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PAUL RENNER
Speaker of the House of Representatives

June 6, 2024

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20240026 - EI

Dear Mr. Teitzman,

Please find enclosed for filing in the above referenced docket the Direct Testimony and Exhibits of Lane Kollen.

If you have any questions or concerns; please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Walter Trierweiler
Public Counsel

/s/ Patricia A. Christensen
Patricia A. Christensen
Associate Public Counsel
Florida Bar No. 0989789

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 6th day of June, 2024, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company _______________________________________/	Docket No. 20240026-EI Filed: June 6, 2024

DIRECT TESTIMONY

OF

LANE KOLLEN

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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EXHIBITS

DIRECT TESTIMONY

OF

LANE KOLLEN

On Behalf of the Citizens of the State of Florida

Before the

Florida Public Service Commission

Docket No. 20240026-EI

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. STATE YOUR NAME, POSITION, EMPLOYER, AND BUSINESS ADDRESS.

A. My name is Lane Kollen. I am the President and a Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 70 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, Institute of Management Accounting, Georgia Society of CPAs, and Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than forty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on hundreds of occasions in proceedings before regulatory commissions and courts at the federal and state levels. In those proceedings, I have addressed ratemaking, accounting, finance, tax, and planning issues, among others.

I have testified before the Florida Public Service Commission on numerous occasions, including base rate, fuel adjustment clause, acquisition, and territorial proceedings involving Tampa Electric Company ("Company"), Peoples Gas System, Inc., Florida Power & Light Company, Duke Energy Florida, Talquin Electric Cooperative, City of Tallahassee, and City of Vero Beach.[1]

B. <u>Purpose of Testimony</u>

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing this testimony on behalf of the Florida Office of Public Counsel ("OPC").

Q. DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to address and make recommendations on specific issues that affect the base revenue requirement and requested increases in this proceeding effective for the 2025 test year and the requested 2026 and 2027 subsequent year adjustments ("SYAs"). I also summarize the effects of all OPC recommendations

[1] I have attached a more detailed description of my qualifications and regulatory appearances as my Exhibit LK-1.

that affect the base revenue requirement and the SYAs, including my recommendations and the recommendations of OPC witnesses David Dismukes (sales and base electric revenues in the test year and in 2026 and 2027), Bion Ostrander (affiliate transactions expense in the test year), Randall Woolridge (return on equity), and Kevin Mara (distribution plant in the test year and distribution plant and operation and maintenance ("O&M") expenses included in the requested 2026 and 2027 SYAs). In addition, I address the Company's request to continue the tax changes provision of the 2021 Stipulation and Settlement Agreement ("2021 Settlement") approved by the Commission in Docket 20210034-EI.

C. Summary of Testimony

Q. PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I recommend the Florida Public Service Commission ("Commission") authorize a base revenue increase effective on or about January 1, 2025 of no more than $75.269 million, a reduction of $221.342 million from the Company's requested increase of $296.611 million.

I recommend the Commission authorize a Competitive Energy Transition Mechanism ("CETM") revenue reduction effective on or about January 1, 2025 of at least $1.828 million, a reduction of at least $3.597 million from the Company's requested $1.769 million increase.

I recommend the Commission authorize an SYA revenue increase on or about January 1, 2026 ("2026 SYA") of no more than $60.257 million, a reduction of at least

$39.818 million from the Company's requested $100.075 million increase.[2] I recommend the Commission authorize an SYA revenue increase on or about January 1, 2027 ("2027 SYA") of no more than $24.286 million, a reduction of at least $47.562 million from the Company's requested $71.848 million.

On the following two tables, I provide a summary of the issues and adjustments to the requested increases in base revenues and CETM revenues, and the requested incremental increases in base revenues through the 2026 and 2027 SYAs that are addressed by OPC witnesses, including the issues and adjustments that I address and the issues and adjustments that are addressed by other OPC witnesses.[3] I note that all amounts shown on the following tables are the revenue effects of OPC recommendations. The rate base effects of OPC recommendations are detailed in my electronic workpapers, as are the revenue effects of the rate base adjustments and cost of capital adjustments recommended by OPC.

[2] OPC Witness Mara also addresses the distribution "electric delivery infrastructure" costs included in the Company's requested 2026 and 2027 SYA revenue increases and recommends that certain costs be excluded from the two SYA increases. The effects of his recommendations to exclude these costs are subsumed in my adjustments to remove all distribution "electric delivery infrastructure" investment costs from the two SYA increases.

[3] The calculations of the amounts shown on the two summary tables and cited throughout my testimony are detailed in my electronic workpapers. In addition, I calculate the effects of Witness Woolridge's recommendation for return on equity on the base revenue requirement and increase, the CETM, and the 2026 and 2027 SYAs, and the effects of Witness Mara's recommendations to remove certain plant costs from thebase revenue requirement.

TAMPA ELECTRIC COMPANY
REVENUE REQUIREMENT RECOMMENDED BY OPC - BASE RATES
DOCKET NO. 20240026-EI
TEST YEAR ENDING DECEMBER 31, 2025
($ MILLIONS)

	Jurisdictional Adjustment After Gross Up	Witness
Requested Base Rate Increase per TEC Filing	**296.611**	
Operating Income Adjustments:		
Increase Revenues Related to Load Growth	(12.298)	Dismukes
Normalize Planned Generation Maintenance Expense for Major Outages	(12.430)	Kollen
Remove Capitalized and Other Portion of Pension Expense	(0.489)	Kollen
Remove Capitalized and Other Portion of Active Employee OPEB Expense	(0.806)	Kollen
Remove Long Term Incentive Plan (LTIP) Expense Tied to Financial Performance	(7.170)	Kollen
Remove SERP Expense	(0.107)	Kollen
Reduce Affiliate Transaction Expense	(6.313)	Ostrander
Remove 50% of D&O Insurance Expense to Share with Shareholders	(0.151)	Kollen
Remove 50% of Board of Directors Expenses to Share with Shareholders	(0.376)	Kollen
Remove Depreciation Expense Related to Distribution Feeder Hardening Plant Reduction	(0.147)	Mara
Reduce Depreciation Expense by Using 20 Year Service Life for Battery Storage Assets	(5.942)	Kollen
Reduce Depreciation Expense by Using Approved 35 Year Service Life for Solar Generating Assets	(9.519)	Kollen
Reduce Dismantlement Expense to Exclude Cost and Expense Escalations After the End of the Test Year	(7.110)	Kollen
Reduce Dismantlement Expense By Removing Solar Site Restoration Environmental Costs	(2.614)	Kollen
Reduce Dismantlement Expense By Using Approved 35 Year Service Life for Solar Generating Assets	(0.955)	Kollen
Include Deferred Carrying Costs on Deferred Production Tax Credits through Dec 31, 2024	(0.460)	Kollen
Amortize Deferred Production Tax Credits Incl Deferred Carrying Costs Over Three Years	(13.845)	Kollen
Amortize Deferred Investment Tax Credits Pursuant to IRA Over Three Years (Grossed Up)	(12.607)	Kollen
Increase Income Tax Expense to Amortize Pre 2022 Solar ITCs Over 35 Versus 30 Years (Grossed Up)	1.636	Kollen
Rate Base Adjustments:		
Remove Spare Power Transfomers	(0.362)	Mara
Remove Distribution Feeder Hardening Plant	(0.356)	Mara
Reduce Accumulated Depreciation to Reflect Solar Battery Storage Service Life of 20 Years	0.275	Kollen
Reduce Accumulated Depreciation to Reflect Solar Service Life of 35 Years	0.440	Kollen
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Carrying Charges	(0.427)	Kollen
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Amortization	0.663	Kollen
Capital Structure and Rate of Return Adjustments:		
Adjust Cost of Capital to Reflect Zero Cost ITCs for Battery Storage Assets	(3.493)	Kollen
Set Return on Equity at 9.5%	(126.379)	Woolridge
Total OPC Adjustments	**(221.342)**	
OPC Recommended Maximum Base Rate Increase	**75.269**	
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)	Kollen
Set Return on Equity at 9.5%	(3.497)	Woolridge
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**
Revenue Requirement Adjustments:		
Remove Grid Grid Reliability & Resilience Projects	(4.599)	(28.788)
Remove Income Tax Gross-Up on Non Equity Return (NOI Multiplier)	(4.529)	(2.453)
Reflect Additional Revenue Due to Customer Growth During SYA Periods	(7.994)	(6.123)
Remove Incremental O&M Expense	(6.696)	(3.420)
Reflect Longer Service Lives for the Solar and Battery Projects	(3.670)	(1.612)
Reflect 3 Year Amortization for Solar Battery Storage ITCs	(2.792)	-
Adjust COC to Reflect Zero Cost Solar Battery Storage ITCs	(0.265)	(0.144)
Set Return on Equity at 9.5%	(9.273)	(5.022)
Total OPC Adjustments	**(39.818)**	**(47.562)**
OPC Recommended Maximum 2026 and 2027 SYA Rate Changes	**60.257**	**24.286**

As reflected in the preceding table for the 2026 and 2027 SYAs, I recommend the Commission reject the Company's request to fundamentally change the present ratemaking framework for limited post-test year base revenue increases to recover increases in certain "business as normal" distribution "electric delivery infrastructure" investment costs.[4] The Company's request is especially troubling given Company Witness Jeff Chronister's deposition testimony that the Company seeks increases to recover these certain "business as normal" costs solely to enhance its earned returns on

[4] Witness Kevin Mara also addresses these "business as normal" distribution "electric delivery infrastructure" investment costs and recommends the costs be removed from the requested 2026 and 2027 SYAs.

equity in the two years after the test year.[5] There has been no change in the statutory ratemaking framework or in the Commission's administrative rules that either precipitated or justify this request. The Company has not even offered a forecast of its earned returns or the underlying costs and revenues to demonstrate need. If the Commission adopts this request, then it will fundamentally change the course and form of ratemaking in the state, unleashing a real and imminent risk of future requests not only by the Company, but also by all other utilities, for SYA rate increases unrestrained by the limited increases for new generating plant assets previously allowed by the Commission. If the Commission is inclined to consider SYAs for "business as normal" distribution costs by the Company and other utilities, then it should establish a rulemaking proceeding to allow all interested parties statewide to participate in the process. If the Commission decides to proceed on an *ad hoc* basis in this proceeding, then I provide a proposed framework to assess the Company's request in this proceeding.

II. OPERATING EXPENSE ISSUES

A. <u>Normalize Planned Generation Maintenance Expense</u>

Q. DESCRIBE THE COMPANY'S GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR.

A. The Company included $68.539 million in generation maintenance expense in the test year. Of this amount, the Company included $25.205 million for planned generation

[5] Transcript of Deposition of Jeff Chronister taken on April 24, 2024 at 137. I address Witness Chronister's deposition testimony on this in greater detail in the SYA section of my testimony.

maintenance expense. The Company plans three major generating unit outages in 2025, which are described generally by Company Witness Carlos Aldazabal as follows:[6]

> There are three major needed outages happening in 2025. These include a 70-day major outage for Bayside Unit 1, a 70-day outage for Polk Unit 2, and a one-month outage for Big Bend Unit 4.

Witness Aldazabal provides a more detailed description for each of these three major generating unit outages.[7] He asserts the Bayside Unit 1 "outage is necessary because the run hours on the steam turbine are expected to be 380,000 and beyond the recommended OEM design of 250,000 hours."[8] He asserts the Polk Unit 2 outage is necessary because the run hours on the turbine are expected to be 66,000 and beyond the OEM recommendation for "a major overhaul at 50,000 hours of operation."[9] He notes further that "[t]his will be the first time opening the turbine since installation in 2017."[10] He asserts the Big Bend 4 outage is necessary for "compressed air system improvements, seawall cathodic protection, boiler circulating pump work, and intake screen replacement."[11]

Q. HOW DOES THE GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR COMPARE TO PRIOR YEARS?

A. The generation maintenance is significantly greater due to the number and scope of outages in the test year compared to actual expenses in prior years. The Company

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[6] Direct Testimony of Carlos Aldazabal at 32.
[7] *Id.*, pp. 32-33.
[8] *Id.*, p. 33.
[9] *Id.*
[10] *Id.*
[11] *Id.*

incurred \$52.202 million in 2021, \$44.830 million in 2022, and \$46.738 in 2023. It budgeted \$59.132 million in 2024 and forecasts \$68.539 million in the test year.[12] The test year expense is \$21.801 million, or 46.6%, greater in the test year than the actual expense incurred in 2023.

The planned generation maintenance component of the generation maintenance expenses follows this same pattern whereby the test year expense is significantly greater compared to actual expenses in prior years. The Company incurred \$8.044 million in planned generation maintenance expense in 2019, \$11.072 million in 2020, \$10.252 million in 2021, \$12.017 million in 2022, and \$9.484 million in 2023.[13] It budgeted \$13.315 million in 2024 and forecasts \$25.205 million in the test year.[14] The test year expense is \$16.021 million, or 68.9%, greater than the actual expense in 2023.

Q. IS THE GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR RECURRING AT THIS LEVEL?

A. No. The generation maintenance expense is abnormally high in the test year compared to actual expenses in prior years. This is due, in significant part, to the number and scope of outages in the test year compared to the prior years. The Company delayed the planned maintenance beyond the original equipment manufacturer ("OEM") recommended run hours and then bunched the outages and a significantly greater level of expense into the test year compared to prior years. This has the effect of significantly

[12] Schedule C-06, sum of total steam power maintenance expense and other power maintenance expense.

[13] Response to Interrogatory No. 37 in OPC's First Set of Interrogatories, excluding now retired Big Bend 1, Big Bend 2, and Big Bend 3 coal-fired generating units. I have attached a copy of this response as my Exhibit LK-2.

[14] Schedule C-06, sum of total steam power maintenance expense and other power maintenance expense.

increasing the requested base revenue increase. The Company 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. In addition, by recording these costs as expense, rather than as "betterments" capital expenditures, the Company has chosen the highest and most harmful revenue requirement pathway. The FERC Uniform System of Accounts ("USOA") allows costs that normally would be expensed to be capitalized if they qualify as "betterments," meaning that they have future utility over multiple years.

Q. IS THE FACT THE GENERATION MAINTENANCE EXPENSE IS ABNORMALLY HIGH AND NONRECURRING AT THE LEVEL IN THE TEST YEAR A CONCERN FOR RATEMAKING PURPOSES?

A. Yes. 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. Assuming the planned generation maintenance expense reverts to the lower normalized level of expense in subsequent years, the Company nevertheless will recover the abnormally high level of expense in the test year and will continue to recover this abnormally high level of expense again and again in subsequent years until base rates are reset in a future rate case proceeding. Such a windfall is unreasonable and will harm customers for the sole purpose of enriching the Company's shareholder.

I also note that the Company included incremental maintenance expenses for new generation assets placed in service in 2026 and 2027 in its requested 2026 and

2027 SYA increases, but did not reflect a reduction in generation maintenance expenses in those years for the existing generation assets.

Q. WHAT IS THE RATEMAKING SOLUTION TO ABNORMALLY HIGH EXPENSES IN THE TEST YEAR?

A. The ratemaking solution is to "normalize" the expense in the test year without any deferrals (i.e. the expenses are adjusted to reflect the more historic levels of planned generation maintenance absent any specific rationale for such increases in subsequent years). An alternative solution is to direct or otherwise allow the Company to capitalize the costs of "betterments" to CWIP instead of expensing the costs. Another alternative solution is to defer the abnormally high expense in excess of the normalized expense and amortize the deferral over an extended period in an attempt to allocate the benefits of the abnormally high expense to the periods benefitting from the planned maintenance scope of work and expenses.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission "normalize" the planned generation maintenance expense in the test year by averaging the actual expense incurred in the years 2019 through 2023 and the budget and forecast expenses in the years 2024 and 2025.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $12.392 million reduction in the planned generation maintenance expense in the test year, and a reduction of $12.430 in the base revenue requirement and the requested base revenue increase.[15]

B. <u>Correct Capitalization Credit to Pension and OPEB Costs</u>

Q. DESCRIBE THE COMPANY'S REQUESTS FOR PENSION AND OPEB EXPENSE.

A. The Company requests recovery of its total pension cost and total OPEB cost without reductions for the amounts that will be capitalized.[16] The amounts the Company included for pension expense and OPEB expense in the test year match the total pension cost and total OPEB cost reflected in the actuarial reports for 2025, meaning the total costs were not reduced for the amounts that will be capitalized.[17]

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH ITS ACTUAL ACCOUNTING DESCRIBED IN RESPONSE TO OPC DISCOVERY AND THE AMOUNTS RECORDED TO EXPENSE AND CAPITAL IN PRIOR HISTORIC YEARS?

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[15] I note that I removed the since retired Big Bend 1, Big Bend 2, and Big Bend 3 planned maintenance expense before calculating the average for the existing generating assets over the seven-year period.

[16] Refer to the response to Interrogatory No. 22 in OPC's First Set of Interrogatories, which shows no credit for the capitalized amounts in the test year or the 2024 budget. Refer also to the response to POD No. 125 in OPC's Tenth Request for Production of Documents, which shows no credit for the capitalized amounts in the test year or the 2024 budget, but shows the credits for the capitalized amounts in all historic years 2016-2023. I have attached a copy of these responses as my Exhibit LK-3.

[17] Refer to the Confidential response to POD No. 5 in OPC's First Request for Production of Documents Bates 2572-2588, "TECO Energy 2024-2025 Retirement Forecasts." I have not attached a copy of this Confidential response.

A. No. The Company uses a "fringe rate" methodology to load its pension and OPEB costs onto payroll costs expensed and payroll costs capitalized for actual accounting purposes.[18] The Company records the total pension cost and total OPEB cost in account 926, then records a credit to account 926 for the capitalized portion of the total actuarial pension and OPEB costs.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reduce the pension and OPEB cost to reflect the credit for the portions of the costs that will be capitalized. OPC has asked several times for the breakdown of the test year total pension cost and the total OPEB cost between expense and capital. In every response, the Company simply provided the total pension cost and the total OPEB cost with no breakdown. The Company's pension "expense" and OPEB "expense" match the total pension cost and total OPEB cost shown in the Mercer actuarial report for 2025 before any reductions for the capitalized portions of the costs. The actuarial reports provide only pension and OPEB costs; they do not breakdown the costs between expense and capital because that is a function of the Company's accounting for payroll and related costs.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. 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

[18] Response to Interrogatory No. 167 in OPC's Ninth Set of Interrogatories, a copy of which I have attached a copy of this response as my Exhibit LK-4.

the reduction in OPEB expense to reduce the requested amounts for the capitalized portions.

C. <u>Allocate Incentive Compensation Tied to Financial Performance Metrics to Shareholder</u>

Q. DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF LONG TERM INCENTIVE COMPENSATION EXPENSE IN THE REVENUE REQUIREMENT.

A. The Company included $7.173 million (total Company) in Long Term Incentive Plan ("LTIP") compensation expense in the revenue requirement. This amount represents compensation paid directly to certain Tampa Electric Company employees, net of allocations from the Company to affiliates and from affiliates to the Company.[19]

Q. DESCRIBE THE COMPANY'S LTIP COMPENSATION EXPENSE.

A. The LTIP compensation expense is tied to the financial performance of its parent Company, Emera, Inc. ("Emera"). The LTIP compensation expense is generally available to all department directors and officers.[20] According to the Company's testimony, "the purpose of the LTIP is to align the long-term incentive pay for senior leaders with corporate and shareholder goals."[21] The Company's testimony also states that "LTIP is administered through the Emera Performance Share Unit ("PSU") Plan

[19] Responses to Interrogatory Nos. 15 and 16 in OPC's First Set of Interrogatories, copies of which I have attached as my Exhibit LK-5.
[20] Direct Testimony of Marian Cacciatore at 13.
[21] *Id.* at p. 20.

and the EMERA Restricted Share Unit ("RSU") Plan."[22] These compensation payments are made in the form of stock grants of Emera stock. Thus, 100% of the LTIP compensation expense is tied to reaching the financial performance goals of Emera that include its stock price. The stock price, by definition, is a measure of Emera's financial performance.

Q. WHAT IS THE COMMISSION'S HISTORIC PRACTICE CONCERNING INCENTIVE COMPENSATION EXPENSE TIED TO FINANCIAL PERFORMANCE METRICS?

A. The Commission has a long-standing practice of disallowing such expenses. In its order in a Progress Energy Florida, Inc. rate case, the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals such as earnings per share ("EPS"). In its discussion related to the disallowance, the Commission stated:[23]

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

Likewise, in its order in a Florida Power and Light Company 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:[24]

> We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder

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[22] *Id.*

[23] *In Re*: Docket 090079-EI, Petition for Increase in Rates by Progress Energy Florida, Inc., Order No. PSC-10-0131-FOF-EI, p. 114.

[24] *In Re*: Docket 080677-EI, Petition for Increase in Rates by Florida Power & Light Company, Order No. PSC-10-0153-FOF-EI, p. 149.

> 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.

Finally, in its order in a Tampa Electric Company rate case, 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:[25]

> 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.

Q. DID THE COMPANY MAKE THE ARGUMENT IN TESTIMONY THAT THE LTIP PAYOUTS ARE PART OF THE TOTAL DIRECT COMPENSATION AND SHOULD BE RECOVERABLE BASED ON THE RESULTS OF ITS MARKET DATA ANALYSES?

A. Yes. The Company's testimony discussed its assertion that the total direct compensation had an overall score of 99.5% in relation to the market median for 2023 it had derived.[26] However, that testimony also details the fact that the Company's internal analysis was based on its own updates to a 2019 comprehensive review, not a current comprehensive review.[27]

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[25] *In Re*: Docket 080317-EI, Petition for Rate Increase by Tampa Electric Company, Order No. PSC-09-0283-FOF-EI, p. 58.

[26] Direct Testimony of Marian Cacciatore at pp. 21-23.

[27] *Id.*

Q. SHOULD THE COMMISSION INCLUDE THE LTIP INCENTIVE COMPENSATION EXPENSE TIED TO EMERA'S FINANCIAL PERFORMANCE IN THE COMPANY'S REVENUE REQUIREMENT?

A. No. The question for ratemaking purposes is not whether the incentive compensation expense tied to financial performance metrics is reasonable in comparison to a market study, but whether customers or shareholders should pay for the expense. The Commission historically has allocated incentive compensation expenses incurred to incentivize the achievement of financial performance metrics, such as earnings per share and total shareholder return, to shareholders and not to customers. The Commission had made these allocations to shareholders because incentive compensation tied to financial performance metrics benefits shareholders to the detriment of customers in rate proceedings such as this. All of the LTIP expense projected in the test year is 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.

Further, incentive compensation incurred to incentivize Emera financial performance also provides the Company's department directors and officers a direct incentive to seek greater and more frequent rate increases from customers in order to improve Emera's stock price. The greater the rate increases and revenues, the greater Emera's stock price, all else equal, and the greater the incentive compensation expense. There is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater incentive compensation for department directors and officers on the other hand. Thus, all LTIP expense should be allocated to shareholders, not to customers.

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues ensure that the expense is recovered regardless of the Company's actual performance and regardless of its operational and safety performance. Thus, the expenses should be directly assigned to Emera shareholders, not to the Company's customers.

In summary, the Company's requests for recovery of LTIP expense tied to Emera's stock price and shareholder return fall clearly within the disallowance precedent and should be allocated to Emera shareholders and not recovered from the Company's customers.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission disallow the LTIP incentive compensation expense tied to Emera's financial performance.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction of $7.170 million in the claimed revenue requirement and requested base rate increase, including the gross up for bad debt expense and PSC fees.

D. <u>Supplemental Executive Retirement Plan Expense</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO INCLUDE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP") EXPENSE IN THE BASE REVENUE REQUIREMENT.

A. The Company requests recovery of $0.107 million in SERP expense in the base revenue requirement.[28] These expenses are incurred to provide certain highly compensated executives retirement benefits in addition to the benefits otherwise available through the Company's pension and OPEB plans. These are considered to be non-qualified plans because the additional compensation exceeds deductible compensation limits set forth in the Internal Revenue Code.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission deny the Company's request to recover this expense. The SERP expense is discretionary. It is incurred to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the Company's shareholders rather than its customers. The expense is not necessary to provide regulated utility service and it is not reasonable to impose the expense on utility customers.

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[28] Response to Interrogatory No. 17 in OPC's First Set of Interrogatories, a copy of which I have attached as my Exhibit LK-6.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction of $0.107 million in the claimed revenue requirement and requested base rate increase.

E. <u>Reduce Directors and Officers Insurance Expense and Board of Directors' Expense to Reflect Sharing Between Company's Shareholders and Customers</u>

Q. DESCRIBE THE TWO CORPORATE RELATED EXPENSES THE COMPANY INCLUDED IN THE REVENUE REQUIREMENT IN THIS PROCEEDING.

A. The Company included expenses related to its parent company, Emera, and its own corporate governance in the revenue requirement. The Company excluded expenses related other investor services from the revenue requirement. Emera's stock and other securities are publicly traded. Emera incurs certain governance expenses and liability insurance expenses related to its directors and officers and charges those expenses to Tampa Electric Company and other Emera affiliates. Tampa Electric Company also incurs certain governance expenses related to its own directors and officers.

The Company incurred Directors & Officers ("D&O") liability insurance expense of $0.303 million (total Company) during the test year.[29] 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

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[29] Response to Interrogatory No. 34 in OPC's First Set of Interrogatories, a copy of which I have attached as my Exhibit LK-7.

incurred to defend against corporate liability and potential losses related arising from decisions made by directors and officers on behalf of an organization.

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.[30] Emera maintains an investor relations organization to interact with present and potential investors. The Emera website details the communications supplied to investors.[31] The communications include such things as news releases, investor presentations, regulatory filings, analyst reports, and other statistical and reporting information.

Q. SHOULD THERE BE A SHARING OF THESE KINDS OF CORPORATE EXPENSES BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. Yes. the benefits from such activities inure primarily to shareholders, not to customers.

Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE SHARING OF THESE KINDS OF EXPENSES?

A. Yes. The Commission determined there should be an equal sharing of D&O insurance expense costs between customers and shareholders in at least two prior rate cases, one for Gulf Power Company and the other for Progress Energy Florida.[32]

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[30] Response to Interrogatory No. 56 in OPC's Second Set of Interrogatories, a copy of which I have attached as my Exhibit LK-8.

[31] Home| Emera. Corporate Profile | Emera

[32] Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, Docket No. 11-0138-EI, In re: Petition for increase by Gulf Power Company, at p. 101; Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc. at p. 99.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an equal sharing of the Company's D&O insurance and Board of Directors expenses between customers and shareholders to allocate these expenses equally based on an assumption the expenses benefit both ratepayers and shareholders, as recognized in previous Commission orders.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of $0.151 million in D&O insurance expense and the revenue requirement and a reduction of $0.375 million in Board of Directors expenses and a reduction of $0.376 million in the revenue requirement after the gross-up for bad debt and Commission fees.

F. <u>Modify Depreciation Rates and Expense to Reflect Industry Standard Service Lives for Battery Storage Assets</u>

Q. DESCRIBE THE COMPANY'S REQUESTED SERVICE LIFE FOR BATTERY STORAGE ASSETS DEPRECIATION PURPOSES.

A. The Company proposes a 10-year service life for battery storage assets for depreciation purposes.

Q. IS A 10-YEAR SERVICE LIFE FOR BATTERY ENERGY STORAGE SYSTEM ("BESS") ASSETS REASONABLE FOR DEPRECIATION PURPOSES?

A. No. It is unduly short. It is not consistent with the Company's plans to actually operate the battery storage assets beyond a 10-year period. Nor is it consistent with the industry standard service life of 15 to 20 years used for planning and ratemaking purposes. For example, the Wisconsin Public Service Commission recently approved the Grant County BESS in WPSC Docket 9804-CE-100, in which Wisconsin Power and Light Company asserted that the BESS had a 20-year service life.[33] Santee Cooper relies on a 20-year service life for Integrated Resource Plan ("IRP") purposes.[34] Lazard relies on a 20-year service life for economic valuations of utility-scale BESS under different configurations.[35] NREL relies on a 15-year service life for utility-scale BESS in its Annual Technology Baseline ("ATB") for resource planning purposes.[36]

Q. DID COMPANY WITNESS NED ALLIS MAKE ANY ATTEMPT TO JUSTIFY THE PROPOSED 10-YEAR SERVICE LIFE FOR THE BATTERY STORAGE ASSETS BASED ON THEIR PHYSICAL LIFE IN THE DEPRECIATION STUDY?

A. No. Witness Allis relied exclusively on the presently approved 10-year life, noting only that "estimates for other utilities typically range from 10 to 15 years (while 20-years may have been used for some larger, newer facilities)."[37] As I noted previously, the trend has been toward longer service lives, with the most recent industry and utility

[33] https://psc.wi.gov/Pages/CommissionActions/CasePages/GrantCountySolar.aspx.

[34] Santee Cooper Integrated Resource Plan Public Stakeholder Meeting June 28, 2022 at 98. I have attached a copy of the cover page and the referenced page as my Exhibit LK-9.

[35] Lazard's Levelized Cost of Storage Analysis Version 7.0 at 4. I have attached a copy of the cover page and the referenced page as my Exhibit LK-10.

[36] https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage.

[37] Exhibit No. NA-1 Document No 2 page 388 attached to the Direct Testimony of Ned Allis.

planning studies reflecting a 20-year service life. Other Company witnesses, including Witness Latta and Witness Chronister, did not independently evaluate the service life, but simply relied on the 10-year life proposed by Witness Allis to calculate the resulting depreciation expense and decommissioning expense. This circular justification among the Company and its outside experts provides no justification whatsoever and fails the Company's required burden of proof.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's proposed 10-year service life service life for the existing and new battery storage assets and instead adopt a 20-year service life for these assets. Battery technology continues to improve and authoritative technology data sources and utilities now widely assume a 20-year service life for planning and economic analyses, as well as for cost recovery purposes. There is no compelling reason to continue to use an outdated, unsupported, and irrelevant 10-year service life in lieu of the 20-year service life widely used for planning and cost recovery purposes.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effect is a net reduction of $5.667 million in the revenue requirement and requested increase. This net reduction reflects a reduction $5.942 million in depreciation expense and the related revenue gross-up expenses, offset in part by $0.275 million for the reduction in the grossed-up return on the increase in rate base due to the resulting lower accumulated depreciation in the test year.

G. <u>Correct Depreciation Rates and Expense to Reflect Presently Approved Service Lives for Solar Assets</u>

Q. DESCRIBE THE COMPANY'S REQUESTED SERVICE LIFE FOR SOLAR ASSETS.

A. The Company proposes a 30-year service life for solar assets.

Q. HOW DOES THE REQUESTED SERVICE LIFE COMPARE TO THE PRESENTLY APPROVED SERVICE LIFE FOR SOLAR ASSETS?

A. The presently approved service life for solar assets is 35 years.[38]

Q. HOW DOES THE REQUESTED SERVICE LIFE FOR SOLAR ASSETS COMPARE TO THE SERVICE LIFE ASSUMED FOR EACH OF THE NEW SOLAR ASSETS INCLUDED IN THE COMPANY'S 2024 10-YEAR SITE PLAN FILED ON APRIL 1, 2024?

A. The Company assumed a service life of 35 years for each of the new solar assets included in the 2024 10-Year Site Plan. The Company filed the 2024 10-Year Site Plan on April 1, 2024, one day before it filed its Petition in this rate case proceeding. The proposed 30-year service life in this proceeding would accelerate the ratemaking recovery by 5 years compared to the planned 35-year physical service life for these assets reflected in the 2024 10-Year Site Plan.

[38] *In Re*: Docket 20210034-EI, Petition for Rate Increase by Tampa Electric Company, 2021 Stipulation and Settlement Agreement, p. 11.

Q. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT IT WILL NOT OPERATE THE EXISTING AND NEW SOLAR ASSETS FOR 35 YEARS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's proposed reduction in the service life for the existing and new solar assets. The Company's recently filed site plan assumes the solar assets will operate for 35 years. If the Company is unable physically to operate these solar assets for the 35 years assumed in its site plan, then it can seek to shorten the service lives of its solar assets if and when the physical evidence supports that conclusion. The Company is not harmed by continuing to use the presently approved service life for depreciation expense, dismantlement expense, and income tax expense; however, customers are harmed by prematurely shortening the service life.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effect is a net reduction of $8.398 million in the revenue requirement and requested increase. This net reduction reflects a reduction of $9.519 million for a reduction in depreciation expense and a reduction of $0.955 million for a reduction in dismantlement expense, offset in part by $1.636 million for the reduction in ITC amortization expense on a revenue equivalent basis for solar assets that were eligible for ITC prior to the effective date of the IRA and offset in part by $0.440 million for the reduction in the grossed-up return on the increase in rate base due to the resulting lower accumulated depreciation in the test year.

H. <u>Reduce Dismantlement Expense to Remove Post Test Year Escalations of Estimated Costs, Reduce Estimated Solar Site Restoration Costs, And Reflect Longer Service Lives for Solar and Battery Assets</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO RECOVER DISMANTLEMENT EXPENSE FOR EXISTING AND NEW GENERATING ASSETS, INCLUDING EXISTING AND FUTURE SOLAR ASSETS.

A. The Company seeks to recover estimated future dismantlement and site restoration costs for the all existing and new generating assets, including existing and future solar assets. No Company witness in either this proceeding or the depreciation proceeding addressed the calculation of the dismantlement expense. The only Company witness to address the estimated dismantlement costs used for the calculation of the dismantlement expense was Witness Kopp, who developed an estimate of these costs in 2023 dollars and excluded any potential contingency costs in the dismantlement study. Witness Kopp did not address the dismantlement expense calculation in this proceeding or the depreciation proceeding, apparently under the mistaken impression that dismantlement would be included in the depreciation rates developed by Witness Allis.[39] Witness Allis does not address the dismantlement costs or dismantlement expense accruals or include them in his proposed depreciation rates.

In response to discovery from OPC in this proceeding, the Company acknowledged that Witness Kopp did not address the dismantlement expense

[39] In the Direct Testimony of Jeff Kopp at p. 5 in this proceeding, he states "Tampa Electric witness Ned Allis is testifying to and sponsoring the depreciation rate calculations. The dismantlement costs that I prepared were used as an input for end-of-life costs in the depreciation calculations."

calculation.[40] In that same response, the Company identified Witness Chronister as the witness supporting the Company's calculations and request for dismantlement expense.[41] Yet, that response is incorrect as well; Witness Chronister has not testified in this proceeding or in the depreciation proceeding regarding the calculation of the proposed dismantlement expense accrual. To the contrary, Witness Chronister apparently was under the impression that Witness Allis and Witness Kopp were the witnesses addressing the calculation of this expense.[42]

In my review of the Company's calculations in this proceeding, I determined that some undisclosed person(s) acting on behalf of the Company made the decision to increase Witness Kopp's estimated dismantling costs by adding 15% for potential contingency costs in 2025 dollars before it calculated the dismantlement expense for 2025.[43] The Company provided no documentary support for this 15% addition, no testimony, and even failed to identify the Company witness or, indeed, any person, responsible for the decision to add these potential contingency costs given that Witness Chronister does not address this issue or any other dismantlement cost issue in his testimony.

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[40] Response to Interrogatory No. 90 in OPC's Fourth Set of Interrogatories, a copy of which I have attached as my Exhibit LK-11.

[41] *Id.*

[42] Direct Testimony of Jeff Chronister at 11 wherein he states: "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." That testimony is incorrect, but still has not been revised.

[43] As noted previously, no Company witness provided testimony or otherwise offered any support for the calculation of the dismantlement expense accruals or the addition of the 15% adder for potential contingency costs. Compounding the failure to provide any testimony on the dismantling expense accruals, the Company also failed to provide the calculations of the requested expense accruals in electronic format, despite repeated requests through written and deposition discovery, until a mere two weeks prior to the intervenor testimony due date, thus precluding any additional written discovery prior to the intervenor testimony filing date.

In the final step of the Company's calculations in this proceeding, I determined that it further escalated the 2025 expense, including the potential contingency costs, to future dollars in 2026, 2027, and 2028, and then calculated the proposed dismantlement expense as the average of the expenses in escalated 2025, 2026, 2027, and 2028 future dollars. The Company performed these calculations for each existing and new generating asset, including the existing and new solar generating assets.

Q. SHOULD THE COMPANY BE ALLOWED TO CALCULATE DISMANTLEMENT EXPENSE BASED ON PROJECTIONS OF THE EXPENSE IN FUTURE DOLLARS ESCALATED BEYOND THE TEST YEAR TO 2026, 2027, AND 2028?

A. No. The Company is limited to the test year costs, including dismantlement expense, which already reflects a forecast of the dismantlement cost extending two years beyond the most recent historic year. The test year concept is important because it is intended to be a comprehensive measure of the cost of service and present revenues for a defined time period. The Company's proposed dismantlement expense goes another three years beyond the test year, a selective adjustment that fails to recognize any other changes in those years to reflect potential increases in revenues due to customer growth and other changes in costs, including rate base and expenses, including reductions in expenses. Such reductions in expenses include reductions in payroll expenses due to productivity gains achieved through investments in rate base and reductions in regulatory assets as they continue to amortize after the test year, among the other hundreds of rate base, revenues, expense, and cost of capital components included in the cost of service, revenue requirements, and revenue deficiencies or surpluses.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission limit the dismantlement expense to costs escalated only through the test year and exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A The effects are a reduction of at least $7.088 million in the proposed dismantlement expense and a reduction of at least $7.110 million in the claimed revenue requirement and requested base revenue increase. This recommendation is extremely conservative given that the unsupported and unjustified potential contingency costs still are included in the dismantlement cost estimate and the proposed dismantlement expense through the test year.

Q. DESCRIBE THE COST CATEGORIES OR COMPONENTS WITNESS KOPP INCLUDED IN HIS ESTIMATED DISMANTLEMENT COSTS FOR THE SOLAR ASSETS.

A. Witness Kopp included labor, material and equipment, disposal, and environmental costs in his estimated costs, which he reduced for scrap proceeds (salvage income). The removal of the solar panels includes labor, material and equipment, and disposal. The panel racks/support costs include labor, material and equipment. The electrical wiring costs include labor, material and equipment. The on-site restoration costs include labor, material and equipment, and environmental. The on-site concrete crushing and removal and the debris costs include only disposal. The environmental costs include removal of access roads, removal of the perimeter fencing, grading and seeding disturbed site areas, and restoration of the rooftop underneath rooftop solar panels.[44]

Q. ARE ALL OF THESE COSTS REASONABLY KNOWN AND MEASURABLE?

A. No. First, for most of the solar facilities, Witness Kopp did not review the terms of the ground leases to assess whether the Company or the owner of the site is responsible for site restoration and environmental remediation or the scope of any activities required by the Company, if any.[45] Witness Kopp explained that the lease agreements include such requirements and that the requirements affect the party(ies) responsible for site restoration and environmental remediation and the scope of the required activities. In response to OPC discovery, Witness Kopp stated "[a] lease agreement states requirements for the leased land on which a storage or solar facility are constructed. These requirements may impact decommissioning assumptions."[46] Witness Kopp also stated that he did not review most of the lease agreements because the "lease agreement was not provided by Tampa Electric for my team to review."[47]

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[44] Response to Interrogatory No. 89(d) in OPC's Fourth Set of Interrogatories, a copy of which I have attached as Exhibit LK-12.

[45] Response to Interrogatory No. 89(e) in OPC's Fourth Set of Interrogatories. See Exhibit LK-12.

[46] *Id.*

[47] *Id.*

Second, neither Witness Kopp nor the Commission know at this time whether the solar sites will be abandoned or remain in use with new equipment installed after the original equipment is retired and removed some 35 years in the future. Witness Kopp simply assumed that the sites will be abandoned. He assumed they will not be refitted with new equipment that will extend the service life of the sites beyond the service life assumption for the original panels, inverters, and other equipment. Yet, there is at least an equal probability that the sites will remain in use refitted with new equipment and that site restoration and environmental costs will not be incurred or will be incurred at a much lower cost when the original equipment is retired and removed.

Third, neither Witness Kopp nor the Commission know at this time the scope of the site restoration, even assuming that it is the responsibility of the Company, including the extent of environmental remediation. The dismantlement, removal of the equipment and structures, and on-site concrete crushing and removal are included as separate components of the estimated costs and can be reasonably estimated based on the need to remove the old equipment; however, it is not known whether, or if so, what additional site restoration and environmental activities will be necessary.

Fourth, other utilities intentionally exclude dismantlement costs because of the uncertainties as to costs that may be incurred and whether the salvage income will exceed any such costs.

Q. IS THERE A PERMANENT PENALTY COST IMPOSED ON CUSTOMERS FOR PREMATURE RECOVERY OF DISMANTLEMENT COSTS BEFORE THE COSTS ACTUALLY ARE INCURRED?

A. Yes. There is a tax penalty in the form of an asset accumulated deferred income tax ("ADIT"), which reduces the cost-free liability ADIT reflected in the cost of capital and increases the base revenue requirement, SYA revenue requirements, and all other rider revenue requirements that include a return on rate base.

This tax penalty is unnecessary, but at least can be minimized by removing or otherwise reducing speculative, uncertain, unknown, and unmeasurable dismantlement costs from the revenue requirement. If, at some later date, these costs are known and measurable, then they can be recovered at that time.

Q. WHAT IS YOUR RECOMMENDATION ON DISMANTLEMENT COSTS FOR THE SOLAR GENERATING ASSETS?

A. I recommend the Commission minimize the dismantlement expense due to the tax penalty and the speculative assumptions as to the scope of the dismantling activities when the original equipment is retired and removed. I recommend the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets. The costs that may be incurred are extremely speculative and are not known and measurable, and are based on Witness Kopp's unsupported assumptions regarding the abandonment of the sites and that the Company will be responsible for the site restoration, further compounded by the Company's unsourced and undescribed potential contingencies assumption, all of which are extremely speculative and not known and measurable.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A The effects are a reduction of at least $2.606 million in the proposed dismantlement expense and a reduction of at least $2.614 million in the claimed revenue requirement and requested base revenue increase. These effects are in addition to the effects on the dismantlement expense from limiting the escalation of the dismantling cost estimate and the dismantlement expense only through the test year.

I. <u>Include Deferred Carrying Costs on Deferred Production Tax Credits through December 31, 2024</u>

Q. DESCRIBE THE TERM IN THE 2021 SETTLEMENT THAT ADDRESSED THE EFFECTS ON THE 2023 AND 2024 GBRAS FROM CHANGES IN THE TAX LAW.

A. Section 11(c)(vi) of the 2021 Settlement agreement approved by the Commission in the prior base rate proceeding states:

> The 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.

Q. IN FACT, WERE THERE CHANGES IN THE TAX LAW THAT MODIFIED EXISTING AND ESTABLISHED NEW TAX CREDITS?

A. Yes. The Inflation Reduction Act of 2022 ("IRA") was signed into law on August 16, 2022. The IRA implemented significant changes in the tax law that increased the investment tax credits ("ITC") percentage rate to 30% for new solar generating assets, extended the availability of the ITC credit to battery storage assets on a standalone basis, established a new production tax credit ("PTC") for solar generating resources based on energy production, gave taxpayers the choice between PTCs and ITCs for solar generating assets, and allowed utility taxpayers to elect out of 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 customers rather than electing one or the other. It also allowed the utility's regulator to enforce that election to provide both benefits to customers for ratemaking purposes. In addition, it 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.

Q. DID THESE CHANGES IN THE TAX CREDITS AVAILABLE TO THE COMPANY AND THE NORMALIZATION REQUIREMENTS AFFECT THE 2023 AND 2024 GBRAS?

A. Yes. The Company elected the PTCs in lieu of the ITCs that it had previously included in the calculation of the 2023 and 2024 GBRA rate increases for solar generating assets.[48] The economic value of the PTCs was greater than the ITCs. In addition, the PTCs earned in 2022 through 2024 were greater than the amortization of the ITCs

[48] Letter from counsel to Tampa Electric Company dated February 19, 2024 addressed to the Commission in which the Company described its election for PTCs in lieu of ITCs and its "proposal" to defer and amortize the PTCs in excess of the ITC amortization included in the calculations of the GBRA rate increases approved by the Commission. For ease of reference, I have attached a copy of this letter and the attached proposal as my Exhibit-13.

earned that the Company assumed in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission in the last base rate proceeding. Instead of flowing through the PTCs to customers in the form of reductions to the approved 2023 and 2024 GBRA rate increases, as required pursuant to the 2021 Settlement in that proceeding, the Company decided unilaterally to defer the PTCs earned in those years in excess of the ITC amortization reflected in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission. The Company then informed the Commission of its decision to defer the PTCs instead of flowing through the savings to customers. The Company recorded the revenue equivalent of the deferred PTCs as a regulatory liability on a revenue equivalent basis.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE PTCS IN THIS PROCEEDING?

A. The Company proposes to amortize the regulatory liability over ten years as a reduction to the base revenue requirement. It also proposes to flow through the revenue equivalent of the PTCs earned in the test year in the base revenue requirement and the revenue equivalent of the PTCs earned by the new solar generating assets included in the 2026 and 2027 SYA revenue requirements.

Q. DOES THE COMPANY'S PROPOSAL INCLUDE A RETURN ON THE DEFERRED PTCS FROM 2022 THROUGH THE END OF 2024?

A. No. Unlike the ITCs prior to the IRA, the PTCs were not subject to the so-called normalization requirement, meaning that the Company could immediately flow through the PTCs to its customers, or if it deferred the PTCs for future amortization, then it could also subtract the deferred PTCs from rate base or include those amounts as cost-free tax credits in its cost of capital. The Company simply deferred the PTCs for future amortization, but failed to address the savings due to the cost-free capital during the deferral period.

Q. IN THE ABSENCE OF FLOWING THROUGH THE PTCS TO CUSTOMERS AS THEY WERE EARNED BY REDUCING THE 2023 AND 2024 GBRA INCREASES, HOW SHOULD THE COMPANY HAVE ADDRESSED THE PTCS TO ENSURE THAT CUSTOMERS WERE MADE WHOLE?

A. The Company should have added a deferred return to the deferred PTCs on a revenue equivalent basis to ensure that customers received the same economic value as if the PTCs had been flowed as reductions to the 2023 and 2024 GBRA rate increases as the PTCs were earned each year. The failure to flow through the reductions in the GBRA rate increases allowed the Company to retain the cash from the PTCs and the related savings in financing costs in those years due to the avoided investor equity and debt financing. Instead of deferring the savings in financing costs as an increase to the regulatory liability, the Company simply retained those savings. This situation can and should be corrected.

I note the Company acknowledges there has been a savings in financing costs by subtracting the regulatory liability from rate base in the test year. While it is appropriate to subtract the regulatory liability from rate base in the test year, that does not address the savings for the deferral years 2022 through 2024, which need to be addressed separately through an addition of a deferred return to the deferred PTC regulatory liability for those three years.

Q. SHOULD THE COMPANY'S CUSTOMERS BE PROVIDED THE COMPANY'S SAVINGS IN FINANCING COSTS?

A. Yes. The savings in financing costs belong to customers who were deprived of the timely flow through of the PTCs earned in the years through 2024.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission compensate customers for carrying costs on the deferred PTCs by adding the deferred carrying costs calculated at the allowed return from the prior rate case to the regulatory liability.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effects are a reduction of at least $0.887 million in the claimed revenue requirement and requested base revenue increase, consisting of an increase of $0.460 million in the *negative* amortization expense and a decrease of $0.427 million due to the additional regulatory liability in the test year times the grossed-up rate of return (equity only).

J. <u>Amortize Deferred Production Tax Credits Over Three Years</u>

Q. IS THE COMPANY'S PROPOSAL TO AMORTIZE THE REVENUE EQUIVALENT OF THE DEFERRED PTCS OVER TEN YEARS REASONABLE?

A. No. The ten years is unduly long. Customers were entitled to the PTCs as they were earned through reductions to the base revenue requirement and reductions to the 2023 and 2024 GBRAs pursuant to the 2021 Settlement in the prior rate case. The refunds to these customers should be made sooner rather than later, especially since the Company failed to record deferred carrying costs on the deferred PTCs and failed to include the PTCs as cost-free capital in the capital structure.

The Company offered no rationale for the ten years other than the PTCs are available for new solar resources annually for ten years. However, there is no nexus between the number of years the PTCs are available for new solar generating assets going forward (test year and subsequent years) and the refunds related to the deferral period preceding the test year. This should be clear based on the Company's request to flow through the annual PTCs earned starting in the test year and each year thereafter.

Q. WHAT IS A REASONABLE AMORTIZATION PERIOD?

A. A three-year amortization period is reasonable. That is the likely number of years until the Company's next base rate case proceeding when base rates will again be reset based on the Company's recent filing history.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission refund the regulatory liability, including the deferred return on the regulatory liability for the years 2022 through 2024, over a three-year amortization period.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of at least $13.182 million in the claimed revenue requirement and requested base revenue increase, consisting of a $13.845 million increase in the negative amortization expense, offset in part by $0.663 for the increase in the test year rate base due to shorter amortization period multiplied by the grossed-up cost of capital.

K. <u>Amortize Deferred Investment Tax Credits Pursuant to The IRA Over Three Years</u>

Q. DESCRIBE THE COMPANY'S DECISIONS TO DEFER AND AMORTIZE THE ITC OVER THE SERVICE LIFE OF THE BATTERY STORAGE ASSETS AND TO *NOT* ELECT OUT OF THE NORMALIZATION REQUIREMENTS.

A. There are two discretionary decisions the Company made, both of which harm customers in order to benefit its shareholder.[49] The first was to defer the ITCs on the battery storage assets and amortize the deferred ITCs over the service life of those assets. The longer the amortization period, the less value of the ITCs to customers and the greater the economic value to the Company's shareholders.

The second was to *not* elect out of the normalization requirements. The failure to elect out of the normalization requirements for these ITCs means that the ITCs must be deferred and amortized over the service life in order to avoid a so-called normalization violation and the loss of the ITCs as a consequence. The failure to elect

[49] Response to Interrogatory 91 in OPC's Fourth Set of Interrogatories. I have attached a copy of this response as my Exhibit LK-14.

out of the normalization requirements also means that the Company cannot reflect the cost-free capital in the cost of capital.

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 savings to the customers who are required to pay the entirety of the cost of the new battery storage assets.

Q. THE COMPANY CLAIMS THAT IT MADE THE DECISION TO *NOT* ELECT OUT OF THE NORMALIZATION REQUIREMENTS TO "ALLOW REGULATED COMPANIES AND CUSTOMERS TO SHARE BENEFITS" AND TO AVOID VOLATILITY IN THE COMPANY'S TAX EXPENSE PROFILE. PLEASE RESPOND TO THESE REASONS.[50]

A. The short response to both stated reasons is that the Company inequitably and opportunistically chose to benefit its shareholder at the expense of its customers. Fundamentally, the Company has no entitlement to "share" in the ITC benefits when it does not share in the costs of the new battery storage assets. Despite its apparent wish to the contrary, the Company still remains subject to cost-based regulation. The Company'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. The only reason for the historic sharing of the pre-IRA ITCs between the utility shareholders and customers was that it was required by the normalization requirements in the Internal Revenue Code. Those requirements do not apply to the new ITCs if the

[50] *Id.*

Company elects out of the normalization requirements. The Commission now has the opportunity and discretion to reflect the entirety of ITC benefit in the cost of service to reduce the cost to customers of 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.

As to the Company’s assertion that its decision to *not* elect out of the normalization requirements somehow is necessary to avoid volatility in the Company’s tax expense profile is simply wrong. The Commission has the discretion to direct the Company to defer the ITC rather than flowing it through as earned, similar to the Company’s unilateral decision to defer the PTCs during the years 2022 through 2024 rather than flowing through those tax credits as they were earned, and then amortize the deferred ITC over a specific and defined amortization period. The deferral and amortization inherently acts to smooth the effect on the Company's tax expense profile. It is not necessary to use the service life for this purpose unless the Commission allows the Company to *not* elect out of the normalization requirements and to harm customers, which I do not recommend.

In summary, there is no benefit to customers from the Company’s decision to *not* elect out of the normalization requirements. There is only harm because the Company has acted against the interests of its customers in favor of its own. It is that simple.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reflect the ITCs as if the Company elected and will continue to elect out of the normalization requirements. It is an annual election and the Company has not yet filed its 2023 federal income tax return or its 2024, 2025, 2026, or 2027 federal income tax returns. If the Company is unwilling to elect out of the normalization requirements each year, then I recommend a reduction in the Company's authorized return on equity 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.

I also recommend the Commission direct the Company to defer the ITCs pursuant to the IRA earned each year, but to amortize the deferred ITCs over a three-year amortization period, the same period that I recommend for the deferred PTCs earned in the years 2022 through 2024 and for the same reasons.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATIONS?

A. The effects of the first recommendation are a reduction of $3.493 million in the base 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. There are additional effects on the 2026 and 2027 SYA revenue requirements that I subsequently address in the SYA section of my testimony.

The effects of the second recommendation are a reduction of $12.607 million in the base revenue requirement due to the shorter amortization period. There is no effect on the CETM revenue requirement. There are additional effects on the 2026 and 2027 SYA revenue requirements that I subsequently address in the SYA section of my testimony.

III. COST OF CAPITAL ISSUES

A. <u>Reduce Return Component of Revenue Requirement to Reflect Witness Woolridge's Recommended Return On Equity</u>

Q. HAVE YOU QUANTIFIED THE EFFECT ON THE COMPANY'S REVENUE REQUIREMENT OF THE 9.50% RETURN ON EQUITY RECOMMENDATION SPONSORED BY WITNESS WOOLRIDGE?

A. Yes. The effect is a reduction of $126.379 million in the Company's claimed base revenue requirement and requested rate increase. I calculated this effect in a sequential manner and it is incremental to all prior cost of capital adjustments that I have addressed and quantified for the base revenue requirement. The effects also include a reduction of $3.497 million in the Company's CETM revenue requirement. In addition, there are effects on the requested 2026 and 2027 SYA revenue requirements that I address in the SYA section of my testimony.

Q. HAVE YOU QUANTIFIED THE EFFECT OF EACH 0.10% RETURN ON COMMON EQUITY?

A. Yes. The effect of each 0.10% return on common equity is $6.319 million on the base revenue requirement. The effects of each 0.10% return on common equity is $0.175

million on the CETM revenue requirement. There also are effects on the requested 2026 SYA and 2027 SYA revenue requirements that I address in the SYA section of my testimony.

IV. SUBSEQUENT YEAR ADJUSTMENT ISSUES

A. Reject Company's *Ad Hoc* Proposal to Modify the Historic Ratemaking Framework to Include Post Test Year Rate Increases for "Business As Normal" Distribution Capital Investment Costs

Q. DESCRIBE THE COMPANY'S *AD HOC* PROPOSAL TO MODIFY THE HISTORIC RATEMAKING FRAMEWORK TO INCLUDE POST TEST YEAR RATE INCREASES TO RECOVER "DELIVERY INFRASTRUCTURE" CAPITAL INVESTMENT COSTS AND OPERATING EXPENSES.

A. The Company's requested 2026 SYA and 2027 SYA revenue requirements and rate increases include "delivery infrastructure" capital investment costs and operating expenses. The Company characterizes these delivery infrastructure projects as "incremental investments in Grid Reliability and Resilience."[51]

Q. TO YOUR KNOWLEDGE, HAS THE COMMISSION PREVIOUSLY ALLOWED ADJUSTMENTS FOR "BUSINESS AS NORMAL" "DELIVERY INFRASTRUCTURE" CAPITAL INVESTMENT COSTS AND OPERATING EXPENSES?

[51] Petition at paragraph 27.

A. No. In some cases, the Commission previously has allowed generation base rate adjustments ("GBRAs") for specific new and material generation capital investment costs and operating expenses for the Company and for other utilities,[52] but to the best of my knowledge, it never has allowed SYAs for "delivery infrastructure" capital investment costs and operating expenses.

Q. THE COMPANY CITES RULE 25-6.0425, FLORIDA ADMINISTRATIVE CODE (F.A.C.), RATE ADJUSTMENT APPLICATIONS AND PROCEDURES IN ITS PETITION IN SUPPORT OF ITS REQUESTED 2026 SYA AND 2027 SYA RATE INCREASES. WHAT DOES THIS RULE STATE?

A. Rule 25-6.0425, F.A.C., ("the Rule") states:

> **25-6.0425 Rate Adjustment Applications and Procedures.**
>
> The Commission may in a full revenue requirements proceeding approve incremental adjustments in rates for periods subsequent to the initial period in which new rates will be in effect.

Q. DOES THIS RULE PROVIDE A FRAMEWORK, ESTABLISH LIMITATIONS, SET FORTH ANY GUIDELINES, AND/OR PROVIDE ANY OTHER CUSTOMER PROTECTIONS FOR SUCH INCREMENTAL ADJUSTMENTS?

A. No.

[52] The Commission approved the Company's requests for one GBRA rate increase in 2022 and another GBRA rate increase in 2023, albeit for reduced amounts due to multiple errors in the Company's calculations of the as-filed requests that were corrected in the 2021 Settlement approved in Docket No. 202100034-EI, the Company's last base rate case proceeding. The two requests allowed the Company to "recover the cost of its investment in, and operation of, Phase Two of its Big Bend Modernization Project and Phases Two and Three of its Future Solar projects to the extent of the GBRAs as specified in this Paragraph 4," reciting paragraph 4(a) of the 2021 Settlement.

Q. WHY IS THIS A PROBLEM?

A. It is a problem because there is no framework, no limitations, no guidance, and no customers protections in the Rule or in any other rule for such rate adjustments. In this case, the Company, on an *ad hoc* basis, simply forecasted additional "electric delivery" infrastructure costs that it may or may not actually incur in 2026 and 2027 and included them in its requested 2026 SYA and 2027 SYA revenue requirements.

The Company offered no framework, offered no limitations on the costs that could be included in the 2026 SYA and 2027 SYA in this proceeding or in SYAs in any future proceeding, offered no guidelines for such incremental adjustments, and failed to offer any reasonable customer protections. Among other potential harms to customers, there is no requirement actually to incur the capital costs included in the SYA revenue requirements, to measure or reflect any savings in maintenance expense or storm costs in the SYA revenue requirements, or to prove up the benefits from the expenditures and expenses, if any.

An *ad hoc* approach, such as this, is ripe for abuse because, ultimately, the Company and/or other utilities may seek subsequent year adjustments based on forecasts of any or all capital investment costs and operating expenses on a selective or comprehensive basis. The Company and/or other utilities may include forecast generation, transmission, distribution, and general costs, both capital and expenses, for an unlimited number of future years, subject to no or only limited reporting oversight, with no reconciliation to actual revenues or costs in those future years, with no assurance that the forecasts are comprehensive, let alone reasonable, and with no offsets for growth in base revenues due to customer and sales growth from year to year.

The Company and/or other utilities may base their forecasts on increasingly unknown, unmeasurable, and speculative assumptions, and wish lists well beyond the test year, with the result they will seek to essentially transfer the ratemaking oversight from the Commission to themselves to do as they wish. In that manner and in those circumstances, the purpose, role, and relevance of agency regulation is titular at best, essentially devolving into regulation of, by, and for the utilities themselves for their own self-interest and to the harm of their customers.

Q. WHAT ARE SOME POTENTIAL SOLUTIONS TO THESE PROBLEMS IN THIS PROCEEDING?

A. There are at least three potential solutions. The first and most obvious, is to simply deny the Company's requests for the requested "delivery infrastructure" costs in the 2026 SYA and 2027 SYA revenue requirements and requested increases. If the requests are denied, then the Company can adjust its actual capital expenditures or not, or for that matter, seek to include them, if appropriate, in its Storm Protection Plan ("SPP") and in its SPP Cost Recovery Clause ("SPPCRC") for cost recovery to the extent not already included in the programs approved in the SPP and in the costs already recoverable through the SPPCRC.

The second solution is to deny the Company's requests for these costs in this proceeding, but then initiate a rulemaking to allow all interested parties to participate in establishing a framework, limitations, and guidance applicable to all utilities and on a consistent basis. As with the first solution, if denied, then the Company can adjust its actual capital expenditures or not, or for that matter, seek to include them, if appropriate, in its Storm Protection Plan ("SPP") and in its SPP Cost Recovery Clause ("SPPCRC") for cost recovery.

The third solution is to establish an *ad hoc* framework, limitations, and guidance applicable solely to the Company and solely to its request to include electric delivery costs in the requested 2026 SYA and 2027 SYA.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny the Company's requests for recovery of these electric delivery costs in the 2026 SYA and 2027 SYA. OPC Witness Kevin Mara makes this same recommendation in his Direct Testimony in this proceeding, albeit with reference to the Grid Resilience and Reliability projects, the term used by the Company to describe the "electric delivery infrastructure" projects included in its requested SYAs. Alternatively, I recommend the Commission establish an *ad hoc* framework, limitations, guidance, and customer protections applicable solely to the Company in response to the Company's *ad hoc* requests applicable solely to the Company in this proceeding, at least at this time.

If the Commission adopts the alternative approach, then I recommend it adopt the following framework, limitations, guidance, and customer protections, and then assess each of the Company's requested electric delivery infrastructure projects against this framework to establish the projects and costs, if any, for this purpose, that should be included in the 2026 SYA and 2027 SYA. These factors are as follows:

1. Incremental adjustments to rates in periods after the test year in a full revenue requirements proceeding are not a substitute in whole or part for a petition by the utility for a full revenue requirements proceeding and are

allowed only if the projects and/or costs meet certain dollar and other qualification thresholds.

2. Incremental adjustments to rates are limited to the recovery of material and known costs of new identifiable and discrete projects placed in service in a subsequent year, historically, the costs of new generating assets.

3. Incremental adjustments to rates are not permitted for new or expanded programs or categories of costs and are not allowed to annualize costs and increase recovery of the costs that may have been included for a partial year in the cost of service in a full revenue requirements proceeding.

4. Incremental adjustments to rates are not permitted for forecasted increases in "business as normal" costs included in the cost of service and the approved base revenue requirement in the test year used in a full revenue requirements proceeding, including the costs of new forms of assets or new technology used to replace retired assets.

5. Incremental adjustments to rates for the recovery of the costs of new identifiable and discrete projects placed in service in a subsequent year, such as new generating units, are to be offset by the forecasted incremental base revenues in the subsequent year on a weather normalized basis as the result of customer growth in the subsequent year compared to the forecasted base revenues in the test year used in a full revenue requirements proceeding.

6. Related to simultaneous significant reductions in costs included in base revenues and/or reductions or other changes costs included in clause recoveries, such as recoveries embedded into base rates for costs that no longer will be incurred or changes in costs recoverable through the fuel adjustment clause and other clauses.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION TO REMOVE THE COSTS OF THE DELIVERY INFRASTRUCTURE PROJECTS FROM THE 2026 SYA AND THE 2027 SYA?

A. The effects are a $4.599 million reduction in the 2026 SYA revenue requirement and a $28.788 million reduction in the 2027 SYA revenue requirement.

B. <u>Correct Errors And Otherwise Modify Company's Calculations of 2026 and 2027 SYA Revenue Requirements</u>

Q. DESCRIBE THE COMPANY'S QUANTIFICATION METHODOLOGY FOR THE SUBSEQUENT YEAR ADJUSTMENTS.

A. The Company's quantification methodology is applied on a project by project basis and detailed in the Excel workbook provided in support of Witness Latta's Exhibit RL-1, Document 5, now sponsored by Witness Chronister.[53] The Company calculated the incremental capital related costs for each project by month in the test year and in the subsequent years 2026 and 2027, including rate base, the return on rate base, income taxes on the return on rate base, tax credits grossed up to revenue equivalents, depreciation expense, and property tax expense.[54] The Company also included estimated incremental operation and maintenance expense on a project by project basis by month in the test year and in the subsequent years 2026 and 2027.

The Company calculated gross plant additions based on the estimated in-service dates, accumulated depreciation based on the monthly depreciation expense starting the month after the in-service date using its proposed depreciation rates, although it failed to provide any of the calculations until mere days before the Intervenor testimony filing date, and property tax expense starting in January in the year following the in-service date using an estimated property tax rate for each year.

The Company utilized its requested return in this proceeding, including its requested ratemaking capital structure and return on equity.

[53] (BS 100d) RL Exhibit 5a Support and (BS 100e) RL Exhibit 5b Support.
[54] *Id.*

The Company estimated operation and maintenance expense, but failed to provide any assumptions, data, or calculations in support of its estimates.

The Company also estimated the ITCs (amortization expense only) and PTCs utilized/earned, but failed to provide any of the underlying calculation support, such as the amount of the ITC utilized/earned, the calculations of the amortization expense over the estimated service lives of the projects, and the income tax gross-up to a revenue equivalent, if any, until mere days before the due date for Intervenor testimony. It also failed to provide any of the underlying calculation support for the PTCs, which required estimates of energy generation, the PTC rate per kWh, and the income tax gross-up to a revenue equivalent, if any, until mere days before the due date for Intervenor testimony. OPC requested all Excel workbooks and calculations in its initial discovery in this proceeding and in subsequent discovery requests, including through the deposition of Witness Chronister, yet the Company failed to provide the Excel workbooks, including the assumptions, data, sources of data, and the calculations of the ITC deferred, ITC amortization, and the PTCs generated until mere days before the due date for Intervenor testimony.

Q. DESCRIBE THE MOST SIGNIFICANT ERROR IN THE COMPANY'S CALCULATIONS.

A. The most significant error is that the Company included an income tax expense gross-up on the weighted debt component of the cost of capital used for the rate of return. This error significantly overstates the revenue requirement for each project in each year of the requested SYAs. The Company made a similar error in its initial as-filed calculations of the proposed generation base revenue adjustments ("GBRAs") in the prior rate case, but it agreed to correct the error by reducing the as-filed requested GBRA revenue requirements in the 2021 Settlement agreement in that proceeding.[55]

The Company's calculation of the revenue requirement multiplied the requested weighted average cost of capital times the rate base. Instead of correctly grossing up only the weighted equity component of the return for income taxes, the Company incorrectly grossed up the entire cost of capital for income taxes, including the weighted debt component of the return.[56] There is no income tax gross up on the debt return. The revenue recovered for the debt return is exactly offset by the underlying interest expense deduction in the calculation of taxable income and income tax expense, resulting in no income tax expense applicable to the revenue recovery and thus, no need to gross up the debt return for income taxes. The revenue recovered for the equity return is different in that there is no equity return deduction in the calculation of taxable income and income tax expense, meaning that the revenue requirement must include an addition for the income tax expense. This addition for the income tax expense is calculated by multiplying the weighted equity return times an "NOI multiplier," also referred to as an income tax gross-up.

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[55] I was personally involved in identifying this error in the prior case and ensuring on behalf of the OPC that it was corrected in the 2021 Settlement. It was my understanding the Company recognized that it was an error and not a negotiated concession. Thus, my reference to the 2021 Settlement is not to cite a settlement concession as precedent, but to note that the error was acknowledged and corrected in the last case.

[56] Response to Interrogatory No. 83(c) in OPC's Fourth Set of Interrogatories. I have attached a copy of the entirety of the response as my Exhibit LK-15.

Q. THE COMPANY REFUSES TO ACKNOWLEDGE THIS ERROR, DESCRIBING THE CALCULATION "AS A REASONABLE PROPOSAL IN THE CONTEXT OF A RATE CASE PROCEEDING."[57] PLEASE RESPOND.

A. The Company's gross-up of the weighted debt return for the 2026 and 2027 SYAs is an outright error. It is not "reasonable" in any conventional usage of that term to calculate the 2026 and 2027 SYA rate increases with an error in the calculation formula. The Company has made no attempt whatsoever to justify the error or explain why it is not an error. It is not a defense to simply claim that an error is a "reasonable proposal."

Q. TO REINFORCE THAT THE GROSS-UP OF THE WEIGHTED DEBT RETURN FOR THE 2026 AND 2027 SYAS IN THIS PROCEEDING IS AN ERROR, DOES THE COMPANY GROSS-UP THE WEIGHTED DEBT RETURN IN THE STORM PROTECTION PLAN REVENUE REQUIREMENT CALCULATIONS?

A. No. The Company's calculation of the return applied to rate base in the Storm Protection Plan revenue requirement calculations correctly grosses-up only the weighed equity return; it does not gross-up the weighted debt return. The Company's Excel workbook filed in that proceeding shows the calculations of the equity and debt components of the grossed-up rate of return and only the equity component is grossed-up for income taxes.[58]

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[57] Response to Interrogatory No. 83(d) and (e) in OPC's Fourth Set of Interrogatories. See Exhibit LK-15.

[58] Excel workbook (BS_54) SPP 2020 Plan Filing Revenue Requirements tab Capital p1 filed by the Company in Docket 20200067-EI. I have attached a copy of the 2020 portion of this tab as my Exhibit LK-16. I note that the line showing the weighted debt return on rate base states that it is grossed-up; however, it is not,

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission correct this error in the calculation of the 2026 and 2027 SYA increases. This is an error that overstates the revenue requirement. It is axiomatic there is no income tax gross-up on the debt component of the return on rate base. The Company's assertion the error is a "reasonable proposal" should be rejected. It is not a reasonable proposal. If the Commission condones this error in this proceeding, then it will encourage Tampa to repeat the error and other utilities to adopt the error in their future requests for GBRAs or other forms of SYAs.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of \$4.529 million in the 2026 SYA revenue requirements and a reduction of \$2.453 million in the 2027 SYA revenue requirements.

Q. ARE THERE ADDITIONAL PROBLEMS WITH THE COMPANY'S CALCULATIONS OF THE SYA REVENUE REQUIREMENTS THAT REQUIRE MODIFICATIONS TO THOSE CALCULATIONS?

A. Yes. First and foremost, the Company failed to reflect increases in revenues due to customer and other sales growth from the test year to each of the subsequent years. The failure to reflect the additional revenues overstates the Company's requested SYAs. OPC witness Dismukes further addresses and quantifies these additional revenues related to the 2026 and 2027 SYAs.

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as demonstrated by the related footnotes for the weighted equity return, which states that it is grossed up, and the weighted debt return, which does not state that it is grossed up, and, in fact, is not grossed up in the actual calculations.

Second, the Company included incremental operation and maintenance expense, but failed to subtract the variable O&M expense savings that it estimated in its cost effectiveness determinations.[59] The failure to reflect these savings overstates the Company's requested SYA revenue requirements.

Third, the Company used unduly short service lives to calculate the depreciation expense for the solar generating and battery storage assets. As I noted in the Operating Income section of my testimony, the Company used a 10-year service life for the battery projects and a 30-year service life for the solar projects included in the test year and the SYAs. The industry standard for battery assets is a 20-year service life. In the last rate case, the order approving the 2021 Settlement established a 35-year service life for the solar projects included in the test year and in the GBRAs. As I previously noted, the Company has failed to provide any compelling argument that the presently authorized 35-year service life for solar assets is unreasonable and should be shortened.

Fourth, the Company failed to elect out of the ITC normalization requirements on the battery storage assets. As I noted in the Operating Income section of my testimony, the Company's failure to elect out of the ITC normalization requirements is unreasonable and harms customers by limiting the ITC amortization period to the service life of the battery storage assets and limits the ability to reflect the cost-free ITCs in the cost of capital.

[59] Direct Testimony of Jose Aponte at pp. 14-33.

Q. WHAT ARE YOUR RECOMMENDATIONS TO ADDRESS THE ADDITIONAL PROBLEMS WITH THE COMPANY'S REQUESTED 2026 SYA AND 2027 SYA REVENUE REQUIREMENTS?

A. I recommend the Commission 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.

I recommend the Commission 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.

I recommend the Commission reject the Company's unjustified and unduly short service lives for the solar and battery projects included in the 2026 and 2037 SYAs that I addressed in the Operating Income section of my testimony.

I recommend the Commission amortize the ITCs on the battery storage assets over a three-year amortization period for the reasons that I addressed in the Operating Income section of my testimony.

I recommend the Commission reflect the ITCs on the battery storage assets as cost-free capital in the cost of capital applied to rate base.

I recommend the Commission use the cost of capital reflecting my recommendations regarding capital structure and OPC witness Woolridge's recommended return on equity.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATIONS?

A. 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.

The effects include reductions of $6.696 million and $3.420 million to exclude all incremental O&M expense for the 2026 SYA and 2027 SYA revenue requirements, respectively.

The effects include reductions of $3.670 million for the 2026 SYA and $1.612 million for the 2027 SYA to reflect my recommendation for longer service lives for the solar and battery projects.

The effects include a reduction of $2.792 million for the 2026 SYA to reflect my recommendation for amortizing deferred ITCs over a three-year amortization period. The Company's 2027 SYA did not include an amortization of ITCs.

The effects include reductions of $0.265 million for the 2026 SYA and $0.144 million for the 2027 SYA to reflect my recommendation to include deferred ITCs as cost-free capital in the cost of capital.

The effects include reductions of $9.273 million for the 2026 SYA and $5.022 million for the 2027 SYA to reflect Witness Woolridge's return on equity recommendation. I calculated these effects in a sequential manner and they are incremental to all prior cost of capital adjustments that I have addressed and quantified for the 2026 and 2027 SYA revenue requirements.

Finally, the effects of each 0.10% return on common equity is $0.464 million on the 2026 SYA revenue requirement and $0.251 million on the 2027 SYA revenue requirement.

V. OTHER ISSUES

A. <u>Reject Company's Request for Unknown Future Tax Change Rate Adjustments</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO PREEMPTIVELY ADDRESS THE EFFECTS OF ANY FUTURE CHANGES IN CORPORATE INCOME TAXES THAT AFFECT THE BASE REVENUE REQUIREMENT, 2026 SYA, 2027 SYA, AND CETM.

A. The Company's Petition states:[60]

> The company requests approval to extend the Corporate Income Tax Change provisions in Section 11 of the 2021 Agreement ("Tax Reform Provision") to be effective January 1, 2025 and thereafter until the company's base rates are next set in a general base rate proceeding like this one.

Q. DESCRIBE THE CORPORATE INCOME TAX CHANGE PROVISIONS IN SECTION 11 OF THE 2021 AGREEMENT.

A. Section 11 broadly describes the effects of potential changes in tax law that could affect the Company's costs in the test year in that proceeding, future year GBRAs, and the CETM until base rates are reset in a general base rate proceeding. That provision of the 2021 Settlement agreement expires when new base rates go into effect resulting from this proceeding.

[60] Petition at paragraph 31.

Among other terms in Section 11, the 2021 Settlement agreement describes the effects on income tax expense, including the amortization of deficient (if the income tax rate goes up) or excess (if the income tax rate goes down) deferred income taxes (protected and unprotected), ADIT, and tax credits resulting from changes in income tax rates and the modification of existing tax credits and new tax credits. It also prescribes a general methodological approach for calculating the effects using the Company's "forecasted earnings surveillance report for the calendar year that includes the period in which Tax Changes are effective to calculate the impact of Tax Changes." I also am aware that OPC intends to make legal arguments opposing this request similar to its arguments in Docket 20230023-GU in the Peoples Gas System rate case.

Q. IS THERE ANY COMPELLING REASON TO EXTEND THE CORPORATE INCOME TAX CHANGE PROVISIONS IN SECTION 11 OF THE 2021 AGREEMENT?

A. No. The effects of any corporate income tax changes can be addressed by the Commission on its own initiative and on a statewide basis or through a Petition filed by the Company on its own initiative if and when such corporate income tax changes are enacted. There is no need in this proceeding to attempt to preemptively prescribe future Company Petitions or the calculation methodologies in such filings, which may be considered to have presumptive validity.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny the Company's request. It is unnecessary and may inappropriately affect the agency's future actions that otherwise would be applicable to all utilities statewide.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's requested base revenue increase, CETM increase, and the SYA increases. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

RESUME OF LANE KOLLEN, PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

Chartered Global Management Accountant (CGMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Society of Depreciation Professionals

Mr. Kollen has more than forty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
City of Austin
Georgia Public Service Commission Staff
Florida Office of Public Counsel
Indiana Office of Utility Consumer Counsel
Kentucky Office of Attorney General
Louisiana Public Service Commission
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York City
New York State Energy Office
South Carolina Office of Regulatory Staff
Texas Office of Public Utility Counsel

Utah Office of Consumer Services

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility	Louisville Gas &	Economics of Trimble County, completion.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
			Customers	Electric Co.	
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8469	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.

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11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.

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09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.

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04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.

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11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Rebuttal Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

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10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.

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07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Union Pacific Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Union Pacific Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.

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11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 03/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

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07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Next Era acquisition of Oncor; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.

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06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.
08/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky (Electric)	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.

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09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.
01/19	2018-00281	KY	Attorney General	Atmos Energy Corp.	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-07 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-00358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.

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10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.
10/19	45253	IN	Duke Energy Indiana	Office of Utility Consumer Counselor	Prepaid pension asset, inventories, regulatory assets and liabilities, unbilled revenues, incentive compensation, income tax expense, affiliate charges, ADIT, riders.
12/19	2019-00271	KY	Attorney General	Duke Energy Kentucky	ADIT, EDIT, CWC, payroll expense, incentive compensation expense, depreciation rates, pilot programs
05/20	202000067-EI	FL	Office of Public Counsel	Tampa Electric Company	Storm Protection Plan.
06/20	20190038-EI	FL	Office of Public Counsel	Gulf Power Company	Hurricane Michael costs.
07/20 09/20	PUR-2020-00015 Direct Surrebuttal	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Coal Amortization Rider, storm damage, prepaid pension and OPEB assets, return on joint-use assets.
07/20 09/20	2019-226-E Direct Surrebbutal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Integrated Resource Plan.
10/20	2020-00160	KY	Attorney General	Water Service Corporation of Kentucky	Return on rate base v. operating ratio.
10/20	2020-00174	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rate base v. capitalization, Rockport UPA, prepaid pension and OPEB, cash working capital, incentive compensation, Rockport 2 depreciation expense, EDIT, AMI, grid modernization rider.
11/20 12/20	2020-125-E Direct Surrebuttal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Summer 2 and 3 cancelled plant and transmission cost recovery; TCJA; regulatory assets.
12/20	2020172-EI	FL	Office of Public Counsel	Florida Power & Light Company	Hurricane Dorian costs.
12/20	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM23, Vogtle 3 and 4 rate impact analyses.
02/21 04/21	2019-224-E 2019-225-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Carolinas, LLC, Duke Energy Progress, LLC	Integrated Resource Plans.
03/21	51611	TX	Steering Committee of Cities Served by Oncor	Sharyland Utilities, L.L.C.	ADIT, capital structure, return on equity.

**Expert Testimony Appearances
of
Lane Kollen
As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
03/21	2020-00349 2020-00350	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Rate base v. capitalization, retired plant costs, depreciation, securitization, staffing + payroll, pension + OPEB, AMI, off-system sales margins.
04/21 Direct 07/21	18-857-EL-UNC 19-1338-EL-UNC 20-1034-EL-UNC 20-1476-EL-UNC Supplemental Direct	OH	The Ohio Energy Group	First Energy Ohio Companies	Significantly Excessive Earnings Test; legacy nuclear plant costs.
05/21 06/21	2021-00004 Direct Supplemental Direct	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	CPCN for CCR/ELG Projects at Mitchell Plant.
06/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
06/21	2021-00103	KY	Attorney General and Nucor Steel Gallatin	East Kentucky Power Cooperative, Inc.	Revenues, depreciation, interest, TIER, O&M, regulatory asset.
07/21 08/21 10/21	U-35441 Direct Cross-Answering Surrebuttal	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Company	Revenues, O&M expense, depreciation, retirement rider.
09/21	2021-00190	KY	Attorney General	Duke Energy Kentucky	Revenues, O&M expense, depreciation, capital structure, cost of long-term debt, government mandate rider.
09/21	43838	GA	Public Interest Advocacy Staff	Georgia Power Company	Vogtle 3 base rates, NCCR rates; deferrals.
09/21	2021-00214	KY	Attorney General	Atmos Energy Corp.	NOL ADIT, working capital, affiliate expenses, amortization EDIT, capital structure, cost of debt, accelerated replacement Aldyl-A pipe, PRP Rider, Tax Act Adjustment Rider.
12/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM25, Vogtle 3 and 4 rate impact analyses.
01/22	2021-00358	KY	Attorney General	Jackson Purchase Energy Corporation	Revenues, nonrecurring expenses, normalized expenses, interest expense, TIER.
01/22	2021-00421	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Mitchell Plant Operations and Maintenance and Ownership Agreements; sale of Mitchell Plant interest.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/22	2021-00481	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Liberty Utilities, Inc. acquisition of Kentucky Power Company; harm to customers; conditions to mitigate harm.
03/22	2021-00407	KY	Attorney General	South Kentucky Rural Electric Cooperative Corporation	Revenues, interest income, interest expense, TIER, payroll.
03/22 04/22	U-36190 Direct Cross-Answering	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Certification of solar resources.
05/22	20200241-EI 20210078-EI 20210079-EI	FL	Office of Public Counsel	Florida Power & Light Company, Gulf Power Company	Hurricanes Sally, Zeta, Isaias; Tropical Storm Eta, pre-planning, restoration and repair, costs, ratemaking recovery.
05/22	U-36268	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Wholesale power contracts, wholesale rate tariffs, wholesale rates.
06/22	20220048-EI 20220049-EI 20220050-EI 20220051-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plans. prudence, reasonableness, cost recovery, including deferred return on CWIP.
06/22	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM26, Vogtle 3 and 4 rate impact analyses.
07/22	S-36267	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Non-opposition to establish revolving LOC and supporting guarantees by member cooperatives.
08/22	53601	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company, LLC	Vendor financing, customer advances, cash working capital, ADFIT and temporary differences, depreciation expense, amortization expense.
09/22	20220010-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plan, Cost Recovery Clause, prudence, reasonableness, deferred return on CWIP.
10/22	5-UR-110	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Levelized recovery of retired plan costs, securitization financing.
10/22	2022-00283	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rockport deferrals and recoveries.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/22	2022-00263	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Fuel adjustment clause methodology and disallowances.
01/23	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM27, Vogtle 3 and 4 rate impact analyses.
1/23 02/23	2022-256-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Progress, LLC	Storm response process, costs, deferrals, deferred carrying costs.
03/23	2022-00372	KY	Attorney General	Duke Energy Kentucky, Inc.	Cash working capital, depreciation, decommissioning, regulatory asset amortization, retired generation asset recovery, modifications to existing tariffs, proposed new tariffs.
06/23	20230023-GU	FL	Office of Public Counsel	Peoples Gas System, Inc.	Restructuring, staffing, O&M expenses, storm expense, depreciation expense, amortization of theoretical depreciation surplus.
07/23	2022-00402	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	CPCNs for combined cycle and owned solar resources, acquisition of PPA solar resources, retirement of coal resources.
07/23 08/23	2023-89-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Progress, LLC	Securitization financing, quantifiable net benefits, regulatory liability for return on ADIT, financing order and tariff language for calculation of storm recovery charges.
08/23	U-36685	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Certification of solar PPAs and related ratemaking.
09/23	6680-UR-124 Direct Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Ratemaking alternatives for recovery of retired plant costs, including securitization financing.
09/23	05-UR-110 (Reopener) Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Ratemaking alternatives for recovery of retired plant costs, including securitization financing.
10/23	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 prudence.
10/23	2023-00159	KY	Attorney General Kentucky Industrial Utility Customer, Inc.	Kentucky Power Company	NOL, COR, and other ADIT, incentive comp, regulatory assets, transmission and distribution cost riders, CAMT and other IRA, tax costs rider, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/23 02/24	2021-00370 Direct Rebuttal	KY	Attorney General Kentucky Industrial Utility Customer, Inc.	Kentucky Power Company	Investigation into adequacy of service and reasonableness of rates.
02/24	2023-00008	KY	Attorney General Kentucky Industrial Utility Customer, Inc.	Kentucky Power Company	Fuel adjustment clause; fuel and purchased power expense; peaking unit equivalent methodology.
03/24	05-23-001513	TX	Cities Served by CenterPoint Gas	CenterPoint Energy Resources Corp.	Capital structure, Tax Rider, NOL ADIT, CAMT ADIT, annualize revenues, incentive compensation, vendor financing, customer financing, working capital.
05/24	56165	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Tax Rider, NOL ADIT, CAMT ADIT, annualize revenues, incentive compensation, vendor financing, customer financing, working capital.
05/24	U-37071	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	RFT for solar resources; certification of Mondu PPA.
06/24	2024-34-E	SC	Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Working capital, cash working capital.

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37. **Planned Maintenance**. For Tampa Electric Company, please provide for each of the years 2019 through 2023 and for 2024 year to date the actual and budgeted planned generation maintenance by unit with explanations for any variances of more than 15%. Provide a comparable summary for the requested generation maintenance, by unit, for intermediate projected year 2024, and projected test year December 31, 2025.

ANSWER: The tables attached provide the actual and budgeted planned generation maintenance by unit with explanations for any variances of more than 15 percent for the years 2019 through 2023 and for 2024 year to date. Additionally, this table includes a comparative summary for the requested generation maintenance, by unit for the intermediate projected test year 2024 and projected test year December 31, 2025.

Planned Outage
Operations & Mainteance

2019		**Actual**	**Budget**	**Variance**	**%**	**Explanation**
Station	**Unit**					
Big Bend	BB1	204.9	489.0	284.1	58%	Scope reductions with units approaching retirement.
Big Bend	BB2	363.3	489.0	125.7	26%	Scope reductions with units approaching retirement.
Big Bend	BB3	2,863.0	2,674.3	(188.7)	-7%	
Big Bend	BB4	2,356.8	1,700.0	(656.8)	-39%	Upon inspection, additional motor and backpass maintenance required.
Big Bend	BB Aero	75.7	100.0	24.3	24%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,744.2	900.0	(844.2)	-94%	Upon inspections, additional repairs on the 1A, B & C HRSG high pressure steam section, and 1C intermediate pressure steam section; and condenser\tunnel cleaning
Bayside	BS2	1,780.0	900.0	(880.0)	-98%	Upon inspections, additional repairs for control systems; Phase Bus; HRSG reheat section piping\drain values, outlet headers; and condenser inlet tunnel, waterbox & debris filter
Bayside	BS Aero	297.5	320.0	22.5	7%	
Polk	PK1	1,013.0	1,075.0	62.0	6%	
Polk	PK2	237.1	187.5	(49.6)	-26%	Upon inspection, additional HRSG drums, breakers and valves maintenance needed.
Polk	PK3	178.9	187.5	8.6	5%	
Polk	PK4	182.0	187.5	5.5	3%	
Polk	PK5	178.5	187.5	9.0	5%	
	Total	11,474.9	9,397.3	(2,077.6)		

2020		**Actual**	**Budget**	**Variance**	**%**	**Explanation**
Station	**Unit**					
Big Bend	BB1	4.8	-	(4.8)	0%	
Big Bend	BB2	184.6	400.0	215.4	54%	Scope reductions with units approaching retirement.
Big Bend	BB3	488.5	400.0	(88.5)	-22%	Upon inspection, additional boiler feed pump and bearing maintenance required.
Big Bend	BB4	6,778.7	6,166.8	(611.9)	-10%	
Big Bend	BB Aero	117.1	95.0	(22.1)	-23%	Upon inspection, additional battery load testing required.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,270.5	1,055.0	(215.5)	-20%	upon inspection, found steam turbine had water induction for hotwell, additional costs to clean and inspect oils systems and equipment
Bayside	BS2	1,656.8	1,060.0	(596.8)	-56%	Upon inspection, repairs to high energy piping including insulation lagging and scaffolding
Bayside	BS Aero	211.3	275.0	63.7	23%	annual unit audits and bore scope inspections

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Polk	PK1	308.6	600.0	291.4	49%	Covid related delayed outages, lead times
Polk	PK2	328.1	400.0	71.9	18%	Covid related delayed outages, lead times
Polk	PK3	75.7	148.7	73.0	49%	Covid related delayed outages, lead times
Polk	PK4	99.1	155.7	56.6	36%	Covid related delayed outages, lead times
Polk	PK5	225.7	400.0	174.3	44%	Covid related delayed outages, lead times
	Total	11,749.6	11,156.2	(593.4)		

2021		Actual	Budget	Variance	%	Explanation
Station	Unit					
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	0.0	200.0	200.0	100%	Scope reductions with units approaching retirement.
Big Bend	BB3	42.3	400.0	357.7	89%	Scope reductions with unit approaching retirement.
Big Bend	BB4	4,960.0	800.0	(4,160.0)	-520%	Scope increase after budget due to natural gas conversion. (1)
Big Bend	BB Aero	30.3	150.0	119.7	80%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,505.1	930.0	(575.1)	-62%	upon inspection, additional repairs for electrical equipment ; control systems; steam header; and condenser inlet tunnel, waterbox & debris filter
Bayside	BS2	1,841.0	935.0	(906.0)	-97%	upon inspection, additional repairs for electrical equipment ; control systems; air inlet systems; exhaust systems; steam header, piping & drains; and condenser inlet tunnel, waterbox & traveling screens
Bayside	BS Aero	236.1	275.0	38.9	14%	
Polk	PK1	262.3	500.0	237.7	48%	Upon inspection, LP economizers needed replacing not maintenance.
Polk	PK2	300.3	165.0	(135.3)	-82%	Upon inspection, additional HRH steam bypass valve, scc dampers, and port consolidation oil maintenance needed.
Polk	PK3	568.7	400.0	(168.7)	-42%	Upon inspection, additional Hot gas path, and APE electrical equipment maintenance needed.
Polk	PK4	371.2	400.0	28.8	7%	
Polk	PK5	176.7	165.0	(11.7)	-7%	
	Total	10,294.0	5,320.0	(4,974.0)		

2022		Actual	Budget	Variance	%	Explanation
Station	Unit					
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	-	-	-	0%	
Big Bend	BB3	60.3	100.0	39.7	40%	Scope reductions with unit approaching retirement.
Big Bend	BB4	513.7	900.0	386.3	43%	Scope reductions due to strong unit performance and past work.
Big Bend	BB Aero	103.0	154.5	51.5	33%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	0%	
Big Bend	BBCT6	-	-	-	0%	

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Big Bend	BBST	-	-	-	0%	
Bayside	BS1	7,833.4	6,380.1	(1,453.3)	-23%	Outage work scope estimate increase due to higher labor rates, material costs due to supply chain issues, overtime due to schedule constraints, and higher planning and outage support costs. Inspection also resulted in additional work scope for steam turbine auxiliaries; condenser inlet tunnel, waterbox & debris filters; HRSG and blow down tanks inspections\repairs; and boiler feed pump motor overhauls.
Bayside	BS2	2,145.6	1,785.1	(360.5)	-20%	upon inspection, additional repairs for HRSG steam headers, drums & piping; circulating water pumps & motors; and condensers. Also, there was higher labor rates and material costs due to supply chain issues.
Bayside	BS Aero	64.5	275.0	210.5	77%	The amount listed ($64.5k) for 2022 Aero outages is not correct. Actual 2022 Aero outage was $355.6k, or $80.6k higher than then $275K budget. The actual spend was for inspections and Unit alignments.
Polk	PK1	517.9	1,000.0	482.1	48%	Due to run hour reductions, less maintenance was needed during planned outages.
Polk	PK2	414.0	190.0	(224.0)	-118%	Upon inspection, additional switchgear, dampers and verticle pole switch needed.
Polk	PK3	128.7	190.0	61.3	32%	Upon inspection, less equipment maintenance required after 2021 Outages.
Polk	PK4	94.9	190.0	95.1	50%	Upon inspection, less equipment maintenance required after 2021 Outages.
Polk	PK5	201.4	190.0	(11.4)	-6%	
	Total	12,077.3	11,354.6	(722.7)		

2023		Actual	Budget	Variance	%	Explanation
Station	Unit					
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	-	-	-	0%	
Big Bend	BB3	-	-	-	0%	
Big Bend	BB4	3,564.9	2,379.8	(1,185.1)	-50%	Upon inspection, additional precipitator, boiler and stack maintenance required.
Big Bend	BB Aero	323.2	177.0	(146.2)	-83%	Unbudgeted maintenance to meet unexpected new environmental regulations (Formaldehyde).
Big Bend	BBCT5	118.5	102.5	(16.0)	-16%	First year of commercial operations, discovery led to additional fire alarm maintenance.
Big Bend	BBCT6	148.0	102.5	(45.5)	-44%	First year of commercial operations, discovery led to additional transformer maintenance.
Big Bend	BBST	316.3	127.5	(188.8)	-148%	First year of commercial operations, discovery led to additional HRSG matinenance.
Bayside	BS1	613.7	1,800.0	1,186.3	66%	reduced scope due to prior year's extensive outage
Bayside	BS2	2,299.0	9,000.0	6,701.0	74%	reduced O&M work due to physical work area inferences with large capital project actives - 2023 fall outage was heavy with capital projects and O&M actives were deferred to a second 2024 spring major outage
Bayside	BS Aero	464.3	450.0	(14.3)	-3%	
Polk	PK1	179.5	280.9	101.4	36%	Maintenance needed during planned outages.
Polk	PK2	476.3	302.8	(173.5)	-57%	Upon inspection, additional switchgear, attemperator valve, NH3 tank repair and HRSG maintenance needed.
Polk	PK3	188.7	302.8	114.1	38%	Maintenance needed during planned outages.
Polk	PK4	507.7	354.7	(153.1)	-43%	Upon inspection, additional switchgear, transformer and motor maintenance needed.
Polk	PK5	284.3	354.7	70.3	20%	Maintenance needed during planned outages.

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	Total	9,484.3	15,735.1	6,250.7

Station	Unit	2024 YTD	2024 FY	2025 FY
Big Bend	BB1	-	-	-
Big Bend	BB2	-	-	-
Big Bend	BB3	-	-	-
Big Bend	BB4	-	800.0	2,000.0
Big Bend	BB Aero	-	250.0	262.5
Big Bend	BBCT5	-	100.0	105.0
Big Bend	BBCT6	-	100.0	105.0
Big Bend	BBST	-	150.0	157.5
Bayside	BS1		1,800.0	7,200.0
Bayside	BS2		8,200.0	2,200.0
Bayside	BS Aero		600.0	600.0
Polk	PK1	-	200.0	-
Polk	PK2	-	446.0	9,500.0
Polk	PK3	-	223.0	1,025.0
Polk	PK4	-	223.0	1,025.0
Polk	PK5	-	223.0	1,025.0
	Total	-	13,315.0	25,205.0

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22. **Benefits.** For each benefit cost charged by, or allocated to Tampa Electric Company, please provide the annual level of each separate benefit cost broken down between expensed, capitalized and other for 2020, 2021, 2022, 2023 and 2024 to date along with a comparison of the benefit costs in projected intermediate year 2024, and projected test year 2025.

ANSWER: Please see Tampa Electric's annual level of each separate benefit cost broken down between expensed, capitalized, and other for the requested years in the attached table.

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	2025	2024				
	Budget	YTD Expense	YTD Capital	YTD Other	YTD Total	Budget - Full year
Benefits Plan Admin Fee	317	30	17	4	51	306
Tuition Reimbursement	223	12	6	1	20	215
Life Insurance	369	49	28	6	83	356
Long Term Care Insurance	149	14	7	2	23	144
Medical & Dental Insurance	33,719	3,428	1,865	414	5,707	32,500
Pension Plan	1,217	-	-	-	-	(1,175)
Postretirement Medical (FAS 106 Active)	2,004	-	-	-	-	1,605
Wellness program	156	11	6	1	19	150
Employer 401K Fixed Match	8,534	791	431	95	1,317	8,225
Employer 401K-IBEW Plan	10,255	982	535	119	1,636	9,884
Long Term Disability Premium	1,245	111	63	14	188	1,200
Emplr Match Stock Purchase	502	77	26	6	108	498
Benefits - Other	-	-	-	-	-	-
Service awards	125	11	6	1	18	120
Insurance-Workers Compensation	653	-	-	100	100	629
Gross Fringe Benefits (less FICA/unemployment taxes)	**59,468**	**5,515**	**2,990**	**762**	**9,268**	**54,657**
Postretirement Medical (FAS 106 Retiree)	3,388	-	-	-	-	2,715
LT Incentive Expense	6,825	-	-	-	-	6,373
Employee Def Comp	-	-	-	-	-	-
Employer 401K Performance Match	-	-	-	-	-	-
Supplemental Executive Retirement Plan	107	(36)	-	-	(36)	117
Long-term disability	1,868	200	-	-	200	1,800
Vacation	1,245	200	-	-	200	1,200
Restoration Plan	130	-	-	-	-	228
Benefits not included in fringe	**$ 13,563**	**$ 364**	**$ -**	**$ -**	**$ 364**	**$ 12,432**
Total Benefits	**$ 73,031**	**$ 5,879**	**$ 2,990**	**$ 762**	**$ 9,632**	**$ 67,089**

	2023				2022			
	Expense	Capital	Other	Total	Expense	Capital	Other	Total
Benefits Plan Admin Fee	258	146	31	435	198	99	25	323
Tuition Reimbursement	120	68	15	204	103	54	14	170
Life Insurance	259	147	32	438	275	144	36	455
Long Term Care Insurance	89	49	11	149	77	41	11	128
Medical & Dental Insurance	17,588	9,787	2,199	29,574	19,599	9,856	2,535	31,991
Pension Plan	(957)	(528)	(116)	(1,602)	1,497	783	197	2,477
Postretirement Medical (FAS 106 Active)	1,137	627	138	1,902	2,182	1,101	287	3,570
Wellness program	72	42	10	124	82	40	10	132
Employer 401K Fixed Match	4,799	2,685	597	8,081	4,399	2,210	574	7,183
Employer 401K-IBEW Plan	5,925	3,319	733	9,977	6,419	3,239	835	10,493
Long Term Disability Premium	820	463	102	1,385	606	324	84	1,014
Emplr Match Stock Purchase	162	93	21	276	208	114	28	350
Benefits - Other	-	-	-	-	-	-	-	-
Service awards	38	21	5	65	40	22	6	67
Insurance-Workers Compensation	390	209	30	628	403	195	32	631
Gross Fringe Benefits (less FICA/unemployment taxes)	**30,700**	**17,127**	**3,807**	**51,636**	**36,088**	**18,222**	**4,674**	**58,984**
Postretirement Medical (FAS 106 Retiree)	2,817	-	-	2,817	4,528	-	-	4,528
LT Incentive Expense	3,599	-	3 30	3,929	4,902	-	484	5,386
Employee Def Comp	-	-	-	-	109	-	-	109
Employer 401K Performance Match	98	54	13	164	1,145	487	126	1,759
Supplemental Executive Retirement Plan	1,092	-	-	1,092	804	-	-	804
Long-term disability	3,328	-	-	3,328	(347)	-	-	(347)
Vacation	1,662	-	-	1,662	1,280	-	-	1,280
Restoration Plan	1,200	-	-	1,200	543	-	-	543
Benefits not included in fringe	**$ 13,795**	**$ 54**	**$ 343**	**$ 14,192**	**$ 12,964**	**$ 487**	**$ 610**	**$ 14,062**
Total Benefits	**$ 44,496**	**$ 17,181**	**$ 4,150**	**$ 65,828**	**$ 49,052**	**$ 18,710**	**$ 5,284**	**$ 73,046**

	2021				2020			
	Expense	Capital	Other	Total	Expense	Capital	Other	Total
Benefits Plan Admin Fee	236	121	31	388	165	82	39	286
Tuition Reimbursement	127	66	16	208	143	69	34	246
Life Insurance	270	140	36	447	255	125	60	440
Long Term Care Insurance	71	37	10	118	64	31	15	110
Medical & Dental Insurance	19,184	9,969	2,571	31,724	14,556	6,970	3,147	24,673
Pension Plan	3,802	2,011	510	6,322	5,419	2,659	1,279	9,357
Postretirement Medical (FAS 106 Active)	2,618	1,386	356	4,360	1,643	806	387	2,836
Wellness program	54	28	7	89	53	27	13	94
Employer 401K Fixed Match	4,750	2,498	643	7,890	4,231	2,085	1,001	7,317
Employer 401K-IBEW Plan	5,729	3,031	777	9,536	5,327	2,602	1,247	9,176
Long Term Disability Premium	768	403	102	1,273	714	352	168	1,233
Emplr Match Stock Purchase	269	143	37	448	157	78	44	279
Benefits - Other	(1)	(1)	(0)	(2)	(5)	-	-	(5)
Service awards	60	33	9	102	77	38	19	135
Insurance-Workers Compensation	405	203	32	640	336	157	58	551
Gross Fringe Benefits (less FICA/unemployment taxes)	**38,340**	**20,069**	**5,135**	**63,543**	**33,134**	**16,080**	**7,511**	**56,727**
Postretirement Medical (FAS 106 Retiree)	5,021	-	-	5,021	3,031	-	-	3,031
LT Incentive Expense	3,567	(0)	317	3,883	6,601	3	497	7,100
Employee Def Comp	193	-	-	193	43	-	-	43
Employer 401K Performance Match	626	342	80	1,048	1,321	698	420	2,439
Supplemental Executive Retirement Plan	316	-	-	316	197	0	2	199
Long-term disability	1,935	-	-	1,935	3,408	-	-	3,408
Vacation	(1,275)	-	-	(1,275)	2,610	-	-	2,610
Restoration Plan	386	-	-	386	334	-	-	334
Benefits not included in fringe	**$ 10,768**	**$ 342**	**$ 396**	**$ 11,506**	**$ 17,545**	**$ 701**	**$ 919**	**$ 19,165**
Total Benefits	**$ 49,108**	**$ 20,411**	**$ 5,531**	**$ 75,049**	**$ 50,680**	**$ 16,782**	**$ 8,430**	**$ 75,892**

Included in benefit costs "other" are costs that were allocated/assessed or direct charged to other affiliates.
Figures shown in 000's
Totals may be affected due to rounding.

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 SERVED: May 20, 2024

TAMPA ELECTRIC COMPANY'S
RESPONSE TO OFFICE OF PUBLIC COUNSEL'S
<u>TENTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 121-132)</u>

Pursuant to Rule 106.206, Florida Administrative Code, and Florida Rule of Civil Procedure 1.350, Tampa Electric Company ("Tampa Electric" or "the company"), hereby responds to Office of Public Counsel's Tenth Request for Production of Documents (Nos. 121-132), served April 30, 2024 ("OPC Tenth POD").

General Objections

1. Tampa Electric objects to each Request for Production in OPC's Tenth POD ("Request") to the extent that it seeks information that is duplicative, not relevant to the subject matter of this docket, and is not reasonably calculated to lead to the discovery of admissible evidence.

2. Tampa Electric objects to each Request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such Requests. Tampa Electric will seek clarification from

Response: Tampa Electric's non-confidential electronic documents responsive to this request will be served by posting on the SharePoint in the folder entitled "POD_10_123."

124. Refer to Schedule C-6 Page 6 of 6 account 411.4 Investment Tax Credit – Curr and account 411.5 Investment Tax Credit – Amort.

a. If the Company netted the amortization amounts into account 411.4 Investment Tax Credit – Curr, then provide a revised version of this schedule where the deferral and the amortization are shown separately and in the correct accounts.

b. Provide a supplemental schedule that shows the deferrals by asset/project and the amortization associated with each new asset/project starting in 2022 and the residual for everything else in service prior to 2022.

Response:

Tampa Electric's non-confidential electronic documents responsive to this request will be served by posting on the SharePoint in the folder entitled "POD_10_124."

With regard to item (a), prior to 2024, the Company included both deferral and amortization of the deferred Investment Tax Credit ("ITC") in account 411.4. On the originally filed C-6 schedule, the Company changed its methodology for 2024 and the 2025 test year to include deferral of the deferred ITC in account 411.1 and amortization of the deferred ITC in account 411.4. In the revised version of the Schedule C-6 attached to this POD request, we have made this adjustment for all other time periods requested, as well as renaming 411.4 to "Investment Tax Credit – Amort" and 411.5 to "Investment Tax Credit – Amort (NU)" to better represent the activity within both line items.

With respect to item (b), please see attachment.

125. Refer to Schedule C-17 Pension Cost.

a. Provide an annual history of pension cost separated into pension expense and pension capitalized for the years 2016 through 2025.

b. Provide an annual history of OPEB cost separated into OPEB expense and OPEB capitalized for the years 2016 through 2025.

c. Provide an annual history of payroll and each related payroll tax cost separated into payroll and each related payroll tax expense and payroll and each related payroll tax capitalized for the years 2016 through 2025. Cross reference the payroll tax expensed provided in your response to the payroll tax expense shown on Schedule C-20 for each year 2023 through 2025 and reconcile any differences.

Response:

Tampa Electric's non-confidential electronic documents responsive to this request will be served by posting on the SharePoint in the folder entitled "POD_10_125."

126. Refer to Schedule C-20, page 1 line 10 and the $90.807 million in total Company property tax expense shown for the test year ended December 31, 2025.

a. Provide a copy of the computation of this test year amount, including all assumptions, data, and quantifications in Excel live format with all formulas intact.

b. Provide the total Company property tax amounts recorded as expense for each calendar year 2020 through 2023.

Response:

Tampa Electric's non-confidential electronic documents responsive to this request will be served by posting on the SharePoint in the folder entitled "POD_10_126."

127. Refer to Schedule C-20, page 2 line 10 and the $88.503 million in total Company property tax expense for the projected prior year ended December 31, 2024. Provide a copy of the computation of this projected prior year amount including all assumptions, data, and quantifications in Excel live format with all formulas intact.

Response:

Tampa Electric's non-confidential electronic documents responsive to this request will be served by posting on the SharePoint in the folder entitled "POD_10_127."

128. Refer to Schedule C-27 and the reference to the tax sharing agreement. Provide a copy of the most recent and the immediately prior version of this agreement.

Response:

Please see Tampa Electric's response to OPC's First Request for Production of Documents, No. 24. This is the most recent tax sharing agreement. There is no prior EUSHI tax sharing agreement.

129. Refer to Schedule C-21 Rent from Electric Property. Provide a schedule showing the history of the budget and actual revenue amounts in this account annually for the years 2016 through the test year by category and/or activities.

	2025 Budget				2024 Budget				2023 Actual				2022 Actual				2021 Actual			
	Expense	Capital	Other	Total	Expense	Capital	Other	Total	Expense	Capital	Other	Total	Expense	Capital	Other	Total	Expense	Capital	Other	Total
a. Pension				1,217				(1,175)	(997)	(528)	(76)	(1,602)	1,568	783	126	2,477	4,000	2,011	311	6,322
b. OPEB																				
Active				2,004				1,605	1,184	627	90	1,902	2,285	1,101	184	3,570	2,753	1,386	220	4,360
Retiree				3,388				2,715	2,817	-	-	2,817	4,528	-	-	4,528	5,021	-	-	5,021
Total OPEB	-	-	-	5,392	-	-	-	4,320	4,002	627	90	4,719	6,813	1,101	184	8,098	7,774	1,386	220	9,381
c. Gross payroll				296,005				294,064				289,309				287,676				260,320
FICA	15,865	5,936	-	21,801	15,450	6,208	-	21,658	13,134	8,174	-	21,308	14,329	5,707	-	20,036	14,727	4,867	-	19,594
Federal Unemployment	72	35	-	107	72	35	-	107	80	36	-	116	82	32	-	114	84	28	-	112
State Unemployment	20	10	-	30	20	10	-	30	20	9	-	29	21	8	-	29	16	5	-	21

	2020 Actual				2019 Actual			
	Expense	Capital	Other	Total	Expense	Capital	Other	Total
a. Pension	5,419	2,659	1,279	9,357	4,358	2,502	1,058	7,918
b. OPEB								
Active	1,643	806	387	2,836	1,203	692	291	2,187
Retiree	3,031	-	-	3,031	3,692	-	-	3,692
Total OPEB	4,674	806	387	5,867	4,895	692	291	5,879
c. Gross payroll				267,105				210,733
FICA	14,221	4,959	-	19,180	10827	4403	-	15,230
Federal Unemployment	81	28	-	109	65	27	-	92
State Unemployment	13	5	-	18	13	5	-	18

	2018 Actual				2017 Actual				2016 Actual			
	Expense	Capital	Other	Total	Expense	Capital	Other	Total	Expense	Capital	Other	Total
a. Pension	6,360	3,064	1,476	10,900	6,412	2,714	1,474	10,599	6,758	2,819	464	10,041
b. OPEB												
Active	1,220	589	283	2,092	822	347	189	1,357	1,001	419	68	1,489
Retiree	5,122	-	-	5,122	3,670	-	-	3,670	4,025	-	-	4,025
Total OPEB	6,342	589	283	7,213	4,492	347	189	5,027	5,026	419	68	5,514
c. Gross payroll				210,455				199,710				191,320
FICA	10677	4002	-	14,679	10811	3421	-	14,232	10761	3296	-	14,057
Federal Unemployment	68	25	-	93	69	22	-	91	69	21	-	90
State Unemployment	23	8	-	31	40	12	-	52	57	18	-	75

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INTERROGATORIES
INTERROGATORY NO. 167
BATES PAGE(S): 30083
MAY 20, 2024**

167. Refer to Schedule C-17 Pension Cost.

a. Explain why none of the Company's pension cost is capitalized. Address why pension cost does not follow or track the allocation of payroll dollars between expense and capital.

b. Indicate whether any of the Company's OPEB cost is capitalized. If not, then address why OPEB cost does not follow or track the allocation of payroll dollars between expense and capital.

c. Indicate separately for pension and OPEB costs whether some portion is capitalized for income tax purposes, e.g., pursuant to Section 163 of the IRC. If so, describe the manner in which the Company calculates the portion of the pension and OPEB costs that are capitalized for income tax purposes, e.g., payroll dollars expensed and capitalized.

ANSWER:

a. A portion of pension cost is capitalized through the fringe rate. MFR Schedule C-17 reflects the cost in O&M as all benefits costs are initially posted to FERC Account 926. The fringe rate subsequently follows the allocation of labor dollars and posts a FERC Account 926 credit with the offset in capital for those payroll dollars that are capitalized.

b. A portion of the active employee OPEB cost is capitalized through the fringe rate. MFR Schedule C-17 reflects the cost in O&M as all benefits costs are initially posted to FERC Account 926. The fringe rate subsequently follows the allocation of labor dollars and posts a FERC Account 926 credit with the offset in capital for those payroll dollars that are capitalized.

c. A portion of the pension and active employee OPEB costs are capitalized for income tax purposes. To calculate the capitalized portion, we apply a capitalization rate to the pension and active employee OPEB costs paid during the year.

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BATES PAGE(S): 13287
APRIL 11, 2024

15. **Incentive Compensation.** For Tampa Electric Company, please provide the level of related incentive compensation bonus payments included in projected intermediate year 2024, and projected test year ending December 31, 2025.

ANSWER: Please see the table below for the company's short-term incentive plan ("STIP") and long-term incentive plan ("LTIP") costs for the projected year 2024 and for the projected test year 2025. These projected amounts were calculated assuming that the target goals will be met, but not exceeded.

The totals of the Tampa Electric Expense and Gross Shared Services Expense for STIP and LTIP in years 2024 and 2025 are the amounts reflected in Marian Cacciatore's direct testimony. 25.77 percent and 27.93 percent of the Gross Shared Services Expense amount are expected to be allocated to other operating entities in 2024 and 2025, respectively. Additionally, there are expenses related to seconded employees, deferred compensation, and employee options that are added to this amount to arrive at the total Tampa Electric expense as shown below. A seconded employee is defined as an employee who is on a full time, temporary assignment to a host affiliate. The employee remains on their homebased payroll, pension, and benefits, and compensation is tax equalized to their home country. Please see Tampa Electric's response to OPC's Request for Production of Documents No. 30 for a detailed description of these stock compensation incentives.

	2024		2025	
	STIP	LTIP	STIP	LTIP
Tampa Electric Expense	21,733,000	4,346,188	22,547,988	4,713,936
Gross Shared Services Expense	5,453,850	2,026,572	5,658,372	2,111,448
	27,186,850	6,372,760	28,206,360	6,825,384
Shared Services Allocated to other companies	(1,405,457)	(522,248)	(1,580,383)	(589,727)
Seconded Employee Expense	427,616	854,678	460,756	937,464
Total Tampa Electric Expense	**26,209,009**	**6,705,190**	**27,086,733**	**7,173,121**

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16. **Stock Based Compensation**. Please list, by amount and account, all stock-based compensation expense that that Tampa Electric Company has included in cost of service for the years 2020 through 2023, projected intermediate year 2024, projected test year ending December 31, 2025, and including, but not limited to executive stock options, performance share awards and any other stock-based compensation awards that will result in such costs being charged to Tampa Electric Company during the projected test year. In addition, provide a description of each distinct stock-based compensation program that will result in charges to Tampa Electric Company during the test year.

ANSWER: The company's two stock-based compensation programs that will be in effect during the test year are the Performance Share Unit Plan ("PSU") and the Restricted Share Unit Plan ("RSU"). Under the PSU and RSU plans, certain executive and senior employees are eligible for long term incentives. Both are granted annually for three-year overlapping performance cycles, resulting in a cash payment. Both are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs or RSUs in accordance with the Plan. The PSU value varies according to the Emera common Share market price and corporate performance. The RSU value varies according to the Emera common share market price. PSUs and RSUs vest at the end of the three-year cycle.

Deferred Share Unit Plans ("DSU")

Under the executive and senior management DSU plan, each participant may elect to defer all or a portion of their annual incentive award in the form of DSUs. Under the Directors' DSU plan, Directors of the company may elect to receive all or any portion of their compensation in the form of DSUs in lieu of cash compensation. When DSU awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of shares. DSUs are granted fully vested and will only payout when the participant leaves the company.

Stock Options

Options are granted to senior management of the company. Stock options granted in 2021 and prior vest in 25 percent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 percent increments on the first, second, third, fourth and fifth anniversaries of the date of the grant. The options have

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a maximum term of 10 years. The company uses the Black-Scholes valuation model to estimate compensation expense related to its stock-based compensation; however, if the ratio is less than 10 percent, the company applies a 10 percent floor (10 percent of the closing share price on the day prior to the grant date). Once options expire, they are forfeited.

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Budget	2025 Budget
EE PSU/RSU	7,100,474.06	3,882,923.22	5,386,090.05	4,003,562.34	6,372,755.00	6,825,382.00
EE DSU	43,480.89	192,706.23	108,685.72	-	-	-
DIR DSU	62,955.14	206,777.80	(361,859.46)	(3,514.83)	343,040.30	401,408.21
EE Option	19,573.63	13,925.66	7,679.25	933.43	-	-
Secondments	1,652,039.60	1,626,733.17	1,146,695.21	623,923.27	854,677.61	937,464.18
Total	**8,878,523.32**	**5,923,066.08**	**6,287,290.77**	**4,624,904.21**	**7,570,472.91**	**8,164,254.39**

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17. Supplemental Employee Retirement Plan (SERP). Please provide the level of SERP expense, by account, included in Tampa Electric Company's cost of service for each of the years 2020 through 2023, projected intermediate year 2024, and projected test year ending December 31, 2025.

ANSWER: The level of SERP expense included in Tampa Electric Company's cost of service for years 2020 – 2023 was as follows:

2020 - $199,215
2021 - $316,255
2022 - $803,523
2023 - $1,323,349

Based on calculations prepared by the company's actuary, Mercer, the expense included in projected year 2024 is $117,008 and the expense included in projected test year 2025 is $106,816. Please see the company's answer to Interrogatory No. 22, below, for the SERP benefit cost broken down between expensed, capitalized, and other.

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34. Directors and Officers Liability Insurance.

a. Has Tampa Electric Company included any amounts in rate base for Directors and Officers liability insurance in 2023, intermediate projected year 2024, and projected test year December 31, 2025? If so, please identify by amount and account.

b. Has Tampa Electric Company included any amounts in operating expense for Directors and Officers liability insurance? If so, please identify by amount and account.

c. Please identify the cost and coverage for each Directors and Officers liability insurance policy that was in effect during each year 2021, 2022 and 2023.

d. Does Tampa Electric Company record any amounts for Directors and Officers liability insurance as prepaids? If not, explain fully why not. If so, please show the monthly amounts for January 1, 2022 through the present.

ANSWER:

a. Yes. Tampa Electric Company included amounts in rate base for Directors and Officers liability insurance in 2023, projected year 2024 and projected test year 2025. Directors and Officers Liability is within FERC account 165 and the amounts included in rate base for the years 2023, 2024, and 2025 are approximately $130 thousand, $128 thousand, and $128 thousand, respectively.

b. Yes. Tampa Electric Company included amounts in operating expense for Directors and Officers liability insurance in 2023, projected year 2024, and projected test year 2025. Directors and Officers Liability recorded operating expenses within FERC account 925 and the amounts included in net operating income for the years 2023, 2024, and 2025 are approximately $309 thousand, $303 thousand, and $303 thousand, respectively.

c. Please see tables below showing cost and coverage for each Directors and Officers liability insurance policy for the years 2021, 2022, and 2023.

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2021 Directors and Officers Policy

Coverage	Insurer	Coverage Limit	Retention	Policy Period	Amount
Directors And Officers Policy	Chubb	15MM	500K	12/31/2020 - 12/31/2021	101,533.29
D&O 1st Excess Policy	AIG	15MM x/s of $15MM	N/A	12/31/2020 - 12/31/2021	71,076.00
D&O 2nd Excess Policy	Berkshire	15MM x/s of $30MM	N/A	12/31/2020 - 12/31/2021	50,093.35
D&O 3rd Excess Policy	Zurich	15MM x/s of $45MM	N/A	12/31/2020 - 12/31/2021	35,065.34
D&O 4th Excess Policy	AWAC	10MM x/s of $60MM	N/A	12/31/2020 - 12/31/2021	18,044.38
D&O 5th Excess Policy	Markel	10MM x/s of $70MM	N/A	12/31/2020 - 12/31/2021	13,465.95
D&O 6th Excess Policy	Swiss Re	10MM x/s of $80MM	N/A	12/31/2020 - 12/31/2021	13,465.95
D&O 7th Excess Policy	Travelers	10MM x/s of $90MM	N/A	12/31/2020 - 12/31/2021	13,465.95
D&O 8th Excess Policy	Arch	10MM x/s of $100MM	N/A	12/31/2020 - 12/31/2021	13,465.95
D&O 9th Excess Policy	Everest	10MM x/s of $110MM	N/A	12/31/2020 - 12/31/2021	13,465.95
D&O 10th Excess Policy	Lloyd's	15MM x/s of $120MM	N/A	12/31/2020 - 12/31/2021	20,198.93
D&O 11th Excess Policy	AXIS	15MM x/s of $135MM	N/A	12/31/2020 - 12/31/2021	17,505.74
					380,846.81

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2022 Directors and Officers Policy

Coverage	Insurer	Coverage Limit	Retention	Policy Period	Amount
Directors And Officers Policy	Chubb	15MM	500K	12/31/2021 - 12/31/2022	115,495.78
D&O 1st Excess Policy	AIG	15MM x/s of $15MM	N/A	12/31/2021 - 12/31/2022	80,846.73
D&O 2nd Excess Policy	Berkshire	15MM x/s of $30MM	N/A	12/31/2021 - 12/31/2022	56,954.48
D&O 3rd Excess Policy	Zurich	15MM x/s of $45MM	N/A	12/31/2021 - 12/31/2022	39,867.90
D&O 4th Excess Policy	AWAC	10MM x/s of $60MM	N/A	12/31/2021 - 12/31/2022	20,515.68
D&O 5th Excess Policy	Markel	10MM x/s of $70MM	N/A	12/31/2021 - 12/31/2022	15,310.36
D&O 6th Excess Policy	Swiss Re	10MM x/s of $80MM	N/A	12/31/2021 - 12/31/2022	15,310.36
D&O 7th Excess Policy	Travelers	10MM x/s of $90MM	N/A	12/31/2021 - 12/31/2022	15,310.36
D&O 8th Excess Policy	Arch	10MM x/s of $100MM	N/A	12/31/2021 - 12/31/2022	15,310.36
D&O 9th Excess Policy	Everest	10MM x/s of $110MM	N/A	12/31/2021 - 12/31/2022	15,310.36
D&O 10th Excess Policy	Lloyd's	15MM x/s of $120MM	N/A	12/31/2021 - 12/31/2022	20,877.77
D&O 11th Excess Policy	CNA	15MM x/s of $135MM	N/A	12/31/2021 - 12/31/2022	18,094.06
					429,204.20

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2023 Directors and Officers Policy

Coverage	Insurer	Coverage Limit	Retention	Policy Period	Amount
Directors And Officers Policy	Chubb	15MM	500K	12/31/2022 - 12/31/2023	110,833.59
D&O 1st Excess Policy	AIG	15MM x/s of $15MM	N/A	12/31/2022 - 12/31/2023	77,583.21
D&O 2nd Excess Policy	Berkshire	15MM x/s of $30MM	N/A	12/31/2022 - 12/31/2023	54,655.07
D&O 3rd Excess Policy	Zurich	15MM x/s of $45MM	N/A	12/31/2022 - 12/31/2023	38,258.70
D&O 4th Excess Policy	AWAC	10MM x/s of $60MM	N/A	12/31/2022 - 12/31/2023	19,687.59
D&O 5th Excess Policy	Markel	10MM x/s of $70MM	N/A	12/31/2022 - 12/31/2023	14,692.13
D&O 6th Excess Policy	Swiss Re	10MM x/s of $80MM	N/A	12/31/2022 - 12/31/2023	14,692.13
D&O 7th Excess Policy	Travelers	10MM x/s of $90MM	N/A	12/31/2022 - 12/31/2023	14,692.13
D&O 8th Excess Policy	Arch	10MM x/s of $100MM	N/A	12/31/2022 - 12/31/2023	14,692.13
D&O 9th Excess Policy	Everest	10MM x/s of $110MM	N/A	12/31/2022 - 12/31/2023	14,692.13
D&O 10th Excess Policy	Lloyd's	15MM x/s of $120MM	N/A	12/31/2022 - 12/31/2023	16,962.94
D&O 11th Excess Policy	CNA	15MM x/s of $135MM	N/A	12/31/2022 - 12/31/2023	14,425.11
					405,866.87

**TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 34
BATES PAGE(S): 13329 - 13333
APRIL 11, 2024**

d. Yes**.** Tampa Electric Company does record amounts for Directors and Officers liability insurance as prepaids. See table below for the monthly balance from January 2022 through present.

Monthly Balance in Prepaid (165)	Amount
Jan-22	285,766.58
Feb-22	259,787.80
Mar-22	233,809.02
Apr-22	207,830.24
May-22	181,851.46
Jun-22	155,872.68
Jul-22	129,893.90
Aug-22	103,915.12
Sep-22	77,936.34
Oct-22	51,957.56
Nov-22	25,978.78
Dec-22	(0.00)
Jan-23	283,424.13
Feb-23	257,658.30
Mar-23	231,892.47
Apr-23	206,126.64
May-23	180,360.81
Jun-23	154,594.98
Jul-23	128,829.15
Aug-23	103,063.32
Sep-23	77,297.49
Oct-23	51,531.66
Nov-23	25,765.83
Dec-23	(0.00)
Jan-24	(0.00)
Feb-24	218,642.80

**TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 56
BATES PAGE(S): 18130 - 18131
APRIL 22, 2024**

56. **Board of Directors Expense.** Indicate whether Tampa Electric Company or its affiliates incurs Board of Directors ("BOD") expense. If so, describe the incurred expenses for each and provide the expense incurred by each of the entities in total and the amount assigned/allocated to Tampa Electric Company in total during the test year and the historic base year on a per books basis. In addition, provide the proforma adjustment(s) to the BOD expense proposed by the Company for the test year.

Answer:

	2023 Historic Base Year	**2025 Test Year**
Tampa Electric Board Expenses	$573,507	$580,000
Emera Allocated Board Expenses	$189,607	$173,324
Total Board of Directors Expenses contained in net operating income	$763,114	$753,324

Tampa Electric currently incurs Board of Director expenses for seven outside directors (not employed by Tampa Electric or Emera). Outside directors receive an annual director fee paid quarterly plus travel expenses for attending board meetings. The Board of Directors provides strategic advice and oversight regarding the business and affairs of the company. Tampa Electric incurred $573,507 in 2023 for Board of Director expenses. The 2025 budget includes approximately $580,000 for seven external directors.

Tampa Electric also incurs board expense allocations passed down from the parent company Emera. Emera executives hold director and/officer positions on internal boards and/or advisory boards. Consistent with the retainer and per meeting fee external directors receive, Emera will allocate a fee for each director and/or officer on a board based on a set fee calculated using market rates for external directors and expenses. The Board of Directors provides strategic advice regarding the operation of each affiliate. Affiliates ultimately benefit from this leadership.

A total of $1,373,934 CAD was incurred by Emera for board expenses in 2023. A total of $252,081 CAD, or $189,607 USD was allocated from Emera to Tampa Electric in 2023 for board expenses. Emera has budgeted for $1,492,771 CAD in

**TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 56
BATES PAGE(S): 18130 - 18131
APRIL 22, 2024**

board expenses for 2025. Tampa Electric will be allocated $232,255 CAD, or $173,324 USD at a 1.34 budgeted conversion rate in the 2025 test year budget.

The breakdown of expenses incurred by each entity is provided in Tampa Electric's response to OPC's Second Request for Production of Documents, No. 37.

santee cooper

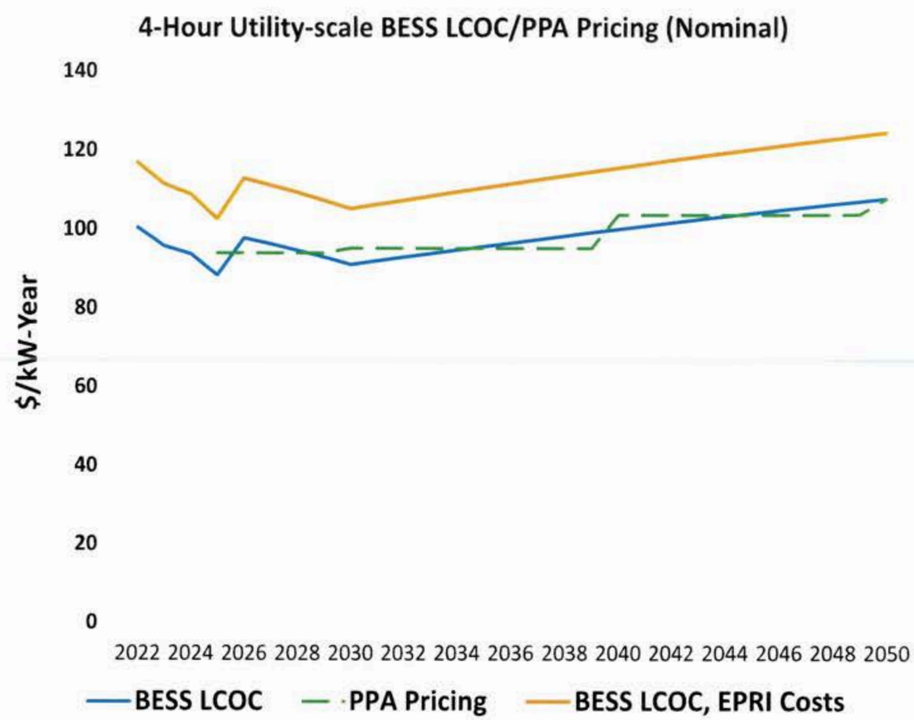
2023 Integrated Resource Plan (IRP)

Public Stakeholder Meeting #3

June 28, 2022

Battery Energy Storage System

- BESS resource options modeled in portfolio optimization
  - Include options covering multiple BESS durations
- Model as PPA resource
  - Assume 75% ITC will be captured
  - PPA capacity rate computed utilizing an approach similar to NREL ATB model
  - Charging and discharging modeled as a system cost/value
- Technology cost trend
  - NREL ATB Moderate Case for capital and O&M costs
  - Subject to change with updated NREL ATB
  - Assume 20-year technology life
- Industry standard technical operating characteristics
- Model ELCC based on Astrapé studies



LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 7.0

LAZARD

LAZARD

LAZARD

Table of Contents

I Introduction

Introduction

Lazard's Levelized Cost of Storage ("LCOS") analysis[1] addresses the following topics:

- **Introduction**
  - A summary of key findings from Lazard's LCOS v7.0
- **Lazard's LCOS analysis**
  - Overview of the operational parameters of selected energy storage systems for each use case analyzed
  - Comparative LCOS analysis for various energy storage systems on a $/kW-year and $/MWh basis
- **Energy Storage Value Snapshot analysis**
  - Overview of the Value Snapshot analysis and identification of selected geographies for each use case analyzed
  - Summary results from the Value Snapshot analysis
- **A preliminary view of long-duration storage technologies**
- **Selected appendix materials**
  - Supplementary materials for Lazard's LCOS analysis, including methodology and key assumptions employed
  - Supporting materials for the Value Snapshot analysis, including pro forma results for the U.S. and International Value Snapshot case studies

Source: Lazard and Roland Berger.
(1) Lazard's LCOS analysis is conducted with support from Enovation Analytics and Roland Berger.

Summary of Key Findings and Observed Trends in the Energy Storage Industry

Technology	• Concerns regarding the availability of Lithium-ion battery modules are increasing given ongoing supply constraints – Supply constraints in commodity markets and manufacturing activities have led end-users to more seriously consider Tier 2 and Tier 3 suppliers – Stationary storage applications are increasingly competing with EVs over module supply as automobile manufacturers continue to shift product offerings away from traditional gasoline- and diesel-fueled vehicles • Module demand from EVs is expect to increase to ~90% from ~75% of end-market demand by 2030. Stationary storage currently represents <5% of end market demand and is not expected to exceed 10% of the market by 2030 • Pressure on legacy integrators continues to build as the industry matures – Battery OEMs are moving downstream in an effort to capture more margin and expand market share, offering fully wrapped DC blocks, i.e., storage modules, container, supporting controls, fire suppression and associated cabling – Concurrently, some developers are expanding in-house engineering, procurement and construction activities – Legacy integrators are moving into energy management software, with many acquiring distributed energy resource management platforms • Market preference has shifted significantly towards Lithium Iron Phosphate ("LFP") vs. Nickel Manganese Cobalt ("NMC") chemistries – Industry participants increasingly prefer LFP chemistries given perceived fire safety, cost and operational advantages (e.g., depth of discharge). The cost advantage of LFP chemistries tends to be more pronounced in shorter-duration applications • Interest in longer-duration technologies continues to grow in tandem with expectations of ever greater penetration of renewable energy generation – Adoption, however, remains limited given a lack of required technology and duration-specific price signals in wholesale markets (e.g. capacity)
Use Cases	• Hybrid applications are becoming more valuable and, by extension, widespread as grid operators begin adopting Estimated Load Carry Capability ("ELCC") methodologies to value resources – Adoption of ELCC methodologies is driving increasing deployment of hybrid resources (e.g., storage paired with solar) to mitigate resource intermittency. Storage co-located with solar is expected to be most attractive in the U.S. Midwest, including in the Southwest Power Pool ("SPP") region – In ERCOT, for example, hybrid assets account for ~35% of storage MW in the current interconnection queue (i.e., ~29% solar, ~1% wind and ~5% other) • Developers are increasingly targeting markets in the Western U.S. (California), Western Europe and South America for long duration storage projects as these areas experience ever greater penetration of intermittent renewable energy generation in tandem with declining dispatchable conventional generation capacity

Source: LCOS surveys, Roland Berger.

II Lazard's Levelized Cost of Storage Analysis v7.0

LAZARD

Energy Storage Use Cases—Overview

By identifying and evaluating the most commonly deployed energy storage applications, Lazard's LCOS analyzes the cost and value of energy storage use cases on the grid and behind-the-meter

		Use Case Description	Technologies Assessed
In-Front-of-the-Meter	1 Wholesale	• Large-scale energy storage system designed for rapid start and precise following of dispatch signal. Variations in system discharge duration are designed to meet varying system needs (i.e., short-duration frequency regulation, longer-duration energy arbitrage[1] or capacity, etc.) – To better reflect current market trends, this report analyzes one-, two- and four-hour durations[2]	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
In-Front-of-the-Meter	2 Transmission and Distribution	• Energy storage system designed to defer or avoid transmission and/or distribution upgrades, typically placed at substations or distribution feeders controlled by utilities to provide flexible capacity while also maintaining grid stability	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
In-Front-of-the-Meter	3 Wholesale (PV+Storage)	• Energy storage system designed to be paired with large solar PV facilities to better align timing of PV generation with system demand, reduce solar curtailment and provide grid support	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	4 Commercial & Industrial (Standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I energy users – Units often configured to support multiple commercial energy management strategies and provide optionality for the system to provide grid services to a utility or the wholesale market, as appropriate in a given region	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	5 Commercial & Industrial (PV+Storage)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I energy users – Systems designed to maximize the value of the solar PV system by optimizing available revenue streams and subsidies	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	6 Residential (PV+Storage)	• Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation (e.g., PV+storage) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide

Source: *Industry interviews, Lazard and Roland Berger.*
Note: Use case numbering shown above serves as an identifier for the corresponding individual use cases discussed on subsequent pages.
(1) For the purposes of this analysis, "energy arbitrage" in the context of storage systems paired with solar PV includes revenue streams associated with the sale of excess generation from the solar PV system, as appropriate, for a given use case.
(2) The Value Snapshot analysis only evaluates the four-hour wholesale use case.

Energy Storage Use Cases—Illustrative Operational Parameters

Lazard's LCOS evaluates six commonly deployed use cases for energy storage by identifying illustrative operational parameters[(1)]

- **Energy storage systems may also be configured to support combined/"stacked" use cases**

[ ] = "Usable Energy"[(2)]

		(A) Project Life (Years)	Storage (MW)[(3)]	Solar PV (MW)	Battery Degradation (per annum)	Storage Duration (Hours)	(D) Nameplate Capacity (MWh)[(4)]	(E) 90% DOD Cycles/ Day[(5)]	(F) Days/ Year[(6)]	D x E x F = (G) Annual MWh	A x G = (H) Project MWh
In-Front-of-the-Meter	1 Wholesale[(7)]	20	100	--	2.6%	1	100	1	350	31,500	630,000
		20	100	--	2.6%	2	200	1	350	63,000	1,260,000
		20	100	--	2.6%	4	400	1	350	126,000	2,520,000
	2 Transmission and Distribution[(7)]	20	10	--	1.5%	6	60	1	25	1,350	27,000
	3 Wholesale (PV+Storage)[(7)]	20	50	100	2.6%	4	200	1	350	63,000	1,260,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)	10	1	--	2.6%	2	2	1	250	450	4,500
	5 Commercial & Industrial (PV+Storage)[(7)]	20	0.50	1	2.3%	4	2	1	350	630	12,600
	6 Residential (PV+Storage)	20	0.006	0.010	1.9%	4	0.025	1	350	8	158

Source: *Lazard and Roland Berger.*

Note: Operational parameters presented are applied to Value Snapshots and LCOS calculations. Annual and Project MWh presented are illustrative. Annual battery output in the Value Snapshot analysis depends on a participation optimization analysis and may vary from the representative project MWh by use case.

(1) The six use cases below represent illustrative current and contemplated energy storage applications and are derived from Industry survey data.
(2) Usable energy indicates energy stored and available to be dispatched from the battery.
(3) Indicates power rating of system (i.e., system size).
(4) Indicates total battery energy content on a single, 100% charge, or "usable energy." Usable energy divided by power rating (in MW) reflects hourly duration of system. This analysis reflects common practice in the market whereby batteries are upsized in year one to 110% of nameplate capacity (e.g., a 100 MWh battery actually begins project life with 110 MWh).
(5) "DOD" denotes depth of battery discharge (i.e., the percent of the battery's energy content that is discharged). Depth of discharge of 90% indicates that a fully charged battery discharges 90% of its energy. To preserve battery longevity, this analysis assumes that the battery never charges over 95%, or discharges below 5%, of its usable energy.
(6) Indicates number of days of system operation per calendar year.
(7) Augmented to nameplate MWh capacity in year 11 of operation.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 90
BATES PAGE(S) 25955 - 25956
MAY 10, 2024

90. Please refer to the Direct Testimony of Jeff Kopp. Identify where in that testimony Witness Kopp describes how 1898 & Co. calculated the decommissioning costs in future dollars and how it calculated the annual decommissioning expense accruals reflected in the test year revenue requirement. If Witness Kopp did not describe these calculations in his testimony, then explain why he did not do so and identify which Company witness(es) addressed these issues and calculations, if at all.

ANSWER:

The Direct Testimony of Jeff Kopp does not describe the calculations for the decommissioning costs in future dollars or the annual decommissioning expense accruals reflected in the test year revenue requirement, because 1898 & Co. did not calculate these values. The company performs these calculations which are included in the details supporting the revenue requirement as described in Witness Chronister's testimonies Volume I and II.

The company, pursuant to its long-standing practice internally manages and performs the dismantlement accrual model calculations. The company's use of this methodology is demonstrated in the following Depreciation Study dockets: 20030409-EI, 20070284-EI, 20110131-EI, 20200064-EI, The methodology and escalation rates used in this instant study are the same as in prior filings. This methodology is as follows:

- Escalation rates are calculated using Moody's Analytics (Economy.com) forecasts.
- Historical information is provided for the years 2022 and prior.
- The needed forecast information is provided for the years 2023 to 2053.
- For the years 2054 and beyond, the same annual change percentage for year 2053 is carried forward.
- Since the vendor cost estimates are provided by 1898 & Co. in 2023 dollars, the dismantlement accrual model initially escalates each unit's cost estimate into 2025 dollars to align with the study, which projects each unit's ending balance of reserve through December 31, 2024.
- Next, each unit's cost estimates are escalated to the projected retirement date to perform the present value calculations and averaging of the next four years' accrual results.
- Three Moody's Analytics indices are used and applied to the four cost estimate categories in the following manner.

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Labor is applied the Compensation Per Hour, Productivity and Costs (2012=100).
Materials & Equipment is applied the Intermediate Goods, Producer Prices (1982=100).
Environmental & Disposal is applied to the GDP Chain Price Deflator (2012=100).
Salvage is applied the Intermediate Goods, Producer Prices (1982=100).

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 89
BATES PAGE(S) 25951 - 25954
MAY 10, 2024

89. Please refer to Exhibit No. JK-1 TECO Decommissioning Cost Estimate Study for Tampa Electric Company dated November 28, 2023.

a. Confirm this decommissioning study is the same study as included by the Company as Exhibit 3 to the 2023 Depreciation and Dismantlement Study filed on behalf of the Company on December 27, 2023 in Docket No. 20230139-EI. If denied, then describe the differences between the two decommissioning cost estimate studies filed in the two separate dockets.

b. Provide the actual or projected in-service dates for each of the solar and battery facilities included in the decommissioning study to the extent not provided in Section 2.0 Plant Descriptions. If the projected in-service dates in the study are different than the actual in-service dates in 2023 and/or 2024 and/or the projected in-service dates in the remaining months of 2024 and in the test year and reflected in the revenue requirement, then explain why they are different.

c. Describe each of the "environmental" site restoration activities included in the decommissioning cost estimates for the solar and storage facilities.

d. Provide a narrative description of the basis for and calculations of the "environmental" costs included in the decommissioning cost estimates for the solar and storage facilities.

e. Many of the Site Specific Assumptions in Section 3.2 address the individual storage and solar facilities and many of the assumptions for many of those solar facilities state: "A solar lease agreement was not available for review" or similar language such as "A lease agreement was not available for review."

   1. Describe the lease that is referred to for each such storage or solar facility and explain why the lease agreement was not available for review.

   2. Explain why these statements are relevant for each such storage or solar facility and how the unavailability of the lease agreement affected the assumptions used for the decommissioning cost estimates as to scope of work required and the cost of that work.

f. Sections 3.3.15 and 3.316 address Future Solar Site I and Future Solar Site II. Among other site specific assumptions, the study states for each of these sites: "Because the location of Future Solar Site I has not yet been determined, an SCI of 100 percent was applied," "A solar lease agreement was not available for review," and "Drawings were not provided for review; project quantities and specifications were assumed based on other TECO solar projects and 1898 & Co. experience."

1. Define the acronym "SCI."
2. Explain in detail how 1898 & Co. was able to develop a site specific decommissioning cost estimate for two future facilities when the site locations are not known, drawings were not provided, there was no lease agreement available for review, and project quantities and specifications were not known.

ANSWER:

a. Exhibit No. JK-1 TECO Decommissioning Cost Estimate Study for Tampa Electric Company dated November 28, 2023 is the same study as included by the company as Exhibit 3 to the 2023 Depreciation and Dismantlement Study filed on behalf of the Company on December 27, 2023 in Docket No. 20230139-EI.

b. The following solar projects were missing in-service dates in the decommissioning study:

- Tampa International Airport in-service date December 2015
- Legoland Solar in-service date November 2016

The following solar projects updated their in-service dates primarily related to the timing of land purchased or leased:

- Brewster Solar had an estimated in-service date of December 2024 in the study, and was updated to December 2026
- Bull Frog Creek Solar had an estimated in-service date of December 2025 in the study, and was updated to December 2024.

TAMPA ELECTRIC COMPANY
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c. The environmental site restoration costs for the decommissioning cost estimates of the solar and storage facilities, include costs for the following activities:

- Removal of the access roads
- Removal of the perimeter fence
- Grading and seeding disturbed site areas
- Restoration of the rooftop underneath rooftop solar panels

d. The "environmental" costs described in response to Interrogatory No. 89(c), above, are included in the decommissioning cost estimates to restore each site to an industrial condition suitable for reuse for development as an industrial facility. Calculations of these costs are included in the workpapers provided in response to OPC's Fourth Request for Production of Documents, No. 67.

e. 1. A lease agreement states requirements for the leased land on which a storage or solar facility are constructed. These requirements may impact decommissioning assumptions. As stated in Exhibit No. JK-1, for select storage and solar facilities, a lease agreement was not provided by Tampa Electric for my team to review.

2. As stated in response to Interrogatory No. 89(e)(1), a lease states requirements for the solar or storage project land, which may impact decommissioning assumptions. Where a lease was not available for review, 1898 & Co. assumed standard decommissioning assumptions based on similar such projects, as described in Section 3.1 of Exhibit No. JK-1.

f. 1. The acronym "SCI" is an abbreviation of "Site Cost Index."

2. The SCI, as defined above in response to Interrogatory No. 89(f)(1), adjusts the national average RS Means labor and equipment rates to be location specific. As the specific location was not known at the time of the study, an SCI of 100 percent was applied, essentially applying national average rates. Since a lease agreement was not available for review, 1898 & Co. assumed standard decommissioning assumptions based on similar such projects, as described in Section 3.1 of Exhibit No. JK-1. At the time of preparation of the Decommissioning Cost Estimate Study, a final design was not available; however, the expected project capacity

was known (74.5 MW). As such, 1898 & Co. was able to estimate project quantities based on other similar solar projects for which we had drawings and equipment information.

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February 19, 2024

VIA: ELECTRONIC TRANSMISSION

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket 20230090; Petition to Implement 2024 Generation Base Rate Adjustment Provisions in 2021 Agreement by Tampa Electric Company

Dear Mr. Teitzman:

Attached for filing in the above-styled matter is Tampa Electric Company's Inflation Reduction Act Implementation Proposal.

Thank you for your assistance in connection with this matter.

Sincerely,

J. Jeffry Wahlen

JJW/ne
Attachment

cc: Walt Trierweiler
Charles Rehwinkel
Mary Wessling
Jon Moyle
Robert Scheffel Wright
Thomas A. Jernigan
Mark F. Sundback
Stephanie U. Eaton
Barry A. Naum

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to Implement 2024 Generation Base Rate Adjustment Provisions in 2021 Agreement, by Tampa Electric Company)	DOCKET NO.: 20230090-EI FILED: February 19, 2024

INFLATION REDUCTION ACT IMPLEMENTATION PROPOSAL

Pursuant to Sections 120.57 and 366.076, Florida Statutes, and Rule 28-106.301, Florida Administrative Code ("F.A.C."), Tampa Electric Company ("Petitioner," "Tampa Electric," or "the company"), files this Proposal to address the impact of the Inflation Reduction Act of 2022 on its August 26, 2022, and August 16, 2023, Petitions ("Original Petitions"), which were filed to implement the 2023 and 2024 Generation Base Rate Adjustment ("GBRA") provisions in Paragraph 4 of the 2021 Stipulation and Settlement Agreement ("2021 Agreement") approved by the Florida Public Service Commission ("FPSC" or "Commission") in Order No. PSC-2021-0423-S-EI, dated November 10, 2021.

Reasons for and Summary of Proposal

The company's Original Petitions requested implementation of the 2023 and 2024 GBRAs as updated to reflect the impact of the ROE Trigger in the 2021 Agreement. The GBRA amounts in the 2021 Agreement were calculated based on the federal income tax laws and regulations in effect at the time the 2021 Agreement was executed and approved. The calculations assumed that the company would claim the investment tax credits ("ITCs") available under the tax laws in effect at the time. Since then, the Inflation Reduction Act of 2022 ("IRA") was enacted, which increased the amount of the ITCs and extended the availability of a production tax credit ("PTC") to the company's second wave of solar assets ("Solar Wave Two") included in its 2022 base rate increase and its 2023 and 2024 GBRAs.[1]

The 2021 Agreement requires "normalization" of any new tax credits. Normalization of the PTCs available for the Solar Wave Two assets going into service in 2022, 2023, and 2024 over a ten year period yields approximately the same revenue requirement as the revenue requirement reflected in the company's 2022 base rates and GBRAs. Accordingly, as explained further below, the company proposes to make no changes to its current base rates or the 2023 and 2024 GBRAs as approved by the Commission, and to leave the unamortized balance of the PTCs associated with the Solar Wave Two assets on the balance sheet for disposition as an income tax expense reduction in the company's next general base rate proceeding.

Federal Tax Changes

1. The IRA was signed into law on August 16, 2022. Among other things, it increased the ITC applicable to certain renewable energy projects from 26 percent to 30 percent of the cost of the asset and extended the PTC in section 45 of the Internal Revenue Code to electricity generated by solar energy facilities. The PTC is a tax credit that reduces income tax expense, the amount of which is based on the amount of energy produced by qualifying assets. The PTC is available for solar energy facilities placed into service on or after January 1, 2022, and thereafter. The higher ITC percentage (30%) and PTC in the IRA applies to qualified facilities, including solar generating assets, for which construction began before January 1, 2025.

[1] Solar Wave Two consists of the three tranches of projects described in the direct testimony of David Sweat in Docket No. 20210034-EI, i.e., the company's 2021 Rate Case. Tranche One consisted of four projects (Magnolia, Mountain View, Jamison, and Big Bend II) totaling 226.5 MW and were scheduled to go in-service by December 1, 2022. (Magnolia went into service in 2021 and was not eligible for PTC.) Tranche Two consisted of four projects (Laurel Oaks, Riverside, Palm River, and Big Bend III) totaling 224 MW and went into service in 2022. Tranche Three consists of three projects (Alafia, Wheeler, and Dover) totaling 149.5 MW and will be in service by the end of 2023.

2. The IRA did not change the statutory federal corporate income tax rate but did create a 15 percent alternative minimum tax effective in 2023 that is not applicable to Tampa Electric because the worldwide adjusted financial statement income of Emera, Inc. is not expected to average over $1 billion USD for 2021, 2022, and 2023.

3. In its Original Petitions, the company noted that the IRA had become law and indicated that it would update its petition to address the implications of the IRA on the 2023 and 2024 GBRA as specified in the 2021 Agreement. The Commission approved implementation of the 2023 and 2024 GBRAs by Order Nos. PSC-2022-0434-TRF-EI, issued December 21, 2022 and PSC-2023-0348-TRF-EI, issued November 17, 2023. In its 2024 GBRA order, the Commission directed Tampa Electric to file a proposal to address the impact of the IRA on its GBRAs by April 1, 2024.

2021 Agreement Tax Change Provisions

4. The 2021 Agreement addresses Tax Changes in two places. The first is Paragraph 4(c), which specifies that a GBRA must be updated when federal or state corporate income tax rates change. That provision has no application here, because the IRA did not change the statutory federal corporate income tax rate in a way that impacts Tampa Electric. The second is Paragraph 11, which specifies the manner in which general base rates and GBRAs must be updated to reflect the impact of Tax Changes.

A. General Base Rates

5. Paragraph 11 of the 2021 Agreement contains the general provisions prescribing the actions to be taken if Tax Changes, including new tax credits, are enacted during the term of the agreement. Subparagraph 11 (c) states that if Tax Changes are enacted and become effective during the Term of the 2021 Agreement, the following provisions apply to the company's general base rates:

(i) The company will calculate the impact of Tax Changes on its retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Changes up or down to a net zero. The company will use its forecasted earnings surveillance report for the calendar year that includes the period in which Tax Changes are effective to calculate the impact of Tax Changes.

(ii) The impacts of Tax Changes, including, without limitation, rate changes and changes to the availability of existing and <u>new tax credits and other similar tax benefits on a normalized basis</u>, on base revenue requirements as calculated in subparagraph 11(c)(i) – up or down - will be reflected in the company's general base rates and charges through a prospective adjustment to those rates and charges to be effective within the later of: (a) 180 days from the date when Tax Changes become law or (b) the effective date of Tax Changes. This prospective adjustment to base rates and charges shall be accomplished through an equal percentage change – up or down - to customer, demand, and energy base rate charges as applicable for all retail customer classes.

(iii) Any effects of Tax Changes on retail revenue requirements from the effective date through the date of the base rate adjustment shall be flowed back to or collected from customers through the ECCR on the same basis as used in any base rate adjustment. (emphasis added)

6. The IRA did not include a statutory federal income tax rate change applicable to Tampa Electric. Some of the projects in the first tranche of Solar Wave Two that were expected to go into service before December 31, 2021, and were included in the calculation of the company's 2022 general base rate increase effective January 1, 2022, did not go into service until early 2022, so they became eligible for the PTC. The company evaluated whether it is in the best interest of its customers to elect the 30 percent ITC or the PTC for these solar generating assets and concluded that electing the PTC is best for customers. Consequently, even though the company's 2022 base rate increase was calculated by applying the traditional ITC for solar assets, the company elected to take the PTC for these assets in its consolidated federal income tax return for 2022 and proposes to address the revenue requirement difference between the ITC and PTC for the Tranche One projects as described below.

B. GBRAs

7. Subparagraph 11(c)(iv) of the 2021 Agreement addresses the impact of Tax Changes on a GBRA that has not gone into effect and states:

> The company will adjust any GBRA that has not gone in effect up or down to reflect the new corporate income tax rate <u>and the normalization of any new tax credits</u> applicable to Future Solar projects on the revenue requirement for the GBRA. The effect of Tax Changes on a GBRA that has gone into effect will be addressed as part of the calculation in subparagraph 11(c)(i), above. *** (emphasis added)

8. The company's 2023 GBRA covered the Tranche Two solar generating facilities that were placed in service in 2022. The 2023 GBRA revenue requirement included in the 2021 Agreement was calculated using the 26 percent ITC applicable at the time the 2021 Agreement was executed and approved.

9. The company's 2024 GBRA covered the Tranche Three solar generating facilities that are scheduled to be placed in service in 2023. The 2024 GBRA revenue requirement included in the 2021 Agreement was calculated using the 26 percent ITC applicable at the time the 2021 Agreement was executed and approved.

10. By virtue of the IRA, the solar generating facilities in the 2023 and 2024 GBRAs are eligible for the ITC at a 30 percent rate or the PTC. Subparagraph 11(c)(iv) of the 2021 Agreement specifies that the effect of any new tax credits will be reflected in the revenue requirement of a GBRA on a normalized basis, i.e., not flowed through.

11. The company evaluated whether it is in the best interest of its customers to elect the 30 percent ITC or the PTC for the Tranche Two and Three solar generating assets in its 2023 and 2024 GBRAs and believes that electing the PTC is best for customers. A comparison of the cumulative present value revenue requirement ("CPVRR") of using the ITC at 30 percent ITC versus electing the PTC on a normalized basis for the 2023 and 2024 GBRA solar assets shows

that electing the PTC provides an incremental benefit to customers over the life of the solar generating facilities in the 2023 and 2024 GBRAs.

C. Evaluation of Solar Wave Two Tax Credits

12. As noted above, the annual revenue requirement for all three tranches of solar facilities in the Company's Solar Wave Two were calculated using a 26% ITC; however, the company has elected or will elect to take the PTC for all of the Solar Wave Two assets (except Magnolia, which went in service in 2021 and is not eligible for PTC) , because doing so is in the best interests of its customers.

13. The company has compared the total revenue requirement impact of the ITC for Solar Wave Two assets embedded in its 2022 base rate increase and its 2023 and 2024 GBRAs with the revenue requirement impact of taking the PTC for those assets and normalizing the credits over a ten year period.[2] This comparison is reflected on Exhibit One and shows that the embedded annual revenue requirement benefit of the ITCs for Solar Wave Two totals approximately $8.6 million and the annual revenue requirement benefit of normalized PTC for Solar Wave Two is approximately $8.9 million.[3]

14. Exhibit One also shows that the sum of the PTC estimated to be received for Solar Wave Two assets in 2022, 2023, and 2024 will be approximately $54 million and that the company will recognize $8.6 million of ITC credits associated with Solar Wave Two in those same years,

[2] The company acknowledges that the Internal Revenue Code does not require Normalization of PTCs in the same manner as it does for investment tax credits; however, the 2021 Agreement specifically contemplates the "normalization" of any new tax credits. Although the 2021 Agreement does not specify the normalization period for the new PTCs, the company proposes to use a 10 year period which is consistent with the 10 year availability period for PTCs and allows the benefits of the PTC to be shared on an intergenerational basis as opposed to benefitting customers in only one year. The Consumer Parties have not objected to this 10 year normalization period for purposes of this Proposal.

[3] The company proposes to reflect this amount of investment tax credit amortization in its financial statements for 2022, 2023, and 2024 on grounds that the company's accounting for the Solar Wave Two assets under generally accepted accounting principles should follow the approach reflected in revenue requirement calculations inherent in the 2021 Agreement.

leaving a forecasted total of $45.4 million of deferred PTC on the company's balance sheet as of December 31, 2024. Using a tax gross up factor of 1.34315, this amount of deferred PTC represents a deferred revenue requirement benefit (reduction) of approximately $61 million.

The Company's Proposal

15. The annual revenue requirement benefit of the ITC embedded in the revenue requirement approved in the 2021 Agreement for the Solar Wave Two assets is within approximately $400,000 of the annual revenue requirement benefit of the PTC for those assets on a ten-year normalized basis; therefore, the company proposes no IRA-related changes to its 2022 base rates or 2023 and 2024 GBRAs as approved and currently in effect. The company also proposes that the disposition of the forecasted deferred PTC balance as of December 31, 2024 of $45.4 million (approximately $61 million revenue requirement benefit) be resolved by the Commission in the company's next general base rate proceeding.

16. If the Commission approves this Proposal, the company will propose an amortization period for the PTC deferred balance, reflect the amortization of the deferred PTC using its proposed period as a reduction to income tax expense in the calculation of test year net operating income, and will explain its proposed amortization period in the direct testimony it files with its MFRs and petition in its next general base rate proceeding. The company anticipates and acknowledges that the appropriate amortization period for the deferred PTC balance will be an issue to be decided by the Commission and that the parties in the company's next base rate case will be free to propose and advocate for amortization periods different than the period proposed by the company.

Ultimate Facts Alleged

17. The ultimate facts that entitle Tampa Electric to the relief requested herein are the facts set forth in paragraphs one through 16 above and the following:

A. The company's proposal will promote regulatory economy and efficiency by minimizing the regulatory activity needed to update the company's base rates and 2023 and 2024 GBRAs for the impact of the Inflation Reduction Act. It will also minimize the potential customer confusion associated with a small mid-year base rate or GBRA change.

B. The term of the 2021 Agreement ends on December 31, 2024.

C. Absent limited exceptions, none of which the company expects to apply, the 2021 Agreement specifies that the company may not petition for new base rates and charges to be effective before the first billing cycle in January 2025.

D. The base rates and charges approved in the 2021 Agreement and currently in effect are fair, just, and reasonable per the agreement and will remain fair, just, and reasonable if the company's proposal specified above is approved by the Commission.

Other

18. Tampa Electric is not aware of any disputed issues of material fact associated with this proposal. The company has discussed the matters set forth in this document with the Office of Public Counsel and is authorized to represent that OPC does not object to the proposals and action requested herein.

20. Tampa Electric is entitled to the relief requested pursuant to Chapters 366 and 120, Florida Statutes, and Order No. PSC-2021-0423-S-EI.

WHEREFORE, Tampa Electric respectfully requests that the Commission enter an Order Approving the Proposal specified above and granting other such relief as may be reasonable and proper.

DATED this 19th day of February, 2024.

Respectfully submitted,

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Proposal, filed on behalf of Tampa Electric Company, has been served by electronic mail on this 19th day of February 2024 to the following:

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Tampa Electric
Solar Wave 2

Original Estimated ITC To Be Received Each Year	2022	2023	2024	
Tranche 1	45.8			
Tranche 2		60.2		
Tranche 3			44.2	
Normalization of Estimated ITC				**Total 2022-2024**
Tranche 1 normalization	1.3	1.3	1.3	3.9
Tranche 2 normalization		1.7	1.7	3.4
Tranche 3 normalization			1.3	1.3
	1.3	3.0	4.3	8.6

Estimated PTC To Be Received Each Year	2022	2023	2024	Total
Tranche 1	8.0	8.0	8.0	
Tranche 2		11.0	11.0	
Tranche 3			8.0	54.0
10-Year Amortization of Estimated PTC To Be Received Each Year				**Total 2022-2024**
Tranche 1 PTC received in 2022	0.8	0.8	0.8	2.4
Tranche 1 PTC received in 2023		0.8	0.8	
Tranche 1 PTC received in 2024			0.8	
Tranche 2 PTC received in 2023		1.1	1.1	2.2
Tranche 2 PTC received in 2024			1.1	
Tranche 3 PTC received in 2024			0.8	0.8
	0.8	2.7	5.4	8.9

Sum of PTC to be received 2022-2024	54.0
Sum of ITC normalization 2022-2024	8.6
Deferred PTCs	45.40
Tax gross up	1.34315
Deferred Revenue Requirement Reduction	61.0

Note: All PTC earned amounts are estimates because the actual amounts will be based on actual MWH generated.

EXHIBIT ONE

Tampa Electric
Solar Wave 2

Original Estimated ITC To Be Received Each Year	2022	2023	2024	
Tranche 1	45.8			
Tranche 2		60.2		
Tranche 3			44.2	

Normalization of Estimated ITC				Total 2022-2024
Tranche 1 normalization	1.3	1.3	1.3	3.9
Tranche 2 normalization		1.7	1.7	3.4
Tranche 3 normalization			1.3	1.3
	1.3	3.0	4.3	8.6

Sum of PTC to be received 2022-2024	57.1
Sum of ITC normalization 2022-2024	8.6
Deferred PTCs	48.50
Tax gross up	1.34315
Deferred Revenue Requirement Reduction	65.1

Note: All PTC earned amounts are estimates because the actual amounts will be based on actual MWH generated.

Estimated PTC To Be Received Each Year	2022	2023	2024	Total
Tranche 1	7.8	8.5	10.2	
Tranche 2	0.5	10.6	10.7	
Tranche 3	-	0.4	8.4	
				57.1

10-Year Amortization of Estimated PTC To Be Received Each Year				Total 2022-2024
Tranche 1 PTC received in 2022	0.8	0.8	0.8	2.3
Tranche 1 PTC received in 2023		0.9	0.9	1.7
Tranche 1 PTC received in 2024			1.0	1.0
Tranche 2 PTC received in 2022	0.1	0.1	0.1	0.2
Tranche 2 PTC received in 2023		1.1	1.1	2.2
Tranche 2 PTC received in 2024			1.1	1.1
				-
Tranche 3 PTC received in 2023		0.0	0.0	0.1
Tranche 3 PTC received in 2024			0.8	0.8
	0.8	2.8	5.8	9.4

Credits:
Rounded in Millions

Exhibit B

Assets	PTC Earned 2022	PTC Earned 2023	PTC Earned 2024	PTC Earned Cumulative Total as of 01/01/2025	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2022	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2023	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2024	ITC amortization per Rate Case/ 2023 and 2024 GBRA Cumulative Total as of 01/01/2025	Variance PTC vs. ITC 2022	Variance PTC vs. ITC 2023	Variance PTC vs. ITC 2024	Variance PTC vs. ITC Cumulative Total as of 01/01/2025
SW2 Tr1	7.80	8.50	10.20	26.50	1.30	1.30	1.30	3.90	6.50	7.20	8.90	22.60
SW2 Tr2	0.50	10.60	10.70	21.80	-	1.70	1.70	3.40	0.50	8.90	9.00	18.40
SW2 Tr3	-	0.40	8.40	8.80	-	-	1.30	1.30	-	0.40	7.10	7.50
Total	8.30	19.50	29.30	57.10	1.30	3.00	4.30	8.60	7.00	16.50	25.00	48.50

Revenue Requirement Equivalent:

Assets	PTC Earned 2022	PTC Earned 2023	PTC Earned 2024	PTC Earned Cumulative Total as of 01/01/2025	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2022	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2023	ITC amortization per Rate Case/ 2023 and 2024 GBRA 2024	ITC amortization per Rate Case/ 2023 and 2024 GBRA Cumulative Total as of 01/01/2025	Variance PTC vs. ITC 2022	Variance PTC vs. ITC 2023	Variance PTC vs. ITC 2024	Variance PTC vs. ITC Cumulative Total as of 01/01/2025
SW2 Tr1	10.48	11.42	13.70	35.59	1.75	1.75	1.75	5.24	8.73	9.67	11.95	30.36
SW2 Tr2	0.67	14.24	14.37	29.28	-	2.28	2.28	4.57	0.67	11.95	12.09	24.71
SW2 Tr3	-	0.54	11.28	11.82	-	-	1.75	1.75	-	0.54	9.54	10.07
Total	11.15	26.19	39.35	76.69	1.75	4.03	5.78	11.55	9.40	22.16	33.58	65.14

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 91
BATES PAGE(S) 25957 - 25958
MAY 10, 2024

91. Please refer to the Direct Testimony of Valerie Strickland at 11 wherein she states: "The company has calculated the ITC in accordance with the long-standing IRS normalization rules. The ITC has been deferred and amortized over the regulatory life of the asset, which is 10 years for energy storage."

a. Describe more specifically what Witness Strickland means when she states "The company has calculated the ITC in accordance with the long-standing IRS normalization rules" for energy storage assets. In your response, indicate whether the Company decided *not* to elect out of the normalization rules for energy storage technology pursuant to the provisions of the IRA.

b. If the Company decided *not* to elect out of the normalization rules for energy storage technology, then explain why it made this decision and why this decision was prudent and reasonable.

c. Indicate whether the Company subtracted the deferred ITC from rate base or included it in the capital structure as cost-free capital in the calculation of its claimed revenue deficiency in this proceeding. In your response, address both the regulatory liability calculated as the grossed-up deferred ITC and the offsetting asset ADIT.

ANSWER:

a. The company calculated the deferral and amortization of ITC to conform with IRS normalization rules under Code Section 46, which is consistent with how the company has calculated the deferred ITC for solar assets placed in service before 2022, that qualified for ITC under Section 48. As a result, the company defers the ITC and amortizes the deferred ITC balance over the regulatory life of the assets, which has the effect of reducing cost of service. The company has not elected out of the normalization provisions enacted in the IRA for the energy storage assets.

b. The company has not elected out of the normalization rules for the expected ITC calculated for its battery storage assets in the test year. As indicated in the Direct testimony of Valerie Strickland, Page 12, normalization accounting has the effect of leveling customers' rates over time, and therefore avoiding volatility in the company tax expense profile, which would occur should the company elect out of normalization. The company plans on placing energy storage assets in service in 2024 and

2025 but not again until 2028, which is reflected in its most recent ten-year site plan. Considering these plans, flowing through the ITC for energy storage in the 2025 test year would materially decrease the company's 2025 tax expense, but there would be no similar expense reduction in 2026 and 2027, meaning that the company's 2025 tax expense with flow through of ITCs for energy storage would not be representative of the company's anticipated tax expense profile during the period its new customer rates will be in effect. The company believes it is prudent and reasonable to rely on the long history of normalizing deferred ITC for the purpose of determining the tax expense in the cost of service, because the normalization method of accounting avoids intergenerational cost inequities and allows regulated companies and customers to share benefits and achieve better balancing of the benefits of ITCs over the life of the assets giving rise to the ITC.

c. As stated in Witness Strickland's testimony on Page 25, the deferred ITCs are in Accumulated Deferred Investment Tax Credits (account 255) and are included as a component of the capital structure using the weighted average cost rate of investor sources of capital. Consistent with the Commission's long history of accounting for deferred ITCs in the capital structure, the company did not subtract deferred ITC from rate base in the test year. The company's methodology for the test year complies with the IRS normalization rules under IRC Section 46 and is consistent with both the company's historical treatment of its ITC and PSC practice, which is to reduce cost of service by the ITC amortization based on the regulatory life of the asset and assigning a cost of capital for the Deferred ITC using the weighted average cost rate of investor sources of capital.

In summary, the company's Accumulated Deferred Investment Tax Credits (account 255) have been included in its capital structure using the weighted average cost rate of investor sources of capital as established in Commission Orders from prior rate proceedings. The regulatory liability calculated for the gross up of the deferred ITC (account 254) and the offsetting asset ADIT (account 190), which net to zero, have been included in the capital structure as cost-free capital.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
OPC'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 83
BATES PAGE(S) 25939 - 25941
MAY 10, 2024**

83. Please refer to Mr. Latta's Direct Testimony Exhibit No. RL-1 Document No. 5 at page 1 of 2, which depicts the calculation of the 2026 and 2027 Subsequent Year Adjustment ("SYA") revenue requirement amounts. Refer also to the Direct Testimony of Mr. Latta at page 61, wherein he states the following:

a. Document No. 5 of my exhibit shows the revenue requirement for the projects to be recovered through the two SYA using the 13-month average in-service value incremental to 2025 consistent with the methodology used for the Generation Base Rate Adjustment in the 2021 Agreement.

b. Refer also to the calculation of the Generation Base Rate Adjustments in the 2021 Agreement that is duplicated in Mr. Chronister's Exhibit No. JC-1 Document No. 2 at 87 of 139. In that calculation, the Company agreed to revise its originally filed calculation of the return on rate base component associated with the assets so that the "NOI Multiplier" applied only to the equity return and not to the debt return.

c. Confirm that the "NOI multiplier" in the Subsequent Year Adjustment revenue requirement calculation was applied to both the equity return and the debt return in the return on rate base portion of the quantification.

d. Explain why the Company did not break out the calculation of the return into a separate equity return and debt return and apply the "NOI Multiplier" solely to the equity return, consistent with the methodology reflected in the Generation Base Rate Adjustment in the 2021 Agreement.

e. Confirm that the Company's application of the NOI multiplier to the debt return is an error given that interest expense is a deduction for income tax purposes.

f. Provide a revised calculation of the Subsequent Year Adjustment revenue requirement amounts for both 2026 and 2027 that uses the same "NOI Multiplier" methodology as used for the Generation Base Rate Adjustment in the 2021 Agreement in electronic format with all formulas in place.

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ANSWER:

a. This is an accurate depiction of what is stated in direct testimony of Witness Chronister, Volume II. Witness Chronister adopted the prepared direct testimony of Witness Latta on May 2, 2024 (DN 02697-2024),

b. This is an accurate depiction of what in Witness Chronister's Exhibit No. JC-1 Document No. 2 at 87 of 139.

c. Yes, the "NOI multiplier" in the Subsequent Year Adjustment revenue requirement calculation was applied to both the equity return and the debt return in the return on rate base portion of the quantification.

d. The 2021 Agreement was the result of a settlement among the parties. Thus, the methodology reflected in the Generation Base Rate Adjustment in the 2021 Agreement was the result of a settlement among the parties. In this proceeding, the method proposed for the SYA is similar to the method proposed for the GBRA in the petition filed in the prior rate case. The Company did not break out the calculation of the return, but rather the company applied an NOI multiplier to the entire return component because the company views that as a reasonable proposal in the context of a rate case proceeding.

e. The company does not consider this to be an error. The company considers the method used in the Subsequent Year Adjustment calculation reasonable as described in the answer to subpart (d) of this response.

f. While the methodology set out in question (f) does not match the methodology proposed by the company in this proceeding, the company made the calculation requested in this interrogatory.

The company will be answering by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see the attached excel file showing the requested calculation of the Subsequent Year Adjustment revenue requirement.

Tampa Electric Company
Storm Protection Plan Estimate
Calculation of the Projected Period Amount
2020 to 2029

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Asset Upgrades
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
1.	Investments													
	a. Expenditures/Additions		$0	$0	$0	$0	$275,000	$550,000	$687,500	$687,500	$687,500	$687,500	$687,500	$687,500
	b. Clearings to Plant		0	0	0	0	0	0	0	0	2,887,500	687,500	687,500	687,500
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	0	0	2,887,500	3,575,000	4,262,500	4,950,000
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	83	330	811	1,526	(6,188)	(15,730)	(27,101)
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	275,000	825,000	1,512,500	2,200,000	0	0	0	0
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	275,000	825,083	1,512,830	2,200,811	2,889,026	3,568,813	4,246,770	4,922,899
6.	Average Net Investment		0	0	0	0	137,500	550,041	1,168,956	1,856,821	2,544,919	3,228,919	3,907,791	4,584,834
7.	Return on Average Net Investment													
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	683	2,733	5,809	9,228	12,647	16,046	19,420	22,785
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	199	796	1,692	2,688	3,684	4,674	5,656	6,636
			0	0	0	0	882	3,529	7,501	11,916	16,331	20,720	25,076	29,421
8.	Investment Expenses													
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	8,663	10,725	12,788
	b. Depreciation Savings		0	0	0	0	0	(83)	(248)	(481)	(715)	(949)	(1,183)	(1,416)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	882	3,447	7,254	11,435	15,616	28,434	34,619	40,792
	a. Recoverable Costs Allocated to Energy		0	0	0	0	441	1,724	3,627	5,718	7,808	14,217	17,310	20,396
	b. Recoverable Costs Allocated to Demand		0	0	0	0	441	1,724	3,627	5,718	7,808	14,217	17,310	20,396
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	441	1,724	3,627	5,718	7,808	14,217	17,310	20,396
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	441	1,724	3,627	5,718	7,808	14,217	17,310	20,396
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$882	$3,447	$7,254	$11,435	$15,616	$28,434	$34,619	$40,792

Notes:

(A) Line 6 x Line 61 x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(B) Line 6 x Line 62 x 1/12 (Jan-Dec)
(C) Applicable depreciation rate is 3.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

WACC												
ROI-Equity Rate	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%	5.9635%
ROI-Debt Rate	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%	1.7369%