampa Electric's proposed revenue requirement by $4,917,948. EXH 835.

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

OPC: *$0.460 million in carrying costs (representing the customer's time value of money) should be added to the deferred PTC balance. The effect of this addition is a reduction of at least $0.887 million in the revenue requirement, assuming an amortization period of 10 years as filed by Tampa Electric. The deferred PTC should be amortized over three years. This results in an additional reduction of at least $13.182 million in revenue requirements.*

ARGUMENT:

The circumstances around the establishment of PTCs and corrected values are set out in the Issue 63 argument section. Witness Strickland testified that under the new IRA provisions, companies can now elect the PTC for their solar facilities in lieu of the ITC. She stated that the IRA did not impose normalization requirements for the solar PTC. TR 3184. She noted that PTCs are not calculated based on the cost of the qualifying asset, but rather on the energy the asset produces over a ten-year period. TR 3184. In other words, all solar generation assets producing energy during the year can be used to reduce taxes if the facility was placed in service within the past 10 years. After the enactment of the IRA, Tampa Electric determined that the PTC was a more beneficial tax credit to use for customers and elected to claim the PTC for its solar plants placed in service in 2022, 2023, 2024, and 2025. TR 3185-3186.

However, Witness Strickland argued that the 2021 Agreement required "normalization" of any new tax credits. TR 3188. She explained that the general normalization rules, in place since 1986, are an accounting method where ITC are spread out over the same time period that the costs of the investment are recovered from customers. TR 3187. She testified that the objective of normalization is to ensure that current and future customers are treated equitably so that that all customers enjoy the tax benefits associated with the utility asset. She contended that this has the effect of leveling customer rates over time and avoids volatility in the Company's tax profile. TR 3187-3188.

Witness Strickland asserted that unlike the ITC, the basic design of the PTC has a normalizing effect that allows current and future customers to enjoy the benefit of the credit over more than one year. TR 3184. She claimed that the difference between normalized ITC and normalized PTC for the solar facilities placed in service in 2022-2024 and the Generation Base Rate Adjustments ("GBRA") was approximately the same revenue requirement (a decrease of $0.400 million). TR

3188. Because of this, the Company made no changes to its 2023 and 2024 GBRAs, and instead proposes an income tax reduction mechanism in this general base rate proceeding. TR 3188-89.

Contrary to Witness Strickland's assertion, the 2021 Agreement does not require normalization of all new taxes. The 2021 Agreement contains Section 11, Corporate Income Tax Changes, subsection (b) entitled *Accumulated Deferred Income Taxes and Normalization*. Order No. PSC-2021-0423-S-EI, issued November 10, 2021, at p. 41. During cross-examination, Ms. Strickland conceded that the term "normalization" used in the 2021 Agreement was not defined in that Agreement and could have a different meaning depending on the context that it was drafted in. TR 3242. She further acknowledged that the 2021 Agreement was drafted and approved before the IRA was approved and enacted. TR 3242. Further, Witness Kollen testified that Section 11(c)(vi)[36] [sic] of the 2021 Agreement states, "[t]he company will adjust any GBRA that has not gone in effect up or down to reflect the new corporate income tax rate and the normalization of any new tax credits applicable to Future Solar projects on the revenue requirement for the GBRA." TR 2311, Order No. PSC-2021-0423-S-EI, issued November 10, 2021, at p. 44. He testified that the Company elected the PTC in lieu of the ITCs previously included in the calculation of the 2023 and 2024 GBRA rate increases for the solar generation. TR 2312. He explained that the economic value of the PTCs was greater than the ITCs. TR 2312. Further, he expounded that the PTCs earned in 2022 through 2024 were greater than the amortization of the ITCs earned that the Company assume in the calculation of the 2023 and 2024 GBRA rate increase approved in the last rate case. TR 2312-13.

The Company deferred the excess amount from the election of PTCs from 2022 through 2024 and created a regulatory liability for this difference rather than adjust the 2023 and 2024 GBRAs. TR 2313. Tampa Electric recorded the revenue equivalent of the PTCs as a regulatory liability on a revenue equivalent basis and proposes to amortize this deferred PTC regulatory liability over a 10-year period. TR 2313. However, given that the regulatory liability represents a benefit that the customers are entitled to ***in the year earned*** (and should have received as a reduction to the GBRA rate increase), Witness Kollen recommends flowing the revenue requirement-reducing value of deferred PTCs over three years. This is the same time period for which they were deferred and the likely period between rate cases. TR 2316.

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[36] This citation to the 2021 Agreement reflected a transposition of the paragraph number. The correct citation to the 2021 Agreement is 11(c)(iv).

Moreover, Witness Kollen testified that as there is no nexus between the 10-year timeframe over which PTCs are claimed annually, and the Company's proposed deferral period. The Company provided no rationale beyond the fact that the PTC benefit is only available for 10 years. Given that 10 years is unduly long and absent reasoned justification, three years should be used as it is reasonable. TR 2315-2316.

Additionally, the legislation giving rise to the PTCs made the benefit of the PTCs available annually for only a 10-year period. Using the Company's original amortization period of 10 years (starting in 2025 for PTCs earned from 2022 through 2024) would give benefits to customers outside this 10-year legislative period. Witness Kollen testified that refunds should be made sooner rather than later, especially since the Company failed to record deferred carrying costs (representing the customer's time value of money) on the deferred PTCs and failed to include the PTCs as cost-free capital in the capital structure. TR 2316. In his rebuttal testimony, Witness Chronister proposed an alternative five-year amortization for the deferred solar PTCs. TR 3454.

In addition, Witness Kollen testified that the Company should have added a deferred return to the deferred PTCs on a revenue equivalent basis to ensure that customers are made whole on the same economic value as if the PTCs had been flowed as reductions to the 2023 and 2024 GBRA rate increases as the PTCs were earned each year. TR 2314. Witness Chronister claimed that no carrying costs on the deferred PTC should be added because deferred PTC regulatory liability were properly reflected as rate base reductions in the Company's Earning Surveillance Reports and the unamortized balance are reductions to the 2025 test year rate base. TR 3452. However, as Witness Kollen stated, not flowing the PTC-related reductions in the GBRA rate increases in 2023 and 2024 allowed the Company to retain cash for the PTCs and the related savings in financing costs in those years due to avoided investor equity and debt financing. TR 2314. He testified that instead of deferring the savings in financing costs as an increase to the regulatory liability, the Company simply retained those savings. TR 2314. He further testified that this situation can and should be corrected since these savings in financing costs belong to customers who were deprived of the timely flow through of the PTCs earned in the years through 2024. TR 2314-15. He recommends adding carrying costs calculated at the allowed return from the prior case to the regulatory liability. TR 2315.

The effect of the $0.460 million in carrying charges requires a reduction of at least $0.887 million in the revenue requirement, assuming an amortization period of 10 years as filed by Tampa

Electric. TR 2282. The Commission should refund the regulatory liability, including the deferred return on the regulatory liability for the years 2022 through 2024, over a three-year amortization period. TR 2316. The effects are an additional reduction of at least $13.182 million in the claimed revenue requirement. TR 2317. The revenue requirement effects include the changes in amortization expense and the return effects of the changes of the deferred balances in rate base.

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

OPC: *ITCs should be reflected as if Tampa Electric elects out of the normalization requirements. The effects of the recommendation is a reduction of $3.493 million in the revenue requirement and a reduction of $0.100 million in the CETM revenue requirement due to the reduction in the cost of capital by including the new ITCs since 2022 as cost-free capital in the capital structure instead of including the new ITCs at the WACC.*

ARGUMENT:

This issue is limited to the ITC treatment of projected battery storage investments in the test year and in 2026 and 2027. On August 22, 2024, Tampa Electric adopted the 20-year battery life OPC Witness Kollen recommended in his testimony. TR 2333, EXH 835. Originally, Tampa Electric recommended a 10-year life for energy storage, to defer the related ITCs and amortize them over the life of the asset which was 10 years. TR 3187.

Under IRS regulations, ITCs are ordinarily to be flowed back over the life of the assets. TR 3197, 3243. On August 16, 2022, the IRA was signed into law. TR 2311. Tampa Electric Witness Strickland acknowledged that the IRA has a provision to elect out of IRS normalization regulations for energy storage technology, but said the Company chose to not to elect out, blaming the language in the 2021 settlement. TR 3187-88. She claimed that the 2021 Agreement required "normalization" of any new tax credits. TR 3188. However, she further acknowledged that the 2021 Agreement was drafted and approved before the IRA was approved and enacted. TR 3242. She agreed that this means the 2021 Agreement could not have foreseen that the IRA would allow utilities to elect out of normalization for energy storage. TR 3242. In fact, the 2021 Agreement did not address battery storage ITCs at all or the IRA change that permitted the election out of normalization for ITCs for energy storage.

Witness Kollen recommends Tampa Electric elect out of ITC "normalization" for the battery storage. TR 2317-20. He recommends that the associated battery storage ITCs should be amortized over a three-year period as discussed in Issue 10. Witness Kollen testified that the failure to elect out of normalization harms customers because: (1) the longer the amortization period, the less value of the ITCs goes to customers and greater economic value goes to Tampa Electric's shareholders; and (2) the ITCs cannot be reflected as cost-free capital in the cost of capital. TR 2317-18. He stated that the Company's failure to elect out of the normalization requirements was a decision that it made to retain a significant portion of the economic value of the ITCs rather than providing the entirety of the tax saving to the customers who are required to pay the entirety of the cost of the new battery storage. TR 2318. This is not a theoretical phenomenon. Emera documents showed that in 2023, flowback to customers of tax credits related to solar investments had the effect of reducing revenues, decreasing cash flow, and contributing to reducing Emera credit metrics. TR 286-287; EXH 445, BSP 16097. Emera's need for cash indicates that this same phenomenon would apply regardless of whether the credit was an ITC or PTC. Mr. Kollen is on the money here.

Witness Strickland argued that flowing through the entire ITC value when the asset goes into service would only give the value of the credit to the customers receiving electric service from Tampa Electric in the year the asset goes in service. TR 3216. Flowing through this customer-provided benefit on a more timely basis could negatively affect Emera credit metrics. Mr. Chronister, Tampa Electric Vice President Finance, claimed that spreading the benefit of the ITCs over an asset's regulatory life via normalization avoids intergenerational cost inequities for customers but was silent about the Emera near-term benefits. TR 3454. Witness Strickland also claimed that deferring the ITC over a shorter period than the regulatory life of the asset would lower the regulated utility's revenues in the short-term and not be representative of the Company's normal tax profile. TR 3215. She also argued that the normalization protects revenues from the effects of lower rates in the short term and allows regulated utilities and customers to share the benefits of accelerated depreciation and ITCs over the life of the asset. TR 3215.

Witness Kollen testified that it is simply wrong that "normalization" is necessary to avoid volatility in the Company's tax profile because the Commission has discretion to direct the Company to defer the ITC rather than flowing it through as earned. TR 2319. Mr. Kollen testified that his recommendation to defer and amortize the ITCs over three years inherently acts to smooth the effect on the Company's tax expense profile. TR 2319-2320.

Moreover, Witness Kollen testified that the only reason for the historic sharing of the pre-IRA ITCs between the utility shareholders and customers was that it was mandated by the normalization requirement in the Internal Revenue Code. TR 2318. Mr. Kollen stated that the IRA allowed the utility taxpayer to elect out the so-called normalization requirements that previously applied to the ITCs, meaning that the utility could elect to provide both the ITC amortization benefit and the ITC cost-free capital benefit to the customer rather than electing one or the other. TR 2312. He further stated that the IRA allowed utility regulators to enforce that election to provide both benefits to customers for ratemaking purposes. TR 2312.

Witness Kollen stated that there is no entitlement to "share" in the ITC benefits when the Company does not share in the costs of the new battery storage assets. TR 2318. Mr. Kollen testified that Tampa Electric's argument to retain some of the benefits and recover all costs is asymmetric, inconsistent with historic cost-based regulation, and is conceptually and practically flawed. TR 2318. He stated that the Commission now has the opportunity and discretion to reflect the entirety of the ITC benefit in the cost of service to reduce the cost to customers of the new battery storage assets through a negative amortization expense and to include the deferred ITC as cost-free capital in the cost of capital rather than being forced to concede this latter benefit to the Company or "share" it with the Company. TR 2318. In other words, the Company's failure to elect out of the normalization requirements only harms customers in favor of its own self-interest. TR 2319. That self-interest is all about cash flow and credit metrics.

Witness Kollen testified that "opting out" of normalization is an annual election, and the Company has not yet filed its 2023 or subsequent year federal income tax return. TR 2320. The Company stated that if the Commission required, they would elect out of normalization for the energy storage ITCs. TR 3253. The Commission should reflect the ITCs as if Tampa Electric elected and will continue to elect out of the normalization requirements. TR 2320. If Tampa Electric is unwilling to elect out of the normalization requirements each year, then the Commission should reduce the Company's authorized ROE or some other form of penalty commensurate with the offense for taking this path of self-interest and self-dealing at the expense of, and harm to, its customers. TR 2320. The effects of the first recommendation are a reduction of $3.493 million in the revenue requirement and a reduction of $0.100 million in the CETM revenue requirement due to the reduction in the cost of capital by including the new ITCs since 2022 as cost-free capital in the capital structure instead of including the new ITCs at the weighted average cost of capital. TR

2320. The Commission should also direct Tampa Electric to defer the ITCs earned each year pursuant to the IRA, but to amortize those deferred ITCs over a three-year amortization period. TR 2320.

ISSUE 66: What amount of Income Tax expense should be approved for the 2025 projected test year?

OPC: *This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The Income Tax expense for the projected 2025 test year should reflect all of OPC's recommended adjustments.*

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

OPC: *This is largely a fallout issue, but Tampa Electric has the burden of proof to demonstrate the reasonableness or prudence of all costs to be included in revenue requirements. The Net Operating Income for the projected 2025 test year should reflect all of OPC's recommended adjustments.*

<u>2025 REVENUE REQUIREMENTS</u>

ISSUE 68: What revenue expansion factor and net operating income multiplier, including the appropriate elements and rates, should be approved for the 2025 projected test year?

OPC:

*Assume pre-tax income of		1.0000%
Regulatory Assessment		0.00085%
Bad Debt Rate		0.00224%
Net Pretax Subtotal		0.99691%
State income tax	5.50%	0.054830%
Taxable income for Federal income tax		0.94208%
Federal income tax at 21%	21.0%	0.19784%
Revenue Expansion Factor		0.74424%
Gross-Up		1.34364%*

ARGUMENT:

On April 2, 2024, Tampa Electric filed the MFRs for this case, which included MFR C-11. EXH 5, MPN J258. This schedule reflected actual 2023 bad debt write-offs of $8,581,000, which equated to a bad debt factor of .299%. The Company also included projected bad debt write-offs of $6,148,000 in 2024 and $5,815,000 in 2025, which equated to a bad debt factor of .224% in both years. Tampa Electric also filed testimony that same day stating that, "[W]e anticipate a downward trend in bad debt expense beginning in 2024, driven by improving inflation rates and the company's sustained commitment to offering adaptable customer support options." TR 472.

However, in a late-filed exhibit provided on August 6, 2024, the Company at that time expected bad debt write-offs of $9,855,000, which would mean a .359% bad debt factor. EXH 236, MPN F2.1-1378. Rather than a "downward trend," this reflects an approximate 60% *increase* in the 2024 bad debt factor since the filing of this petition. Tampa Electric attempted to blame a reduction in federal low-income customer assistance funding for this sharp increase of the bad debt factor since this case was filed; however, the evidence is clear that the Company was aware of this decrease in funding as early as July 2023, well before this case was filed. EXH 438, BSP 7106. This document also demonstrates the Company's concession that higher electric bills can increase the risk of bad debt. This acknowledgment is made even more clear in Board meeting minutes which unequivocally state, "High utility bills – on top of other household inflationary pressures – puts stress on customers and leads to higher bad debt expense and increases the frequency of disconnections – which can lead to social pressure." TR 296; EXH 245, BSP 3.

Yet, the Company testified that in spite of its request to raise current residential rates by approximately 12% in 2025,[37] the Company still expects the 2025 bad debt factor to decrease to the amount in the MFR C-11 filed on April 2, 2024. TR 515. This is unsupported by the evidence. To the contrary, this 60% increase in the 2024 bad debt factor is evidence not only that the Company's 2025 revenues are underforecasted,[38] but also that the affordability issues that current customers are already facing will persist into 2025,[39] not to mention if the Commission authorizes an increase in base rates.

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

OPC: *The Commission should approve a revenue increase of no more than $43.8 million for 2025.*

2025 COST OF SERVICE AND RATES

ISSUE 72: No position.

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[37] TR 110.
[38] *See Issue 2*.
[39] *See Issue 119*.

ISSUE 73: No position.
ISSUE 74: No position.
ISSUE 75: No position.
ISSUE 76: No position.
ISSUE 77: No position.

ISSUE 78: What are the appropriate basic service charges?

OPC: *The basic service charges should reflect all the adjustments recommended by OPC.*

ISSUE 79: What are the appropriate demand charges?

OPC: *The demand charges should reflect all the adjustments recommended by OPC as approved by the Commission.*

ISSUE 80: What are the appropriate energy charges?

OPC: *The energy charges should reflect all the adjustments recommended by OPC as approved by the Commission. *

ISSUE 81: No position.
ISSUE 82: No position.
ISSUE 83: No position.
ISSUE 84: No position.
ISSUE 85: No position.
ISSUE 86: No position.

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

OPC: *Yes*

ARGUMENT:

The Commission should approve Tampa Electric's Proposed tariff modifications to Contribution in Aid of Construction (Fifth revised Tariff Sheet No. 5.105). So long as, the amount of CIAC would be credited as a reduction in rate base immediately when the agreement to pay CIAC is completed, even if there is an outstanding balance. TR 3814.

ISSUE 88: No position.
ISSUE 89: No position.
ISSUE 90: No position.
ISSUE 91: No position.
ISSUE 92: No position.

ISSUE 93: No position.

2026 AND 2027 SUBSEQUENT YEAR ADJUSTMENTS

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

OPC: *An SYA should not be necessary or allowed absent compelling circumstances, nor is it good policy to approve one without significant limitations. If the test year is chosen appropriately, it should be representative of rates on a going-forward basis, negating the need for another rate adjustment so soon thereafter, absent any extraordinary circumstances. To evaluate if extraordinary circumstances exist to grant an SYA, the Commission should consider the criteria articulated in the issue.*

ARGUMENT:

An SYA should not be necessary or allowed absent compelling circumstances, nor is it good policy to approve one without significant limitations. TR 2322-2327. The only rationale for an SYA rate increase in 2026 and 2027 provided by Witness Chronister was that expected rate base growth from normal plant additions and the major projects, absent an alternative regulatory approach, would require additional base rate relief for 2026 and 2027. TR 3419. One might ask whether Emera's cash needs would have been so onerous on Tampa Electric's customers that Emera needed to divide it three ways? These SYAs have historically existed primarily, if not entirely, in the realm of negotiated settlements. The concept exists as a heretofore unutilized tool available to the Commission, in response to a showing of extraordinary circumstances, which are lacking here. Emera's ask is all take, and no give. Granting the SYAs could discourage utilities from engaging in settlement negotiations.

The Commission elaborated on its legal authority for SYAs in Order No. PSC 2010-0153-FOF-EI ("FPL 2010 Order").[40] Section 376.076(2), Florida Statutes, states that "[t]he commission may adopt rules for the determination of rates in full revenue requirement proceedings which rules provide for adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods." However, the statutory interpretation in rule 25-6.0425, F.A.C., Rate Adjustment Applications and Procedures, merely provides "[t]he Commission may in a full revenue requirements proceeding approve incremental

[40] *See* Order No. PSC-2010-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for rate increase for Florida Power & Light Company,* and Docket No. 090130-EI, *In re: Depreciation and dismantlement study by Florida Power & Light Company.*

adjustments in rates for periods subsequent to the initial period in which new rates will be in effect," but does not provide any framework, limitation, guidance, or customer protections for SYAs. TR 2323-2324. Witness Kollen pointed out that the Company offered no framework, offered no limitations on the cost that could be included in the 2026 SYA and 2027 SYA or in future SYAs, offered no guidelines for such incremental adjustments, and failed to offer any reasonable customer protections. TR 2324.

However, in the FPL 2010 Order, the Commission had expressed some policy considerations that should be followed in this case. The Commission stated that back-to-back rate increases should be allowed only in extraordinary circumstances. *Id.* At 9. Historically, the Commission has used the test year concept for setting rates. *Id.* Under this concept, the test year is deemed to be representative of the future and is used to set rates that will allow the utility the opportunity to earn a rate of return within an allowed range. *Id.* Tampa Electric Witness Aldazabal, a CPA and seasoned participant in the regulatory process, acknowledged that the Commission does not set rates for a single year with the expectation that the Company will be right back in the next year. TR 733-734. If the test year is truly representative of the future, then the utility should earn a return with the allowed range for at least the first 12 months of new rates. *Id.*

Moreover, any rate adjustments due the subsequent year information are inherently more unreliable the further out in time the request is made. In the FPL 2010 Order, the Commission recognized that the projected 2011 test year was too speculative, therefore was not appropriate for rate setting. *Id.* At 12. They opined that the projection period was developed in times of great economic instability and was too far into the future to give the Commission confidence in the integrity of the data since the actual events of 2009 had shown potential significant variance from the projections. *Id.* There, the Commission had also considered the accuracy of the utility's forecast and the economic conditions at the time in determining the appropriateness of granting an SYA. The Commission recognized, in denying the SYA, that if the Company was unable to earn within its allowed range of return, it has the option of filing a base rate increase along with a request for interim rate relief. *Id*. The Commission's limited, past practice had been to limit SYAs to the placement into service of large, discrete revenue-impacting generation facilities, such as the GBRAs. TR 2322-2323, *Id.* At 16. However, in the FPL 2010 Order the Commission declined to approve the GBRA mechanism in the context of a traditional rate case proceeding or outside a separate generic proceeding due to the magnitude of this potential policy change. *Id.*

Given its previously articulated policy, the Commission should weigh the following factors. When generation facilities and/or major capital projects are placed in service, Tampa Electric must demonstrate that it would earn below the approved equity range due to the material revenue requirement impact in the year(s) immediately after a rate case. Further, Tampa Electric should demonstrate the need for generation and/or facilities in the subsequent year. Given the lack of other directives in either the statute or rule, the Commission should not expand its use of an SYA beyond large revenue impacting generation or equivalent type facilities. All historical and traditional "business-as-normal" distribution "electric delivery infrastructure" investment costs should NOT be allowed in an SYA. TR 2322-2323. Witness Kollen suggested six factors if the Commission considers an SYA, summarized as follows: (1) project and/or costs meet certain dollar or other qualification; (2) it is limited to material and known costs for new, identifiable, discrete projects after test year; (3) there is no new, expanded programs or category of costs and no annualized costs for costs included in test year; (4) there are no forecasted increases in "business as normal" costs included in test year; (5) weather normalized customer growth revenues should be included to offset an requested SYA revenue; and (6) significant cost reductions should be properly recognized as offsets. TR 2326-2327.

Thus, if the test year is chosen appropriately, it should be representative of rates on a going-forward basis, negating the need for another rate adjustment so shortly after the original test year, absent any extraordinary circumstances. To evaluate if extraordinary circumstances exist to grant an SYA, the Commission should consider the following criteria based on its previously articulated policy: (1) is the cause of the SYA a specific new and material generation-type capital investment cost and operation expense (i.e. a discrete, material capital project); (2) would the associated revenue requirement cause the Company to earn below the earnings range approved for the test year in the subsequent year; and (3) can the Company demonstrate a need for the cause of the increase and that it is cost-effective. When applying the above three criteria, the Commission should consider Mr. Kollen's factors 1 through 4 when determining criteria 1, and then factors 5 and 6 when determining criteria 2. Their findings in criteria 1 and 2 should then be applied to determine criteria 3, if the Company has established the requisite need for the increase and that it is cost-effective. If the proposed SYAs fail to meet these criteria, then the Commission is left with a rate case that has been divided into 3 parts, accompanied by speculative forecasts of modest future growth.

ISSUE 95: Should the Commission approve the inclusion of TECO's proposed Solar Projects in the 2026 and 2027 SYA? What, if any, adjustments should be made?

OPC: *This project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT: *See Issue 18.*

ISSUE 96: Should the Commission approve the inclusion of TECO's proposed Grid Reliability and Resilience Projects in the 2026 and 2027 SYA? What, if any, adjustments should be made?

OPC: *No, the Commission should deny the inclusion of Tampa Electric's proposed GRR Projects for the following reasons: (1) these projects are historically, traditional "business as normal" activities; (2) these projects are NOT for specific new and material generation capital investment costs and operation expenses (i.e. a discrete, material capital project); (3) "delivery infrastructure" investments have not previously been allowed recovery in an SYA.*

ARGUMENT:

As part of its application, Tampa Electric is requesting adjustments in base rates and charges to become effective in the first billing cycles of January 2026 and January 2027. TR 106. Tampa Electric likens these SYAs to the GBRA and Solar Rate Adjustments approved by the Commission in other cases in that these adjustments are designed to only recover incremental costs of projects Tampa Electric puts into service in 2026 and 2027. TR 107. Tampa Electric's proposed 2026 SYA amount is approximately $100.1 million and its proposed 2027 SYA amount is $71.8 million. TR 107.

The Grid Reliability and Resilience Projects ("GRR Projects"), as revised, make up $4,139,116 and $25,889,595, respectively, of these revenue requirements. EXH 835. The GRR Projects are alternately described in Company documents as the "Advanced Distribution Infrastructure Project" (EXH 439, BSP 7275) or "Advanced Distribution Infrastructure program" or "ADI Program" (EXH 430, Unnumbered 15) ("ADI"). OPC does not agree that the Commission should treat the GRR Projects or any portion thereof as a discrete project for separate cost recovery. The 2026 and 2027 components of the GRR Projects are merely a continuation of a grouping of various, individual projects that Tampa Electric began planning for and deploying sometime before this rate case. TR 1280-1281; EXH 244; EXH 350; EXH 420; EXH 429.

In June of 2023, in the early stages of preparing the ask in this case, the Tampa Electric Board considered an unnamed proposal that was then in development to combine between 65 and 70 distribution initiatives into a single project. TR 232-236; EXH 244. Less than two months later at a subsequent Tampa Electric Board meeting, the nascent combination of component projects was "named" ADI. By the time the project received a name, it had been whittled down to 40 "components" that were selected from items already included in the long-term forecast ("LTF"). TR 239-240; EXH 439, BSP 7275.

In May of 2024, after this case was filed, the Capital Leadership Team conducted a high-level review[41] and scrutinized the proposal before the Board considered and ultimately approved it. This is how the GRR Projects/ADI was described to that entity:

> Many of the components and projects that comprise ADI ***have already been embedded within the existing grid modernization roadmap and prior long-term forecasts (LTFs).*** ADI represents an aggregation and acceleration under one program of more than forty discrete, yet interdependent investments ***that were within TEC's plans***. Several foundational ADI projects, including investments in private LTE, Volt/VAR control, and upgrades to digital relays within TEC's substations, ***have already been separately approved and are actively being executed.***

(Emphasis added.) EXH 370, MPN F2.2-7211. Elsewhere in the document, the proponents tout ADI's "aggregated and programmatic approach" would accomplish "utilizing regulatory rules for AFUDC project." EXH 370, MPN F2.2-7211, 7225. The components of the GRR Projects that were included in the 2026 and 2027 SYAs are the Grid Communication Network, the Customer Information Device Expansion, and the Grid Communication Network Hardware, Work Management, and Control Systems components. TR 1272.

Typically, the replacement of aged or obsolete infrastructure should be accounted for during the test year in a traditional rate case and should not require subsequent post-test year adjustments. Tampa Electric asserts that the GRR Projects are part of grid modernization strategy to create a "system of systems" to provide various improvements. TR 1262-1263. This assertion is undercut by Tampa Electric Vice President of Electric Delivery, Chip Whitworth, who described the GRR

[41] This scrutiny either took the form of endorsement or approval. See conflicting statements about the purpose of the CLT. TR 246-247, 693, 1270.

projects as "necessary to replace obsolete systems and equipment that have reached end of life." TR 1120. For example, the Grid Communication Network project involves replacing Tampa Electric's out-of-date SCADA system. TR 1264. The Customer Information Device Expansion is just about changing the billing approach to certain devices, eliminating reliance on workarounds in existing systems, and preparing the utility for "growth," which one would hope would be a routine activity of any utility. TR 1247. Finally, the Control System component relies on line sensors. It appears Tampa Electric is not even including this component in the SYAs anymore per a letter filed in the docket less than a week before the hearing. EXH 835.

The record descriptions of the overall ADI Project indicates that it is little more than a re-packaging of the component parts of business-as-normal distribution or energy delivery plant additions that were already resident in the budget/forecast. It would appear that the reason Board approval was not sought before the case was filed for the overall aggregation of these components was that most of them were already approved or did not individually need Board approval. The CLT document notes that $869 million of the approximately $900 million in capital identified with the ADI project "was already accounted for in the 2023 LTF." TR 254; EXH 370, MPN F2.2-7226.

Further, despite the naming conventions employed by Tampa Electric, the GRR Projects are actually a disparate grouping of individual components that have been grouped together for financial reasons. The August 2023 Board document describes the newly christened ADI as "components" that "have been packaged" and were a result of "bundling capital projects." EXH 439, BSP 7276. There was an indication that in November 2023, that Tampa Electric "Board approval to proceed" would be sought. EXH 439, BSP 7286. However, on April 2, 2024, this case was filed without such approval being sought. TR 248.

Witness Collins admitted at the hearing that the disparate GRR projects were "projects, some of which were less than 50 million [dollars], and by making them part of a bigger pie, the total now is earning AFUDC" (TR 241) and that pooling the projects together meant earning more AFUDC than doing each component separately. TR 242.[42] The importance of this evidence is that Tampa Electric has sought to create an extra revenue requirement basis for adding a portion of the GRR Project to the SYA for the years 2026 and 2027. After a bit of a scavenger hunt through the

[42] Since AFUDC is a benefit that shareholders get (TR 242), this is another area where Tampa Electric is putting the interests of its owners ahead of those of its bill paying customers.

existing LTF, what purports to be a single project is a fluctuating[43] agglomeration of components that was given an internal name (ADI) that recognizes that it is really just distribution infrastructure. By giving it a grid-related name, perhaps the thought was that it could be made to appear to be a discrete, tangible, billion-dollar project instead of essentially a lot of software bundled to create a separate increase on the bill.

OPC experts Mara (TR 2376-2378) and Kollen (TR 2322-2335) confirmed that the ADI/GRR initiative was not a discrete new project but instead business-as-normal distribution upgrade and obsolescence replacement activity – precisely what is expected of a utility. These experts provide compelling evidence that these "energy delivery" investments are part of the maintaining and upgrading the distribution portion of the system, which has never been the basis for an SYA. OPC engineering expert Mara provided this succinct critique of the proposed SYA treatment of the GRR/ADI costs:

> In traditional ratemaking, the capital projects are planned for and deployed between rate cases or during the test year of the current rate case, then the costs are reviewed for prudence in the next base rate case or current rate case. Further, the types of maintenance and replacement of obsolete equipment are normally included in the Company's annual budgets and would be accounted for in a representative test year which includes costs and revenue one year into the future. However, increases in the test year costs for these routine type of activities above normal levels unnecessarily increases costs for customers and should be scrutinized for imprudent spending.

TR 2376.

As detailed further in Issue 94, if the test year is chosen appropriately, it should be representative of rates on a prospective basis, negating the need for another rate adjustment so shortly after the original test year, absent any extraordinary circumstances. To evaluate whether extraordinary circumstances exist to grant an SYA, the Commission should consider following criteria based on its previously articulated policy: (1) is the cause of the SYA a specific new and material generation-type capital investment costs and operation expenses (i.e. a discrete, material capital project); (2) would the associate revenue requirement cause the Company to earn below the earnings range approved for the test year in the subsequent year; and (3) can the Company demonstrate a need for the cause of the increase and that it is cost-effective?

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[43] The evidence shows that the project was perhaps originally 65, then 70 and then 40 and now something less than 40 components. TR 235, 239: EXH 244, BSP 7075, 7076. The last change was made the week before hearing when two components were pulled from the pending revenue requirement ask. EXH 835.

Applying the above test to the GRR projects included in the 2026 and 2027 SYAs shows that these projects should be denied by the Commission. None of the projects are generation-type and the Company has failed to demonstrate a need for the cause of the increase because many of these projects are simply planned replacement of aged or obsolete infrastructure. TR 2377. The fact that Tampa Electric slapped a label on a mixed bag of expenditures does not change this ratemaking fundamental, nor does it qualify this hodge-podge of costs under Commission policy for an SYA. While, as discussed in Issues 99, 100, and 101, *infra*, it is certainly questionable whether the brick-and-mortar projects of the headquarters, new operations center, and the South Tampa Resiliency Project qualify for SYA treatment, it is undeniable that those projects are closer to resembling the Commission policy of recognizing discrete and material, tangible generation facilities for SYA recovery.

Furthermore, the projects are further out in the future and thus less reliable than the forecast. TR 2376-2377. On the eve of hearing, the Company revised the plan. EXH 835. While the components were being assembled in 2023, the scope fluctuated significantly. Even if the Commission were to incrementally grant the additional revenues for these projects through an SYA, the Company is under no obligation to spend the revenues on them. TR 2377. The Company could choose to use the revenue elsewhere or not at all. TR 2377. In a traditional rate case, deployment with any problems or failures can be viewed from the prospective of prudent management and costs. TR 2377.

The only rationale provided by Tampa Electric in its original filing to justify the inclusion of GRR Projects in the 2026 and 2027 SYAs is that selected portion of projects will be in-service by December 2026 and providing value to customers. TR 1268. This weak attempt at justification does not stand up to scrutiny. If this was the only metric for projects to be included in an SYA, then there would be no need for utilities to request recovery for projects completed between rate applications. Instead, they could include anything completed post-test year that would provide value in an SYA. Such an approach would create a slippery slope allowing all costs that could be described as interrelated to receive separate rate recovery.

Based on the foregoing, the Commission should deny Tampa Electric's requested GRR projects in the 2026 and 2027 SYAs. This will result in a reduction of $4.599 million from the 2026 SYA and $28.788 million from the 2027 SYA. EXH 835. Doing so is consistent with prior

Commission policy and will alleviate some of the burden being faced by Tampa Electric's customers in light of the instant application to increase rates.

ISSUE 97: **Should the Commission approve the inclusion of TECO's proposed Polk 1 Flexibility Project in the 2026 SYA? What, if any, adjustments should be made?**

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT:

The Polk 1 Flexibility Project consists of converting the existing combined cycle unit to what the Company calls a "highly efficient" simple cycle unit with the latest technology to better utilize that asset, according to Tampa Electric Witness Aldazabal. TR 652. He testified that the project is expected to cost $80.5 million and be placed in service in May 2025. TR 652. Polk 1 Flexibility project's first full year in service will be in 2026. TR 3417. Witness Chronister's Exhibit 5, page 1, shows an incremental revenue requirement for 2026 SYA of $5,185,793 at an ROR of 7.37%. EXH 32. OPC is recommending an ROR of 7.19% which would reduce the revenue requirement for these projects. TR 2798. The effect of each 10% change in the return on common equity has a $6.319 million impact on the base revenue requirement, or $63.19 million per 100 basis points. TR 2321. The Tampa Electric Polk 1 Flexibility Project inclusion in the 2026 SYA should not be allowed unless it meets the following criteria: (1) it is a specific new and material capital investment cost and operation expense (i.e. a discrete, material capital project); (2) the associated revenue requirement would cause Tampa Electric to earn below the earnings range approved in this docket in the subsequent year; and (3) Tampa Electric can demonstrate a need for the generation. This project meets the first criteria. However, as a single project, this project would not cause the Company to move a full 10 basis points. If combined with the other projects placed into service in the test year, but with a full year revenue requirement in 2026, then the revenue requirement might exceed the $63.19 million or 100 basis points (even excluding all GRR projects). OPC has taken no position of the need for this generation project.

ISSUE 98: **Should the Commission approve the inclusion of TECO's proposed Energy Storage Projects in the 2026 SYA? What, if any, adjustments should be made?**

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT:

Witness Stryker testified that Tampa Electric is building 115 MW of energy storage capacity that includes: (1) a 15 MW energy storage project for the Dover project in service September 2024; (2) a 40 MW energy storage project for the Lake Mabel project in service January 2025; (3) a 40 MW energy storage project for the Wimauma project in service February 2025; (4) and a 20 MW energy storage project for what was originally called the "South Tampa Energy Capacity Storage Project" (now to be located at the Bayside Power Station), expected to be in service December 2025. TR 811, 840. He testified that these energy storage projects are expected to cost $156.1 million. TR 841. Two of these projects' first full year in service will be in 2026. TR 842, 3417. Witness Chronister's Exhibit 5, page 1, shows an incremental revenue requirement for the 2026 SYA of $8,990,287 at an ROR of 7.37%. EXH 32. OPC is recommending an ROR of 7.19% which would reduce the revenue requirement for these projects. TR 2798. The effect of each 10% change in return on common equity has a $6.319 million impact on the base revenue requirement, or $63.19 million per 100 basis points. TR 2321. The Tampa Electric proposed Energy Storage Projects inclusion in the 2026 SYA should not be allowed unless they met the following criteria: (1) they are specific new and material generation-type capital investment cost and operation expense (i.e. a discrete, material capital project); (2) the associated revenue requirement would cause Tampa Electric to earn below the earnings range approved in this docket in the subsequent year; and (3) Tampa Electric can demonstrate a need for the energy supply projects and that they are cost-effective. These projects meet the first criteria. However, as only energy storage projects, they would not cause the Company to move a full 20 basis points. If combined with the other projects placed into service in the test year, but with a full year revenue requirement in 2026, then the revenue requirement might exceed the $63.19 million or 100 basis points (even excluding all GRR projects). OPC has taken no position of the need for these energy storage projects.

ISSUE 99: Should the Commission approve the inclusion of TECO's proposed Bearss Operations Center Project in the 2026 SYA? What, if any, adjustments should be made?

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT:

Witness Aldazabal testified that Tampa Electric is building the Bearss Operations Center with an expected in-service date of June 2025 and Energy Management System project and which is 32 percent complete with an expected in-service date of October 1, 2025, (together referred to as "Bearss project"). TR 668. He testified that the Bearss project is expected to cost $335 million. TR 665. The project's first full year in service will be in 2026. TR 3417. Witness Chronister's Exhibit 5, page 1, shows an incremental revenue requirement for the 2026 SYA of $27,025,746 at an ROR of 7.37%. EXH 32. OPC is recommending an ROR of 7.19% which would reduce the revenue requirement for these projects. TR 2798. The effect of each 10% change in return on common equity has a $6.319 million impact on the base revenue requirement, or $63.19 million per 100 basis points. TR 2321. The proposed Bearss Operation Center is being placed into service in 2025 during the test year without a full year revenue requirement. The Tampa Electric proposed Bearss Operations Center Project inclusion in the 2026 SYA should not be allowed unless it meets the following criteria: (1) it is a specific new and material capital investment cost and operation expense (i.e. a discrete, material capital project); (2) the associated revenue requirement would cause Tampa Electric to earn below the earnings range approved in this docket in the subsequent year; and (3) Tampa Electric can demonstrate a need for the facility. The project meets the first criteria. However, the Bearss Project itself would not cause the Company to move a full 50 basis points. If combined with the other projects placed into service in the test year, but with a full year revenue requirement in 2026, then the revenue requirement might exceed the $63.19 million for

100 basis points (even excluding all GRR projects). OPC has taken no position on the need for the Bearss Operations Center Project.

ISSUE 100: Should the Commission approve the inclusion of TECO's proposed Corporate Headquarters Project in the 2026 SYA? What, if any, adjustments should be made?

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT:

Witness Aldazabal testified that Tampa Electric is in the process of building the Corporate Headquarters project with an expected in-service date of June 1, 2025. TR 669-70. He testified that the Corporate Headquarters project is expected to cost $188.7 million. TR 673. The project's first full year in service will be in 2026. TR 3417. Witness Chronister's Exhibit 5, page 1, shows an incremental revenue requirement for the 2026 SYA of $10,787,343 at an ROR of 7.37%. EXH 32. OPC is recommending an ROR of 7.19% which would reduce the revenue requirement for these projects. TR 2798. The effect of each 10% change in return on common equity has a $6.319 million impact on the base revenue requirement, or $63.19 million per 100 basis points. TR 2321. The proposed Corporate Headquarters Project is being placed into service in 2025 during the test year without a full year revenue requirement. The Tampa Electric proposed Corporate Headquarters Project inclusion in the 2026 SYA should not be allowed unless it meets the following criteria: (1) it is a specific new and material capital investment cost and operation expense (i.e. a discrete, material capital project); (2) the associated revenue requirement would cause Tampa Electric to earn below the earnings range approved in this docket in the subsequent year; and (3) Tampa Electric can demonstrate a need for the facility. The project meets the first criteria. However, the Corporate Headquarters project, itself, would not cause the Company to move a full 20 basis points. If combined with the other projects placed into service in the test year, but with a full year revenue requirement in 2026, then the revenue requirement might exceed the $63.19 million or 100 basis points (even excluding all GRR projects). OPC has taken no position on the need for the Corporate Headquarters project.

ISSUE 101: Should the Commission approve the inclusion of TECO's proposed South Tampa Resilience Project in the 2026 and 2027 SYA? What, if any, adjustments should be made?

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

ARGUMENT:

The resolution of this issue should follow the outcome of Issue 22. The absence of sufficient federal government funding that recognizes the benefits being provided to the Air Force Base indicates that Tampa Electric has not demonstrated that the entire cost of the project is prudent. The absence of such an equitable contribution is an indicator that the Company has failed to meet its burden of proof that the project is reasonable and prudent, apart from the fact that the capital for the second phase of the project was reprofiled by accelerating it by 3 years. OPC is not seeking disallowance of the project from the test year. Rather, recognition of the reprofiling and lack of equitable federal contribution should be considered in determining the overall revenue requirement. For the SYA years, the Commission should decline to include these costs as a separate revenue requirement given the overall facts and circumstances surrounding the reprofiling and inequitable federal sharing. The project does not meet the test set out in Issue 94 for recognition of a separate additional SYA-based rate increase.

ISSUE 102: Should the Commission approve the inclusion of TECO's proposed Polk Fuel Diversity Project in the 2026 and 2027 SYA? What, if any, adjustments should be made?

OPC: *To the extent the Commission authorizes an SYA, this project should not be included in the 2026 and 2027 SYA unless (1) it represents a specific new and material generation capital investment cost and operation expense (i.e. a discrete, material capital project); (2) its revenue requirement would cause Tampa Electric to earn below the new earnings range in 2026; and (3) Tampa Electric can demonstrate a need for the generation.*

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

OPC: *The overall rate of return should be the OPC proposed ROR for 2025 of 7.19% using OPC proposed ROE of 9.50%.*

ARGUMENT: *See Issue 39.*

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

OPC: *Yes. Should the Commission allow a 2026 SYA, the additional forecasted revenues reflected due to customer growth should be increased by at least $7.994 million. Should the Commission allow a 2027 SYA, additional forecasted revenues reflected due to customer growth should be increased by at least $6.123 million.*

ARGUMENT:

As recommended by OPC Witness Kollen, and to the extent the Commission grants any SYA, the Commission should reduce the requested 2026 and 2027 SYA revenue requirements and requested increases by the revenue amounts quantified by OPC Witness Dismukes to reflect the additional base revenues due to growth in customers and sales in 2026 compared to the test year and then in 2027 compared to 2026 for application as credits against the 2026 SYA and 2027 SYA revenue requirements. TR 2324. The effects include reductions of $7.994 million for the 2026 SYA and $6.123 million for the 2027 SYA to reflect an increase in base revenues due to the Company's forecast growth in customers in 2026 and 2027 along with additional base revenues to remove the out of model adjustments in the same manner as those adjustments are addressed by Witness Dismukes. TR 2334-2335.

ISSUE 105: Should the Commission approve the inclusion of TECO's proposed incremental O&M expense associated with the SYA projects in the 2026 and 2027 SYA?

OPC: *No, the Commission should subtract the variable O&M expense savings that Tampa Electric estimated in its cost effectiveness determinations. Otherwise, the requested SYA revenue requirement, if even authorized, would be overstated.*

ARGUMENT:

The Commission should exclude all incremental O&M expense for the projects reflected in the 2026 and 2027 SYAs to address the Company's failure to reflect the O&M expense savings the Company estimated in its cost effectiveness determinations for those projects. Otherwise, any requested SYA revenue requirement, if even authorized, would be overstated. The effects include reductions of $6.696 million and $3.420 million to exclude all incremental O&M expense for the 2026 and 2027 SYA revenue requirements, respectively. TR 2334-2335.

ISSUE 106: Should the depreciation expense and Investment Tax Credits amortization used to calculate the proposed 2026 and 2027 SYA be adjusted to reflect the Commission's decisions on depreciation rates and ITC amortization for the 2025 projected test year?

OPC: *To the extent that the Commission even authorizes an SYA, then yes, these adjustment should be reflected.*

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

OPC: *To the extent that the Commission even authorizes an SYA, the Commission should reduce the revenue requirement for the GRR Projects by at least $4.599 million in the 2026 SYA and by at least $28.788 million in the 2027 SYA.*

ARGUMENT: *See Issues 96 and 104.*

ISSUE 108: No position.

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

OPC: *The 2026 SYA, if allowed over the objection of OPC, should not become effective any sooner than the first billing cycle in 2026. The 2027 SYA, if allowed over the objection of OPC, should not become effective any sooner than the first billing cycle in 2027.*

ISSUE 110: Should TECO be required to file its proposed 2026 and 2027 SYA rates for Commission approval in September 2026 and 2027, respectively, reflecting then current billing determinants?

OPC: *To the extent that the Commission even authorizes an SYA, over OPC objection, yes.*

OTHER

ISSUE 111: Should TECO's proposed Corporate Income Tax Change Provision be approved?

OPC: *No. It will be reversible error if the Commission approves Tampa Electric's proposed Corporate Income Tax Change Provision under the circumstances of this case. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017)*

ARGUMENT:

As a preliminary consideration, OPC further relies on the assertions by Tampa Electric as supporting basis for denial of the relief sought on this issue. The Company's representative argued vigorously that with respect to his misplaced notion that OPC was seeking to cross-examine Tampa Electric Witness Collins about certain aspects of the August 21, 2024, formal approval of the DEF settlement in order to assert the 10.3% ROE as precedent, it was stated:

> I think we are going to spend a lot – if it is relevant, we are going to spend a lot of time this week. By its terms, it has no precedential value, and by its terms, no individual part of the agreement –
>
> (TR 137)

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> Mr. Chairman, Tampa Electric didn't sign an agreement that says that the settlement agreement has no precedential value. Office of Public Counsel, Walmart, FIPUG did. Now they are wanting to talk about their settlement agreement, and they are implying that it has precedential value in this case. That's why we are objecting. They are the ones that agreed to that in their settlement agreement.
>
> (TR 138-139)

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> All of these settlement agreements are give and take between the parties. And they all have language in them that says you can't pick one little piece out of it and say, this is what we all agreed to, because it represents give and take.
>
> (TR 154)

What is extraordinary about the assertions by Tampa Electric is that they precisely encapsulate why it is improper for the Company to cherry-pick a provision or provisions of a settlement agreement and affirmatively ask the Commission to grant affirmative and substantive relief on that basis. Yet, Tampa Electric has done precisely that in seeking relief on this issue. The provision that Tampa Electric referenced with regard to prohibition to assert that a term in an existing settlement agreement provides a basis for granting affirmative relief exists in Paragraph 16(b) of the current Tampa Electric Agreement. Order No. PSC-2021-0423-S-EI in Docket No. 20210034-EI, at p. 50. This provision applies to Tampa Electric and to the Commission since it adopted it by order. Failure to observe this term is reversible error. Section 120.68(7)(e)3, Fla. Stat; *Citizens of Fla. v. Graham*, 213 So. 3d 703, at 710-711 (Fla. 2017). ("[T]he Commission departed from the essential requirements of law by failing to adequately address application of the settlement agreement to the FPL transmission interconnection costs.")[44]

There are several grounds for requiring the Commission to deny Tampa Electric's request to establish a tax adjustment mechanism. The Commission should reject Tampa Electric's effort to rely solely on the fact that this provision has been negotiated by the signatories to the current 2021 Agreement, the 2017 Tampa Electric Agreement and perhaps the negotiated settlements of DEF and FPL, including the most recent DEF settlement, which the Commission sought to limit consideration of.[45]

With regard to the substance of the issue, the Commission has established a policy in a final order that a rate case is not the proper venue for establishing a prospective change in rates as a result of a future change in federal income tax rates.[46] *See* Order No. PSC-2017-0099-PCO-EI, issued in Docket No. 20160186-EI ("*2017 Gulf Tax Decision*"). The Commission has ruled that, absent a concrete law implementing a change in tax rates, such a measure would be premature and that a separate, subsequent proceeding is the only appropriate way to address this problem when and if a change in the tax law occurs. This should be the end of the inquiry. In two recent natural gas rate cases, the Commission denied similar efforts to create a tax mechanism borrowed from settlement agreements at a time with no adopted or even pending change in tax law.[47] Tampa Electric has not demonstrated that its circumstances differ at all from the precedent established in the *Gulf, FCG,* or *FPUC* cases.

Additionally, Tampa Electric, through its employee witnesses in this case, is acting inconsistent with the 2021 Agreement terms adopted by Order No. PSC-2021-0423-S-EI in Docket No. 20210034-EI. Tampa Electric seeks to have the Commission rely on the negotiated provision and terms in that 2021 Agreement as precedent which is prohibited by an express term of the 2021

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[44] This objection and analysis applies equally to the relief sought on Issue 112 and Issue113. The analysis on this point applies equally to those issues.
[45] *See* Paragraph 19 in proffered EXH 243, F2.1-4093. This exhibit demonstrates that there was a negotiated Tax Mechanism included in the 2024 settlement that the Commission approved on August 21, 2024.
[46] PSC Order No. PSC-2017-0099-PCO-EI, issued March 14, 2017, pp. 107-08, *In re: Petition for rate increase by Gulf Power Company* and *In re: Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals and Plant Smith Units 1 and 2 regulatory asset amortization, by Gulf Power Company.* ("*2017 Gulf Tax Decision*").
[47] *See* Order No. PSC-2023-01770-FOF-GU, Issued June 9, 2023, Issued Docket No. 20220069-GU, at pp. 71-72, *In re: Petition for rate increase by Florida City Gas. ("FCG")*; Order No. PSC-2023-0103-FOF-GU, Issued Mach 15, 2023, Docket No. 20200067-GU, at pp. 120-121, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company – Indiantown Division. ("FPUC").*

Agreement. As a matter of policy, the Commission should further decline to authorize the provision because it is single issue ratemaking that would ignore the other relevant conditions that might exist at a time when tax laws might change in the future.

Negotiated provisions in other company situations are presumptively accompanied by bargained-for revenue requirement concessions that would indicate fairness and balance in the negotiated prescriptive adjustment to rates and revenue requirements in the future. No such bargained-for consideration is present in this fully litigated case.

In 2017, Gulf Power argued against OPC and intervenors even raising the issue about whether a mechanism should be adopted. The issue was worded:

> In the event federal legislation is passed and signed into law between now and a reasonable period after new base rates become effective that results in a change in the corporate income tax rate to which GTEC is subject, or changes in the depreciation allowance for tax purposes associated with plant additions incorporated in test year rate base, what adjustments or provisions, if any, should the Commission make to address such changes? Should the Order in this case require a limited reopening within a reasonable period after new base rates become effective to address income tax expense as well as the accumulated deferred income taxes in the capital structure in the event such legislation is passed that would impact Gulf's revenue requirements?[48]

On behalf of the entire Commission, the Prehearing Officer then ruled:

> I find the issue is premature and not ripe for consideration at this time. Should federal tax changes occur in the future, the issue may be addressed at the appropriate time in a separate proceeding.[49]

The *2017 Gulf Tax Decision* became final and controlling for that case. The parties ultimately settled the case and in the shadow of the decision, negotiated a tax rate adjustment provision that became the first such mechanism in Florida.[50] Both orders established the predicate that if the parties wanted certainty in the resolution of tax changes, the method for accomplishing it was in a rate case settlement since the remedy was not available in a conventional litigated rate case. Consistent with Commission precedent, the issue should be stricken and this portion of the brief

[48] *2017 Gulf Tax Decision* at 107.
[49] *Id.* at 108.
[50] PSC Order No. PSC-2017-0178-S-EI, issued May 16, 2017, at pp. 15-6, *In re: Petition for rate increase by Gulf Power Company* and *In re: Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals and Plant Smith Units 1 and 2 regulatory asset amortization, by Gulf Power Company.*

should be moot. Nevertheless, and in an abundance of caution and for preservation of the record on appeal, OPC will address this matter on the merits.

For Tampa Electric to arrive at the hearing, hat in hand, and demand to receive a Commission-ordered tax adjustment mechanism on top of a fully litigated revenue requirement award is fully inconsistent with the policy enunciated in the *2017 Gulf Tax Decision*. Since the Company conceded that there is no impact of the August 2022 IRA on the Company, it is undisputed that the purpose of the proposal is premature for some future, unknown (and purely speculative) tax law change.

The ruling in the *2017 Gulf Tax Decision* established a policy that prohibits the relief sought by Tampa Electric. Agency action authorizing the tax adjustment provision would be a violation of Section 120.68(7)(e)3, Florida Statutes, which requires that a court reverse unexplained agency action that is contrary to Commission policy or practice. The Florida Supreme Court has cautioned that not just any explanation will do in efforts to explain deviation from precedent. The agency cannot merely check a box here. In *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017), the Court reversed this Commission's decision to ignore a provision in a settlement agreement without explanation or rationale. Citing to *McDonald v. Department of Banking & Finance*, 346 So. 2d 569 (Fla. 1st DCA 1977), the Court took pains to note that not just any explanation will do in stating:

> The final order must display the agency's rationale. It must address countervailing arguments developed in the record and urged by a hearing officer's recommended findings and conclusions or by a party's written challenge of agency rationale in informal proceedings, or by proposed findings submitted to the agency by a party.
>
> Failure by the agency to expose and elucidate its reasons for discretionary action will, on judicial review, result in the relief authorized by Section 120.68(13): an order requiring or setting aside agency action, remanding the case for further proceedings or deciding the case, otherwise redressing the effects of official action wrongfully taken or withheld, or providing interlocutory relief.

Citizens at 712.

The *Citizens* Court also cited with approval *Seminole Electric Cooperative, Inc. v. Department of Environmental Protection,* 985 So. 2d 615 (Fla 5th DCA 2008), in which the Fifth District Court of Appeals set aside agency action that disregarded a stipulated evidentiary record and proposed order with sparse explanation. The Court also pointed out that "[o]ther contexts in which an agency has insufficiently addressed its action include *orders ignoring precedent on point*..." *Citizens* at 713. (Emphasis added.)

Any "heads-I-win-tails-you-lose" decision that rewards Tampa Electric for merely asking to receive what was denied to customers in 2016 would be arbitrary and undermine any "explanation" or rationale that might be offered to a reviewing court. Most certainly, such an arbitrary result would run afoul of the warning in the *Citizens, McDonalds,* and *Seminole* cases.

Policy reasons for not adopting the proposal beyond the legal prohibitions are that the proposal is entirely designed to favor dollar-for-dollar pass through of tax rate *increases* for the Company in a manner that would ignore whether other equally offsetting cost reductions were occurring. The mechanism – if adopted outside of a negotiated posture where it is bargained for consideration – would create an asymmetrical environment of single-issue ratemaking. Debits in the form of tax rate increase would be recovered while credits in the form of synergies or other savings would be retained inside of the earnings range.

The negotiated provisions of each IOU contain specific dollar values and thresholds that are negotiated specific to the bargained-for consideration in each settlement and order. For the reasons set out above, plus the fact that the Commission lacks an evidentiary basis to determine these values beyond pirating them from the terms of the existing Tampa Electric 2021 Agreement, the Commission should avoid creating reversible error. Tampa Electric's request to create a Tax Mechanism in this case should be rejected.

For the reasons set out above, adoption of the proposed Corporate Income Tax Change Provision in this proceeding will constitute reversible error. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

ISSUE 112: Should TECO's proposed Storm Cost Recovery Provision be approved?

OPC: *No. It will be reversible error if the Commission approves Tampa Electric's Storm Cost Recovery Provision under the circumstances of this case. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017)*

ARGUMENT:

In addition to the objections stated related to Issue 111, as set out in the argument there and incorporated by reference here, the Commission should deny Tampa Electric the authority to continue the Storm Cost Recovery Mechanism or SCRM. It appears that Tampa Electric is seeking to rely primarily on the fact that this provision has been negotiated by the signatories to the current 2017 and 2021 Agreements. Paragraph 8 of the 2021 Agreement contains the SCRM. This provision combines several elements of existing law with negotiated and agreed terms. It only partially piggybacks the existing rule 25-6.0143, F.A.C., for determination of cost-eligibility and the file-and-suspend time frames, and hearing and interim provisions as interpreted by the Florida Supreme Court. *Citizens of State v. Wilson*, 567 So. 2d 889 (Fla. 1990); *Citizens of State v. Wilson*, 571 So. 2d 1300 (Fla. 1990); *Citizens of State v. Wilson*, 568 So. 2d 904 (Fla. 1990). These elements of the SCRM are available to Tampa Electric and the Commission by operation of law and can be implemented regardless of the provisions of the 2021 Agreement.

On the other hand, there are various threshold or numeric values such as the maximum monthly recovery amount and the recovery period, or the excess storm cost of $100 million in Paragraph 8(b) of the 2021 Agreement, which are the product of negotiation. Apart from the precedential value of the term of the existing Agreement, there is no evidentiary basis for these values. Likewise, the threshold amount of the storm reserve and ability to include it in the surcharge is a negotiated term. The agreements by signatories to effectively not contest the initial interim implementation of the SCRM charge after a storm and the agreement not to seek to apply an earnings test to the recovery are part of bargained-for consideration as set out in Paragraph 8(c). These are negotiated terms that have no basis in evidence or law outside of the give-and-take that yielded bargained-for consideration. There is no evidence in this hearing record other than the precedential nature of the 2021 Agreement that would enable the Commission to determine these threshold or numeric values.

It is notable that Paragraph 8(d) of the settlement expressly requires that Tampa Electric's ability to utilize the SCRM expires when rates are set in this case; no exceptions. Tampa Electric seeks to rely on the very existence of Paragraph 8 as the basis to "cut-and-paste" it wholesale into a litigated Commission order. This is prohibited! The Company's approach does not provide the Commission, absent pirating it from the 2021 Agreement, with an alternative record basis that is supported by competent, substantial evidence to implement it.

For the reasons set out above, wholesale adoption of this SCRM provision in this case would constitute reversible error. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

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

OPC: *No. It will be reversible error if the Commission approves Tampa Electric's proposed Asset Optimization Mechanism under the circumstances of this case. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).*

ARGUMENT:

In addition to the objections stated related to Issue 111, as set out in the argument there and incorporated by reference here, OPC objects to the Commission even considering, much less authorizing the Asset Optimization Mechanism ("AOM") proposal in this case. Another instance of impermissible pirating of negotiated provisions can be found in Tampa Electric's request that the Commission unilaterally extend the AOM established in the 2017 Agreement[51] and renegotiated and renewed in the 2021 Agreement.[52] Despite the express language in Paragraph 16(b) that states "[n]o party will assert in any proceeding before the Commission or before court that the 2021 Agreement of any of the term in the 2021 Agreement shall have any precedential value," Tampa Electric seeks to do precisely this by urging that the Commission "extend" the provision and add two additional assets upon which shareholders would be able to capitalize. This Company request should be rejected for multiple reasons.

The primary basis for rejection is that the proposal is contrary to law as it is inconsistent with a Commission Order. Tampa Electric is prohibited from asserting that a term of the existing settlement agreement approved and adopted by the Commission in Order No. PSC-2021-0423-S-EI forms the basis for precedent. The evidence is overwhelming that Tampa Electric is only asking that the provision found in the Order No. PSC-2021-0423-S-EI in Docket No. 20210034-EI, at p. 50, to be extended and then enhanced with two additional elements: renewable energy credits ("REC") and releases of natural gas pipeline capacity.[53] Witness Heisey agreed that absent the extension of the negotiated provision, the AOM would expire on December 31, 2024. TR 3119, 3129, 3145. Asserting the extension of the existing negotiated term would be inconsistent with the order and would subject this rate case order to appellate review. OPC submits that merely proposing the AOM be based on the existing settlement term is contrary to the order. It is clear

[51] Order No. PSC-2017-0456-S-EI at p. 33.
[52] Order No. PSC-2021-0423-S-EI at p. 35.
[53] It is significant that the capacity release component was part of the 2017 Agreement. The Commission is entitled to assume that in the negotiations for the 2021 Agreement it was removed. TR 3127.

that Tampa Electric recognizes that the appropriate way to determine the appropriateness of such a mechanism is via petition in a standalone evidentiary proceeding. The Company did this twice. A 2013 petition by Tampa Electric was withdrawn (TR 3146) and the 2016 Petition was resolved in a negotiation that involved bargained-for consideration and resulted in two temporary AOM provisions that were set to expire initially at the end of the 2017 Agreement and then again at the end of the current 2021 Agreement. The mere reference to such a term does not substitute for or bring forward the petitioned-for evidentiary proceeding that never happened and which was ultimately (and temporarily) replaced by the 2017 and 2021 AOM provisions.

Apart from any legal prohibitions against adoption of the current AOM proposal, approving it via this base rate case would involve basing it on multiple levels of bootstrapping of negotiated settlement provisions of other utilities that were unrelated to the evidence in the record. FPL filed a petition in Docket No. 20160088-EI that was resolved via negotiation and settlement. As noted above, Tampa Electric filed its own petitions in 2013 (withdrawn) and 2016, for an AOM. TR 3146; Order No. PSC-2017-0456-S-EI at p. 33. Tampa Electric's 2016 petition was resolved via a 2017 settlement adopted and approved in Order No. PSC-2017-0456-S-EI. This 2017 Tampa Electric settlement order specifically referenced the 2016 AOM petition filed in Docket No. 20160160-EI. In 2016 when the initial FPL pilot was renewed, it was also referred to as a "Pilot Incentive Mechanism."[54] The 2016 FPL petition never resulted in an order as it was supplanted by the 2016 FPL settlement approved and adopted in PSC-2016-0560-AS-EI at 1. Subsequent to the adoption of the 2016 FPL mechanism through the negotiated bargained for consideration, the Tampa Electric 2017 AOM was approved for implementation by specific reference to the 2016 petition. Order No. PSC-2017-0456-S-EI at pp. 1, 33. In the 2021 Tampa Electric settlement, the term specifically refers to the 2016 petition and expressly indicates that it expires at the end of the agreement term (ending December 31, 2024). Order No. PSC-2021-0423-S-EI at p. 35.

In no instance has the Commission ever substantively and independently determined that an AOM of any utility be authorized on a standalone basis. Until now, all AOM provisions are negotiated and based on bargained-for consideration. Outside of impermissible reliance on a term of Tampa Electric's or another company's settlement, there is no basis for approving an AOM.

[54] *See* Order No. PSC-2013-0023-S-EI at pp. 22-24.

OPC asserts that any Commission reliance on other company settlement terms would violate the spirit – if not the letter – of the other company agreements.

Further evidence of the impropriety of even considering the AOM here is the long-standing Commission policy that would require it to be substantively addressed in the fuel adjustment docket.[55]

Finally, there has been no record established that would allow the Commission to base a determination of the threshold values proposed by Tampa Electric beyond their existence in the precedential terms of the 2021 Agreement. This competent, substantial evidence vacuum includes the negotiated values pirated from prior Tampa Electric settlements. Furthermore, these provisions cannot be reconciled with the negotiated values in the DEF and FPL terms which were the product of bargained for consideration. *See also* Paragraph 24 of Proffered Exhibit EXH 243, MPN F2.1-4099. Just as the robustly protested prehearing schedule severely constrained OPC's ability to prepare for hearing; the stated conclusion date and time for the hearing only compounded this problem. This case was tried against an unusual procedural background. Prior to the hearing, Tampa Electric announced that it would not cross-examine any of the 14 intervenor witnesses. TR 957. Additionally, at the outset of the evidentiary hearing the Chair announced that the hearing would end on Friday. TR 7. This meant that a hearing involving the presentation of testimony, evidence, and cross-examination of 36 witnesses (both direct and rebuttal) starting at 1 p.m. on Monday, would have no more than 4½ business days to be concluded. This created a dynamic that endangered the due process rights of the customers, as it was obvious to all that the only thing standing in the way of a Friday conclusion, was the cross-examination by the intervenor attorneys and the Staff. The Commission should have anticipated how Tampa Electric would respond to these circumstances that required the compression of the cross-examination of 18 Tampa Electric witnesses and two Staff witnesses into approximately four days (or less). Whether by design or borne of the fortuity of opportunity, objections to intervenors' cross-examination seemed to arrive with unusual frequency, draining hearing time and interposing diversion and perhaps serving to run-out the pre-ordained 4 ½ day hearing clock.[1]

By Wednesday of the short week allotted for the hearing, it was becoming increasingly obvious that objections aimed at limiting inquiry into areas that the Company would rather not be explored,

[55] *See* Order No. 12923-EI, issued January 24, 1984, at p. 2, Docket No. 19830001-EI; Order No. PSC-2000-1744-PAA-EI, issued September 26, 2000, at p. 1, Docket No. 19991799.

dovetailed nicely with the Commission's own expressed desire to meet a seemingly artificial and preordained hearing conclusion time. The *de facto* cumulative impact on intervenors was a limitation of cross-examination. TR 147-159. The more time that was taken up with procedural and other delays, the less of the preemptively fixed hearing time was available for actual cross-examination. This phenomenon appeared to worsen as the hearing approached the Friday deadline.[56]

This manifestation of procedural harm was most noticeably found in objections to questions that sought to compare the indefensibly excessive 11.5% ROE sought by the Company to the recently awarded 10.3% ROE that the Commission had approved just three business days before the start of this hearing. Despite that fact that there was no effort to position the 10.3% ROE as a precedent, much time was spent by Tampa Electric and the Commission effectively working to hunt down a basis for objecting to such a comparison. *See e.g.,* TR 147-159. No recognized, concrete basis for an objection was offered on this point at the hearing, though many were explored: "relevance," (TR 137, 147, 162, 206) "comparison" not allowed (TR 146-147), the DEF settlement not "codified," (TR 151, 152, 156-157) or that simply while the question has been fair game before, "let's move on to something else." TR 3610-3611. The result of the series of objections and rulings meant that cross-examination by OPC and other intervenors was seriously hampered and obstructed by frequent objection and interjection any time the DEF 2024 Settlement Agreement was mentioned.

The most egregious substantive example occurred when one out of the many untethered objections was sustained as it related to a question concerning the service-sustaining required level of shareholder profit between the requested 11.5% and the current 10.2% authorized by a settlement codified by order adopting Tampa Electric Agreements 2021 and 2022. TR 3609-3610. Counsel for FRF's cross-examination of Tampa Electric's Vice President of Finance, Jeff Chronister, sought to undertake a proper testing of the validity of the $80 million annual revenue requirement ROE that was a centerpiece element of the Tampa Electric case. Mr. Chronister was asked if there was any evidence that the Company cannot provide safe, reliable electric service at fair, just, and reasonable rates at an authorized profit level below the requested 11.5% but above

[56] What could not be shown on the record was the number of questions and amount of evidence that was cut out of prepared cross-examination and evidence introduction. The OPC can only represent to the tribunal that such did occur as a result of ensuring the OPC was not the cause of being unable to meet the need to conclude by Friday.

the current 10.2%. TR 3610-3611. Upon an objection, shortly before the 7:00 p.m. Thursday evening adjournment (August 29, 2024), the acting Chair indicated that he would go along with the [Tampa Electric] objection. The ruling contained a statement that such questions (incorrectly characterized as a hypothetical), while of the type that had perhaps been allowed in the past, was not going to be allowed on this occasion. The acting Chair quickly sustained the objection and blocked further inquiry of this crucial witness on this significant point. TR 3610-3611.[2]

By enjoining questions exploring this matter, the Agency's action bordered on effective prejudgment of that issue and contravened the customer's right to cross-examine witnesses adverse to the rate payers. *See* Section 120.57(1)(b), Fla. Stat. OPC stated its objections to the prehearing process at the outset of the hearing. TR 14-17. Prior to the conclusion of the hearing, OPC renewed these objections and voiced additional objections to the conduct of the hearing. TR 3817-3820. These objections as stated in the record, supporting pleadings and herein are preserved and renewed in this brief.

For the reasons set out above, adoption of the proposed Asset Optimization Mechanism provision in this proceeding will constitute reversible error. *See* § 120.68(7)(e)3, Fla. Stat. and *Citizens v. Graham*, 213 So. 3d 703 (Fla. 2017).

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

OPC: *The CETM should be reduced by $1.828 million in 2025 to reflect OPC's positions on ROE of 9.5% and inclusion of the battery storage related ITCs as zero cost of capital.*

ARGUMENT:

Due to several OPC recommended adjustments discussed more fully in previous issues, the revenue requirement for the CETM should be reduced as follows. The effect of Witness Woolridge's recommended 9.5% ROE on the CETM is a reduction of $3.497 million in revenue requirement. TR 2321. Witness Kollen testified that the inclusion of the new ITCs since 2022 as cost-free capital in the capital structure instead of including them at the weighted average cost of capital reduces the CETM revenue requirement by $0.100 million. TR 2320.

ISSUE 115: No position.
ISSUE 116: No position.

ISSUE 117: What is the appropriate effective date for TECO's revised 2025 rates and charges?

OPC: *The 2025 rates and charges should not become effective any sooner than the first billing cycle in 2026.*

ISSUE 118: No position.

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

OPC: *Tampa Electric's excessive rate increase request is contrary to the State's goal of providing affordable electric rates and will have a negative impact on ratepayers. Now, more than ever, the Commission must consider affordability of the customer's bills when evaluating Tampa Electric's rate request. Ultimately, the Commission must hold Tampa Electric to its burden and only approve the portions of Tampa Electric's rate request which are fair, just, and reasonable.*

ARGUMENT:

1) <u>Affordability and rate impact must be considered in order to determine fair, just, and reasonable rates.</u>

The Commission must consider affordability and the impact that Tampa Electric's requested rate increase will have on customers when setting fair, just, and reasonable rates. The Florida Legislature recently mandated that:

> The purpose of the state's energy policy is to ensure an adequate, reliable, and cost-effective supply of energy for the state in a manner that promotes the health and welfare of the public and economic growth.
>
> ….
>
> [T]he state's energy policy must be guided by….[e]nsuring a cost-effective and **affordable** energy supply.
>
> § 377.601 Fla. Stat. (2024). (Emphasis added).

Additionally, the Commission acknowledges that the affordability of electricity is an important factor in setting fair, just, and reasonable rates:

> In the midst of industry and technological change, the FPSC's focus remains constant: how do we best ensure safety, reliability, and **affordability** for all customers. EXH 358, MPN F2.2-6419. (Emphasis added).

The most important reasons to consider the affordability of electric rates were provided by Tampa Electric's customers themselves. Some examples include:

> **"**What do we do when we can't **afford** our electricity?" EXH 832, MPN F2.1-3423. (Emphasis added).
>
> "Please do not increase our Teco rates. Inflation is out of control right now and people can barely **afford** to live as it is." EXH 832, MPN F2.1-3597 (Emphasis added).
>
> "Please don't do this and make electricity **affordable** again." EXH 832, MPN F2.1-3410 (Emphasis added).
>
> "Inflation has taken a toll on everyone but senior citizens are the ones that can least **afford** it." EXH 832, MPN F2.1-3390. (Emphasis added).
>
> "We can't **afford** this!" EXH 832, MPN F2.1-3506. (Emphasis added).
>
> "Now more than ever it is crucial to ensure that essential services remain **affordable** and accessible to all Floridians." EXH 832, MPN F2.1-3775 - F2.1-3776. (Emphasis added).
>
> "Stop TECO from raising rates. No one will be able to **afford** to live here anymore." EXH 832, MPN F2.1-3959. (Emphasis added).
>
> "The state is being priced out of lower-middle-class budgets in where we can no longer **afford** to live in this state. Please do not allow this rate increase to go through, as we need the state to really step up to help the citizens to live **affordably**." EXH 832, MPN F2.1-3477 (Emphases added).

Tampa Electric itself acknowledged the importance of affordability,[57] and Tampa Electric Vice President of Customer Experience Karen Sparkman testified that "providing safe, reliable, and affordable electricity" is an important element of the customer experience. TR 430. However, it appears that Tampa Electric was merely paying lip service to this paramount consumer issue. When asked whether she agreed that a bill increase will likely result in a greater number of customers who will struggle to pay their electric bill, the Vice President of Customer Experience quipped that, "as a customer and how I prioritize my own household, I am not going to struggle to pay my bill." TR 522. Not only was this a tone-deaf and irrelevant statement, but it's also not surprising considering her income level. EXH 758, BSP 13300. Ms. Sparkman then went on to

[57] "Although what's 'affordable' can be subjective, there's no disagreement in the industry that maintaining affordable rates for customers is important for several reasons." TR 295; EXH 245, BSP 3.

accuse customers who struggle to afford their bills of simply not having their household priorities in order. TR 522-523. To the contrary, customers are already trying to prioritize their expenses in order to pay their Tampa Electric bill. In fact, several customers who participated in the customer service hearings, which Ms. Sparkman attended, testified to doing just that:

> "[T]here are times where I cannot even **afford** food, medical expenses and daycare for my children." SH1-TR 30. (Emphasis added.)
>
> "I have managed to get into the medical field, but I'm struggling because of the rate hikes keep continuing. I had to drop out of school and get another job to be able to help pay for bills. And even then, just with my two jobs, sometimes it's hard for me to even be able to **afford** transportation, or even just having food at home so I can cook." SH1-TR 49-50. (Emphasis added.)
>
> "Many seniors, like myself, currently deal with the rising cost of medicine, food and housing. I have a neighbor right now that cannot **afford** to run her AC due to illness and the huge monthly cost for her medicine." SH3-TR 40. (Emphasis added.)
>
> "This year, I couldn't even **afford** a birthday party for my three children that has their birthdays in March. I have to now depend on family and ask for extra money, because my TECO bill is extremely too high." SH3-TR 50. (Emphasis added.)
>
> "As a single mom just recently got divorced, it is hard to tell my son that he can't play baseball this year because mommy can't **afford** the cleat, glove or a bat. I just felt like if TECO put theirself in our shoes and just lived the life of one of us that's struggling, they may see things from a different side." SH3-TR 55-56. (Emphasis added.)

As the Vice President of Customer Experience at Tampa Electric, Ms. Sparkman's statements are Tampa Electric's statements. Such callousness shows that Tampa Electric does not accept any responsibility for the affordability challenges that customers face. It is clear that Tampa Electric views affordability as the customer's problem,[58] not the Company's, even though Tampa Electric is the one asking for "fairly significant"[59] rate increases. Furthermore, the Company has attempted to minimize the seriousness of this issue by suggesting that only a "small pocket of customers"[60] struggle with paying their bill, despite the Company's own Board presentations citing S Census

[58] EXH 446, BSP 7026.
[59] EXH 249, MPN F2.1-4283-4284.
[60] TR 515, 525-526, 562.

Bureau data that shows that energy poverty concerns affect a considerable portion of the Company's customer base.[61]

Requesting such an overstuffed, excessive rate increase when a considerable portion of your customer base is experiencing energy poverty, and then blaming those customers for not prioritizing their households correctly when those customer's bills are among the highest in the country[62] is unconscionable. As one customer described it, "Teco should be ashamed of themselves for proposing this rate hike in the first place. How about taking from your record profits instead of from my children's mouths." EXH 832, MPN F2.1-3376.

OPC Expert Witness Dismukes testified that, "[t]he consistent march to more and more, and higher and higher rate requests are keeping affordable rates out of reach for low-income ratepayers." TR 2185. Affordability and the impact that even higher rates will have on all of Tampa Electric's customers are essential considerations to the determination of fair, just, and reasonable electric rates. One customer accurately summarized the importance of this issue as follows:

> "I am writing to express my deep concern regarding the recent proposal by TECO Electric to raise electricity costs. As a loyal customer and member of the community, I believe such an increase would impose significant financial burdens on many households and businesses, especially in the current economic climate. The prospect of higher electricity bills is alarming, particularly for individuals and families already struggling to make ends meet. With the cost of living steadily rising, any additional expenses, such as increased utility bills, could push many families over the edge financially." EXH 832, MPN F2.1-3946.

2) <u>The Commission must deny all unnecessary investments within Tampa Electric's requested rate increase at a time when customers are already struggling to afford their bills.</u>

It is one thing for a utility to request a rate increase in order to pay for needed investments, but it is quite another to take the opportunity to exaggerate the utility's "requirements." Certain aspects of Tampa Electric's requested rate increase stand out as particularly excessive and unnecessary, especially when juxtaposed against the testimony of Tampa Electric's low-income customers who are already struggling to afford their bills. Some examples of those excessive and unnecessary aspects in this case include:

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[61] EXH 446, BSP 7025. (*See also* EXH 831, BSP 204.)
[62] EXH 237, MPN F2.1-1393.

Inflated ROE	$ 82.1 million	*See Issue 39*
Accelerated Depreciation	$ 15.5 million	*See Issue 7*
Accelerated Maintenance Expense	$ 10.0 million	*See Issue 45*
Underforecasted Revenue	$ 12.4 million	*See Issue 2*
ITC & PTC Slowdown	$ 26.4 million	*See Issues 63-65*
Total	**$ 146.4 million**	

As presented elsewhere in this brief, these exaggerations of Tampa Electric's needs amount to approximately $150 million of inflated revenue "requirements," which is approximately half of Tampa Electric's requested rate increase. If Tampa Electric's requested rate increase is approved as filed and no consideration is given to ensuring that customer's bills are affordable, there can be no doubt that even more families and businesses in Tampa Electric's service area will struggle to make ends meet. Outlandish ROEs, accounting tricks, and corporate excess should never be entertained by the Commission, especially not when many Tampa Electric customers are telling the Commission at every opportunity that they are already struggling to pay their current bills.

ISSUE 120: No position.
ISSUE 121: No position.

Statement of procedural objections and preservation of rights.

Just as the robustly protested prehearing schedule severely constrained OPC's ability to prepare for hearing, the predetermined deadline for the hearing only compounded this problem. This case was tried against an unusual procedural background. Prior to the hearing, Tampa Electric announced that it would not cross-examine any of the 14 intervenor witnesses. TR 957. Additionally, at the outset of the evidentiary hearing the Chair announced that the hearing would end on Friday. TR 7. This meant that a hearing involving the presentation of testimony, evidence, and cross-examination of 36 witnesses (both direct and rebuttal) starting at 1 p.m. on Monday, would have no more than 4½ business days to be concluded. This created a dynamic that endangered the due process rights of the customers as it was apparent that the only thing standing in the way of a Friday conclusion was the cross-examination by the intervenor attorneys and the Staff. The Commission should have anticipated how Tampa Electric would respond to these circumstances that required the compression of the cross-examination of 18 Tampa Electric witnesses and two Staff witnesses into approximately four days (or less). Whether by design or borne of the fortuity of opportunity, objections to intervenors' cross-examination seemed to arrive with unusual frequency, draining hearing time and interposing diversion and perhaps serving to run-out the pre-ordained 4½ day hearing clock.[63]

By Wednesday of the short week allotted for the hearing, it was becoming increasingly obvious that objections aimed at limiting inquiry into areas that the Company would rather not be explored, dovetailed nicely with the Commission's own expressed desire to meet a seemingly artificial and preordained hearing conclusion time. The *de facto* cumulative impact on intervenors was a limitation of cross-examination. TR 147-159. The more time that was taken up with procedural and other delays, the less of the preemptively fixed hearing time was available for actual cross-examination. This phenomenon appeared to worsen as the hearing approached the Friday deadline.[64]

This manifestation of procedural harm was most noticeably found in objections to questions that sought to compare the indefensibly excessive 11.5% ROE sought by the Company to the recently awarded 10.3% ROE that the Commission had approved just three business days before the start of this hearing. Despite that fact that there was no effort to position the 10.3% ROE as a precedent, much time was spent by Tampa Electric and the Commission effectively working to hunt down a basis for objecting to such a comparison. *See e.g.,* TR 147-159. No recognized, concrete basis for an objection was offered on this point at the hearing, though many were explored: "relevance," (TR 137, 147, 162, 206) "comparison" not allowed (TR 146-147), the DEF settlement not "codified," (TR 151, 152, 156-157) or that simply while the question has been fair game before, "let's move on to something else." TR 3610-3611. The result of the series of objections and rulings meant that cross-examination by OPC and other intervenors was seriously hampered and obstructed by frequent objection and interjection any time the DEF 2024 Settlement Agreement was mentioned.

The most egregious substantive example occurred when one out of the many untethered objections was sustained as it related to a question concerning the service-sustaining required level

[63] For the first two cross-examining attorneys there were 11 objections lodged by Tampa Electric counsel that were generally not sustained. TR 137, 1456, 147, 162, 206, 214, 253, 290, 311, 369, 377.
[64] What could not be shown on the record was the number of questions and amount of evidence that was cut out of prepared cross-examination and evidence introduction. The OPC can only represent to the tribunal that such did occur as a result of ensuring the OPC was not the cause of being unable to meet the need to conclude by Friday.

of shareholder profit between the requested 11.5% and the current 10.2% authorized by a settlement codified by order adopting Tampa Electric Agreements 2021 and 2022. TR 3609-3610. Counsel for FRF's cross-examination of Tampa Electric's Vice President of Finance, Jeff Chronister, sought to undertake a proper testing of the validity of the $80 million annual revenue requirement ROE that was a centerpiece element of the Tampa Electric case. Mr. Chronister was asked if there was any evidence that the Company cannot provide safe, reliable electric service at fair, just, and reasonable rates at an authorized profit level below the requested 11.5% but above the current 10.2%. TR 3610-3611. Upon an objection, shortly before the 7:00 p.m. Thursday evening adjournment (August 29, 2024), the acting Chair indicated that he would go along with the [Tampa Electric] objection. The ruling contained a statement that such questions (incorrectly characterized as a hypothetical), while of the type that had perhaps been allowed in the past, was not going to be allowed on this occasion. The acting Chair quickly sustained the objection and blocked further inquiry of this crucial witness on this significant point. TR 3610-3611.[65]

By enjoining questions exploring this matter, the Agency's action bordered on effective prejudgment of that issue and contravened the customer's right to cross-examine witnesses adverse to the rate payers. *See* Section 120.57(1)(b), Fla. Stat. OPC stated its objections to the prehearing process at the outset of the hearing. TR 14-17. Prior to the conclusion of the hearing, OPC renewed these objections and voiced additional objections to the conduct of the hearing. TR 3817-3820. These objections as stated in the record, supporting pleadings and herein are preserved and renewed in this brief.

[65] The putative basis for the objection and it being sustained was the question was a hypothetical. This characterization was in error as the question was seeking a direct statement of what profit level would allow the Company to meet its obligations to serve. CEO Collins had earlier testified that the 11.5% was not the minimally required ROE under constitutional standards. TR 198. Accordingly, it was appropriate for the parties and perhaps even incumbent upon the Commission to discern where below 11.5% such a point existed. The intervenors preserved their objection to this error. TR 3820.

Respectfully submitted,

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CERTIFICATE OF SERVICE
DOCKET NO. 20240026-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 21st day of October 2024, to the following:

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TAMPA ELECTRIC COMPANY	
REVENUE REQUIREMENT RECOMMENDED BY OPC - BASE RATES	
DOCKET NO. 20240026-EI	
TEST YEAR ENDING DECEMBER 31, 2025	
($ MILLIONS)	
	Jurisdictiona Adjustment After Gross Up
Requested Base Rate Increase per TEC Filing	**296.611**
Operating Income Adjustments:	
Less: July 24, 2024 TEC Filing Adjustments	($1.089)
Less: Agust 1, 2024 TEC Filing Adjustments	
Less: August 22, 2024 TEC Filing Adjustments	($7.541)
Requested Base Rate Increase After TEC Filing Adjustments	**$287.981**
Increase Revenues Related to Load Growth	(12.298)
Normalize Planned Generation Maintenance Expense for Major Outages	(9.992)
Remove Capitalized and Other Portion of Pension Expense	(0.489)
Remove Capitalized and Other Portion of Active Employee OPEB Expense	(0.806)
Remove Long Term Incentive Plan (LTIP) Expense Tied to Financial Performance	(7.170)
Remove SERP Expense	(0.107)
Reduce Affiliate Transaction Expense	(6.313)
Remove 50% of D&O Insurance Expense to Share with Shareholders	(0.151)
Remove 50% of Board of Directors Expenses to Share with Shareholders	(0.376)
Remove Depreciation Expense Related to Distribution Feeder Hardening Plant Reduction	(0.147)
Reduce Depreciation Expense by Using Approved 35 Year Service Life for Solar Generating Assets	(9.519)
Reduce Dismantlement Expense to Exclude Cost and Expense Escalations After the End of the Test Year	(7.110)
Reduce Dismantlement Expense By Removing Solar Site Restoration Environmental Costs	(2.614)
Reduce Dismantlement Expense By Using Approved 35 Year Service Life for Solar Generating Assets	(0.955)
Remove Depreciation Expense Related to Customer Experience Projects	(0.830)
Include Deferred Carrying Costs on Deferred Production Tax Credits through Dec 31, 2024	(0.460)
Amortize Deferred Production Tax Credits Incl Deferred Carrying Costs Over Three Years	(13.845)
Amortize Deferred Investment Tax Credits Pursuant to IRA Over Three Years (Grossed Up)	(12.607)
Increase Income Tax Expense to Amortize Pre 2022 Solar ITCs Over 35 Versus 30 Years (Grossed Up)	1.636
Rate Base Adjustments:	
Remove Spare Power Transfomers	(0.362)
Remove Distribution Feeder Hardening Plant	(0.356)
Remove Accumulated Depreciation Related to Customer Experience Projects	0.416
Remove Customer Experience Projects	(6.247)
Reduce Accumulated Depreciation to Reflect Solar Service Life of 35 Years	0.440
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Carrying Charges	(0.427)
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Amortization	0.663
Capital Structure and Rate of Return Adjustments:	
Adjust Cost of Capital to Reflect Zero Cost ITCs for Battery Storage Assets	(6.087)
Set Return on Equity at 9.5%	(123.785)
Total OPC Adjustments	**(219.898)**
OPC Recommended Maximum Base Rate Increase	**68.083**
Requested Levelized Revenue Increase for CETM per TEC Filing	**1.769**
Adjust Cost of Capital to Reflect Zero Cost ITCs on Battery Storage Assets	(0.175)
Set Return on Equity at 9.5%	(3.422)
OPC Recommended Change in Levelized CETM Rates	**(1.828)**

TAMPA ELECTRIC COMPANY		
REVENUE REQUIREMENT RECOMMENDED BY OPC		
BASE RATES CHANGE FOR 2026 AND 2027 SYAs		
DOCKET NO. 20240026-EI		
TEST YEAR ENDING DECEMBER 31, 2026		
($ MILLIONS)		
	2026 SYA	**2027 SYA**
Base Rate Change for 2026 and 2027 SYAs per TEC Filing	**100.075**	**71.848**
Less: July 24, 2024 TEC Filing Adjustments	(0.079)	0.422
Less: Agust 1, 2024 TEC Filing Adjustments	(4.739)	(3.262)
Less: August 22, 2024 TEC Filing Adjustments	(2.844)	(3.534)
	92.413	**65.474**
Revenue Requirement Adjustments:		
Remove Grid Grid Reliability & Resilience Projects	(4.546)	(28.247)
Reflect Additional Revenue Due to Customer Growth During SYA Periods	(7.994)	(6.123)
Remove Incremental O&M Expense	(6.981)	(3.463)
Reflect Longer Service Lives for the Solar and Battery Projects	(5.957)	(1.612)
Reflect 3 Year Amortization for Solar Battery Storage ITCs	(2.792)	-
Adjust COC to Reflect Zero Cost Solar Battery Storage ITCs	(0.267)	(0.144)
Set Return on Equity at 9.5%	(9.224)	(4.995)
Total OPC Adjustments	**(37.761)**	**(44.584)**
OPC Recommended Maximum 2026 and 2027 SYA Rate Changes	**54.651**	**20.890**

TAMPA ELECTRIC COMPANY REVENUE REQUIREMENT BASED ON RECORD - BASE RATES DOCKET NO. 20240026-EI TEST YEAR ENDING DECEMBER 31, 2025 ($ MILLIONS)	Jurisdictional Adjustment After Gross Up
Requested Base Rate Increase per TEC Filing	**296.611**
Less: July 24, 2024 TEC Filing Adjustments	(1.089)
Less: Agust 1, 2024 TEC Filing Adjustments	-
Less: August 22, 2024 TEC Filing Adjustments	(7.541)
Requested Base Rate Increase After TEC Filing Adjustments	**287.981**
Operating Income Adjustments:	
Increase Revenues Related to Load Growth	(12.298)
Normalize Planned Generation Maintenance Expense for Major Outages	(9.992)
Remove Capitalized and Other Portion of Pension Expense	(0.489)
Remove Capitalized and Other Portion of Active Employee OPEB Expense	(0.806)
Remove Long Term Incentive Plan (LTIP) Expense Tied to Financial Performance	(7.170)
Remove SERP Expense	(0.107)
Reduce Affiliate Transaction Expense	(6.313)
Remove 50% of D&O Insurance Expense to Share with Shareholders	(0.151)
Remove 50% of Board of Directors Expenses to Share with Shareholders	(0.376)
Remove Depreciation Expense Related to Distribution Feeder Hardening Plant Reduction	(0.147)
Reduce Depreciation Expense by Using Approved 35 Year Service Life for Solar Generating Assets	(9.519)
Reduce Dismantlement Expense to Exclude Cost and Expense Escalations After the End of the Test Year	(7.110)
Reduce Dismantlement Expense By Removing Solar Site Restoration Environmental Costs	(2.614)
Reduce Dismantlement Expense By Using Approved 35 Year Service Life for Solar Generating Assets	(0.955)
Remove Depreciation Expense Related to Customer Experience Projects	(0.830)
Include Deferred Carrying Costs on Deferred Production Tax Credits through Dec 31, 2024	(0.460)
Amortize Deferred Production Tax Credits Incl Deferred Carrying Costs Over Three Years	(13.845)
Amortize Deferred Investment Tax Credits Pursuant to IRA Over Three Years (Grossed Up) (OPT OUT)	(12.607)
Increase Income Tax Expense to Amortize Pre 2022 Solar ITCs Over 35 Versus 30 Years (Grossed Up	1.636
Energy Storage South Tampa Resilience Project Change	
Rate Base Adjustments:	
Remove Spare Power Transfomers	(0.362)
Remove Accumulated Depreciation Related to Customer Experience Projects	0.416
Remove Customer Experience Projects	(6.247)
Remove Distribution Feeder Hardening Plant	(0.356)
Reduce Accumulated Depreciation to Reflect Solar Service Life of 35 Years	0.440
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Carrying Charges	(0.427)
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Amortization	0.663
Capital Structure and Rate of Return Adjustments:	
Adjust Cost of Capital to Reflect Zero Cost ITCs for Battery Storage Assets	(3.490)
Set Return on Equity at 10.20%	(80.001)
Total OPC Adjustments	**(173.516)**
Maximum Base Rate Increase at Current ROE	**114.465**
Requested Levelized Revenue Increase for CETM per TEC Filing	**1.769**
Adjust Cost of Capital to Reflect Zero Cost ITCs on Battery Storage Assets	(0.100)
Set Return on Equity at 10.20%	(2.270)
Change in Levelized CETM Rates at Current ROE	**(0.601)**

Appendix 1B

TAMPA ELECTRIC COMPANY		
REVENUE REQUIREMENT BASED ON RECORD		
BASE RATES CHANGE FOR 2026 AND 2027 SYAs		
DOCKET NO. 20240026-EI		
TEST YEAR ENDING DECEMBER 31, 2026		
($ MILLIONS)		
	2026	**2027**
	SYA	**SYA**
Base Rate Change for 2026 and 2027 SYAs per TEC Filing	**100.075**	**71.848**
Less: July 24, 2024 TEC Filing Adjustments	(0.079)	0.422
Less: Agust 1, 2024 TEC Filing Adjustments	(4.739)	(3.262)
Less: August 22, 2024 TEC Filing Adjustments	(2.844)	(3.534)
	92.413	**65.474**
Revenue Requirement Adjustments:		-
Remove Grid Grid Reliability & Resilience Projects	(4.546)	(28.247)
Reflect Additional Revenue Due to Customer Growth During SYA Periods	(7.994)	(6.123)
Remove Incremental O&M Expense	(6.981)	(3.463)
Reflect Longer Service Lives for the Solar Projects	(5.957)	(1.612)
Reflect 3 Year Amortization for Solar Battery Storage ITCs	(2.792)	-
Adjust COC to Reflect Zero Cost Solar Battery Storage ITCs	(0.267)	(0.144)
Set Return on Equity at 10.20%	(6.050)	(3.260)
Total OPC Adjustments	**(34.587)**	**(42.849)**
Maximum 2026 and 2027 SYA Rate Changes At Current ROE	**57.826**	**22.625**

Appendix 1B