BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: DOCKET NO. 20250011-EI

Petition for rate increase by
Florida Power & Light Company.
_____/

VOLUME 16
PAGES 3458 - 3696

PROCEEDINGS: HEARING

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

DATE: Tuesday, October 14, 2025

TIME: Commenced: 9:00 a.m.
Concluded: 6:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
237-243	As identified in the CEL		3581
980	As identified in the CEL		3581
982	As identified in the CEL		3581
1431	As identified in the CEL		3581
1491	As identified in the CEL		3581
29-43	As identified in the CEL		3694

P R O C E E D I N G S

(Transcript follows in sequence from Volume 15.)

CHAIRMAN LA ROSA: Good morning. Everybody. So we are -- we have got, obviously, a list of witnesses here today. My understanding is that we are going to hear from FIPUG's witness, Pollock, first.

MR. MOYLE: That's right, and I would like to express my appreciation to all of the parties for working with us on getting him up and out first thing, so thank you.

CHAIRMAN LA ROSA: Excellent. No problem. Thank you. And thank you to all the parties. This has been going -- this is an ongoing sentiment throughout the entire hearing and the process in preparing for these couple of weeks, so thank you all for doing that, and thank goodness everything has worked good so far.

So let's go ahead and start the day and turn it over to you. You may call your witness.

MR. MOYLE: Okay. Thank you, we would call Mr. Jeff Pollock to the stand, and he has not been sworn.

CHAIRMAN LA ROSA: Yes.

Mr. Pollock, do you mind raising your right hand?

Whereupon,

JEFFRY POLLOCK

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

THE WITNESS: Yes.

CHAIRMAN LA ROSA: Excellent. Great. Thank you.

Sir, feel free to get settled in and get situated. The microphone in front of you, I would like you to turn it on when you start speaking.

And, Jon, I turn it over to you, sir.

EXAMINATION

BY MR. MOYLE:

Q Mr. Pollock, would you please state your name and business address for the record?

A Jeffrey Pollock. 14323 South Outer Forty Drive, St. Louis, Missouri, 631 -- 63017.

Q And did you cause direct testimony and Exhibits 1 to 7 to be filed in this case on June 9th --

A Yes.

Q -- 2025?

A Yes.

Q Did you also cause to be filed errata on June -- I am sorry, July 17th, 2025?

A Yes.

Q And if I asked you the questions today that are set forth in the prefiled testimony, would your answers be the same?

A Yes.

MR. MOYLE: Mr. Chair, I move that the testimony of Mr. Pollock be admitted into the record as though read.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of Jeffry Pollock was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Florida Power & Light Company for Base Rate Increase	**DOCKET NO. 20250011-EI** **Filed: June 9, 2025**

CONFIDENTIAL INFORMATION REDACTED

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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LIST OF EXHIBITS

Exhibit	Description
JP-1	Authorized Return on Equity for Vertically Integrated Electric Investor-Owned Utilities in Rate Cases Decided in 2023 Through May 2025
JP-2	Authorized Common Equity Ratio for Vertically Integrated Electric Investor-Owned Utilities With "A" Moody's Ratings
JP-3	Monthly Peak Demands as a Percent of the Annual System Peak Demand
JP-4	Summary of FIPUG's Revised Class Cost-of-Service Study Results at Present Rates
JP-5	FPL Proposed Class Revenue Allocation Forecast Test Year Ending December 31, 2026
JP-6	FIPUG's Recommended Class Revenue Allocation Forecast Test Year Ending December 31, 2026
JP-7	Size Thresholds Applicable to Very Large Load Customers

C40-4424

GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
2021 Agreement	Stipulation and Settlement Agreement in Docket No. 20210015-EI
12CP+8% AD	Twelve Coincident Peak + 8% (or 1/13th) Average Demand
12CP+25% AD	Twelve Coincident Peak + 25% Average Demand
BESS	Battery Energy Storage System
CDR	Commercial/Industrial Demand Reduction Rider
CIAC	Contribution in Aid of Construction
CILC-1	Commercial/Industrial Load Control Program
CCOSS	Class Cost-of-Service Study
DEF	Duke Energy Florida
ECCR	Energy Conservation Cost Recovery
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
GSD(T)	General Service Demand / GSD – Time of Use
GSLD(T)	General Service Large Demand / GSLD – Time of Use
FERC	Federal Energy Regulatory Commission
IGC	Incremental Generation Charge
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
kW / kWh	Kilowatt / Kilowatt-Hour
LLCS	Large Load Contract Service
LOLP	Loss of Load Probability
MFR	Minimum Filing Requirement

Term	Definition
Moody's	Moody's Ratings (f/k/a Moody's Investor Services)
MW	Megawatts
NERC	North American Electric Reliability Corporation
O&M	Operation and Maintenance
PTC	Production Tax Credit
ROE	Return on Equity
ROR	Rate of Return
RRA	Regulatory Research Associates
RROR	Relative Rate of Return
RSAM	Reserve Surplus Amortization Method
SERC	SERC Reliability Corporation
T&D	Transmission and Distribution
TAM	Tax Adjustment Mechanism
TECO	Tampa Electric Company

C40-4426

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 14323 South Outer Forty Rd., Suite 206N, St. Louis, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science in electrical engineering and a Master of Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and in several Canadian provinces. This includes frequent appearances in rate cases and other regulatory proceedings before this Commission. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). A substantial number of FIPUG members purchase electricity from Florida Power & Light Company (FPL). They are among the largest FPL customers and consume significant quantities of electricity, often around-the-clock, and require a reliable, affordably-priced supply of electricity to power their operations. FIPUG has been actively participating and representing its members' interests for decades in regulatory and

legal proceedings, including FPL rate cases, before the Commission and the Florida Supreme Court. Therefore, FIPUG members have a direct and substantial interest in the issues raised in, and the outcome of, this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A First, I present an overview of FPL's proposals, including the primary cost drivers for the proposed base revenue increases and FPL's requested return on equity (ROE). Second, I address the following specific issues:

- Class cost-of-service study (CCOSS);
- Class revenue allocation;
- Contribution in Aid of Construction (CIAC) policy; and
- Large Load Contract Service (LLCS).

Q ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?

A Yes. My colleague, Mr. Jonathan Ly, will address FPL's proposed 29% reduction to the credits paid under the Commercial/Industrial Demand Reduction Rider (CDR) and Commercial/Industrial Load Control Program (CILC-1) rate schedules. He also sponsors FIPUG's recommended CCOSS.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-7**.

Q ARE YOU ACCEPTING FPL'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. In various places, I use FPL's proposed revenue requirement to illustrate certain

cost allocation and rate design principles. These illustrations, in no way, provide an endorsement of FPL's revenue requirement or any other proposals on issues not addressed in my testimony.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Overview

- FPL's proposed base revenue increase and subsequent year adjustment is being driven by $18.4 billion of rate base additions and related costs (*i.e.,* operation and maintenance (O&M), depreciation, and property taxes), and a higher cost of capital, which is primarily driven by an increase in the ROE from 10.8% under the Stipulation and Settlement Agreement (2021 Agreement) which resolved FPL's last rate case in 2021, to 11.9%.[1]
- FPL's proposed 11.9% ROE is 110 basis points higher than its currently authorized ROE, 209 basis points higher than the 9.81% average ROE authorized by state regulatory commissions nationwide for other vertically-integrated electric investor-owned utilities (IOUs) in rate case decisions in 2023 through May 2025, and between 140 and 160 basis points higher than the ROEs the Commission authorized for Duke Energy Florida (DEF) and Tampa Electric Company (TECO) in their respective 2024 rate cases.[2] The 110 basis point increase in ROE accounts for about $1,152 million of the $2,478 million cumulative base revenue increases for the 2026 and 2027 projected test years. Setting FPL's ROE to 10.5%, the same as approved for TECO, would reduce FPL's cumulative base revenue increases by $1,412 million.

[1] The original Stipulation and Settlement provided for an ROE of 10.6% - however, contained therein was a trigger provision which increased its ROE to 10.8% beginning Sept. 1, 2022. *In Re: Petition for Rate Increase by Florida Power & Light Company*, Docket No. 20210015-EI, Order Implementing Florida Power & Light Company's Return on Equity Trigger at 5 (Oct. 21, 2022). See also, Docket No. 20210015-EI, *Final Order Approving 2021 Stipulation and Settlement Agreement* at 17 (Dec. 2, 2021) and *Amendatory Order* (Dec. 9, 2021).

[2] *In Re: Petition for Rate Increase by Duke Energy Florida, LLC*, Docket No. 20240025-EI, Final Order Approving 2024 Settlement Agreement at 10 (Nov. 12, 2024) and *In Re: Petition for Rate Increase by Tampa Electric Company*; Docket No. 20240026-EI, Final Order Granting In Part and Denying In Part Tampa Electric Company's Petition for Rate Increase at 95 (Feb. 3, 2025).

- FPL's financial capital structure is comprised of 59.6% equity and 41.4% debt. This stands in stark contrast to other IOUs with an "A" rating from Moody's Ratings (Moody's) which, on average, are capitalized with only 53.2% equity. Equity financing is more costly than debt financing because the ROE includes a risk premium over the cost of debt and, further, because equity returns are subject to income taxes. Reducing FPL's financial equity ratio from 59.6% to 53.2% would lower its proposed (2026-27) base revenue increases by over $1 billion.

- Florida is viewed as a very constructive regulatory environment for IOUs. Further, a large percentage (39% to 40%) of FPL's annual revenues are collected in various cost recovery mechanisms that allow rates to be adjusted outside of base rate cases. This constructive regulatory environment, coupled with its substantially above-average equity ratio and the risk mitigation measures FPL is proposing (*i.e.,* base rate adjustments to recognize changes in income tax rates, Tax Adjustment Mechanism (TAM), CIAC policy change), is compelling evidence that FPL faces significantly less regulatory risk than many of its peer IOUs. Accordingly, FPL's regulatory risk should be reflected by approval of a lower equity ratio that is more in line with the authorized financial equity ratio for DEF (at 53%) and TECO (at 54%) and an ROE that is more in line with the authorized ROEs for DEF and TECO.

Class Cost-of-Service Study

- FPL filed two sets of CCOSSs for each projected 2026-2027 test year. One set of studies allocates production plant and related expenses using the Twelve Coincident Peak and 25% Average Demand (12CP+25% AD) method. The second set of studies uses 12CP+8% (or 1/13th) AD as required by the Commission's rules. In both sets of studies, transmission plant and related expenses are allocated using the Twelve Coincident Peak (12CP) method.

- FPL is proposing to set rates in this proceeding using 12CP+25% AD rather than 12CP+8% AD.

- Neither the 12CP+25% AD, 12CP+8% AD, nor the 12CP method reflect the reality that FPL is a summer-peaking utility. The summer peak demands drive the need to install capacity to maintain system reliability. This is because 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. If system planners installed capacity sufficient to serve the average of 12 monthly peak demands, FPL would not be able to serve all of its load during the peak periods.

- FPL's rationale for allocating 25% of production on Average Demand is to recognize the increasing role energy is given in generation facility planning and the increasing amounts of tax subsidized rate-base intensive utility scale solar generation that FPL plans to install during its proposed four-year rate plan that spans calendar years 2026 through 2029. FPL asserts that these solar plant additions will lower system fuel costs – hence the justification for weighting energy by 25% instead of 8%.

- Although solar plants produce zero-cost energy and may lower system fuel costs, FPL has recognized that its increasing dependence on solar is causing both operational challenges and diminished reliability, thereby requiring FPL to install increasing amounts of battery energy storage systems (BESS) to stabilize the grid while the sun is setting. In essence, the zero-cost energy is driving FPL to spend twice the capital to prevent costly outages.

- Besides the fact that 25% is arbitrary and unsupported, the solar plants comprise but one component of an integrated generation fleet that is designed to match supply and demand in real time. Thus, there is no valid reason to use different methods to allocate the costs of solar plants than are used to allocate the costs of all other FPL generating plants.

- Production and transmission plant and related expenses should be allocated using the Four Coincident Peak (4CP) method. The 4CP method appropriately recognizes that FPL is a summer-peaking utility. The summer months are also when generation capacity is more limited and the transmission system experiences its lowest load carrying capability. Therefore, the 4CP method allocates production and transmission costs to the cost-causers; that is, it more appropriately recognizes cost-causation principles than either the 12CP or 12CP+25% AD methods.

- 4CP is a necessary improvement over the 12CP method that has been used in past rate cases. The 4CP method recognizes the reality that FPL is a summer-peaking utility. The summer peak demands drive the need to install capacity to maintain system reliability. The 4CP method is based on demands that occur coincident with the summer (June, July, August, and September) test-year peak demands. 4CP recognizes that it is the summer peak demands that primarily drive the need for new capacity additions to maintain reliability.

- The 4CP method is further supported by FPL's stochastic loss of load probability (LOLP) analysis, which confirms that FPL's reliability needs are mostly concentrated during the summer months with little or no concerns during the non-summer months, except during scheduled maintenance periods.

- Further, the Commission recently approved 4CP for both production and transmission plant and related expenses in the most recent TECO rate case (Docket No. 20240026-EI). Like FPL, TECO's monthly peak demands are spikey. This lends further support that the 4CP method is consistent with cost-causation principles and accepted regulatory practice.

- FPL classifies all distribution network investment and related expenses as demand-related costs. This practice is not consistent with cost causation because it fails to recognize that the distribution system must be ready to serve load, irrespective of customers' power and energy requirements. For example, without the investments required to provide voltage support, electricity cannot flow from the transmission system to serve distribution customers. Thus, a portion of distribution network should be classified as a customer-related cost.

- Classifying a portion of the distribution network as a customer-related cost is an accepted practice in many regulatory jurisdictions.

- FPL has not conducted any analysis to quantify the customer-related costs of the distribution network. Therefore, the Commission should require FPL to conduct a study to quantify the cost to provide voltage support and determine whether there are other specific identifiable distribution network costs that are required for grid-readiness. This study should be filed no later than 90 days prior to filing a test-year letter for the next rate case.

- FPL provides non-firm service to the CILC customer classes and to certain General Service Demand (GSD(T) and General Service Large Demand (GSLD(T)) customers who have opted into Rider CDR. As Mr. Ly discusses in his testimony, non-firm service is a lower quality of service than firm service. Non-firm service provides additional resources that are available to serve firm loads when necessary during periods of resource inadequacy, either on the FPL system or throughout the state of Florida. Thus, the cost to provide non-firm service (*i.e.,* the interruptible credits) is properly allocated to firm customers.

- FPL treats all non-firm load as firm load in its CCOSS. Consistent with this assumption, FPL adjusted base revenues to remove the payments received under the CILC rates and Rider CDR (*i.e.,* the interruptible credits) directly from the CILC and certain GSLD classes that take non-firm service.

- However, in the Energy Conservation Cost Recovery (ECCR) Clause, FPL allocates the interruptible credits using the same production demand allocation method as is used to allocate production plant, but non-firm load is included. This allocation effectively charges CILC and those customers in the GSLD classes that receive non-firm service for a portion of the capacity benefits these

customers provide for the sole benefit of firm service. Put simply, it is unfair for customers who voluntarily agree to be disrupted by FPL during critical peak load conditions and are paid by FPL to be available, to contribute to the payments that ultimately are used to pay the interruptible customers. The circular logic of this construct is unreasonable. Customers who agree to be interruptible should not be required, in effect, to make payments to themselves for being interruptible.

- To negate the impact of charging CILC and certain GSLD customers for the cost of non-firm service in the ECCR, a further adjustment is required to the CCOSS. Specifically, FPL should spread the interruptible credits that would otherwise be charged to the CILC and applicable GSLD classes to all firm customers in proportion to their amount of firm load. This is discussed more fully in the testimony of Mr. Ly.

- Mr. Ly recommends further changes to FPL's CCOSS for certain rate base and net operating income allocations that do not reflect cost causation.

Class Revenue Allocation

- FPL misapplied the Commission's long-standing policy to limit the movement to cost because it used 1.5 times each class's *operating* revenues (*i.e.,* base revenues + clause revenues + CILC/CDR incentive payments + non-sales revenues), rather than 1.5 times each class's total bill (*i.e.*, base revenue + clause revenues). For the CILC and certain GSLD classes, total operating revenues are further inflated because they improperly include the CILC/CDR incentive payments paid to CILC and CDR customers for demand response.

- Further, in applying the 1.5 times constraint, FPL did not reflect the impact of using the 12CP+25% AD method in various cost recovery clauses, such as the Capacity Payment Recovery and ECCR clauses, if it is approved by the Commission for production demand allocation. Currently, capacity related clause revenues are allocated to customer classes using the 12CP+8% AD method. Because 12CP+25% AD would increase clause revenues from non-residential customer classes (other than General Service), the impact must be reflected if gradualism is applied on the basis of total revenues.

- The sole issue in this case is to reset base rates. Thus, the proper application of gradualism should be to limit the increase to any customer class to not exceed 1.5 times the system average *base revenue* increase (excluding cost recovery clauses), and no class should receive a rate decrease. This approach also recognizes that gradualism is not applied to customer classes in clause-related adjustments.

- The Commission should adopt FIPUG's proposed class revenue allocation as shown in **Exhibit JP-6** for the 2026 test year. The target base revenue requirements for 2027 should be set using the recommended target 2026 base revenues.

- If the Commission authorizes lower increases than FPL has proposed, the target base revenues shown in **Exhibit JP-6** should be adjusted proportionally, subject to the above-stated constraints.

Contribution in Aid of Construction

- FPL's proposed CIAC policy would be a significant and drastic change over the current long-standing policy. The new policy is also a response to the potential influx of new very large load customers and the significant capital spend for new and/or upgraded facilities. Because FPL may not be the only utility in Florida affected by new very large loads, and as the CIAC policy is based on a specific rule (25-6.064 FAC), the Commission should consider vetting any changes to a utility's current policy, such as FPL's proposals, in a general rulemaking proceeding.

- The most significant change is that the proposed CIAC policy would apply (as of the rate-effective date) to ***all*** non-governmental customers with *at least* 15 megawatt (MW) of load who require FPL to install new facilities or to ***any*** new load for which FPL estimates spending *at least* $25 million for all new and/or upgraded facilities. Specifically, the customer would pay for 100% of the cost upfront before service commences. Under the current policy, new or existing customers pay the portion of the estimated costs that exceed four times the annual base revenue. Effectively, the new CIAC policy would shift cost recovery risk from FPL to the affected customers. FPL has offered little to suggest the current CIAC policy is unworkable.

- The current CIAC policy has been in place for decades — and worked well — even for customers with loads as large as several of FPL's current customers with peak demands ranging from 15 MW to slightly over 50 MW. Other than the fact that FPL serves relatively few large load customers, FPL has not explained (1) why 15 MW is a reasonable size threshold; (2) how serving 15 MW of additional load is related to the $25 million incremental cost threshold; and (3) whether serving such loads would require material changes in its standard business practices that increase risk.

- FPL has not provided any evidence of an elevated risk to serve existing customers who add load to support expanding operations — something that clearly benefits the state and local economies in FPL's service territory.

Current FPL customers have already established a credit history and a known business relationship with FPL. Thus, the current CIAC policy should continue to apply to serve the growing needs of FPL's existing customers.

- Absent clear and compelling evidence to the contrary, the new CIAC policy should apply when customers request more than 50 MW of new load, and the required spend for new and/or upgraded facilities exceeds the costs that are supported under the applicable base rates.

- The five-year period for refunding an upfront CIAC should be extended for customers who have a specified load ramp period – to provide a reasonable opportunity for the customer to recoup the initial payment.

Large Load Contract Service

- FPL is seeking approval of the proposed LLCS-1 and LLCS-2 rate schedules and the proposed LLCS Agreement. As proposed, these rates would apply to new large (25 MW or higher) loads that operate at an 85% or higher load factor.

- The proposed LLCS rates would include a demand charge based on an ever-changing Incremental Generation Charge (IGC) and terms and conditions that, coupled with credit support requirements, would ensure payment of the applicable fixed costs over the proposed 20-year contract term, even if service is terminated early. These terms, which are far more stringent than those that apply to existing FPL customers, would subject LLCS customers to significant risks and price uncertainty.

- FPL may not be the only Florida electric utility that could experience significant growth from new very large load customers. Further, the proposed LLCS rate schedules and Agreement are unlike any other tariff structure approved by the Commission to date. Accordingly, in lieu of vetting the LLCS issues in this rate case, the Commission should consider a rulemaking proceeding to establish standard policies and practices that would apply to all new very large load customers served by Florida utilities.

- If the Commission opts to vet the proposed LLCS rate schedules and Agreement in this proceeding, it should adopt certain special protections to ensure that the significant investments required to serve new very large load customers are not shifted to existing FPL customers. However, some of the proposed LLCS pricing and terms and conditions are overreaching and unnecessary and need to be addressed prior to approval to ensure the potential LLCS customers are treated fairly.

- For example, FPL is already accustomed to serving customers with loads of 25 MW or more. Thus, 25 MW is neither an unusual nor extraordinarily large load and, further, the low size threshold may ultimately force existing FPL customers onto the LLCS rate, namely those who are planning to add load and/or make process improvements (which result in increasing the customer's size and load factor) after the rate-effective date. Under no circumstances should any existing FPL customer be forced onto LLCS.

- Incremental pricing is also overreaching because an LLCS customer would be charged an all-in cost for electricity that exceeds the all-in cost to serve similarly situated transmission loads. Incremental pricing is fundamentally incompatible with long-standing ratemaking practices in which rates are set based on average or embedded generation costs. Incremental pricing would not protect existing customers from experiencing higher fuel costs caused by growing loads.

- While FPL does not expect to provide service to any LLCS customers during the test years, FPL is projecting to serve data center loads that are substantially larger than the proposed 25 MW size threshold — and in some cases may substantially exceed 50 MW. A new 50 MW load would have a more direct and significant impact on resource planning, than a 25 MW load.

- FPL is not the only utility that is projecting an influx of new very large loads and proposing special terms and conditions that would apply to these loads. However, the size thresholds established by other electric utilities are much higher, ranging from 50 MW to over 100 MW.

- If LLCS is approved, the size threshold should be set no lower than 50 MW, and it should apply only to 50 MW or more of new load that is not located at, or adjacent to, an existing load, and only if the customer's total annual load factor is 85% or higher. Setting a higher size threshold and limiting its applicability to only new loads, thereby excluding existing customers or premises that may expand in the future, will avoid undue discrimination while protecting existing FPL customers.

- Because LLCS customers would be contractually committed to 20-year, or longer, contracts with minimum demand charges and exit fees for early termination, there is no justification for incremental pricing. However, if incremental pricing is approved, then LLCS customers should be charged the fixed and variable costs (including fuel) of the incremental capacity additions.

- FPL's test-year revenue requirements do not include any LLCS customers. If FPL commits to serving LLCS customers in 2028 and 2029 as projected, the Commission should require FPL to file a limited proceeding in 2027 with updated Minimum Filing Requirements (MFRs) to ensure that the base rates set in this proceeding continue to be just and reasonable.

C40-4437

2. OVERVIEW

Q WHAT BASE RATE INCREASES IS FPL PROPOSING TO IMPLEMENT?

A FPL is proposing a "four-year rate plan" that would increase base rates by $1,544.8 million (16.9%) in 2026 followed by a $933 million (8.3%) increase in 2027.[3] Subsequent year base rate increases would reflect the costs associated with 3,278 MW of solar and 1,192 MW of BESS projects that FPL expects to place in service in calendar years 2028 and 2029.[4] These projects would raise base rates by an additional $562 million.[5]

Q HAVE ANY OTHER BASE RATE INCREASES BEEN IMPLEMENTED RECENTLY?

A Yes. FPL implemented base rate increases pursuant to the 2021 Settlement Agreement. The last of these increases was implemented just this year. Over the past four years, base rates have increased by 17.8%.

Q WHAT ARE THE PRIMARY REASONS FOR FPL'S PROPOSED BASE RATE INCREASE?

A FPL expects to add nearly $18.4 billion of rate base through 2027.[6] The $18.4 billion of rate base additions include:

- 2,086 MW of new solar projects: $3,128.1 million;[7]
- 2,239 MW of new four-hour BESS projects: $3,236.5 million;[8] and
- Various other plant additions: $12,020 million.[9]

[3] Direct Testimony of Tara Dubose, Exhibit TD-3 at 1-2.
[4] Application at 24.
[5] FPL Response to FEL INT No. 1, Attachment No. 1.
[6] MFR Schedule B-11.
[7] *Id.*, Direct Testimony of Tim Oliver at 5.
[8] *Id.*
[9] MFR Schedule B-11.

Additionally, FPL is proposing higher depreciation and dismantling expenses and a much higher cost of capital. This includes an increase in ROE from 10.8% to 11.9%.[10] ***The 110-basis points of higher ROE drives about $1,152 million (over 46%) of the proposed $2,478 million base revenue increases in 2026 and 2027.***

Q WHAT ARE YOUR SPECIFIC CONCERNS WITH FPL'S PROPOSED RETURN ON EQUITY?

A As shown in **Exhibit JP-1**, FPL's proposed 11.9% ROE is excessive when compared to the ROEs authorized by state regulatory commissions in rate cases decided in 2023 through May 2025 for vertically-integrated electric IOUs. As can be seen, the average ROE authorized by state regulators is 9.81% for this same period.

Q ARE FLORIDA ELECTRIC IOUS DEMONSTRABLY RISKIER THAN VERTICALLY-INTEGRATED ELECTRIC IOUS IN OTHER REGULATED STATES?

A No. First, the regulatory climate in Florida is *very* supportive of Florida electric IOUs, which translates into lower risk for investors. This directly reflects the Commission's ratemaking policies, which include: the use of a projected test year and multi-year rate plans; timely cost recovery as reflected in both interim rate increases and in the various cost recovery clauses that allow rates to be adjusted outside of a rate case; allowing a return on construction work in progress; and authorizing securitization (or prompt cost recovery) for storm damage and other major events. These risk-lowering policies are described in a 2021 assessment of Florida regulation conducted by Regulatory Research Associates (RRA) which ranked Florida above 46 other states for investor supportiveness by giving it a score of Above Average/2. RRA stated:

[10] Petition at 2.

> ***Florida regulation is viewed as quite constructive from an investor perspective*** by Regulatory Research Associates, a group within S&P Global Commodity Insights. In recent years, ***the Florida Public Service Commission has issued a number of decisions, most of which adopted multiyear settlements that were supportive of the utilities' financial health***. Florida has not restructured its electric industry, and the state's utilities remain vertically integrated and are regulated within a traditional framework. PSC-adopted equity returns have tended to exceed industry averages when established, and ***the commission utilizes forecast test years and frequently authorizes interim rate increases. As a result, utilities are generally accorded a reasonable opportunity to earn the authorized returns.*** In addition, a constructive framework is in place for new nuclear and integrated gasification combined cycle coal power plants that allows a cash return on construction work in progress for these investments outside of the base rate case process. Whether any of the state's electric utilities will proceed with the construction of nuclear power plants in the foreseeable future remains questionable given the challenges such projects posed for utilities in neighboring states in recent years. State law permits the electric utilities to securitize certain nuclear generation retirement or abandonment costs, and one of the state's major companies has done so. ***Mechanisms are in place that allow utilities to reflect in rates, on a timely basis, changes in fuel, purchased power, certain new generation, conservation, environmental compliance, purchased gas and other costs. Additionally, the state has been very proactive in providing utilities cost-recovery mechanisms for costs related to major storms. Additionally, in 2019 the state adopted a Storm Protection Plan Cost Recovery Clause that allows utilities to seek more timely recovery of storm hardening investments outside a general rate case.*** RRA currently accords Florida regulation an Above Average/2 ranking. (Section updated 4/29/21)[11] (emphasis added)

The Florida Commission's ranking remains at Above Average/2.[12] Two states rank equal to Florida and only one state regulatory commission, Alabama, is ranked higher.

[11] S&P Capital IQ [PRO], RRA Evaluation of the Florida Public Service Commission.

[12] *Id.*, RRA Regulatory Focus, RRA State Regulatory Evaluations – Energy at 4 (Mar. 11, 2025).

Q WHAT PERCENTAGE OF FPL'S REVENUES ARE SUBJECT TO RECOVERY UNDER THE VARIOUS COST RECOVERY MECHANISMS AUTHORIZED BY THE COMMISSION?

A FPL's projects that cost recovery mechanisms would account for 40% and 39% of its projected annual sales revenues in the 2026 and 2027 test years, as shown in Table 1.

Table 1
Percent of Revenues Collected Under the Various Commission-Approved Cost Recovery Mechanisms ($Millions)

Mechanism	2026	2027
Fuel	$3,651.0	$3,542.8
Capacity	$64.0	$62.6
Environmental	$466.0	$442.7
Conservation	$93.8	$88.4
Storm Protection	$1,038.0	$1,179.9
Regulatory Assmt. Fee	$13.5	$13.6
Franchise Fees	$665.3	$667.9
Gross Receipts Taxes	$371.9	$374.0
Total Clause Revenues	$6,267.6	$6,255.7

Source: FPL Response to OPC POD 14 (Rates-Clauses).

Q IS THERE ANY APPRECIABLE REGULATORY LAG IN BASE RATE CASES?

A No. There is no appreciable regulatory lag in setting base rates. The Commission is statutorily required to render a decision within eight months after a base rate case is filed. However, because the Commission has authorized the use of a fully projected future test year, the rates approved by the Commission and placed in effect during the test year will exactly recover the Commission-approved projected test-year costs to serve – unless, of course, actual sales, investment, and expenses vary from the utility's projections. Further, the Commission has consistently allowed utilities to propose

subsequent year adjustments that provide for cost recovery of specific assets placed in service after the rate case test year. Thus, there is virtually no regulatory lag in recovering even the costs of future plant additions.

Q WHAT DOES THE ABSENCE OF ANY APPRECIABLE REGULATORY LAG MEAN IN SETTING AN AUTHORIZED RETURN ON EQUITY FOR FPL?

A The absence of any appreciable regulatory lag in setting base rates significantly reduces FPL's regulatory risk. This, coupled with this Commission's other supportive ratemaking policies (*i.e.,* future rather than historical test year, the ability to adjust rates outside of a base rate case through separate cost recovery annual clause mechanisms) demonstrate that FPL faces comparable (if not lower) regulatory risk as most other regulated vertically integrated electric IOUs. Therefore, the lower regulatory risk should translate into a lower ROE and equity capitalization than is authorized for other electric IOUs regulated by less supportive commissions.

Q ARE THERE ANY RISK-MITIGATION FACTORS THAT ARE UNIQUE TO FPL?

A Yes. First, FPL has maintained a substantially above-industry average financial equity ratio. **Exhibit JP-2** lists the financial equity ratios for vertically integrated electric IOUs with an "A" credit rating from Moody's, including FPL, DEF and TECO. The industry average for A-rated vertically integrated electric IOUs is 53.2%.

Table 2 summarizes FPL's financial equity ratio compared with its peer Florida utilities, DEF and TECO.

Table 2 Florida Vertically Integrated Electric Utilities Financial Equity Ratios	
Utility	**Percent**
FPL	59.6%
DEF	53.0%
TECO	54.0%

As can be seen, DEF and TECO maintain financial equity ratios of 53% and 54%, respectively. Setting FPL's common equity ratio to 53.2% would reduce its cumulative 2026-27 base revenue increases by over 1 billion.

Second, FPL is proposing the TAM. Modeled after the current reserve surplus amortization method (RSAM), the TAM would allow FPL to use up to $1,717 million in tax credits to offset revenue requirements in 2028 and 2029 to maintain an FPSC-adjusted ROE within the ROE range authorized by the Commission.[13]

Third, FPL proposes that any changes in tax laws that occur during the four-year rate plan that affect the corporate income tax rate or the value of either the production tax credits (PTCs) and/or investment tax credits (ITCs) be reflected by adjusting base rates without the need for a general rate case. As the tax credits authorized under the Inflation Reduction Act may be curtailed under pending legislation, this provision would significantly reduce FPL's operating risk, while also casting significant doubt on the cost-effectiveness of solar and BESS capacity additions currently planned for 2027, 2028, and 2029. Further, because FPL is proposing to transfer ITCs to a third party, which supports a one-year amortization of

[13] Direct Testimony of Ina Laney, Errata, p. 51, line 12; Direct Testimony of Scott R. Bores at 56.

the BESS additions during the four-year plan, any change in the ability to transfer clean energy tax credits to third parties could potentially trigger a rate adjustment. This is not a trivial matter because FPL's proposal to amortize ITCs over one-year provides a $512 million offset to the proposed 2026 base revenue increase.[14]

And finally, as discussed in more detail later, FPL is proposing to change the CIAC policy to require certain customers to fully pay for all costs associated with any new and/or upgraded facilities – a policy FPL is unaware of having been adopted by any other utility.[15] This policy change effectively shifts the risk of under-recovery from FPL to the affected customers.

All of these risk-mitigating factors, unique to FPL, significantly reduce FPL's regulatory and financial risks. If adopted, these factors would clearly support an ROE that is more in line with the ROEs approved for DEF and TECO.

[14] Direct Testimony of Ina Laney at 23.

[15] FPL Response to FIPUG Interrogatory No. 48.

3. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each customer class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups, or classes. Most of a utility's costs are incurred to jointly serve many customers; therefore, the CCOSS provides a mechanism for allocating the utility's costs to customers in a reasonable way based on cost causation. For purposes of rate design and revenue allocation, customers are grouped into homogeneous customer classes according to their usage patterns and service characteristics. A more in-depth discussion of the procedures and key principles underlying CCOSSs is provided in **Appendix C**.

Q HAS FPL FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS PROCEEDING?

A Yes. FPL filed CCOSSs for each of the two (2026-2027) test years utilizing two different methodologies. FPL's preferred study uses 12CP+25% AD.[16] FPL also filed a CCOSS using the 12CP+8% AD method.[17] The latter methodology is required by this Commission's filing requirements.

Q SHOULD EITHER OF THESE STUDIES BE USED TO SET CLASS REVENUE REQUIREMENTS IN THIS CASE?

A No. FPL's filed CCOSSs are flawed and cannot be used to determine class revenue requirements.

[16] Direct Testimony of Tara DeBose at 24-25.

[17] *Id.*

Q WHAT ARE THE FLAWS WITH FPL'S CLASS COST-OF-SERVICE STUDIES?

A First, the 12CP+25% AD method is not consistent with cost-causation principles because it allocates costs to all hours of the year. Further, it is based on an unspecified and subjective assessment of the purported benefits associated with more capital intensive (solar) plants and a flawed and incomplete application of Capital Substitution theory. Capital Substitution erroneously assumes that the sole purpose of more capital-intensive power plants is to lower fuel costs, rather than meet expected peak demand. Further, the same theory is not applied to the allocation of fuel costs and, thus, it suffers from a lack of fuel symmetry. 12CP+25% AD also suffers from double-counting. For these reasons, many state regulatory commissions, including Florida, have rejected allocation methods similar to 12CP+25% AD.

Second, transmission demand-related costs were allocated to customer classes using the 12CP method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. FPL, however, is a summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.

Third, FPL failed to recognize that a portion of the distribution network is a customer-related cost, a practice that is both accepted and consistent with cost-causation principles.

Fourth, FPL did not recognize that the customers providing demand response on Rider CDR and the CILC rate schedules are improperly charged for a portion of the incentive payments they receive.

Fifth, as Mr. Ly discusses in his testimony, FPL allocated various rate base and net operating income components using total O&M expenses and/or O&M labor expense (*e.g.,* interest on long-term debt, revenue taxes, rent from electric property,

regulatory commission expenses) that have no clear relationship to O&M and/or labor expenses.

Q HOW SHOULD THE FLAWS IN FPL'S CLASS COST-OF-SERVICE STUDY BE CORRECTED?

A First, production and transmission demand-related costs should be allocated to customer classes using the 4CP method. The 4CP method is based on demands that occur coincident with FPL's summer period (June through September) peak demands. As discussed later, the 4CP method more fairly allocates costs to the cost-causers. The 4CP method was approved by this Commission for TECO because it more fairly allocates the costs, in addition to other reasons, such as promoting economic development.

Second, a portion of FPL's distribution network should be considered a customer-related cost, rather than 100% demand-related.

Third, a further adjustment should be made to the incentive payments to CILC and Rider CDR customers to ensure that these customers receive the full value of the demand response they provide to help maintain a reliable system and to mitigate curtailments to firm load customers.

Fourth, as previously stated, FIPUG witness, Mr. Ly, addresses additional changes that should be made to FPL's CCOSS.

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Production Plant

Q HOW IS FPL PROPOSING TO ALLOCATE PRODUCTION PLANT AND RELATED EXPENSES TO RETAIL CUSTOMER CLASSES?

A FPL recommends using an energy-based cost allocation methodology. Specifically, Ms. DeBose recommends the 12CP+25% AD method. Under 12CP+25% AD, production plant and related expenses would be allocated 25% to average demand and 75% to 12CP. Average demand, however, is the same as a pure energy allocator. Further, the 12CP method spreads costs to all twelve months. Thus, FPL's 12CP+25% AD method incorrectly allocates FPL's production capacity costs on power and energy usage throughout the year.

Q WHY DOES FPL PROPOSE ALLOCATING 25% OF FPL'S PRODUCTION PLANT ON A PURE ENERGY BASIS?

A FPL witness, Ms. Tara DeBose, asserts that the 12CP+25% AD method better aligns cost allocations with FPL's portfolio of generating resources and how the Company currently plans and operates its generating facilities. She cites significant amounts of solar generation, how solar is unique due to its zero fuel cost, and that solar constitutes a larger share of total generation costs.[18]

Q DO YOU AGREE WITH HER ASSERTION?

A No. First and foremost, the use of 12CP to allocate costs to a utility that has strong summer peak demands is contrary to cost causation. Giving substantial weighting to the non-summer months in allocating production and transmission costs ignores the reality that FPL is a summer-peaking utility. This is demonstrated in **Exhibit JP-3**, the results of which are summarized in Figure 1.

[18] *Id.* at 21.

Figure 1
Monthly Peak Demands as a Percent of
The Annual System Peak: 2022 – 2027

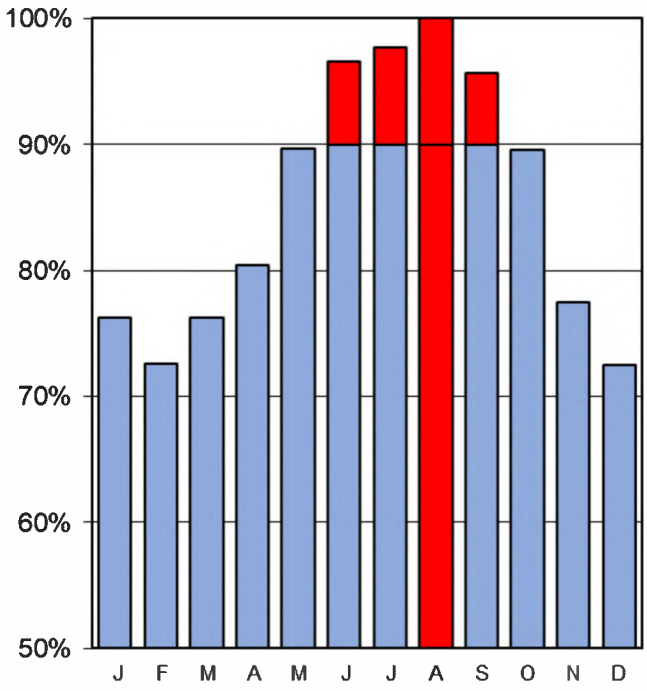

Figure 1 clearly demonstrates that FPL's peak demand loads occur in the summer months. 12CP would only be appropriate if FPL's loads were relatively flat and/or non-seasonal.

Q WHAT ARE YOUR CONCERNS WITH THE 12CP METHOD?

A 12CP gives approximately equal weighting to the power demands that occur during each of the 12 monthly system peaks. In other words, 12CP assumes that the demands occurring in the spring and fall months are as critical to system reliability as meeting summer period demands.

As can be seen from **Exhibit JP-3** and Figure 1, there are substantial differences in FPL's monthly system peak demands. Historically, the demands during the summer months have consistently been much closer to the annual system peak than the peak demands in the non-summer months.

Q IS FPL PROJECTING TO REMAIN A SUMMER PEAKING UTILITY?

A Yes.[19]

Q DOES THE 12CP METHOD BEST REFLECT COST CAUSATION?

A No. The 12CP method overlooks FPL's primary obligation, which is to have sufficient generation capacity to meet the expected system peak demand to ensure that "the lights stay on" and service is reliable. Once installed, the capacity to meet the expected peak demand is also available to meet system demand throughout the year. Thus, meeting system peak demand is the *cost-causer*, while serving loads in other periods is the *byproduct* of this obligation. Giving equal weight to non-peak months, such as March or November, dilutes the impact of demands occurring in peak months, such as July and August. FPL must plan for sufficient capacity to meet the expected summer peak demands if it is to continue providing reliable service to its firm customers. The 12CP method fails to recognize this reality, as well as FPL's own system planning principles.

To illustrate further, if FPL only had to plan for capacity to meet the average of the 12CPs during the (2026) test year, it would need only 24.7 MW, plus reserves. If FPL only had 24.7 MW of capacity plus reserves, it would not be able to meet the 27.4 MW to 28.6 MW peak demands that it is projecting in the summer months of June, July, August, and September 2026.[20] In other words, the lights would go out since FPL would have to curtail service to firm customers because it would have insufficient capacity to meet the expected firm system peak.

[19] MFR Schedule E-18.

[20] *Id.*

Q IS THERE AN AUTHORITY THAT SUPPORTS YOUR OPINION THAT 12CP IS NOT AN APPROPRIATE METHOD FOR FPL?

A Yes. The National Association of Regulatory Utility Commissioners' cost allocation manual states:

> This [the 12CP] method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky.[21]

Clearly, FPL's annual load shape is spiky and its non-summer monthly peaks do not lie within a narrow range.

Q HAS THE COMMISSION RECENTLY ADDRESSED THE ALLOCATION OF PRODUCTION PLANT AND RELATED EXPENSES?

A Yes. In the most recent TECO rate case, the Commission approved the 4CP method.

Q WHY DID THE COMMISSION APPROVE THE 4CP METHOD?

A The Commission stated:

> We are more persuaded by the testimony and evidence offered in support of the 4 CP methodology. We find that the selection of which CP months to use in this case was reasonable for the reasons stated above. Because TECO's peaks are primarily a function of energy consumption associated with weather, we find that there is a strong correlation between weather and residential and small commercial energy consumption. Large commercial and industrial customers tend to be high load factor customers and their consumption is not as strongly correlated to weather; therefore their energy consumption stays fairly consistent throughout the year. ***The 4 CP method more closely allocates costs to those customer classes of TECO that are responsible for driving up system peak demand. Giving equal weight to non-peak months via the 12 CP method would dilute the impact of demands occurring in peak months and therefore shift costs away from the cost-causers. We also find that TECO's transition from large coal-fired generation units to cleaner resources, like solar, has diminished the importance of shoulder months for operational planning and cost***

[21] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 46 (Jan. 1992).

> ***attribution purposes.*** Our decision is further supported by the testimony from TECO witness Williams stating an additional benefit of the 4 CP method is that it can serve as a catalyst for economic development by making manufacturers and other large employers in TECO's service territory more competitive than competing regions.
>
> Moreover, FIPUG and FEA offered testimony supporting 4 CP on the basis that it better addresses cost-causation principles by allocating costs to the cost-causer—the classes responsible for peak demand. Specifically, we are persuaded by the testimony that 4 CP allows TECO to meet system peak demand, which is the cost-causer, while simultaneously allowing TECO to plan for sufficient capacity to meet the expected summer peak and secondary winter peak demand.[22] (emphasis added)

Q ARE THERE ANY FUNDAMENTAL DIFFERENCES BETWEEN FPL AND TECO THAT WARRANT USING A DIFFERENT METHOD OF ALLOCATING PRODUCTION PLANT AND RELATED EXPENSES FOR FPL THAN WAS APPROVED FOR TECO?

A No. Both utilities are in the process of a significant transformation of their respective generation fleets through the retirement of coal-fired and older base load plants and the addition of significant amounts of solar plants. Further, both utilities have predominant seasonal monthly peaks: TECO in both the summer and winter months and FPL in the summer months. Finally, as explained in the TECO rate case, setting cost-based rates using the 4CP method will also enhance economic development by making manufacturers and other competitive enterprises in FPL's service territory more competitive.

[22] Docket No. 20240026-EI, *Final Order Granting in Part and Denying in Part Tampa Electric Company's Petition for Rate Increase* at 128 (Feb. 3, 2025).

Q IS THERE ADDITIONAL EVIDENCE THAT THE SUMMER PERIOD IS MORE CRITICAL FROM A RELIABILITY PERSPECTIVE?

A Yes. FPL's LOLP analysis reveals that the loss of load risk is mostly concentrated in summer evenings. Further, while outages also occur during shoulder months (spring and fall), this is because the shoulder months are when FPL conducts maintenance.[23] The fact that there is zero loss of load expectation during the winter period and for the vast majority of the spring and fall periods further demonstrates that these periods are irrelevant from a cost-causation perspective.

Q DOESN'T FPL'S LOLP ANALYSIS DEMONSTRATE THAT SOME PRODUCTION PLANT AND RELATED EXPENSES SHOULD ALSO BE ALLOCATED TO THE SHOULDER MONTHS?

A No. First, the stochastic LOLP analysis was limited to the FPL system.[24] Thus, it completely ignored the integrated nature of the electric utilities in Florida and in the SERC Reliability Corporation (SERC) Southeast region. The apparent stress on FPL's system during the shoulder hours is not solely — or even primarily — load driven. It is primarily driven by the increasing penetration of variable (solar) energy and hybrid (solar/BESS) resources that FPL continues to add to the system. This impact of variable and hybrid resources was addressed in recent industry reports. For example, the North American Electric Reliability Corporation (NERC) found:

> In the *2024 LTRA* [Long-Term Reliability Assessment], NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are

[23] Direct Testimony of Andrew W. Whitley, Exhibit AWW-1 at 30.

[24] Deposition of FPL expert Arne Olson.

> lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**[25] (emphasis added)

NERC also discusses the reliability implications of this changing resource mix.

> New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.
>
> As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.[26]

While NERC currently assesses the SERC Florida Peninsula region as having normal risk (because NERC's resource adequacy criteria are being met),[27] FPL's growing

[25] NERC, 2024 Long-Term Reliability Assessment at 6 (Dec. 2024).

[26] *Id.* at 8.

[27] NERC evaluates the following adequacy criteria for each of the first five years of the LTRA period (*i.e.,* 2025-2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss. (*Id.* at 12.)

dependence on intermittent generation will make the system increasingly more vulnerable to stresses. The stress is demonstrated by the growing resemblance of FPL's net peak load shape to a "duck curve."[28] The duck curve has created significant challenges for grid operators. In a recent posting by the U.S. Energy Information Administration:

> The duck curve presents two challenges related to increasing solar energy adoption. The first challenge is grid stress. The extreme swing in demand for electricity from conventional power plants from midday to late evenings, when energy demand is still high but solar generation has dropped off, means that conventional power plants (such as natural gas-fired plants) must quickly ramp up electricity production to meet consumer demand. That rapid ramp up makes it more difficult for grid operators to match grid supply (the power they are generating) with grid demand in real time. In addition, if more solar power is produced than the grid can use, operators might have to curtail solar power to prevent overgeneration. [29]

Q HAS FPL RECOGNIZED THE PROBLEMS ASSOCIATED WITH THE DUCK CURVE?

A Yes. During his deposition, FPL witness, Mr. Andrew Whitley, stated that:

> **Q So prior to E3 pointing out this potential resource inadequacy in the third quarter of 2024, was FPL aware of this resource -- potential resource adequacy issue?**
>
> A FPL was aware of potential operational concerns with our peaks, particularly during the net firm peak demand period. And so over the past two years, in conjunction with power delivery, the integrated resource team was looking at the potential for having enough operational reserves to adequately supply our customers during that time, and that led into E3's study, which led into the resource adequacy analysis.

[28] A duck curve refers to a very steep upward slope in net peak demand that occurs as the sun begins to set requiring a correspondingly rapid increase in the dispatch of thermal generation to offset a rapid decline in solar generation.

[29] As solar capacity grows, duck curves are getting deeper in California - U.S. Energy Information Administration.

Q But the operational issues that Florida Power & Light is aware of, were they related to or due to, in any way, the increase in solar?

A They were a result of our system at the time over the past two years, which included a large amount of solar. So that was a concern for our operational team.

Q So the addition of solar over those last two years contributed to the operational concerns FPL had, do I have that right?

A Yes. The solar shifted how our system was. We were adding solar because it was a cost-effective resource, and it did contribute to operational concerns that we needed to examine going forward.[30]

Q DO THESE DEVELOPMENTS HAVE ANYTHING TO DO WITH DETERMINING THE PROPER METHOD OF ALLOCATING PRODUCTION PLANT AND RELATED EXPENSES?

A No. These developments have nothing to do with FPL's obligation to provide capacity resources sufficient to meet the expected firm peak demands, and they do not change how production plant and related expenses are appropriately allocated to customer classes.

Q WHAT OTHER CONCERNS DO YOU HAVE WITH FPL'S PREFERRED PRODUCTION DEMAND ALLOCATION METHOD?

A First, in stark contrast to peak demand methods (such as 1CP, 2CP, 4CP, and to a much lesser extent, 12CP), the 12CP+25% AD method is an over-simplification of the planning process and is not consistent with cost-causation principles.

Second, Ms. DeBose's assertion that an energy allocator is justified by the increasing amount of solar resources is both misleading and inaccurate because

[30] Deposition of Andrew Whitley at 36-37 (May 7, 2025).

investment decisions are driven by the need to meet the expected system peak demand.

Third, unlike baseload (combined cycle gas turbine) plants, FPL's solar plants can operate only on sunny days — they are not physically capable of serving load in any given hour. Whereas FPL's combined cycle gas turbine plants have operated at capacity factors ranging from 53% to 55% over the past five years, FPL's solar plants have operated at lower capacity factors (ranging from 22% to 24%).[31] Thus, while solar plants are capital intensive, it is improper to characterize them solely as an investment that can save fuel costs. At best, solar plants are an *intermittent* energy resource, but as the amount of solar power increases, their intermittency is creating significant operational and reliability issues, as previously discussed.

Fourth, though unstated in Ms. DeBose's testimony, the only differences between baseload and peaking capacity are the investment and fuel costs. Baseload units have higher investment per kilowatt (kW) of capacity and lower fuel costs per megawatt-hour produced than peaking units. In other words, Ms. DeBose theorizes that FPL's baseload plants are justified by their lower energy costs rather than an ability to meet peak demand. This theory is referred to as Capital Substitution. However, Ms. DeBose never cites to any planning studies that support the assumption that the investment in solar capacity is caused primarily by year-round energy usage. In fact, Capital Substitution is a gross oversimplification of utility system planning principles.

[31] S&P Capital IQ, Florida Power & Light Company, Power Plant Portfolio report.

Q HOW IS MS. DEBOSE'S CAPITAL SUBSTITUTION THEORY AN OVERSIMPLIFICATION OF UTILITY SYSTEM PLANNING PRINCIPLES?

A Capital Substitution overlooks three realities.

First, the need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate the portion of production plant that Ms. DeBose considers to be demand related does not recognize the peak demands that drive capacity needs. Moreover, allocating the remainder of production plant based on energy ignores the important role of load-following capabilities.

Second, fuel savings are not a cost driver. All new plants save fuel costs due to improvements in generation technology, not because they are more capital intensive. Solar is no different except that the increasing penetration of solar plants, which may lower system fuel costs, are also creating operational and reliability concerns that can only be addressed by adding dispatchable capacity resources (such as BESS, combustion turbines, and combined cycle gas turbines) to "back-up" the solar plants when the sun stops shining. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lowest overall cost — not solely to lower fuel costs. For example, combined cycle gas turbines have become the technology of choice, not because they have lower fuel costs, but because they can provide flexible load-following capabilities needed to balance loads and resources in real time and meet operating reserve requirements. These capabilities are essential to keeping supply and demand in constant balance, particularly as more intermittent resources are added to the system.

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Third, an energy allocation assumes all hours are critical to the choice of generation. However, capacity factor, which measures how often a power plant is dispatched to produce energy, does not determine the type of capacity to install. Thus, allocating investment to all hours is contrary to cost causation.

Q HOW IS ALLOCATING INVESTMENT TO ALL HOURS CONTRARY TO COST CAUSATION?

A The following simplified example demonstrates how an energy allocation is contrary to cost causation. Let us suppose two drivers need to lease cars from a fleet that contains only two types of cars, "**Car P**" and "**Car B**":

	Car P	Car B
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high gas mileage (like a nuclear or combined cycle gas turbine), while **Car P** has a low fixed charge but gets poor gas mileage (like a combustion turbine). The breakeven cost is 1,000 miles; that is, driving either car 1,000 miles would cost $1,000. However, **Car B** would be less expensive if driven more than 1,000 miles. In fact, **Car B** would be less expensive whether the total driving distance was 1,500 miles, 3,000 miles, or 4,500 miles, etc. In other words, beyond 1,000 miles, total mileage driven would not be a factor in deciding whether to lease **Car P** or **Car B**.

Q HAS THIS COMMISSION PREVIOUSLY REJECTED A PRODUCTION COSTING METHOD THAT ALLOCATES COSTS BEYOND THE BREAKEVEN POINT?

A Yes. This Commission has previously rejected the Equivalent Peaker method

because it "…implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours past the break-even point.[32]

Q MS. DEBOSE STATES THAT SOLAR PLANTS ARE UNIQUE COMPARED TO OTHER GENERATING SOURCES BECAUSE THEY HAVE ZERO FUEL COSTS AND SIGNIFICANTLY REDUCE OVERALL SYSTEM FUEL COSTS AS SOLAR BECOMES A LARGE PERCENTAGE OF THE GENERATION MIX.[33] DOES THIS RATIONALE JUSTIFY ALLOCATING A LARGER PERCENTAGE OF FPL'S PRODUCTION PLANT COSTS ON AN ENERGY BASIS?

A No. First, Ms. DeBose infers that solar plants are "energy-only" resources. However, there is no such thing as an energy-only resource. Different resources have different attributes. Some resources are dispatchable at any time, while others must run when there are sufficient water levels, wind speeds, or solar radiance. These attributes determine how much of the resource's nameplate capacity can be supplied during critical hours.

Second, as solar becomes a larger percentage of FPL's generation mix, the amount of firm capacity diminishes significantly, but it also creates the "duck curve" phenomenon that increases the stress on the remaining dispatchable resources that must quickly ramp-up (ramp-down) when the sun begins to set (rise).

Third, FPL is installing intermittent resources not because fuel costs are zero but, instead, because of public policy to lower the cost of emission-free generation. In implementing this policy, lawmakers have consistently authorized generous tax

[32] *In Re: Petition of Gulf Power Company for an Increase in its Rates and Charges*, Docket No. 891345-EI, Order Granting Certain Increases at 48 (Oct. 3, 1990).

[33] Direct Testimony of Tara DeBose at 21.

subsidies rather than enact a carbon fee on fossil fuel resources. However, in evaluating cost-effectiveness, FPL included *both* the tax subsidies and lower carbon emissions costs (which assumes that a carbon tax would be enacted in addition to generous tax subsidies) to justify its growing dependence on very rate-base intensive solar farms and BESS projects. Therefore, public policy preferences are the "cause" for installing high-capital cost/low-emission resources and any fuel savings are simply the result (or byproduct) of this preference. None of this supports FPL's proposed 12CP+25% AD method.

Q HAS MS. DEBOSE FULLY APPLIED THE CAPITAL SUBSTITUTION THEORY ON WHICH THE 12CP+25% AD METHOD IS BASED?

A No. The 12CP+25% AD method only partially recognizes the trade-off between capacity and energy. It ignores the fuel benefits that higher load factor customers bring to the system. In other words, if an allocation methodology is selected where high load factor customers are allocated a significant amount of production capacity investment based on their energy consumption, they should also receive a correlating benefit from the lower variable fuel costs incurred during off-peak periods. In other words, the 12CP+25% AD method suffers from a fuel symmetry problem.

Q HAVE OTHER STATE REGULATORY COMMISSIONS RECOGNIZED THE FUEL SYMMETRY PROBLEM ASSOCIATED WITH METHODOLOGIES SUCH AS THE 12CP+25% AD METHOD?

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s. In one such case the

Commission adopted the Examiner's Report which cited the lack of fuel symmetry in rejecting Capital Substitution, an energy-based allocation method. Specifically:

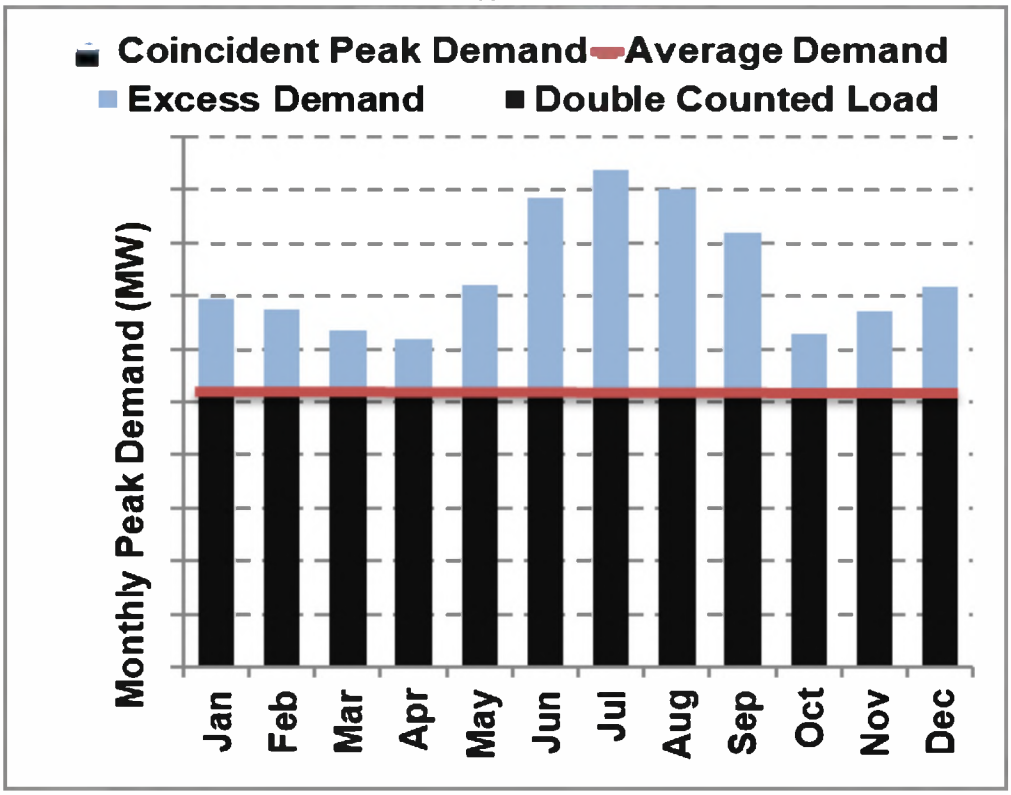
> The examiners find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal…the high load factor classes, which will bear higher cost responsibility for base load units, will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[34]

Q ARE THERE ANY OTHER FLAWS WITH THE 12CP+25% AD METHOD?

A Yes. The 12CP+25% AD method also suffers from a "double-counting" problem. Double-counting can occur when plant-related costs are allocated partially on a coincident peak basis and on an average demand (or energy) basis. This is illustrated in Figure 2. Average demand is the black shaded area, while peak demand is represented by the combined black and blue shaded areas.

[34] *Application of El Paso Electric Company for Authority to Change Rates and Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Docket Nos. 7460 and 7172, Examiners Report at paragraph 238, which was opted by Final Order (Mar. 30, 1988) and largely unchanged (and not at all in respect to the reference herein) by the Order on Rehearing (May 10, 1988) and Second Order on Rehearing (Jun. 16, 1988).

Figure 2
12CP+25% AD Method



In other words, the combination of 12CP and AD allocators used in the 12CP+25% AD method causes energy usage to be double-counted: once in the AD allocator and a second time in determining each class's 12CP demand.

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED BY OTHER STATE REGULATORY COMMISSIONS AS A CRITICAL FLAW IN ENERGY-BASED ALLOCATION METHODOLOGIES?

A Yes. For example, both the Iowa Utilities Board and the Public Utility Commission of Texas have cited the double-counting problem in numerous cases. Specifically, the Public Utility Commission of Texas states:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4 CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and thus "double dipping" is taking place.[35]

Q HAVE SIMILAR CAPITAL SUBSTITUTION-BASED PRODUCTION COST ALLOCATION METHODS BEEN PROPOSED IN PRIOR CASES BEFORE THIS COMMISSION?

A Yes. In the past, the Commission has evaluated a wide range of cost allocation methods – from to 30% demand/70% energy (1982)[36] to 100% demand/0% energy (in 2024).[37] The energy-weighted methods are typically characterized as recognizing how certain generating resources, such as nuclear, combined cycle gas turbines, and solar projects are characterized as having high capital costs, while providing significant fuel savings, *i.e.,* Capital Substitution.

Q HAS THIS COMMISSION PREVIOUSLY REJECTED CAPITAL SUBSTITUTION-BASED ALLOCATION METHODS?

A Yes. As previously stated, the Commission addressed and specifically rejected the Equivalent Peaker in a 1982 rate case. Further, in the most recent TECO rate case, the Commission rejected proposals to allocate up to 50% of production plant and related expenses, on energy. Instead the Commission approved TECO's 4CP method.

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[35] *Id.* at paragraph 236.

[36] Docket No. 820097-EU as referenced in the Direct Testimony of Tara DeBose at 22.

[37] Docket No. 20240026-EI, *Prepared Direct Testimony and Exhibit of Jordan Williams* at 25 (Apr. 2, 2024).

Q WHAT DO YOU RECOMMEND?

A The Commission should adopt the 4CP method because it more accurately allocates costs to the cost-causers and enhances economic development. The Commission should, once again, reject 12CP+25% AD and other variants, such as 12CP+50% AD, because they are not consistent with cost causation, oversimplify utility system planning principles, and suffer from the fuel symmetry and double-counting problems as described herein. By allocating demand-related costs primarily based on energy, thereby over-allocating costs to energy-intensive customer classes, such an approach would also have negative impacts on competitiveness and economic development.

Transmission Plant

Q HOW IS FPL PROPOSING TO ALLOCATE TRANSMISSION PLANT AND RELATED COSTS?

A FPL uses 12CP to allocate transmission plant.

Q IS 12CP APPROPRIATE FOR TRANSMISSION PLANT ALLOCATION?

A No. The same system peak demands that drive production plant allocation also drive the transmission system. In fact, like generating units, the transmission system has less load-carrying capabilities during the summer months. As demonstrated in **Figure 1** and **Exhibit JP-3**, the 4CP method best reflects the system loads that drive FPL's capacity needs. Thus, the 12CP method does not reflect cost causation.

Q WHAT ALLOCATION METHOD DID THE COMMISSION APPROVE FOR TRANSMISSION PLANT IN THE MOST RECENT TECO RATE CASE?

A The Commission approved the 4CP method to allocate transmission plant. In approving 4CP, the Commission stated:

C40-4465

C. Transmission Costs (Issue 72)

1. Analysis and Conclusion

Transmission costs should be allocated consistent with our decision on the previous issue, Issue 71, regarding the allocation of production costs. We approved TECO's proposed 4 CP methodology, therefore TECO's transmission costs shall also be allocated based on the 4 CP methodology.[38]

Q WHAT ALLOCATION METHOD WILL RECOGNIZE THE REALITIES OF FPL'S SYSTEM LOADS?

A The 4CP method better reflects the realities that FPL has been, and projects it will continue to be, a summer-peaking utility. The peak demands during the summer months are more critical to maintaining the reliability of the bulk power system.

Q WHAT DO YOU RECOMMEND?

A The Commission should require FPL to adopt the 4CP method to allocate transmission plant and related costs to retail customer classes. The 4CP method should include the months June, July, August, and September.

Distribution Network Costs

Q WHAT ARE DISTRIBUTION NETWORK COSTS?

A The electric distribution network consists of FPL's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to Federal Energy Regulatory Commission (FERC) Account Nos. 364, 365, 366, 367 and 368.

[38] *Id., Final Order Granting in Part and Denying in Part Tampa Electric Company's Petition for Rate Increase* at 130 (Feb. 3, 2025).

Q HOW IS FPL PROPOSING TO CLASSIFY AND ALLOCATE DISTRIBUTION NETWORK COSTS?

A FPL is proposing to classify all distribution network costs as demand related.

Q IS IT REASONABLE TO CLASSIFY ALL DISTRIBUTION NETWORK COSTS TO DEMAND?

A No. As further discussed below, classifying a portion of the distribution network as a customer-related cost is consistent with the principles of cost causation; that is, it better reflects the factors that cause a utility to incur these costs.

Q WHAT FACTORS CAUSE A UTILITY TO INVEST IN AN ELECTRIC DISTRIBUTION NETWORK?

A The purpose of the electric distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Thus, the central roles of the distribution network are to:

- Provide access to a safe, delivery-ready power grid (*i.e.*, a customer-related cost); and
- Meet customers' peak electrical power needs *(i.e.*, a demand-related cost).

Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage support which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence of the customer. This is why classifying a portion of the distribution network as customer-related is consistent with cost causation. In other words, investments that must be made solely to attach a customer to the system are clearly customer-related. These customer-related costs should be allocated based on the number of customers served rather than on peak demand.

Q WHY WOULD CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND NOT BE CONSISTENT WITH COST CAUSATION?

A Although the distribution network is sized to meet expected peak demand, it must also provide direct connection to the customer while providing the necessary voltage support to allow power to flow to the customer. Absent a distribution network and the voltage support, electricity cannot flow to customers. Thus, the distribution network investment is essential and unrelated to the amount of power and energy consumed by customers, which is why classifying these costs entirely to demand is not consistent with cost causation.

Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE ELECTRIC DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. For example, the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[39]

Q WHAT DO YOU RECOMMEND?

A FPL should be ordered to study the merits of classifying a portion of its distribution network costs as customer-related. The study should be filed with the Commission no later than 90 days prior to filing a test-year letter in its next rate case.

[39] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, at 90 (Jan. 1992).

Allocation of CILC/CDR Incentives

Q HOW DOES FPL PROPOSE TO TREAT THE CILC/CDR CLASSES IN ITS CLASS COST-OF-SERVICE STUDY?

A Ms. DeBose proposes to treat the CILC/CDR classes as though they are receiving firm service – the same as all other customers receive. To accomplish this, Ms. DeBose restated the base revenues by reversing the CILC/CDR incentives paid to non-firm customers taking service on Rider CDR and the CILC rate schedules.

Q IS FPL'S TREATMENT OF NON-FIRM LOADS IN THE CLASS COST-OF-SERVICE STUDY REASONABLE?

A Yes, with one exception. Rider CDR customers receive a $8.76 per kW-month credit in exchange for allowing FPL to curtail their interruptible loads under certain defined circumstances. Similarly, as compensation for agreeing to curtail their interruptible loads, CILC customers pay lower demand charges. These incentives (or interruptible credits) are a cost to provide service to FPL's firm customers.

However, in the ECCR, the interruptible credits are recovered from all customer classes, including those classes that have non-firm load (CILC and the GSD/GSLD classes with Rider CDR customers). This allocation effectively charges non-firm customers for a portion of the costs of their demand response that FPL can use to serve firm customers – effectively diminishing the value of the interruptible credits received by non-firm customers.

Q ARE YOU PROPOSING TO CHANGE THE ECCR TO ADDRESS YOUR CONCERNS?

A No. However, to compensate for the diminished value of the interruptible credits paid

to non-firm customers, I recommend a further adjustment to FPL's CCOSS. Specifically, the amount of the interruptible credits that the CILC/CDR customers are charged should be spread back to all customer classes based on each class's firm peak demand. Mr. Ly develops the firm peak demands by customer class.

Q WHY SHOULD THE INTERRUPTIBLE CREDITS CHARGED TO THE CILC/CDR CUSTOMERS BE ALLOCATED TO ALL CLASSES BASED ON EACH CLASS'S FIRM PEAK DEMAND?

A The interruptible credits are not a cost allocable to non-firm loads. They are a cost to serve firm load. As Mr. Ly discusses in his testimony, FPL can curtail non-firm load to alleviate any emergency condition or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators.[40] Further, the Commission's Rules state:

> (4) Treatment of Non-Firm Load. If non-firm load (i.e., customers receiving service under load management, interruptible, curtailable, or similar tariffs) is relied upon by a utility when calculating its planned or operating reserves, the utility shall be required to make such reserves available to maintain the firm service requirements of other utilities.[41]

Thus, non-firm load may be curtailed due to a capacity shortage or emergency anywhere in Peninsular Florida. By allowing FPL to curtail controllable load when resources are needed to maintain system reliability (that is, when there are insufficient resources to meet customer demand), FPL can maintain service to firm (*i.e.*, non-interruptible) customers. For this reason, FPL removes non-firm loads in assessing

[40] FPL Tariff, Commercial/Industrial Load Control Program, Fourth Revised Sheet No. 8.652 (Jan. 1, 2022).

[41] 25 Fla. Admin. Code R. 25-6.035.

resource adequacy, and FPL incurs no production capacity costs to serve non-firm loads.

Other Issues

Q SHOULD ADDITIONAL CHANGES BE MADE TO FPL'S CLASS COST-OF-SERVICE STUDY?

A Yes. My Ly discusses how FPL relies heavily on total O&M and O&M Labor expenses to allocate certain rate base and net operating income components. He recommends revised allocation methods that reflect cost causation.

FIPUG Revised Class Cost-of-Service Study

Q HAS MR. LY INCORPORATED ALL OF THE CHANGES TO FPL'S CLASS COST-OF-SERVICE STUDY AS DISCUSSED IN YOUR AND HIS TESTIMONIES?

A Yes. FIPUG's revised CCOSS is presented in Mr. Ly's **Exhibit JL-3**. A summary of the results at present rates are shown in **Exhibit JP-4**.

Q REFERRING TO EXHIBIT JP-4, PLEASE DEFINE THE TERMS RATE OF RETURN, RELATIVE RATE OF RETURN, AND INTERCLASS SUBSIDY?

A The rate of return (ROR) is the ratio of net operating income to the allocated rate base. Net operating income is the difference between operating revenues at current rates and allocated operating expenses, adjusted for the allocation of demand.

The relative rate of return (RROR) is the ratio of each class's rate of return to the overall average rate of return. A RROR above 100 (or "parity") means that a class is providing a rate of return higher than the system average, while a RROR below 100 indicates that a class is providing a below-system average rate of return.

The interclass subsidy measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is subsidizing the service provided to other classes (*i.e.*, revenues are above cost).

Q ARE THERE ANY NOTABLE CHANGES BETWEEN THE RESULTS OF FIPUG'S REVISED AND FPL'S PROPOSED CLASS COST-OF-SERVICE STUDIES?

A Yes. For the most part, the RORs from all classes are closer to parity in FIPUG's revised CCOSS than is shown in FPL's proposed CCOSS.

4. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES FPL SERVES?

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism.

Q WHAT IS THE PRINCIPLE OF GRADUALISM?

A Gradualism is a concept that is applied to avoid rate shock; that is, no class should receive an overly-large or abrupt rate increase. Thus, rates should move gradually to cost rather than all at once because moving rates immediately to cost would result in rate shock to the affected customers.

Q SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A Yes. Cost-based rates are fair because each class's rates reflect the cost to serve each particular class, no more and no less; they are efficient because, when coupled with a cost-based rate design, customers are provided with the proper incentive to

minimize their costs, which will, in turn, minimize the costs to the utility; they enhance revenue stability because an increase or decrease in sales and revenues are offset by an increase or decrease in expenses, thus keeping net income stable; and they encourage conservation because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions. Cost-based rates also encourage economic development.

Q DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A Yes. The Commission's support for cost-based rates is long-standing and unequivocal. This policy has been consistently implemented in rate cases by moving rates toward parity.

Q HOW IS FPL PROPOSING TO SPREAD THE PROPOSED BASE REVENUE INCREASE?

A FPL witness, Ms. Tiffany Cohen, relied on the results of FPL's CCOSS. Specifically, she proposes moving rates to cost, with the exceptions that (1) no class would receive a base revenue decrease and (2) the increase would not exceed 1.5 times a class's operating revenues.[42] For 2026, the maximum increase would be 14.4%.[43] Ms. Cohen asserts that this is consistent with this Commission's practice in prior rate cases.[44]

[42] Direct Testimony of Tiffany A Cohen at 17.

[43] MFR Schedule E-08 Test.

[44] Direct Testimony of Tiffany A Cohen at 17.

Q IS FPL'S PROPOSED CLASS REVENUE ALLOCATION CONSISTENT WITH THE COMMISSION'S PAST PRACTICE?

A No. First, Ms. Cohen used the operating revenues derived in FPL's CCOSS to measure the 14.4% maximum increase. However, the Commission's past practice applied the 1.5 times constraint to a customer's total bill (*i.e.* sales revenue).[45] The total bill is comprised of base revenues under the applicable rate schedules plus revenues recovered under the various cost recovery clauses.

Q ARE OPERATING REVENUES THE SAME AS SALES REVENUES?

A No. Operating revenues include sales revenues, the payments to CILC/CDR customers, as well as other non-sales related adjustments. Thus, operating revenues – especially for the CILC/CDR classes — are significantly higher than the corresponding sales revenues. Therefore applying the maximum base revenue increase to operating revenues seriously inflates the increases to the vast majority of the non-residential customer classes that are purportedly providing rates below parity under FPL's CCOSS.

Q BESIDES INCORRECTLY USING OPERATING REVENUES, DOES FPL'S CLASS REVENUE ALLOCATION CORRECTLY MEASURE THE FULL IMPACT OF ITS PROPOSED BASE REVENUE INCREASE ON CUSTOMERS' BILLS?

A No. If FPL's proposed 12CP+25% AD method is adopted, it will also change how purchased capacity and load management costs are allocated and recovered in the

[45] *In Re: Petition for Increase in Rates by Florida Power & Light Company*, Docket No. 080677-EI, Order Denying in Part, and Granting in Part, Florida Power & Light Company's Request for a Permanent Rate Increase and Setting Depreciation and Dismantlement Rates and Schedules at 179 (Mar. 17, 2010).

applicable clauses. Currently, these costs are allocated using the 12CP+1/13th AD method. Changing to 12CP+25% AD would shift more of these costs to the vast majority of the non-residential customer classes. FPL ignored this cost shift in measuring the impact of the proposed increase.

Q HAVE YOU REVISED FPL'S PROPOSED CLASS REVENUE ALLOCATION TO CORRECT THESE ERRORS?

A Yes. **Exhibit JP-5** shows the impact of FPL's proposed 2026 base revenue allocation when corrected to measure the increase in sales revenues, including the impact of changing the allocation of purchased capacity and CILC/CDR payments from 12CP+1/13th AD to 12CP+25% AD. As can be seen, several customer classes would receive increases higher than 1.5 times the system average increase of 15.2% in total sales revenues. In particular, the CILC classes, would receive increases of nearly 20% or higher. Had FPL applied the 1.5 times constraint properly, these increases would not exceed 15.2%.

Q DO YOU AGREE WITH FPL'S PROPOSED CLASS REVENUE ALLOCATION IF IT IS CORRECTED AS YOU DISCUSS HEREIN?

A No. First, as previously stated, I disagree with FPL's CCOSS and recommend an alternative study that uses the 4CP method as recently adopted for TECO. Under FIPUG's revised CCOSS, the non-residential customer classes are providing returns closer to parity than under FPL's CCOSS. Further, several classes are already earning returns above FPL's proposed retail rate of return. Accordingly, their rates should not be increased. Second, I applied gradualism relative to the base revenues and not total sales.

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Q WHY SHOULD GRADUALISM BE MEASURED RELATIVE TO BASE REVENUES AND NOT SALES REVENUES?

A First, only base revenues are subject to change in this proceeding. Second, a base rate case is the only venue in which gradualism can be properly applied. Gradualism is not applied in setting any of the charges under FPL's separate cost recovery mechanisms:

- Fuel Cost and Purchase Power Recovery Clause;
- Energy Conservation Cost Recovery Clause;
- Environmental Cost Recovery Clause;
- Storm Protection Plan;
- Capacity Payment Recovery Clause;
- Franchise Fees Clause; and
- Gross Receipts Taxes.

Thus, measuring the impact of those proposed increases on ***base*** revenues is the only proper way to determine whether FPL's proposed class revenue allocation results in rate shock.

Q HAVE YOU DEVELOPED A CLASS REVENUE ALLOCATION BASED ON FIPUG'S RECOMMENDED CLASS COST-OF-SERVICE STUDIES?

A Yes. **Exhibit JP-6** is my recommended class revenue allocation based on FIPUG'S revised CCOSS. First, I quantified the target revenue deficiency (columns 2 and 3), which measures the increase required to move each customer class to cost. Second, I applied gradualism by setting the base rate increases at 0% for customer classes that would otherwise require a revenue decrease of up to 24.9%, which is 1.5 times the system average base rate increase (column 4). This left a small revenue shortall

(column 5), which I then spread to the customer classes that were unaffected by the gradualism constraint (column 6) in proportion to rate base. The resulting (dollar and percent) increases are shown in columns 7 and 8. The target base revenues are shown in column 9. My recommendation will result in moving all customer classes closer to parity.

Q SHOULD THE SAME CLASS REVENUE ALLOCATION BE USED IN SPREADING THE 2027 INCREASE?

A Yes. The same construct illustrated in **Exhibit JP-6** should be applied in determining the spread of the 2027 increase.

Q IF THE COMMISSION APPROVES LOWER INCREASES FOR EITHER 2026 OR 2027 THAN FPL HAS PROPOSED, HOW SHOULD THE LOWER INCREASES BE SPREAD BETWEEN CUSTOMER CLASSES?

A The increases approved by the Commission should be spread in proportion to the target base revenues shown in **Exhibit JP-6**, column 9.

5. CONTRIBUTION IN AID OF CONSTRUCTION

Q HOW IS FPL PROPOSING TO CHANGE THE CONTRIBUTION IN AID OF CONSTRUCTION POLICY?

A FPL's proposed CIAC policy would require a customer to pay upfront the *estimated* costs of the upgraded facilities if a non-governmental Applicant meets one of two criteria:

(1) has a total load of 15 MW, or more, at the point of delivery ***or***

(2) requires new or upgraded facilities with a total estimated cost of $25 million, or more, at the point of delivery.

The Applicant would be eligible to receive a credit for the upfront payment over a maximum of five years, provided that the credit does not exceed the annual base energy and demand charges.

Q IS FPL'S PROPOSAL A SIGNIFICANT POLICY CHANGE?

A Yes. The current CIAC policy has been in effect for decades. Under the current policy, FPL's customers are able to locate and expand their facilities in FPL's service territory without requiring an upfront payment for 100% of the estimated cost of new and upgraded facilities, unless the estimated costs exceed four times the projected annual demand and energy base revenues.

FPL's new CIAC policy would require these very same customers to fully pay for 100% of the estimated cost of the facilities necessary to serve expansions that occur after the rate-effective date. Effectively, the new policy would shift the risk from FPL to new or existing customers who meet the criteria. Thus, the proposal goes well beyond the asserted need to protect existing customers from the influx of new large

loads and any significant costs FPL may incur to provide new and or upgraded facilities.

Q WHY MIGHT A POLICY CHANGE BE NECESSARY?

A FPL states that the proposed CIAC policy would shift the (cost recovery) risk to the cost-causer to avert the possibility that these costs would be shifted to other FPL customers.[46] Although there is merit in mitigating cost-shifting, FPL's proposal would effectively punish customers who fail to predict their future loads with 100% accuracy. However, changing circumstances may warrant revisiting the current policy.

FPL is projecting an influx of new very large customers who could require major new and/or upgraded facilities (such as substations and feeders) to meet their projected power demands. The sheer magnitude of the additional load and potential incremental cost to connect these new large load customers to the grid is unprecedented, so much so that FPL is proposing an entirely new class of service, Large Load Contract Service (LLCS) to address the issue.

Further, LLCS customers may require FPL to make potentially significant new capital investments without any assurance that the load will generate sufficient revenues in the initial five years of service, which is deemed necessary to support the investment. In the most extreme circumstance, the costs not recovered from the customer would then have to be recovered from other FPL customers. Given the very large size of projected LLCS customers, such cost shifts could be material.

[46] Direct Testimony of Tiffany C. Cohen at 33.

Q WOULD COSTS ALWAYS BE SHIFTED TO OTHER CUSTOMERS IF A NEW CUSTOMER'S LOAD FAILS TO FULLY (100%) MATERIALIZE?

A No. The notion that any of the costs of new or upgraded facilities required to connect a customer to the system would always be shifted and/or stranded (to the detriment of other customers) if a new customer's load fails to fully materialize is based on several questionable assumptions.

First, it assumes that none of the equipment, such as transformers, feeder lines, capacitors, and pull offs, can be kept in inventory to meet emergency needs or repurposed to serve other loads, existing or new, in the event that the expected load of a new large customer does not materialize. In other words, some of the equipment may be fungible.

Second, FPL has not studied or made any precise determination of how much of a customer's projected load must materialize to prevent cost-shifting.[47] Thus, it is questionable whether any costs would be shifted if 90% or more of the customer's load materializes.

Third, FPL has not demonstrated how the proposed $25 million spending threshold would balance the needs of new and existing customers. Line extension policies are intended to prevent upward rate pressure as a consequence of connecting new customers to the grid that require FPL to incur large and/or extraordinary costs. For example, if the proposed base rates can support new and/or upgraded facilities that cost $100 per kW-year, but a new customer requires FPL to incur $150 per kW-year in costs, the new customer should be required to pay $50 per kW-year to prevent

[47] Deposition of Tiffany Cohen at 154-155 (May 6, 2025).

base rates from increasing. If the new customer is not charged $50 per kW-year, those costs would be shifted to other FPL customers.

Finally, a customer should not be held to a higher standard than FPL. FPL is not held accountable for under-forecasting its projected load five years in advance — as such, it is even less realistic to expect a customer to precisely forecast its Year 5 load. Further, as base rates continue to escalate, an increasing amount of transmission and distribution (T&D) costs are recovered, even if a customer is operating at less than 100% of its projected load.

Q HAS FPL CLEARLY ARTICULATED THE REASONS FOR THE PROPOSED POLICY CHANGE?

A No. FPL asserts that the 15 MW threshold is appropriate as it would be required to make significant investments for new/upgraded T&D facilities and would present a significant risk to customers if the forecasted load used to calculate the CIAC does not materialize.[48] However, FPL is projecting to serve new very large loads that would require significant more capacity (and associated facilities) than is required to serve FPL's current largest customer.

Also, other than characterizing 15 MW and $25 million as "significant," FPL never explained why it chose 15 MW, or how serving 15 MW of additional load is related to the $25 million spending threshold. The 15 MW size threshold is especially puzzling given that FPL currently serves large customers (with loads as high as 50+ MW). Nor has FPL articulated how serving new similar size loads would make them too risky to serve under the current CIAC policy and requires material changes to its

[48] FPL Response to FIPUG Interrogatory No. 58.

standard business practices. Further, FPL has not demonstrated whether (and by how much) the (cost recovery) risk from existing or new customers with 15 MW to 50 MW of load has become significantly more elevated than in the recent past.

Therefore, FPL has not provided any compelling reason or evidence to apply a more stringent CIAC policy to serve the growing needs of its existing customers.

Q DO YOU HAVE SPECIFIC CONCERNS WITH THE POLICY CHANGE?

A Yes. First, the new CIAC policy in paragraph (c) of the CIAC tariff is poorly drafted. Specifically, the proposed CIAC policy states that a CIAC will be required for non-governmental Applicants with:

> (i) a total load of 15 MW or more at the point of delivery **or** (ii) that require new or upgraded facilities with a total estimated cost of $25 million or more at the point of delivery…[and] shall be required to advance the total estimated work order job cost of installing the facilities required to provide service prior to the construction of the requested facilities.[49] (emphasis added)

As drafted, an Applicant would only have to meet one of the two criteria — either have a 15 MW total load (regardless of the spend) ***or*** (regardless of the customer's load size) requires new or upgraded facilities that FPL estimates will cost *at least* $25 million — to be subject to the new policy. Thus, assuming FPL were to replace damaged or obsolete equipment to maintain service to an existing customer, it could require the customer to fully pay for new facilities if the customer has *at least* 15 MW of load (currently) or it spends *at least* $25 million for facilities to serve a customer with less than 15 MW of load.

[49] FPL Tariff, General Rules and Regulations for Electric Service, First Revised Sheet No. 6.199.

Second, assuming that FPL intends to apply the proposed CIAC policy only to customers for whom FPL spends *at least* $25 million or increases load by *at least* 15 MW of new load, some existing FPL customers that require FPL to add facilities just to maintain service could be impacted. However, existing customers have already established a credit history and a trusted relationship with FPL. Absent clear and compelling evidence to the contrary, the risk of non-payment by existing customers should be minimal.

Third, the proposal would also exempt governmental Applicants, thereby giving them preferred treatment compared to nongovernmental Applicants. This exemption seems to be unduly discriminatory as government customers typically use electricity no differently than commercial customers.

Fourth, the proposed spending threshold could result in different treatment for otherwise similarly situated customers who may require the same equipment to connect to the FPL system at the point of delivery but at different points in time. As previously explained, a new policy should not apply unless FPL is having to incur costs for new facilities that are clearly above and beyond the costs that are currently supported in current base rates. Other than the possibility of providing service on the LLCS rate schedules, FPL has provided no evidence that the current CIAC policy should be revised.

Finally, the proposal would penalize a customer who may require a period of time to ramp-up to its full projected load. Five years from the in-service date might not be sufficient for a customer's load to fully materialize, thereby denying the customer a reasonable opportunity to recoup its required upfront investment.

Q WHAT DO YOU RECOMMEND?

A FPL's proposed CIAC policy should be denied. First, FPL has successfully applied the current CIAC current policy for many years, including customers with total loads of 15 MW to 50 MW.

Second, a drastic policy change should not be made unless there is compelling evidence that the current policy has failed to protect customers. Thus, the proposed CIAC policy should only apply to *new* much larger loads, such as the loads FPL is projecting to serve under the proposed LLCS rate schedules.

Third, to achieve FPL's stated objective (*i.e.,* to assign costs to the cost-causer while also mitigating potential cost-shifting), the policy should be clarified to apply only to *new* or *incremental* load but *only* if FPL is required to incur interconnection costs that are clearly in excess of the level of costs that are currently supported in base rates.

Fourth, in accordance with Florida law, a policy change of this magnitude should be considered in a rulemaking proceeding, as the Commission has a CIAC Rule in place.[50]

Finally, the refund period for the upfront payment should be extended for customers who require a load-ramp period. I recommend extending the refund period to five years after the customer achieves fully projected load. This would allow the customer time to ramp-up operations and recoup the upfront costs.

Q WHAT REVISIONS DO YOU RECOMMEND?

A I recommended the following ***revisions*** to FPL's proposed CIAC policy:

[50] 25 Fla. Admin. Code R. 25-6.064.

(c) For Applicants that (i) ***require or increase their*** total load ***served by FPL*** by at ***least 50 MW*** at the point of delivery ***and*** (ii) require new or upgraded facilities with a total estimated cost ***that exceed $XX million in nominal dollars*** at the point of delivery, the Applicant shall be required to advance the total estimated work order job cost of installing the facilities required to provide service prior to the construction of the requested facilities.….The total amount to be refunded through bill credits shall not exceed the total estimated work order job cost of installing the facilities, less the required CIAC, nor will the refund exceed: (1) a period of five (5) years from the in-service date; or (2) ***for a customer with a projected load ramp, five (5) years from the end of the load ramp.***[51]

[51] The $XX shall reflect the estimated cost to extend facilities to serve a 50 MW load that are currently supported in base rates.

6. LARGE LOAD CONTRACT SERVICE

Q HAVE YOU REVIEWED FPL'S PROPOSAL TO CREATE TWO NEW RATE SCHEDULES FOR LARGE LOAD CONTRACT SERVICE?

A Yes. The proposed LLCS-1 and LLCS-2 rate schedules would apply to new customers with loads of 25 MW or more that operate at an 85% load factor. LLCS-1 would apply in certain defined regions within FPL's service territory that can accommodate up to 3,000 MW of additional load with minimal transmission system upgrades. LLCS-2 would apply to all other large loads that choose to locate in other regions.[52] Most likely, LLCS-1 and LLCS-2 customers would take service at a transmission voltage.

Q ARE LLCS-1 AND LLCS-2 DESIGNED IN A MANNER SIMILAR TO FPL'S OTHER RATE SCHEDULES FOR LARGE TRANSMISSION CUSTOMERS?

A No. FPL has specific rate schedules (*i.e.,* GSLD-3 and GSLDT-3) that apply to large customers that take service directly from the transmission system. Although the Base, transmission Demand, and non-fuel Energy charges in the proposed LLCS rates would be designed using the corresponding GSLD-3 unit costs and prices at parity, unlike GSLD-3, FPL is not proposing to set a fixed price to recover generation capacity costs. Instead, FPL's proposed ICG that would be priced to recover the cost of incremental generation above and beyond the total system fixed production that would be deployed to serve LLCS customers.[53]

LLCS customers would also be subject to more stringent terms and conditions, such as:

[52] Direct Testimony of Tiffany C. Cohen at 24-25.

[53] *Id.* at 25.

- Minimum monthly demand charges for at least 90% of the customer's Load Ramp and Contract Demand;
- A minimum 20-year contract term;
- Exit fees for early termination;
- Upfront CIAC for all costs to extend electric service;
- Maintain a security amount equal to the total ICGs to be paid by the customer during the contract term; and
- Not eligible for non-firm service.[54]

Q DO YOU HAVE ANY GENERAL CONCERNS WITH THE PROPOSED LLCS RATE SCHEDULES?

A Yes. As previously discussed, the scope and design of the proposed rates and terms and conditions are unlike any other tariff approved for FPL or any other electric utility in Florida. In fact, I raise many issues and concerns with FPL's proposals. Further, FPL may not be the only Florida electric utility projecting significant growth due to the influx of data centers and other new large loads. Therefore, in lieu of vetting the LLCS rate schedules and Agreement in this case, the Commission should consider a rulemaking proceeding to establish standardized policies and practices that should apply to new very large load customers served by all Florida utilities .

Q DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE PROPOSED LLCS RATE SCHEDULES?

A Yes. First, the proposed 25 MW size threshold is too low. As previously stated, FPL currently serves customers with loads from 25 MW to up to 50+ MW. If any of these existing FPL customers were to add 25 MW or more of load and/or make process

[54] MFR No. E-14, Attachment No. 1 of 15 at 130-136, 190-205.

improvements that raise the customer's load factor to 85% or higher, they could potentially be swept into the much more stringent and costly LLCS rate schedules.

Second, no other FPL customers — certainly not any existing customers with similar size firm loads — have been subjected to either incremental pricing or the very aggressive terms and conditions that would apply to the LLCS rate schedules and related Agreement. In fact, incremental pricing is fundamentally incompatible with this Commission's long-standing ratemaking practices, which set rates for firm service based on a utility's average or embedded cost. Embedded cost pricing assumes that all customers are served from the utility's generation fleet and further, that both existing and new customers are obligated to pay higher rates to maintain the reliability and integrity of the system resulting from inflation and/or load growth. Further, setting the IGC at the cost of the BESS is entirely unrealistic because a very large high load factor customer could not be reliably served solely from a BESS.

Third, the all-in costs of the proposed LLCS rate schedules would be excessive relative to the costs to serve a similarly sized transmission load. For example FPL projects that the all-in cost to provide service under Schedule LLCS-1 would be [redacted]¢ per kilowatt-hour (kWh).[55] However, if a comparable transmission-level service were priced at parity, it would cost only 7.6¢ per kWh.[56] This cost differential has nothing to do with the type of service provided and, therefore, is not just and reasonable.

Finally, subjecting the IGC to changes in future generation capacity costs could potentially result in a highly volatile rate and create significant price uncertainty if the

[55] FPL Response to Florida Retail Federation Request for Production Request No. 1, Attachment FRF POD 1-1 Confidential at 630 (Bates Page FPL 041515).

[56] MFR Schedule A-02, Attachment MFR A-02 2027 TY, at GSLD 3_MFR_FPL_A_2_Test - the cost (col. 26) is repriced at a monthly 85% load factor.

reset is based on subsequent tranches of expected capacity additions. In summary, the proposed LLCS pricing would not only be discriminatory, it would be very unattractive given the excessive cost and price uncertainty.

Q WHY IS THE PROPOSED 25 MW SIZE THRESHOLD A PROBLEM?

A As previously stated, FPL already serves customers with loads of 25 MW or more. In fact, the largest FPL customer currently has a load of about 50 MW. Thus, setting a 25 MW size threshold could force current FPL customers on the LLCS rate schedule. Further, the proposed 25 MW size threshold is unrealistic given that FPL is projecting to serve data center loads that range in size from [redacted] MW to [redacted] MW per site.[57] Load additions of this magnitude are far more likely to require FPL to accelerate generation and transmission capacity upgrades than an additional 25 MW load.

Finally, other utilities have adopted much larger size thresholds under similar circumstances. A list of the other utilities and the size thresholds applicable to new large loads is provided in **Exhibit JP-7**. As can be seen, the predominant practice for the larger utilities is to establish a large load size threshold ranging from 50 MW to 100 MW.

Q WOULD THE PROPOSED INCREMENTAL GENERATION CHARGE MITIGATE THE IMPACT OF SERVING NEW LARGE LOADS ON EXISTING FPL CUSTOMERS?

A It might. However, notwithstanding the obvious price discrimination, if a customer contractually commits to a long-term (20+) year contract, that period should be more than adequate to ensure recovery of the embedded costs.

[57] FPL Response to Florida Retail Federation Request for Production Request No. 1, Attachment FRF POD 1-1 Confidential at 557 (Bates Page FPL 041442).

Further, incremental pricing alone will not prevent FPL from incurring higher fuel costs which would be passed through to all customers. Finally, generation capacity is not typically directly assigned to specific customers or customer classes — it is a common cost that serves all customers and customer classes. This Commission has never adopted such a practice and should not do so in this case, especially given the very stringent LLCS contract requirements.

Q IS THERE ANY PRECEDENT FOR DIRECTLY ASSIGNING SPECIFIC GENERATION CAPACITY COSTS TO CERTAIN CUSTOMER CLASSES?

A No. However, some other utilities have submitted proposals in other jurisdictions where the supplier would dedicate specific generating resources to serve new very large load customers. In these instances the customer would be charged for both the fixed and variable costs associated with the direct assigned generation. By directly assigning only the fixed costs while spreading the variable costs, FPL's proposal is not only unfair to existing FPL customers, but also to future LLCS customers.

Q ARE YOU ASSERTING THAT THE PROPOSED LLCS RATE SCHEDULES SHOULD NOT BE APPROVED?

A No. I agree that special protections are necessary to ensure that new very large load customers do not cause FPL to incur significant costs that could ultimately be shifted to the existing customer base in the event that the new loads either fail to fully materialize or the customer(s) terminate their contract(s) early. However, certain aspects of the LLCS rate schedules and associated Agreement are overreaching and unnecessary.

Q IF THE COMMISSION APPROVES THE LLCS RATE SCHEDULES AND AGREEMENT, WHAT CHANGES SHOULD BE MADE?

A First, the size threshold should be set no lower than 50 MW, and it should apply only to 50 MW or more of new load that is not located at, or adjacent to, an existing load, and only if the customer's total annual load factor is 85% or higher. Setting a higher size threshold and limiting its applicability to only new customer loads would provide a clearer separation between existing FPL customers and new very large load customers that may take service from FPL in the future.

Second, because LLCS customers would be committed to 20-year, or longer, contracts with minimum demand charges and exit fees for early termination, there is no justification for pricing a portion of this service at incremental cost. However, if the Commission adopts incremental pricing, my recommendation would be to directly assign both the fixed capacity and variable costs of the specific generation resources that would be physically constructed to serve LLCS customers.

Q IS FPL PROJECTING TO SERVE ANY LOAD ON THE LLCS RATE SCHEDULES DURING THE 2026 AND 2027 TEST YEARS?

A No. FPL is not expecting to serve any LLCS load during the 2026 and 2027 test years. Thus, FPL has not included any revenues or allocated any test-year costs to LLCS customers.

Q WHEN IS FPL EXPECTING THAT SERVICE UNDER THE PROPOSED LLCS RATE SCHEDULES WOULD COMMENCE?

A FPL is expecting to serve LLCS loads during the term of its proposed 4-year rate plan.

This includes at least [redacted] MW of load with projected in-service dates after 2027.[58] To put this in perspective, [redacted] MW of load is [redacted]% of FPL's projected 2027 system peak demand.

Q IF ANY OF THE LLCS LOAD COMMENCED SERVICE DURING THE 2026 AND 2027 TEST YEARS, WOULD THIS HAVE AFFECTED THE RATES ESTABLISHED FOR FPL'S OTHER RATE SCHEDULES?

A Yes. Any LLCS load served during the 2026 and 2027 test years would have contributed additional base revenues and LLCS customers would have been allocated a portion of the test-year costs that FPL is proposing to recover solely from the established retail customer classes. Clearly, FPL would not have proposed the same test-year rates had it projected to serve any LLCS load in the two test years at issue here, 2026 and 2027. At this point, such tariffs are premised not upon firm written commitments or agreements, but on speculative ideas that these loads may appear in FPL's service territory outside of the test-year period, raising questions as to whether adopting such rates for possible load outside of the two test years is in order and makes sense.

Q WHY IS THIS A CONCERN?

A The purpose of this proceeding is to establish new base rates using the 2026 and 2027 test years proposed by FPL. Base rates that reflect test-year costs are both just and reasonable. However, if during the four-year rate plan, events expected to occur immediately after the test years have a significant impact on FPL's revenues and costs, the test years would become stale and the rates may no longer be just and reasonable.

[58] *Id.*

Notwithstanding expectations that FPL will commence serving new LLCS customers after 2027, FPL is not proposing to reset base rates until after the four-year rate plan expires in 2030. However, the Commission should not ignore the potentially significant incremental revenues and costs associated with serving the LLCS loads. To the extent LLCS revenues and costs are of a significant magnitude, it raises concerns about the integrity of the test years used in the rate-setting process and the reasonableness of any subsequent piecemeal ratemaking adjustments to recognize expected capacity additions in 2028 and 2029. If the test years become stale due to the addition of LLCS load beginning in 2028, the base rates approved in this proceeding would no longer be just and reasonable.

Q HOW SHOULD THIS CONCERN BE ADDRESSED?

A Without an additional investigation, the Commission will not have the information needed to assess the impact of any new very large loads and to determine whether the approved 2027 base rates are just and reasonable. Therefore, the Commission should require FPL to file a limited proceeding with MFRs for the years 2028 and 2029 if any new large load customers have made firm commitments to commence service either in 2028 or 2029.

7. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A The Commission should make the following findings:

- Adopt a lower ROE that reflects FPL's reduced regulatory lag and financial risk.
- Adopt the 4CP method of allocating production and transmission plant.
- Require FPL to conduct analysis of its distribution network to determine whether any portion of the costs (*i.e.,* voltage support) is required just to serve customers and to provide the results no later than 90 days prior to filing a test-year letter in its next rate case.
- Adopt FIPUG's revised class cost-of-service study.
- Reject FPL's proposed class revenue allocation because it does not apply gradualism properly.
- Adopt FIPUG's recommended class revenue allocation that applies gradualism to base revenues.
- Modify FPL's proposed changes to its CIAC policy as follows:
  - Limit the application to new FPL customers as of the rate-effective date.
  - Remove the size threshold or, alternatively, raise the threshold to apply to *increases* in load of *at least* 50 MW that also require FPL to spend in excess of a specific spending threshold.
  - Establish a spending threshold that reflects the cost of new or upgraded facilities that are in excess of the costs that are currently supported in base rates.
  - Extend the refund period to five years after the completion of the customer's load-ramp period.
- Alternatively, the changes to the long-standing CIAC policy that FPL is proposing should be vetted in a separate rulemaking proceeding involving all Florida electric utilities who may also be required to spend significant capital to serve new very large load customers.

- Modify the proposed LLCS rate schedules as follows:
  - Increase the size threshold to at least 50 MW.
  - Specifically prohibit the rates from applying to existing FPL customers who increase load above 50 MW or more at an existing or adjacent premises or improve their load factors to 85% or more.
  - Replace incremental pricing with average cost pricing, or directly assign the fixed and variable costs of the incremental generation that serves the incremental load.
- Alternatively, the LLCS rate schedules and Agreement should be vetted in a separate rulemaking proceeding involving all Florida electric utilities who may also receive service requests from new very large load customers.
- Require FPL to file a limited proceeding with MFRs in 2028 and 2029 if new very large loads contractually commit to commencing service in 2028 and 2029.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 14323 South Outer 40 Rd., Suite 206N, Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, Wisconsin and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

C40-4498

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
EL PASO ELECTRIC COMPANY	Texas Industrial Energy Consumers	57568	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Imputed Capacity	6/4/2025
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	56693	Direct	TX	Competitive Generation Service	2/19/2025
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	56865	Direct	TX	Voluntary Renewable Energy Tariff Rate Design	1/21/2025
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	46120	Cross-Answering	IN	Class Cost-of-Service Study; Classification and Allocation of Production Plant; Classification of Distribution Plant; Class Revenue Allocation; Federal Tax Credits	1/16/2025
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-671-ER-24	Direct	WY	Class Cost-of-Service Study; Class Revenue Allocation; Rule 12 - Line Extensions; Rate Design; Insurance Cost Adjustment	12/20/2024
ROCKY MOUNTAIN POWER	Utah Large Customer Group	24-035-04	Surrebuttal	UT	Class Cost-of Service Study; Rate Design; Regulation No. 12	12/19/2024
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	46120	Direct	IN	Return on Equity; Class Cost-of-Service Study; Class Revenue Allocation	12/19/2024
ROCKY MOUNTAIN POWER	Utah Large Customer Group	24-035-04	Rebuttal	UT	Class Cost-of Service Study	11/26/2024
ROCKY MOUNTAIN POWER	Utah Large Customer Group	24-035-04	Direct	UT	Class Cost-of-Service Study; Class Revenue Allocation; Regulation No. 12; Rate Design; Insurance Cost Adjustment; Energy Balancing Mechanism	10/30/2024
WISCONSIN ELECTRIC POWER COMPANY AND WISCONSIN GAS LLC	Wisconsin Industrial Energy Group	5-UR-111	Surrebuttal	WI	Class Cost-of-Service Studies; Class Revenue Allocation; General Primary Rate Design; Microsoft Electric Rate; Rate Increase Presentation	9/20/2024
WISCONSIN PUBLIC SERVICE CORPORATION	Wisconsin Industrial Energy Group	6690-UR-128	Surrebuttal	WI	Class Cost-of-Service Studies; Class Revenue Allocation; General Primary Rate Design; Rate Increase Presentation	9/18/2024
WISCONSIN ELECTRIC POWER COMPANY AND WISCONSIN GAS LLC	Wisconsin Industrial Energy Group	5-UR-111	Rebuttal	WI	Class Cost-of-Service Studies; Class Revenue Allocation	9/9/2024

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
WISCONSIN PUBLIC SERVICE CORPORATION	Wisconsin Industrial Energy Group	6690-UR-128	Rebuttal	WI	Class Cost-of-Service Studies; Class Revenue Allocation	9/5/2024
WISCONSIN ELECTRIC POWER COMPANY AND WISCONSIN GAS LLC	Wisconsin Industrial Energy Group	5-UR-111	Direct	WI	Class Cost-of-Service Studies; Class Revenue Allocation; General Primary Rate Design	8/21/2024
WISCONSIN PUBLIC SERVICE CORPORATION	Wisconsin Industrial Energy Group	6690-UR-128	Direct	WI	Class Cost-of-Service Studies; Class Revenue Allocation; General Primary Rate Design	8/19/2024
COMMONWEALTH EDISON COMPANY	Nucor Steel Kankakee, Inc.	24-0378	Direct	IL	Allocation of Beneficial Electrification Costs	7/24/2024
SOUTHERN PIONEER ELECTRIC COMPANY	Air Products and Chemicals, Inc. and National Beef Packaging Company, LLC	24-SPEE-540-TAR	Settlement	KS	Renewable Energy Program	7/8/2024
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Surrebuttal	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/3/2024
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	56211	Direct	TX	Customer Load Study Charge; Transmission Line Extensions; Rider IRA	6/19/2024
DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240025-EI	Direct	FL	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/11/2024
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Cross-Rebuttal	TX	Distribution Load Dispatch Expense; Residential Class MDD; LCUST Allocation Factor; Call Center Cost Allocation; Wholesale Distribution Service for Battery Energy Storage System	6/7/2024
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/6/2024
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/5/2024
DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240013-EG	Direct	FL	Curtailable General Service; Interruptible General Service	6/5/2024

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Direct	TX	Transmission Operation and Maintenance Expense; Property Insurance Reserve; Class Cost-of-Service Study; Rate Design; Tariff Changes	5/16/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Cross-Rebuttal	TX	Turk Remand Refund	5/10/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Surrebuttal	SC	Class Cost-of-Service Study; Revenue Allocation and Rate Design	4/29/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Direct	TX	Turk Remand Refund	4/17/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/8/2024
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	55378	Direct	GA	Deferred Accounting; Additional Sum; Specific Capacity Additions; Distributed Energy Resource and Demand Response Tariffs	2/15/2024
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020

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ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020

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SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: ***J. Pollock Testimony filed from 1976 through the prior year***						

APPENDIX C

Procedure for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that

a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Florida Power & Light Company for Base Rate Increase	**DOCKET NO. 20250011-EI Filed: June 9, 2025**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20250011-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 6th day of June 2025.

KITTY TURNER
Notary Public, Notary Seal
State of Missouri
Lincoln County
Commission # 15390610
My Commission Expires 04-25-2027

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2027.

Highlighted Version
The highlighted cells indicate the revised numbers.

FLORIDA POWER & LIGHT COMPANY
FIPUG's Recommended Class Revenue Allocation
Forecast Test Year Ending December 31, 2026
(Dollar Amounts in $000)

Line	Customer Class	Base Revenues	Target Revenue Deficiency	Required Increase	Gradualism Constraints	Apply Gradualism Constraints	Adjust to Required Increase	Increase	Percent Increase	Target Base Revenues
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	CILC-1D	$83,739	$24,803	29.6%	24.9%	($3,952)	$0	$20,851	24.9%	$104,590
2	CILC-1G	$4,001	$844	21.1%	21.1%	$0	$56	$900	22.5%	$4,901
3	CILC-1T	$32,344	$4,529	14.0%	14.0%	$0	$487	$5,016	15.5%	$37,360
4	GS(T)-1	$711,160	$31,419	4.4%	4.4%	$0	$7,356	$38,775	5.5%	$749,935
5	GSCU-1	$2,348	($420)	-17.9%	0.0%	$420	$0	$0	0.0%	$2,348
6	GSD(T)-1	$1,672,374	$444,421	26.6%	24.9%	($28,000)	$0	$416,421	24.9%	$2,088,795
7	GSLD(T)-1	$519,887	$157,668	30.3%	24.9%	($28,216)	$0	$129,452	24.9%	$649,339
8	GSLD(T)-2	$166,005	$60,507	36.4%	24.9%	($19,172)	$0	$41,335	24.9%	$207,340
9	GSLD(T)-3	$31,515	$4,771	15.1%	15.1%	$0	$348	$5,119	16.2%	$36,634
10	MET	$4,270	$137	3.2%	3.2%	$0	$44	$181	4.2%	$4,451
11	OS-2	$1,983	$1,186	59.8%	24.9%	($692)	$0	$494	24.9%	$2,477
12	RS(T)-1	$5,899,121	$806,840	13.7%	13.7%	$0	$65,288	$872,128	14.8%	$6,771,249
13	SL/OL-1	$184,516	$11,968	6.5%	6.5%	$0	$2,124	$14,092	7.6%	$198,608
14	SL-1M	$1,520	($110)	-7.3%	0.0%	$110	$0	$0	0.0%	$1,520
15	SL-2	$1,810	($134)	-7.4%	0.0%	$134	$0	$0	0.0%	$1,810
16	SL-2M	$551	($132)	-23.9%	0.0%	$132	$0	$0	0.0%	$551
17	SST-DST	$177	($112)	-63.1%	0.0%	$112	$0	$0	0.0%	$177
18	SST-TST	$7,066	($3,421)	-48.4%	0.0%	$3,421	$0	$0	0.0%	$7,066
19	TOTAL RETAIL	$9,324,387	$1,544,765	16.6%		($75,704)	$75,704	$1,544,765	16.6%	$10,869,152
	Sources	E-13a	OPC POD 14 MFRS RATES	(1) + (2)	E-13a	$139 MM Purchased Capacity & CILC/CDR Payments		1.5x Average =	24.9%	

C40-4521a

FLORIDA POWER & LIGHT COMPANY
FIPUG's Recommended Class Revenue Allocation
Forecast Test Year Ending December 31, 2026
(Dollar Amounts in $000)

Line	Customer Class	Base Revenues	Target Revenue Deficiency	Required Increase	Gradualism Constraints	Apply Gradualism Constraints	Adjust to Required Increase	Increase	Percent Increase	Target Base Revenues
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	CILC-1D	$83,739	$24,803	29.6%	24.9%	($3,952)	$0	$20,851	24.9%	$104,590
2	CILC-1G	$4,001	$844	21.1%	21.1%	$0	$56	$900	22.5%	$4,901
3	CILC-1T	$32,344	$4,529	14.0%	14.0%	$0	$487	$5,016	15.5%	$37,360
4	GS(T)-1	$711,160	$31,419	4.4%	4.4%	$0	$7,356	$38,775	5.5%	$749,935
5	GSCU-1	$2,348	($420)	-17.9%	0.0%	$420	$0	$0	0.0%	$2,348
6	GSD(T)-1	$1,672,374	$444,421	26.6%	24.9%	($28,000)	$0	$416,421	24.9%	$2,088,795
7	GSLD(T)-1	$519,887	$157,668	30.3%	24.9%	($28,216)	$0	$129,452	24.9%	$649,339
8	GSLD(T)-2	$166,005	$60,507	36.4%	24.9%	($19,172)	$0	$41,335	24.9%	$207,340
9	GSLD(T)-3	$31,515	$4,771	15.1%	15.1%	$0	$348	$5,119	16.2%	$36,634
10	MET	$4,270	$137	3.2%	3.2%	$0	$44	$181	4.2%	$4,451
11	OS-2	$1,983	$1,186	59.8%	24.9%	($692)	$0	$494	24.9%	$2,477
12	RS(T)-1	$5,899,121	$806,840	13.7%	13.7%	$0	$65,288	$872,128	14.8%	$6,771,249
13	SL/OL-1	$184,516	$11,968	6.5%	6.5%	$0	$2,124	$14,092	7.6%	$198,608
14	SL-1M	$1,520	($110)	-7.3%	0.0%	$110	$0	$0	0.0%	$1,520
15	SL-2	$1,810	($134)	-7.4%	0.0%	$134	$0	$0	0.0%	$1,810
16	SL-2M	$551	($132)	-23.9%	0.0%	$132	$0	$0	0.0%	$551
17	SST-DST	$177	($112)	-63.1%	0.0%	$112	$0	$0	0.0%	$177
18	SST-TST	$7,066	($3,421)	-48.4%	0.0%	$3,421	$0	$0	0.0%	$7,066
19	TOTAL RETAIL	$9,324,387	$1,544,765	16.6%		($75,704)	$75,704	$1,544,765	16.6%	$10,869,152
	Sources	E-13a	OPC POD 14 MFRS RATES	(1) + (2)	E-13a	$139 MM Purchased Capacity & CILC/CDR Payments		1.5x Average =	24.9%	

C40-4521b

BY MR. MOYLE:

Q Mr. Pollock, do you have any changes to your testimony?

A I do not.

Q Okay. Did you prepare a summary of the key aspects of your testimony?

A I did.

Q Okay. Would you please provide the Commission and the parties with that summary?

A Happy to.

Thank you, Commissioners. Good morning, Mr. Chairman and Commissioners.

I address a wide range of issues ranging from return on equity and capital structure to cost allocation, contribution in aid of construction and large load contract service terms and conditions, but specifically, I want to highlight the Issues 89 and 90, which address the methodology for allocating production transmission plant.

As discussed in my testimony, a class cost of study service should reflect cost causation principles recognizing the system loads and not different types of capacity resources drive the need for utilities' production transmission investment, it follows that the allocation of production in transmission plant and

related expenses should reflect FPL's system load characteristics.

Now, what are though characteristics? The 4 CP method is -- of course, recognizes the reality that FPL is a strong summer peaking utility. You can see that in my testimony and exhibits, and in figure 1 particularly. The 4 CP is based on the demands that occur in the months June, July, August and September. It recognizes that summer is the primary driver to cause new capacity additions to maintain reliability.

Summer months are also when the transmission system experiences its lowest load carrying capability due to hot weather and humidity. Thus, 4 CP more appropriately allocates costs to those customers that cause them, the summer peaks.

Just last year, you affirmed that the 4 CP approach, which you approved in TECO's 2021 rate case, was, once again, approved for Tampa Electric in its 2024 rate case. The 4 CP is a necessary and proved methodology to 12 CP that's been used previously at the Commission. 12 CP gives equal weight to peak power demands that occur in each of the 12 months, but if system planners installed only enough capacity to serve the average of 12 monthly peaks, FPL would not be able to serve all of its load. In contrast, the 4 CP method

is forced on serving the load and it's consistent with cost causation.

As Tampa Electric -- as with Tampa Electric, FPL is undergoing, and has undergone, a similar makeover of what has now become a very diverse generation fleet, which has operated as an integrated system to meet customer demands, so the same facts and circumstances that led to your decision and approval of 4 CP for Tampa Electric are also present and support the 4 CP method for FPL.

I thank you for your attention.

MR. MOYLE: Mr. Pollock is available for cross.

CHAIRMAN LA ROSA: Thank you.

OPC?

MS. CHRISTENSEN: Good morning.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Pollock.

A Good morning.

Q In your testimony you filed on June 9th, you address ROE and capital structure, correct?

A Correct.

Q And you would agree that it's been accepted practice under Bluefield and Hope to estimate the

required return on equity using modeling, right?

A You said using modeling?

Q Uh-huh.

A Using quantitative analysis, yes.

Q Okay. And you would agree that the discounted cash flow method is one of those models that is generally used to estimate ROE?

A Yes.

Q And you did not conduct any DCF modeling yourself, did you?

A That's right, I did not.

Q And you would agree that the capital asset pricing model is another method frequently used to estimate ROE, correct?

A Yes.

Q And you did not do any CAPM analysis yourself, did you?

A That's correct. I did not.

Q And finally, you would degree that the risk premium model is also a method used to estimate ROE?

A Some analysts do use that.

Q Okay. And you did not do any risk premium analysis yourself, correct?

A Correct.

Q The sole analysis you did regarding the

appropriate ROE was to look at the currently authorized ROEs for vertically integrated electric IOUs, correct?

A Yes.

Q Okay. Specifically, let's take a look at page 13 of your testimony. And on page 13 of your direct testimony, lines five through 10, you say that FPL's request for the 11.9 is excessive when compared to the ROEs authorized by state commissions decided in 2023 through March 2025, is that correct?

A Through May, yes.

Q And in your Exhibit JP-1, you show the average ROE authorized by state regulators is 9.81 percent for 2023 through March 2025 timeframe, right?

A Through May 2025, yes.

Q And back on your direct testimony on page 13, I think it's 40 -- C40-4574. Anyway, back on line 13 of that page, I believe.

A I am sorry, what page?

Q I believe we are still on page --

A 13.

Q -- 13.

A Okay.

Q Line 13, you say that Florida is a very supportive of Florida's electric IOUs, which translates into lower risk for investors, correct?

A Yes.

Q And then you cite all of the risk reducing mechanisms in Florida, and say that the Regulatory Research Associates ranked Florida above 46 other states for being investor -- for investor supportive necessary, correct?

A Yes.

Q And if we flip over to page 16 of your testimony, and specifically I am looking at lines 11 through 13, you testify that the lower regulatory risk should translate into a lower ROE and equity capitalization than is authorized for other electric IOUs regulated by less supportive commissions, correct?

A Yes, all other things being equal.

Q Okay. And your equity ratio recommendation was 53 .2 percent based on your review of DEF and TECO's equity ratios, correct?

A That's the industry average for A rated vertically integrated utilities, that's what 53.2 is.

Q If we flip over to the top of page 17 of your testimony, you show that FPL's equity ratio requested in this case of 59.6 percent is at least five points higher than Duke at 53 percent equity ratio and TECO at 54 percent equity ratio, correct?

A Correct.

Q And then on page 18 of your testimony, lines 11 and 12, you state that if all the risk -- if all the risk mitigating factors are adopted, these factors would clearly support an ROE that is more in line with the ROEs approved for DEF and TECO, correct?

A Yes.

Q And you would agree that the approved ROE for TECO was 10.5 percent, correct?

A Yes.

Q And the approved ROE for DEF was 10.3 percent, right?

A Yes.

Q And given your earlier statement that the higher the equity ratio, the lower the ROE, you would agree that based on this statement, FPL's ROE should be lower than Duke's ROE, correct?

A All other things being equal, but I have not done the analysis to confirm that FPL's credit metrics can be satisfied with the lower ROE.

Q Fair enough.

You would agree that review of other vertically integrated electric IOU analysis is not an ROE calculation but, rather, a check if the ROE is set appropriately, correct?

A Can you rephrase the question, please?

Q Certainly.

You would agree that your review of the other vertically integrated electric IOU approved ROEs is not an analysis but, rather, more of a check on whether or not the requested ROE is appropriate?

A That's right. It's the an observation about where the industry is currently.

Q Thank you, I have no further questions.

CHAIRMAN LA ROSA: FEL?

MR. MARSHALL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MARSHALL:

Q Good morning, Mr. Pollock.

A Good morning.

Q Could we go to master page 04-45, part of CEL Exhibit 1431?

You sponsored these interrogatory answers, correct?

A I am sorry, which ones are we talking about?

Q The ones that should be on the screen, FIPUG's responses to FEL's 1st Set of Interrogatories.

A Yes.

Q So FIPUG is an unincorporated association?

A Yes.

Q And as such, it does not have a registered

agent?

A Yes.

Q And it should be obvious, but just to confirm, FIPUG is not a natural person?

A FIPUG is not what?

Q A natural person?

A A natural person?

Q Yeah, like a specific human being, a natural person.

A Well, FIPUG is not a person. It's a group of people that are joined at the hip with a common interest.

Q If we could go to master page 04-654? This is Exhibit 1491.

And these are discovery responses to production of documents requests?

A Can you identify which ones?

Q Yes. This would be FIPUG's Response to FEL's First Request for Production of Documents.

A Okay.

Q And as an unincorporated association, FIPUG does not have articles of incorporation?

A Correct.

Q And has no bylaws?

A That's correct.

Q If we could next move to master number F10-2610, which is Exhibit 980 on the CEL? Do you have it in front of you?

A I do.

Q This was one of your workpapers to support your testimony?

A Yes.

Q And it has Florida in the column Above Average/2, is that right?

A Yes.

Q Can you explain what that means?

A That means from an investor's perspective, Regulatory Research Associates believes that the Florida commission is very supportive of investors.

Q Switching topics to cost of service.

You agree that cost of service should reflect cost causation?

A Yes.

Q And one of the reasons that you take issue with the 12 CP methodology is that 12 CP assumes that the demands occurring in the spring and fall months are as critical to system reliability as meeting summer peak demands?

A Yes, as well as winter.

Q If we could go to master page C17-2312, which

is part of admitted Exhibit 64?

Now, you don't testify against the use of the stochastic loss of load probability methodology in your testimony, is that right?

A Well, actually, I think my testimony does address it indirectly. I think Mr. Ly addressed it more directly than I did, but, yeah, I mentioned it.

Q Do you see the loss of load probability heat map for 2027 in front of you?

A I do.

Q And it shows October to be the month most critical for system reliability?

A Well, it may be the most critical, but if you read the observations, I think you can pretty well see that the loss of load risk is mostly concentrated in the summer evenings.

Q Just to confirm, October isn't one of the four months that you recommend to be included in your 4 CP methodology?

A It's not. Given the way that the stochastic model works, it's not surprising that October and April would be higher.

Q And April isn't one of your four months either?

A It's not.

Q Would you agree that FPL can also have significant winter peaks?

A In the distant past, I remember testifying in an FPL rate case when it actually snowed in West Palm Beach, so, yes, I think FPL can have winter peaks. Whether that continues to be the case, I don't know what the current saturation is of heating appliances.

Q Did the Northwest Florida portion of FPL's territory have an all time peak in January of 2025?

A I don't know that. I know that it did snow pretty heavily, so I am assuming that it drove the electric demand up.

Q And is the 522 Northwest Florida -- I am sorry, 522-megawatt Northwest Florida Battery Project the single biggest capacity addition being added to FPL's system this year?

A I don't really know anything about the battery. We --

Q But assuming that's true, and we can take it subject to check, or I can -- we can go to the ten-year site plan to confirm it, that's being added for winter reliability need, correct?

A I don't know. I mean, the battery is there to support the system when it needs capacity in a very short-term need.

Q If we could go to master page C19-2904? It's part of Exhibit 162.

A Okay. I see it.

Q This indicates that the 522-megawatt Northwest Florida battery is needed for winter peaking capacity?

A That's what the response says, yes.

Q And just to be clear, January isn't one of your four months either included in your 4 CP months?

A Winters is not. Of course, the system is planned on a systemwide basis, not just regional basis.

Q If we could next go to master page F10-2617, which is going to be Exhibit 982 on the CEL?

A I have it.

Q This is one of your workpapers to support your testimony?

A Yes.

Q And this is from the NARUC manual?

A Yes, it is.

Q And I believe you quote the highlighted language in your testimony, is that right?

A Yes.

Q And the next sentence following the highlighted language is that the 12 CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other

reliability index values in all months?

A That's what it says, yes.

Q On page 31 of your testimony, lines one to two, you claim that investment decisions are driven by the need to meet the expected system peak demand?

A Yes.

Q And on what basis do you believe that FPL is adding solar to its system to meet peak demand and to not swap steel for fuel, for example, as they claim?

A Well, I mean they are adding solar because it's more cost-effective than the alternatives, but still they have to have capacity in order to meet the expected peak.

Q Do you have any analysis of the firm capacity values of the solar that FPL is adding to its system that differs from FPL's own analysis?

A No.

Q Would you agree that fuel is allocated on an energy basis?

A Fuel costs are. Capital costs are not.

Q On page 31, lines nine through 11 of your testimony, you do say that solar plants are an intermittent energy resource, is that right?

A That's one of their attributes. Yes.

Q And if you have -- allocate -- just to be

clear, you know, there is various cost of service methodologies that have been proposed in this case, and some have an AD component to them, right?

A You said AD for average demand?

Q Yes.

A Yes.

Q And that's an energy idea, average demand?

A Yeah, that's saying that you are incurring the costs of all 8,760 hours in a year.

Q And solar plants are part of the production plant being allocated as part of all of the cost of service studies, correct?

A As I said in my summary, it's part of an integrated fleet that's operated on an integrated basis to serve load.

Q If we go to page 33 of your testimony, lines 15 through 17?

A I am there.

Q And here, you have an analogy between choosing two different kinds of cars, correct?

A Yes.

Q Would you agree with me that if you were not concerned about the per mileage charge but only the fixed charge, that you would always choose car P in this example?

A Okay. So if I am running a car and I don't care what it costs, then I am going to pick the one that has the lowest daily charge -- or daily charge? Yeah, I probably would. But if I rent a car, I am going to look at the total cost.

Q Right. And that's because you might be going the distance, and efficiency could come into play in deriving what that total cost is?

A Yes. Yeah, it just depends on how intensively you plan to use the car, how many miles I am going to drive, but at a certain point, it doesn't make any difference.

Q If we could next go to master page C40-4521b, which should be part of your Exhibit JP-6, which is exhibit?

MR. SCHULTZ: Ma was the number again, C 40 dash?

MR. MARSHALL: 4521b, as in bravo.

BY MR. MARSHALL:

Q This is FIPUG's recommended class revenue allocation for this case, is that right?

A It is. Yes.

Q And this is based on FIPUG's revised class cost of service study?

A Yes.

Q All right. And then in column eight, you have a percent increase based on the proposed allocation, is that right?

A Yeah. That's the -- column eight is column seven divided by column one, so it's the base revenue increase.

Q And then there is a total row at the bottom that would be adding up basically every -- all -- adding up all the -- between all the classes?

A Yes, the -- yeah, line 19 is the sum of total retail.

Q And class GST-1 is receiving, would you agree, is receiving about 33 percent of the system average increase?

A That's right.

Q And residential would be at about 89 percent of the system average increase?

A That's right.

Q And both RS and GS are higher than the target required increase because of redistributions due to gradualism constraints, is that right?

A Yes.

Q If we could next go to master page C40-4519b, as in bravo, which should be your revised Exhibit JP-4?

A Okay.

Q And this is based on FIPUG's revised class cost of service study at present rates, is that right?

A Yes.

Q And to be clear, if it's in parenthesis, the interclass subsidy on the right, that means that that class is paying more money than as indicated by FIPUG's revised class cost of service study?

A That's right. So a negative amount, means a class that it is subsidizing other classes.

Q And so this would show that GS, then, is providing interclass subsidy to the other classes of over $56 million?

A Yes.

Q And then for RS, that would be almost $107 million?

A Yes.

Q And would you agree that the primary classes being subsidized by dollar amounts are GSD-1, GSLD-1 and GSLD-2?

A Yes.

Q Switching topics to the -- your testimony regarding the CDR and CILC credits.

On page 43, lines 15 through to 20, you refer to -- of your testimony -- you refer to the credits being recovered from all customer classes, is that

right?

A That's right. Yeah, it's a treatment of the credits in the cost of service study.

Q And you suggest that the amount of interruptible credits that the CILC/CDR customers are charged should be spread back to all customer classes based on each class' firm peak demand?

A That's right. If you think of the demand response as a resource, you are allocating the cost back to the classes that cause those resources, so in this case, the firm customer classes.

Q But you don't include the Residential On-Call Program with that recommendation?

A I didn't address that program.

Q And you don't address the Business On-Call Program either?

A No.

Q And would you agree that CDR and CILC customers haven't been interrupted in over a decade?

A I have heard that statement made.

Q If it would be cheaper just to build the replacement generation for those megawatts represented that are available through the CDR and CILC program than the cost of the credits, shouldn't that be what FPL does?

A Well, I think FPL will do the least costly thing, and to maintain a program that's been in effect, and beneficial, and has demonstrably deferred capacity for decades, it's probably not something you want to change at this stage when you need every tool in the toolbox to a keep ahead of load.

Q Would you agree that if FPL were to build replacement generation that, you know, replacement generation can't just walk away from the program?

A I am sorry, if they can do what?

Q Well, right, if CDR/CILC programs, with notice, could -- can exit the program, correct?

A If you give advanced notice, that's right.

Q And that wouldn't be true of replacement generation?

A Well, I mean, generation does age and it has to be retired, so there is a natural lifespan of generation, just as there might be a life span for a demand response resource. Either way, they are resources, and so you should treat them as such.

Q Would you also agree that replacement generation is not limited to use 25 times per year?

A Well, it depends. In an emergency, then there is no limitation in terms of how long the curtailments can last. That's the benefit of the program, the

CDR/CILC programs, is that in an emergency, which could occur anywhere in the state, you can utilize that resource as needed. And if the emergency continues, you are not going to restore power to those customers.

Q Would you agree that replacement generation is not -- would not be limited to being used 25 times per year?

A It depends on what the replacement generation is.

Q Let's say batteries, for example.

A Batteries? Well, you have to charge and discharge them. So you have got, what, four hours may maybe. But you have also got to have a grid that will allow them to charge. If you don't have a grid that's functional, then they won't recharge.

Q Would you agree that rates should move towards cost, is that right?

A Yes.

Q And is another way of saying that is that classes should be moving towards parity?

A Yes.

Q You also address the large load, the LLCS tariffs in your testimony?

A Yes, I do.

Q And would you agree that special protections

are necessary to ensure that new very large load customers do not cause FPL to incur significant costs that could ultimately be shifted to the existing customer base?

A Well, that's a -- that's a very loaded question, but to kind of break it down. Yes, these are very extraordinary large loads. Yes, they are going to cause, you know, FPL to incur significant costs. Of course, we don't want those costs that are going to be needed to serve those customers to be shifted to anybody else, so you are naturally going to implement some type of contract mechanisms to ensure that those customers are there to pay those costs for the long-term.

Q Thank you, Mr. Pollock. That's all my questions for you this morning.

A Can I ask you a question? Do you ever take a breath?

Q I have been known every now and then.

A Thank you.

CHAIRMAN LA ROSA: Excellent.

Let's move to FAIR.

MR. LAVIA: Good morning, Chair. FAIR has no questions.

CHAIRMAN LA ROSA: FEIA?

MR. MAY: No questions.

CHAIRMAN LA ROSA: Walmart?

MS. EATON: No questions.

CHAIRMAN LA ROSA: FEA?

CAPTAIN RIVERA: No questions, thank you.

CHAIRMAN LA ROSA: Welcome.

MR. BREW: No questions.

Okay. All right, FRF.

FPL?

MS. MONCADA: No questions.

CHAIRMAN LA ROSA: Staff?

MR. STILLER: No questions.

CHAIRMAN LA ROSA: Commissioners, are there any questions?

Seeing none, back to FIPUG for redirect.

MR. MOYLE: Thank you.

FURTHER EXAMINATION

BY MR. MOYLE:

Q I just have one follow-up question.

You were asked questions about 4 CP and 12 CP. Is it fair to say that in your professional opinion, that 4 CP more appropriately allocates costs to those to cause the cost compared to the 12 CP methodology?

A Yes. And as FPL has said many times, that, yes, it can have a winter peak, but the summer peaks are always -- we always know there is going to be a summer

peak, and they are going to be sustained and long duration, so you have got to have that capacity to meet those summer peaks.

Q Okay. That's all the questions I have.

CHAIRMAN LA ROSA: Great. Thank you.

Move testimony into the record?

MR. MOYLE: Well, the testimony, I believe, has already been moved and admitted. We would like to move Exhibits 1 through 7 that were attached to Mr. Pollock's direct testimony. I believe those are Comprehensive Exhibit List Exhibits 237 to 243.

CHAIRMAN LA ROSA: Okay. Not seeing any objections, so moved.

(Whereupon, Exhibit Nos. 237-243 were received into evidence.)

CHAIRMAN LA ROSA: FEL -- or I am sorry, OPC?

MS. CHRISTENSEN: No, we didn't have any exhibits.

CHAIRMAN LA ROSA: FEL?

MR. MARSHALL: We would move in Exhibits 980, 982, 1431 and 1491.

CHAIRMAN LA ROSA: Any objections to those?

MR. MOYLE: No.

CHAIRMAN LA ROSA: Okay. So moved.

(Whereupon, Exhibit Nos. 980, 983, 1431 & 1491

were received into evidence.)

CHAIRMAN LA ROSA: Anything else? Excellent.

Mr. Pollock, thank you very much. You may be excused.

THE WITNESS: Thank you very much for the accommodation, and congratulations on your appointment.

(Witness excused.)

CHAIRMAN LA ROSA: Let's move -- if I am understanding correctly, back to FPL's Witness Reed, if I am not mistaken, is that accurate?

MS. MONCADA: That is correct. This is FPL's last witness on direct.

CHAIRMAN LA ROSA: Okay.

MS. MONCADA: FPL calls John Reed.

CHAIRMAN LA ROSA: Excellent.

Mr. Reed, do you mind standing and raising your right hand?

Whereupon,

JOHN J. REED

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Great. Thank

you.

Feel free to get comfortable there, and we will get started as soon as you are ready.

EXAMINATION

BY MS. MONCADA:

Q All right. Mr. Reed, are you ready to proceed? Is your mic on?

A Yes, I am. Thank you.

Q Thank you.

Can you please state your full name and business address for the record?

A Yes, my name is John J. Reed. I am the Chairman of the Board of Concentric Energy Advisors. My business address is 293 Boston Post Road, Marlborough, Massachusetts.

Q Thank you.

Did you cause to be filed -- did you prepare and cause to be filed 77 pages of direct testimony on February 28th, with an errata to that testimony on July 25th of this year?

A Yes, I did.

Q And other than that errata, do you have any changes to your testimony?

A No, nothing further.

Q If I asked you the same questions contained in

those test -- in that testimony today, would your answers be the same?

A Yes, they would.

Q Thank you.

MS. MONCADA: Mr. Chair, I would ask that Mr. Reed's testimony be entered into the record.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of John J. Reed was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250011-EI

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JOHN J. REED

Filed: February 28, 2025

C16-2043

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom and in what capacity are you employed?

A. I am the Chairman of Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q. On whose behalf are you testifying?

A. I am submitting this testimony on behalf of Florida Power & Light Company ("FPL" or the "Company").

Q. Please describe your background and professional experience.

A. I have more than 40 years of experience in the North American energy industry. Prior to my current position with Concentric, I served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company, North America's largest gas distribution utility. I have provided expert testimony on regulatory, financial, and economic matters on more than 300 occasions before the Federal Energy Regulatory Commission ("FERC") and the National Energy Board ("NEB") of Canada, numerous state and provincial utility regulatory agencies, various state and federal courts, and arbitration panels in the United States and Canada. My work has included prior testimony before the Florida Public Service Commission ("Commission" or "FPSC") on multiple occasions. A copy of my résumé is included

as Exhibit JJR-1. A listing of the testimony I have sponsored in the past 20 years is included as Exhibit JJR-2.

Q. Please describe Concentric's activities in energy and utility engagements.

A. Concentric provides regulatory, economic, market analysis, and financial advisory services to a large number of energy and utility clients across North America. Our market analysis services include energy market assessments, market entry and exit analyses, and energy contract negotiations. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. Our regulatory and economic services include regulatory policy, utility ratemaking (e.g., cost of service, cost of capital, rate design, alternative forms of ratemaking), and the implications of regulatory and ratemaking policies. We also regularly conduct utility benchmarking studies in which we compare companies, services, and policies of particular companies or regulatory jurisdictions to a set of comparable peers to assess performance on a variety of quantitative and qualitative metrics.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit JJR-1: Résumé of John J. Reed
- Exhibit JJR-2: Expert Testimony of John J. Reed
- Exhibit JJR-3: Situational Assessment Rankings
- Exhibit JJR-4: Cost Efficiency Rankings
- Exhibit JJR-5: Operational Metrics
- Exhibit JJR-6: Rate Level Comparison

- Exhibit JJR-7: Benchmarking Workpapers
- Exhibit JJR-8: Consumer Price Index and Producer Price Index
- Exhibit JJR-9: Average Weekly Electric Utility Employee Earnings
- Exhibit JJR-10: Handy-Whitman Construction Cost Indices
- Exhibit JJR-11: Annual Non-Fuel O&M Savings per Customer
- Exhibit JJR-12: 2021-2023 Combined Situational Assessment and Cost Efficiency Rankings
- Exhibit JJR-13: 2023 Assessment and Efficiency Tables
- Exhibit JJR-14: Emissions Comparison
- Exhibit JJR-15: Rate Level and Reliability Comparison

Q. How is the remainder of your testimony organized?

A. Following this introduction, my testimony is presented in the following sections:

II. Testimony Purpose and Summary

III. Approach to Benchmarking

IV. Business Environment and Situational Assessment

V. Benchmarking Results

VI. Conclusion

TESTIMONY PURPOSE AND SUMMARY

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by FPL to conduct an analysis of FPL's and the former Gulf Power Company's ("Gulf") (together, "the Combined Company") financial and operational performance over the past ten years through the use of a benchmarking study, including

the review of macroeconomic and service area economic drivers that have contributed to the Company's requested rate increase.

Q. Have you completed similar benchmarking analyses in the past for FPL?

A. Yes, I have. I have presented testimony in FPL's five last rate cases. The approach I have taken in the analysis discussed here is similar to the FPL benchmarking evaluations I have completed and presented in the past.

Q. Have you changed any aspects of your benchmarking analyses compared to benchmarking analyses you have done in the past for FPL?

A. Yes, I have. NextEra Energy, Inc. ("NextEra") acquired Gulf in 2019 and Gulf and FPL legally merged into a single corporation in January 2021, with FPL as the surviving entity. During 2021, FPL continued to be regulated as two separate ratemaking entities in the former service areas of FPL and Gulf. Effective January 1, 2022, FPL became regulated as one electric ratemaking entity with new unified rates and tariffs.[1] As a result, Gulf filed its own FERC Form 1 report through 2021, but FPL and Gulf began reporting combined FERC Form 1 data starting in 2022. Therefore, in order to have consistent data for the ten years used for the benchmarking analyses, I aggregated Gulf and FPL (the "Combined Company") for FERC Form 1 data for the years 2014 through 2021.

[1] As part of the Company's 2021 settlement agreement, a transition rider/credit mechanism was implemented to address the initial difference in the costs of serving the existing FPL and Gulf Power customers. The transition rider/credit will decline to zero over a five-year period, at which point rates would be fully aligned by Jan. 1, 2027.

Q. How did you structure your benchmarking analysis?

A. My analysis begins with a situational assessment, which establishes the "degree of difficulty" that the management of a utility faces in achieving top performance, and then evaluates performance on cost, operational, environmental, total rate, and other measures. Finally, for the cost benchmarking, by arraying the "degree of difficulty" on one axis and cost performance on a second axis, we can evaluate whether management has outperformed or underperformed relative to peer group companies.

Q. Please summarize the results of your benchmarking study regarding FPL's performance.

A. FPL continues to deliver highly reliable electric service at low prices for the benefit of its customers. My benchmarking analysis shows that FPL has consistently and substantially out-performed similarly sized companies across a wide array of financial and operational metrics including:

- cost efficiency – the ability to maximize output and minimize costs,
- service quality and system reliability,
- operational performance including emissions, and
- rate level.

The Company has achieved these results in spite of the fact that it faces a greater than average set of challenges (i.e., "degree of difficulty") from exogenous factors that impact a utility's ability to achieve top performance.

The Company's exceptional performance has resulted in significant economic and reliability benefits for its customers. As I explain in more detail later in my testimony, for 2023 alone, if the Combined Company had been merely an average performer, its non-fuel operational and maintenance costs and annual fuel costs charged to customers would have been higher than its actual costs by $2.9 billion[2] and $838 million,[3] respectively. In addition, if the Combined Company had been an average performer rather than an exceptional one, its customers would have experienced a level of average service interruption duration that would have been twice the level that FPL customers actually experienced over the last five years with an average interruption duration of 106 minutes, rather than the Combined Company's actual average duration of 46 minutes.[4]

Q. Please highlight some of your key analyses and conclusions regarding the Combined Company's performance.

A. As discussed throughout my testimony, the Combined Company continues to significantly outperform its industry peers in a variety of key metrics.

- Peer Groups – I evaluated the Combined Company's performance over the past 10 years (from 2014-2023) relative to four peer groups: (1) the "Straight Electric Group" - 28 similarly sized electric-only utilities with ownership in generating resources, (2) the "Florida Utility Group" – two investor-owned electric utilities that own generating resources and are subject to regulation by

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[2] See pages 39-40 of this testimony and Exhibit JJR-11, page 1 of 2.
[3] See page 62 of this testimony.
[4] Metric comparison is for FPSC Distribution Only SAIDI. Florida Utility Group five-year average distribution SAIDI of 106 minutes includes Florida Public Utilities and excludes the Combined Company. See pages 58-59 of this testimony.

the FPSC (Duke Energy Florida, and Tampa Electric Company)[5]; (3) the "Large Utility Group" – 11 large electric utility holding companies with at least two million electric customers and net generation comprising 40 percent or more of total energy sales; and (4) the "Southeastern U.S. Group" - 15 electric utilities with service territories in the U.S. Southeast region, for purposes of benchmarking the Combined Company's residential rate levels.

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- Exogenous Factors – For each of the first three peer groups, I considered the exogenous factors faced by each company. FPL's high proportion of residential customers, lower energy consumption per customer, its customer count growth rates, and other features of FPL's service area contribute to a more challenging operating environment for FPL relative to its peers. As Exhibit JJR-3 demonstrates, the Combined Company has ranked in the top quartile (facing the highest challenges from factors outside of its control) relative to its U.S. industry peers for the past ten years and has ranked as the most challenged among Florida utilities for five of the past ten years, including the most recent two years. Notably, of the large utilities, the Combined Company has faced the highest challenges in all ten years of the last decade. Despite the greater "degree of difficulty" that FPL faces, its performance over the last ten years compares remarkably well with its peers that face less difficult situational challenges to management performance.

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[5] Florida Public Utilities is also included in the Florida Utility Group for purposes of distribution reliability benchmarking only.

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- Cost Efficiency - The Combined Company is the top performer among comparable companies in terms of cost efficiency. Exhibit JJR-4 shows that the Combined Company has ranked first of the 29 companies in the Straight Electric Group and is the highest ranked company in the Florida Utility Group and in the Large Utility Group throughout this 10-year period. In terms of controlling operation and maintenance expenses specifically, the Combined Company has been the top performer among all three peer groups for each of the past 10 years.

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- Service Quality and System Reliability- It is important to note that the Combined Company's high level of cost efficiency has not been achieved at the expense of system reliability. As shown in Exhibit JJR-5, the Combined Company is a top performer in terms of controlling the duration of its distribution system outages and has consistently achieved above-average performance on the frequency of interruptions.

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- Operational Performance - With a generating fleet that produces over 95 percent of its electric power from natural gas combined-cycle, solar, and nuclear resources, the Combined Company is a clean-energy company. In fact, the Combined Company has one of the lowest emissions profiles among major U.S. utilities in terms of carbon dioxide, sulfur dioxide and nitrogen oxides. In the last 10 years, the Combined Company's fossil generation fleet performance has

been best-in-class among comparable companies in terms of forced outages and availability every year (See Exhibit JJR-5). The performance of FPL's nuclear fleet is another important factor in its ability to achieve its favorable air emissions profile. FPL's Total Industrial Safety Accident Rate has been below or close to the industry average for the last ten years, and FPL's nuclear fleet has shown steady improvements in capacity factor and availability since 2014.

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- Rate Level – Compared to electric utilities in the Southeastern U.S. Group, the Combined Company has maintained competitive residential rates, even with the challenges of restoring the system following several major hurricanes and integrating the higher-cost Gulf Power system into FPL. As shown on page 1 of Exhibit JJR-6, in each year of the analysis, the Combined Company's typical residential bill[6] was below the average bill for the Southeastern U.S. Group consisting of 12 companies operating across eight states.

On an overall basis, the Combined Company's performance continues to stand out as exceptional compared to its peers in Florida, the Southeast and across the United States. The Combined Company continues to excel at controlling costs and achieving high levels of service quality for its customers, even in the face of more challenging exogenous factors and economic drivers over which it has little or no control. In addition, all customers are benefiting from the consolidation of FPL and Gulf, as much

[6] Based on comparison of typical residential bill data from Edison Electric Institute's "Typical Bills and Average Rate" reports.

of the work to realize merger efficiencies began at the time Gulf was acquired by NextEra in January 2019.

APPROACH TO BENCHMARKING

Q. Please describe your approach to evaluating FPL's and Gulf's historical performance.

A. Providing reliable and reasonably priced electric service involves a complex array of infrastructure, general corporate services, customer services, and operational and financial resources. Assessing whether a particular company has successfully achieved both its cost control objectives and service obligations involves an evaluation of its financial and operational performance, including cost efficiency, service quality and system reliability. I have measured the Combined Company's cost efficiency against three different peer groups to evaluate the Company's relative performance in the 10-year period of analysis, 2014 to 2023, and across time to capture the trend in its performance. I developed additional analyses to determine whether any cost improvements were made at the expense of reductions in operational performance, service quality and system reliability. I have considered all of these aspects of the Combined Company's performance and, where possible, I measured and quantified the associated customer benefit.

Q. In general, what steps did you take in constructing your benchmarking analysis?

A. The first step of the benchmarking analysis was to define the timeframe over which the analysis was to be performed. The second step was to develop the composition of the peer groups used to compare to the Combined Company. The third step was to define

the financial and operational metrics to be used in the benchmarking and to collect the necessary data to evaluate these metrics. Finally, in recognition of the significantly different service area characteristics that each of the peer group companies face, and the consequently different performance challenges and opportunities created by these service area characteristics, I developed a situational assessment ranking that reflects the "degree of difficulty" that each peer group member faces in seeking to maximize its cost efficiency.

Q. Why did you combine FPL and Gulf in your benchmarking analysis?

A. Portions of my analysis are based on data obtained from FERC Form 1. As stated in section II above, NextEra bought Gulf Power in 2019 and Gulf and FPL legally merged into a single corporation in January 2021. Historically, Gulf filed its own FERC Form 1 report through 2021, but FPL and Gulf began reporting combined FERC Form 1 data starting in 2022.

Q. How did you combine FPL and Gulf in your benchmarking analysis?

A. In order to benchmark 2022 and 2023 data alongside historical data from 2014 through 2021, I combined FPL and Gulf FERC Form 1 data by category for the years 2014 through 2021. I aggregated the FPL and Gulf data prior to 2022 to create equivalent data to the consolidated 2022 and 2023 data.

Q. How did you select the companies to include in your benchmarking peer groups?

A. My objective in determining the sets of peer group electric utilities was to achieve the largest group of companies for which consistent data were available and which were, broadly speaking, operationally similar to the Combined Company. Because the Combined Company is an electric-only utility with ownership in generating resources,

I established one peer group of companies with electric-only utility operations that have at least 450,000 customers and own generating resources. I refer to this group of 29 comparable companies as the "Straight Electric Group." I established a second peer group consisting of investor-owned electric utilities that own generating resources and are subject to regulation by the FPSC. This "Florida Utility Group" includes the Combined Company, Duke Energy Florida, and Tampa Electric Company. I established a third peer group made up of large electric utility holding companies with at least two million electric customers and net generation comprising 40 percent or more of total energy sales. This "Large Utility Group" consists of 12 companies, including the Combined Company. Lastly, I established a fourth peer group, the "Southeastern U.S. Group," made up of 12 companies operating across eight states, including the Combined Company, for purposes of benchmarking the Combined Company's residential rate levels. The composition of each of my peer groups is shown in Exhibit JJR-7, page 1.

Q. Why did you use the number of customers as a criterion for determining the companies in your Straight Electric Group?

A. The purpose of this benchmarking analysis is to develop a meaningful comparison of the Combined Company's financial and operational metrics that are indicative of utility performance. Many of the challenges and opportunities for a company are a function of its size. Because my focus is on controllable economic efficiencies, size is an important attribute, and a utility's size tends to vary most directly as a function of the number of customers it serves.

Q. Please describe the process you used to define and benchmark the cost efficiency metrics used in your analysis.

A. For my benchmarking analyses, I developed ordinal rankings for both the financial and operational performance of the companies in each of three peer groups. These rankings reflect the performance of each company in each peer group as measured by the level of input cost per unit of "output," such as customer expense per customer, or operations and maintenance ("O&M") expense per megawatt-hour ("MWh") sold. I ranked each company in each peer group according to the 11 measures of productivity that I developed. To develop an overall assessment based on the rankings of all the performance measurement categories, I took an average of the ordinal rankings for all performance measures, and I ranked the companies in the peer groups based on those averages. This approach allowed me to compare the Combined Company's "cost efficiency" to the other companies in each peer group.

To put the benchmarking results in context, I also conducted a "situational assessment" to rank the level of challenges to performance that the companies in each peer group face. Like the cost efficiency metrics, I took an average of all the ordinal values to determine the Combined Company's overall level of exogenous performance challenges.

Q. What data sources did you rely on for the performance metrics that you developed?

A. I compiled data from several sources. I obtained much of the data from FERC Form 1 and U.S. Securities and Exchange Commission ("SEC") Form 10-K reports (as

reported by S&P Global Market Intelligence). For supplemental metrics related to FPL's operational performance, I obtained data from the Generating Availability Data System ("GADS") database produced by the North American Electric Reliability Corporation ("NERC"), ABB's Velocity Suite,[7] the U.S. Energy Information Administration ("EIA") Form EIA-861, Edison Electric Institute ("EEI") reports, rate case information as compiled by S&P Global Market Intelligence, Annual Distribution Reliability Reports and Company Annual Reports filed by investor-owned electric utilities with the FPSC.

Q. Were data available for all peer companies for each metric and year included in your benchmarking study?

A. No, not in every instance. However, such instances of unavailable data are rare and do not adversely affect the conclusions of my cost efficiency or situational assessments even as unavailable data are excluded from peer group average, rank, and percentile calculations. In total, there are only 56 instances of unavailable data, which is less than one percent of the 7,600 total data points analyzed in my cost efficiency and situational assessments, which span 11 different financial and operational metrics and 8 different exogenous factors analyzed annually across a 10-year period for three different peer groups including a total of 40 companies. Sufficient data were available and relied upon for my benchmarking analysis, allowing for informed conclusions regarding the Combined Company's cost efficiency and situation assessments.

[7] ABB's Velocity Suite was formerly owned by Ventyx and is known as the Ventyx Velocity Suite.

BUSINESS ENVIRONMENT AND SITUATIONAL ASSESSMENT

Business Environment

Q. What economic factors and timeframes did you consider in your analysis?

A. I considered a number of national and regional economic factors that affect the Combined Company's performance trends over time, including inflation and increases in the cost of utility labor and utility construction costs.

These economic factors influence the Company's need for rate relief and the level of rate relief that it is requesting in this proceeding. The most relevant period for considering the economic drivers is the period subsequent to FPL's last rate case, which was filed in March 2021 with a final order issued December 2, 2021.

Q. Please describe the national economic trends that have most affected the Combined Company's costs.

A. Two common measures of the national economy's general price level that are indicators of inflationary pressures on the Combined Company's costs are the Consumer Price Index for urban consumers ("CPI-U") and the Producer Price Index for finished goods ("PPI"). Exhibit JJR-8 shows the performance of the CPI-U and PPI for finished goods since 2014. The CPI-U has increased by 13.55 percent between November 2021 and December 2024, while the PPI for all manufactured goods has increased by 12.64 percent.

The cost of utility labor also has a significant impact on FPL's costs. Exhibit JJR-9 shows electric utility employee average weekly earnings as reported by the Bureau of Labor Statistics. Since November 2021, average weekly earnings have increased from

approximately $1,897 to approximately $2,198 in December 2024, or 15.87 percent in nominal growth over this 3-year period, which equate to a 5.0 percent compound annual growth rate ("CAGR").

Lastly, overall utility construction costs, which directly affect the cost of additions to rate base, have increased significantly in recent years. The Handy-Whitman Index of Public Utility Construction Costs provides a good indication of the rising cost of construction incurred by FPL. This index is calculated on a regional basis and incorporates all construction costs including materials and labor. Exhibit JJR-10 presents the Handy-Whitman Index for the South Atlantic region between January 1, 2014 and July 1, 2024. Exhibit JJR-10 demonstrates that the separate data series for Steam Production Plant, Hydraulic Production Plant, Nuclear Production Plant, Other Production Plant, Transmission Plant, and Distribution Plant have all increased significantly since FPL's last rate case was decided. The Distribution Plant index has the greatest growth rate of 50.15 percent between January 1, 2022 and July 1, 2024, which equates to a CAGR of 17.65 percent. The remaining five construction cost indices have increased between 14.07 percent and 39.20 percent, which equates to CAGRs that range from 5.4 percent to 14.1 percent.

Situational Assessment

Q. What is the purpose of your situational assessment?

A. Using benchmark studies alone to compare the performance of utilities is inherently difficult because no two utility companies face the same set of circumstances in terms of service area economic and operational factors. The purpose of a situational

assessment is to recognize each utility's cost advantages or disadvantages that are not within its control. Often, a utility's above-average or below-average performance on a single performance metric can be explained by the results of the situational assessment. I use my situational assessment to evaluate the Combined Company's performance in context.

Q. Please describe your situational assessment.

A. I started by identifying exogenous factors that would influence a utility's performance, positively or negatively, as compared to other companies in a different relative position. Using publicly reported data, I examined eight exogenous factors: (1) Percent Sales Residential; (2) Percent Sales Other; (3) Use per Customer; (4) Growth in Number of Customers (percent); (5) Growth in Sales; (6) Percent Generation Nuclear; (7) Energy Losses/Total Energy Disposition; and (8) Accumulated Depreciation as a Percent of Gross Plant.

The results of my situational assessment are presented in Exhibit JJR-3, pages 1 through 10. This exhibit shows the rank order of each of the companies in each of the comparison groups for each situational measure, as well as an overall score in the far-right column based on the average rank. These metrics generally provide insight regarding the operational challenges and opportunities that the peer group companies face that could be expected to affect cost. In my situational assessments, a ranking of one indicates the company with the highest level of challenge for a particular measure.

As shown in Exhibit JJR-3, the Combined Company has ranked in the top quartile as one of the most disadvantaged utilities (by factors outside of its control) relative to its industry peers, the most disadvantaged among Florida utilities for seven of the past 10 years, including the most recent two years, and the most disadvantaged among the large utilities in all ten years of the last decade.

Q. Please discuss the Percent Sales Residential metric and how the Combined Company compares to its peers.

A. On a dollars per kilowatt-hour ("kWh") basis, residential customers are more expensive to serve than commercial and industrial customers. As a result, utilities with a higher proportion of residential customers tend to have higher costs and higher rates. The Combined Company's rank order for the percent of its sales to residential customers as compared to the other 28 companies in the Straight Electric Group is shown in Figure 1, below. As shown there, the Combined Company is either first, second or third in this group (in terms of being the most challenged) in each of the last 10 years on this metric. Fifty percent of the Combined Company's combined sales by volume were sales to residential customers in 2023.

Figure 1: Percent Sales (MWh) Residential

Percent Sales (MWh) Residential
Straight Electric Group Rankings

More Disadvantaged ↑ More Residential Sales

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the next metric, Percent Sales Other, and how the Combined Company compares to its peers.

A. Sales Other[8] are non-retail sales, which typically represent the lowest unit cost sales for a utility company. Utilities with higher levels of sales for resale tend to have skewed average rate statistics which look lower than an otherwise comparable utility. As shown in Figure 2 below, in the Straight Electric Group the Combined Company is in the first or second most challenged quartile for all years. The Combined Company has a lower Percent Sales Other metric than the Straight Electric Group average, Florida Group

[8] "Sales Other" represents all sales other than sales to residential, commercial, and industrial customers. These are typically Sales for Resale.

average, and Large Utilities Group average in all years, as shown in Exhibit JJR-7, page 4. All else being equal, this would indicate that FPL's unit costs should be higher than the other companies in these groups.

Figure 2: Percent Sales (MWh) Other
Percent Sales (MWh) Other
Straight Electric Group Rankings

More Disadvantaged ↑ Less Sales for Resale

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the next metric, Use per Customer,[9] and how the Combined Company compares to its peers.

A. Because many of the costs of serving an individual customer are fixed, utilities with lower use per customer tend to have higher unit cost. In the Straight Electric Group,

[9] Use per customer measures the average volume of sales for all electric customers.

the Combined Company is in the most challenged quartile for use per customer each year as shown in Figure 3, below.

Figure 3: Use per Customer

Use per Customer
Straight Electric Group Rankings

More Disadvantaged ↑ Lower Use per Customer

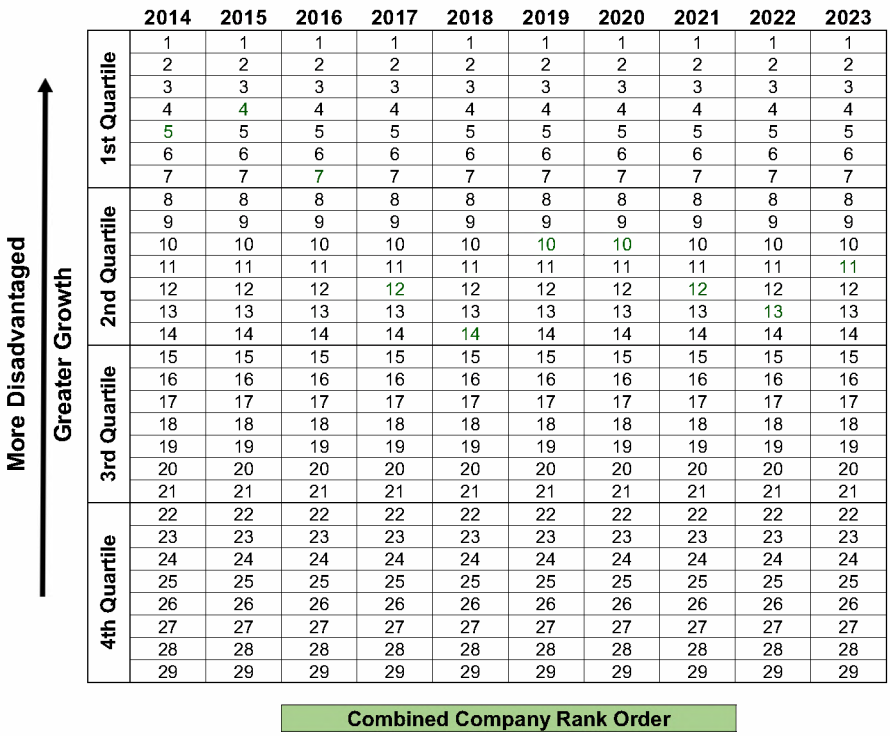
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the next metric, Growth in Number of Customers, and how the Combined Company compares to its peers.

A. High growth in the number of customers creates challenges in terms of managing capital expenditures and resource utilization over time. The Combined Company has experienced strong growth in the number of customers: in the Straight Electric Group for the past ten years, the Combined Company has been ranked in the highest growth quartile for three years and in the second highest growth quartile for seven years, as shown in Figure 4 below.

Figure 4: Growth in Number of Customers (%)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Q. Please discuss the Growth in Sales Volume metric and how FPL compares to its peers.

A. As described for the growth in customers, high growth in sales volume requires companies to invest more capital compared to companies with slow or no growth, creating greater challenges in terms of capital spending.[10] The Combined Company's sales volume 5-year CAGR has been ranked in the first quartile of the Straight Electric Group for four of the past ten years and ranked in the second quartile of the Straight Electric Group for six of the last ten years, as shown in Figure 5, below.

[10] While Concentric's situational assessment considers high sales growth as creating challenges, high sales growth can also enable fixed costs to be spread over a larger base, with the potential to obtain efficiencies and control costs, particularly with new technologies being deployed.

Figure 5: Growth in Sales Volume
Growth in Sales (5-year CAGR)
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

More Disadvantaged ↑ Greater Growth

Combined Company Rank Order

Q. Please discuss the Percent Generation Nuclear metric and how FPL compares to its peers.

A. The non-fuel costs for nuclear generation are higher than those for coal-fired, oil-fired, gas-fired and hydroelectric generating resources; utilities with a higher proportion of nuclear generation face greater cost challenges than utilities with a lower level of nuclear generation. Since September 2009, the Combined Company is the only Florida utility with operating nuclear units. This places significant pressure on the Combined Company's cost structure relative to its peers in the region. In comparison to the 29 peer utilities in the Straight Electric Group, the Combined Company is in the second quartile each year as shown in Figure 6, below.

Figure 6: Percent Generation Nuclear
Percent Generation Nuclear
Straight Electric Group Rankings

More Disadvantaged ↑ Greater Percent Generation Nuclear

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the Energy Losses/Total Energy Disposition metric and how the Combined Company compares to its peers.

A. Energy losses are a product of the transmission and distribution infrastructure through which the energy is transmitted. Electric utilities that have greater reliance on long-distance transmission facilities tend to experience higher losses than utilities that are able to site generation closer to load centers. This metric demonstrates a significant challenge faced by the Combined Company. In the Straight Electric Group as shown in Figure 7 below, the Combined Company has been in the highest or second highest quartile each year for this metric, meaning that it faces more challenging circumstances than most of its peers.

Figure 7: Energy Losses/Total Energy Disposition

Energy Losses / Total Energy Disposition
Straight Electric Group Rankings

More Disadvantaged ↑ Greater Losses

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the Five-Year Additions to Utility Plant as a Percent of Gross Plant metric and how the Combined Company compares to its peers.

A. I use this metric as a reasonable proxy for the age of a utility's asset base and level of recent capital spending. First, I gathered each utility's gross additions to utility plant, excluding nuclear fuel, as reported in FERC Form 1. I calculated the five-year rolling sum for each utility's gross additions to utility plant to capture recent capital spending.[11] I then divided this figure by the utility's gross plant. Utilities with a higher proportion of recent additions to gross plant tend to have a newer asset base, while

[11] For example, the 2023 five-year rolling is a sum of 2019-2023 gross additions to utility plant; the 2022 value is a sum of 2018-2022 gross additions to utility plant, etc.

those with a lower proportion tend to have an older asset base. Utilities with an older asset base tend to have lower rates, reflecting plant values that are more fully depreciated and that reflect expenditures in earlier-year dollars. On the other hand, utilities with newer asset bases reflect the effects of inflation and the effects of being less depreciated, leading to higher rates. The Combined Company's ranking clearly reflects the high level of investments that have been made in the last several years to modernize generation, strengthen the reliability of its transmission and distribution systems and to connect new customers to its system. In the Straight Electric Group as shown in Figure 8 below, the Combined Company has ranked first, second, or third in all years since 2014 in having relatively newer plant. The Combined Company's ranking compared to its peers in all three peer groups indicates that the Combined Company has made comparatively greater investments over this period than have its peer utilities. This trend is also consistent with the Company's growth in customers over the period, which has outpaced its peers.

Figure 8: Five-Year Additions to Utility Plant as percent of Gross Plant

5-Yr Adds. to Util. Plant/Gross Plant
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

More Disadvantaged ↑ Lower Age of Asset Base

Combined Company Rank Order

Q. Please summarize your conclusions with respect to your situational assessment.

A. My situational assessment indicates that the Combined Company faces the greatest situational disadvantages of any utility in the Large Utility Group in every year out of the ten years comprising my analysis. In the Florida Utility Group, the Combined Company is the most disadvantaged in five of the last ten years of my analysis, including the two most recent years. In the Straight Electric Group, the Combined Company is in the most disadvantaged quartile every year as shown in Figure 9, below.

Figure 9: Overall Situational Assessment Rank
Situational Assessment Overall Rank
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

More Disadvantaged

Combined Company Rank Order

It is important to keep the situational assessment in context when viewing performance metrics. I offer these metrics as a means of "getting the lay of the land" in understanding the cost efficiency metrics. This is not a perfect means of capturing all of the challenges or advantages of the Combined Company and the companies in the peer groups, but it represents a reasonable cross-section of key factors influencing a utility's operations based on publicly available information.

BENCHMARKING RESULTS

Overview

Q. What metrics did you use to assess the Combined Company's financial and operational performance?

A. I evaluated the Combined Company's performance across a variety of financial and operational metrics including cost efficiency – the ability to maximize output and minimize costs – service quality and system reliability, operational performance including emissions and the level of its rates.

Regarding cost efficiency – the ability to maximize output and minimize costs, I first considered expense performance metrics:

- Total Non-Fuel O&M expenses
- Non-Fuel Production O&M expenses
- Transmission O&M expenses
- Distribution O&M expenses
- Administrative and General ("A&G") expenses
- Customer expenses
- Uncollectible expenses

In addition to expense performance, I also considered the efficiency metrics:

- Days sales outstanding
- Labor efficiency
- Gross asset base

- Additions to plant per new customer

To ensure that the Combined Company's performance on cost and corporate metrics did not occur at the expense of reliability, I compiled the following service quality and system reliability metrics to measure the Combined Company's operational performance:

- Distribution system average interruption duration index ("SAIDI")
- Distribution system average interruption frequency index ("SAIFI")
- Customer average interruption duration index ("CAIDI")

In addition to reliability of service, I also considered operational and emissions performance metrics:

- Fossil plant heat rate
- Fossil plant equivalent availability factor
- Fossil plant equivalent forced outage rate
- Nuclear capacity factor
- Nuclear equivalent availability factor
- Nuclear forced loss rate
- Nuclear industrial safety accident rate
- Emissions from generating stations

Finally, I considered the level of the Combined Company's rates relative to their peers in the U.S. Southeast region using the following metrics:

- Average duration between filing dates of past rate case applications
- Typical 1,000 kWh residential total bill
- Average total rates for residential, commercial, and industrial segments

The detailed definitions of each of the cost efficiency and reliability and operational performance metrics I used are presented on page 2 of Exhibit JJR-5 and page 2 of Exhibit JJR-7.

Q. Did the metrics account for companies of different sizes?

A. Yes. Most metrics are calculated on an expense per customer or an expense per MWh sold basis. The cost efficiency metrics presented in my analysis are an average of the per customer values and the per MWh values for each cost element. For example, the A&G expenses cost efficiency metric reflects each utility's A&G expenses per MWh sold and A&G expenses per customer and presents the average performance rank on these two metrics as the measure of A&G cost efficiency.

Q. Did you make any adjustments to the metrics?

A. Yes. I reduced the Combined Company's O&M expenses as reported in the Company's 2017 through 2023 FERC Form 1s to remove the base O&M storm recovery costs associated with several storms.

In September 2017, FPL was impacted by Hurricane Irma, which resulted in damage that was primarily limited to FPL's transmission and distribution systems. In December 2017, FPL determined that it would not seek recovery of Hurricane Irma storm restoration costs of approximately $1.3 billion through a storm surcharge from

customers and instead recorded such costs as storm restoration costs in FPL's consolidated statements of income.

Hurricane Dorian impacted FPL in September 2019. In December 2019, FPL determined that it would not seek recovery of Hurricane Dorian storm restoration costs of approximately $260 million through a storm surcharge and instead recorded and expensed such costs as storm restoration costs in FPL's consolidated statements of income. The $260 million of storm restoration costs primarily included costs for pre-staging resources in advance of the storm to repair damage to FPL's distribution system.

Approximately 93 percent and 97 percent of FPL's total storm restoration O&M costs associated with Hurricane Irma and Hurricane Dorian, respectively, were charged to distribution O&M. The remaining storm restoration O&M costs were charged to steam production O&M expense, nuclear production O&M expense, other power generation O&M expense, transmission O&M expense, customer service expense, and A&G O&M expense. I also included O&M adjustments for years 2018 through 2020 by FERC expense account to reflect differences between FPL's estimated storm restoration cost accruals and updated actual costs for Hurricanes Irma and Dorian provided by FPL's accounting group.

Hurricane Isaias and Tropical Storm Eta impacted FPL's service territory in 2020 and Hurricanes Sally, Elsa, and Tropical Storm Fred impacted FPL in 2021. FPL determined that it would not seek recovery of approximately $205 million of storm

restoration costs for Hurricane Isaias and Tropical Storm Eta and approximately $55 million of storm restoration costs for Hurricanes Sally, Elsa, and Tropical Storm Fred and instead recorded and expensed such costs as storm restoration costs in FPL's consolidated statements of income. In 2022 FPL's service area was impacted by Hurricanes Ian and Nicole and in 2023 the FPSC approved FPL's request to begin recovering eligible storm costs of approximately $1.3 billion, primarily related to surcharges for Hurricanes Ian and Nicole.[12] In 2023 FPL was also impacted by Hurricane Idalia and two storm events in November and December of 2023 and recorded and expensed approximately $0.5 million in its consolidated statements of income. I also included O&M adjustments for years 2021 through 2023 by FERC expense account to reflect differences between FPL's estimated storm restoration cost accruals and updated actual costs for Hurricanes Dorian, Isaias, Sally, Elsa, Ian and Nicole, and Tropical Storms Eta and Fred, provided by FPL's accounting group.

Q. Did you adjust O&M expenses for Gulf to remove storm recovery costs?

A. Yes. Gulf accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The Company may make discretionary accruals and is required to resume accruals of $3.5 million annually if the reserve falls below zero. These annual accruals are reported in Gulf's FERC Form 1 as Property Insurance under A&G Expenses. Gulf accrued total expenses of $28.2 million in 2018 and $3.5 million annually for years 2015 through 2017 and 2019. I

[12] In addition, approximately $2 million were recorded and expensed in FPL's 2022 consolidated statements of income.

made an adjustment to Gulf's 2018 A&G expense to remove the incremental discretionary accrual amount of $24.7 million (i.e., $28.2 million less $3.5 million).

Q. Did you adjust O&M expenses for other peer companies to remove storm recovery costs?

A. Yes. I made adjustments to Duke Energy Florida, Duke Energy Progress, Duke Energy Carolinas, and Tampa Electric Company to remove storm O&M restoration costs charged to FERC Form 1 reported distribution O&M expense and transmission O&M expense.

- Duke Energy Florida reduced its Hurricane Irma and Hurricane Nate storm restoration regulatory asset by $6 million and recorded the $6 million as O&M expense pursuant to a June 13, 2019 settlement agreement.
- Duke Energy Progress included $26 million in O&M expense in 2019 for Hurricane Dorian, while deferring $179 million to regulatory assets.
- Duke Energy Carolinas and Duke Energy Progress included $8 million in O&M expense in 2022, while deferring $87 million to regulatory assets. [13]
- Tampa Electric Company included $3 million in O&M expense in 2017, while deferring $90 million to the company's storm reserve for Hurricane Irma. Tampa Electric Company was later required to charge an additional $1.7 million to base O&M, excluding the amount from its deferred regulatory asset, pursuant to a 2019 settlement agreement.

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[13] Duke Energy Carolinas and Duke Energy Progress reported $8 million combined in O&M expense. Of the approximately $87 million deferred in regulatory assets, $32 million was deferred for Duke Energy Carolinas and $55 million was deferred for Duke Energy Progress. I allocated the $8 million O&M expense between the two companies using the same proration as the regulatory asset deferrals.

Detail regarding storm restoration costs by FERC account was not available for Duke Energy Florida, Duke Energy Progress, Duke Energy Carolinas, or Tampa Electric Company. I therefore allocated total storm restoration O&M adjustments between distribution O&M expense and transmission O&M expense based on proration of unadjusted distribution O&M expense and transmission O&M expense reported in each company's FERC Form 1 for year of required adjustment.

Cost Efficiency

Q. Which metrics provide the best indication of the Combined Company's overall performance relative to the peer groups?

A. While each metric is significant and may help identify particular areas of strength or weakness, the best indication of the Combined Company's overall level of performance in controlling costs is Total Non-Fuel O&M expenses per customer. This category covers all four primary operating functions (generation, transmission, distribution, and customer service), and includes all administrative and general functions. Further, this metric has the advantage of removing the effects of differences in fuel costs, which can vary due to availability, location, and state or local environmental policies.

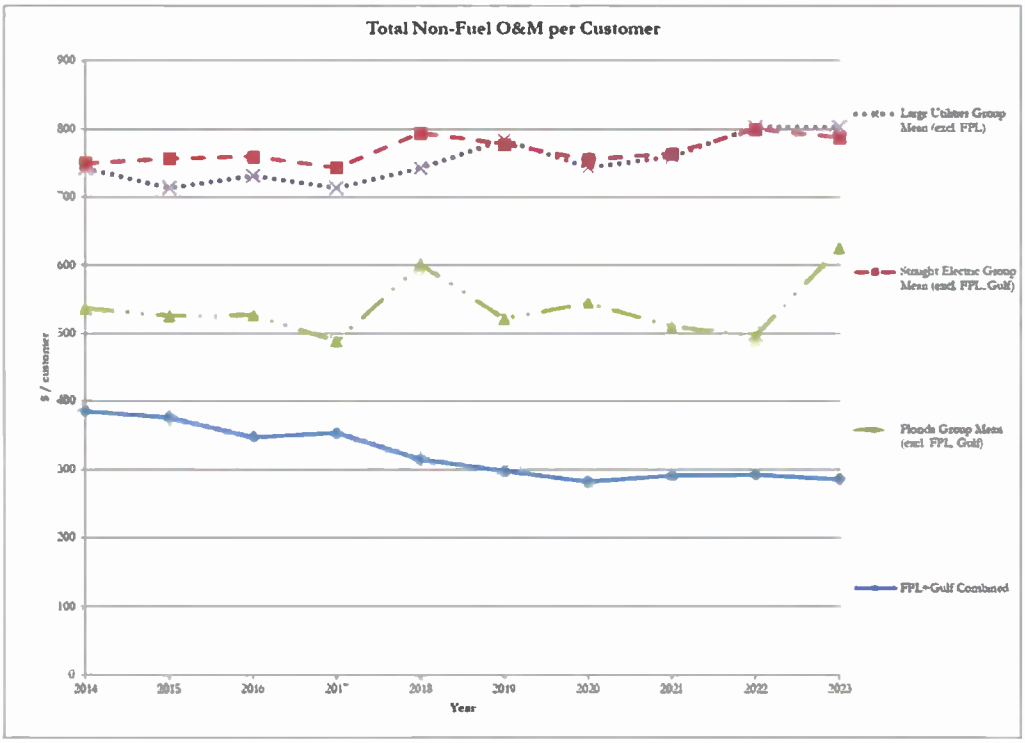
Q. Please discuss how the Combined Company compares to its peers in regard to the Total Non-Fuel O&M expense metric.

A. The Combined Company's performance controlling its non-fuel O&M expense per customer and per MWh sold is very strong in each year of my analysis. The Combined Company's top performance in all three peer groups on a sustained basis is illustrated in Figure 10 below for non-fuel O&M per customer. The Combined Company's 2023

non-fuel O&M is $286 per customer, compared to the 2023 Straight Electric Group average of $787 per customer, the Florida Group Average of $626 per customer, and the Large Utilities Group average of $803 per customer. Over the past 10 years, the Combined Company's non-fuel O&M per customer has decreased by 26 percent from $385 per customer in 2014 to $286 per customer in 2023. Meanwhile, over the past 10 years the 2023 non-fuel O&M Straight Electric Group average has increased by 5 percent, the Florida Group Average has increased by 16 percent, and the Large Utilities Group average has increased by 8 percent.

The Combined Company's non-fuel O&M per MWh sold has decreased by 24 percent from $17.05 per MWh in 2014 to $12.99 per MWh in 2023. Between 2014 and 2023, the non-fuel O&M per MWh sold average for the Straight Electric Group, the Florida Group, and the Large Utilities Group has increased by 16 percent, 23 percent, and 26 percent, respectively.

Figure 10: Total Non-Fuel O&M Expense per Customer[14]



[14] Source: Exhibit JJR-7, page 28

Figure 11: Total Non-Fuel O&M[15]
Total Non-Fuel O&M
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Has the Combined Company's performance controlling non-fuel O&M expense in particular benefited its customers?

A. Yes, the Combined Company's performance has translated into real cost savings to its customers each year. In 2023, the Combined Company's non-fuel O&M expense was $286 per customer. This is $502 per customer less than what customers would have paid in 2023 if the Combined Company's non-fuel O&M expense had been merely average at $787 per customer (i.e., consistent with the average of the companies in the Straight Electric Group in 2023). This non-fuel O&M expense performance difference of $502 per customer, multiplied by the Combined Company's 2023 average customer

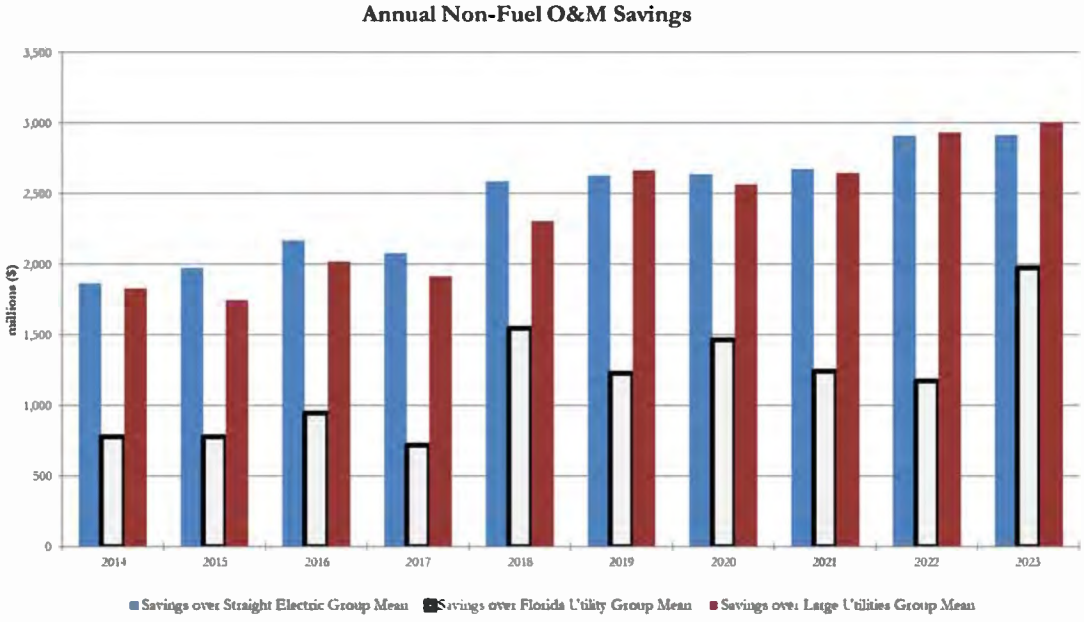
[15] Combined metric ranking is for average of two metrics: Total Non-Fuel O&M per customer and Total Non-Fuel O&M per MWh Sold.

count of 5,810,486 customers results in estimated savings of $2.9 billion for year 2023 alone. I repeated this calculation of the Combined Company's annual non-fuel O&M savings over the Straight Electric Group average performance for each year. Since FPL's last rate case in 2021, the Combined Company's non-fuel O&M savings over the Straight Electric Group's average performance total $5.8 billion.[16] Since the acquisition of Gulf in 2019, the Combined Company's non-fuel O&M savings over the Straight Electric Group's average performance total $11.1 billion.[17] Exhibit JJR-11 and Figure 12 below present the non-fuel O&M savings that have accrued to the Combined Company's customers in comparison to each peer group of comparable companies between 2014 and 2023. The Combined Company's estimated non-fuel O&M savings over the Florida Utility Group's average performance is $2.0 billion for year 2023 alone and totals $5.8 billion for years 2020 through 2023.

[16] $5.8 billion is sum of 2022 through 2023 estimated FPL annual non-fuel O&M savings over the Straight Electric Group average performance as shown in Exhibit JJR-11.

[17] $11.1 billion is sum of 2020 through 2023 estimated FPL annual non-fuel O&M savings over the Straight Electric Group average performance as shown in Exhibit JJR-11.

Figure 12: FPL Annual Non-Fuel O&M Savings[18]



Q. Please discuss how the Combined Company compares to its peers in controlling Non-Fuel Production O&M expense.

A. The Combined Company is consistently a strong performer in controlling its Non-Fuel Production O&M Expense. For Non-Fuel Production O&M Expense per customer, the Combined Company is ranked second or third best of the Straight Electric Group and Large Utility Group and is the top performer in the Florida Utility Group for each of the past 10 years. For Non-Fuel Production O&M per MWh Produced, the Combined Company is the top performer in the Straight Electric Group and Florida Utility Group, and the second best performer in the Large Utility Group, for each year, as shown in Exhibit JJR-7, pages 11 and 12.

[18] Source: Exhibit JJR-11, page 1

The Combined Company's Non-Fuel Production O&M metric, as shown in Figure 13, below, is ranked first among the Straight Electric Group and Florida Utility Group in all years, but for 2015, where it is ranked second among the Straight Electric Group. The combined Non-Fuel Production O&M metric includes Non-Fuel Nuclear Production O&M per Nuclear MWh Produced in its average for the Combined Company and other peer companies with nuclear generation. However, this metric is not applicable and excluded from combined metric for companies that do not own and operate nuclear generation.

Figure 13: Non-Fuel Production O&M[19]
Non-Fuel Production O&M
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Please discuss how the Combined Company compares to its peers in regard to controlling Transmission O&M expense.

A. The Combined Company has also performed well in controlling Transmission O&M expenses, being ranked in the top quartile of the Straight Electric Group for each of the eight years since 2016 and was ranked in the second quartile for the two years prior to 2016, as shown in Figure 14, below. The Combined Company has been ranked first among the Florida Utility Group for the most recent three years since 2021.

[19] Combined metric ranking is for average of three metric rankings including: Non-Fuel Production O&M (Excluding Nuclear) per Customer, Non-Fuel Production O&M per MWh Produced (Excluding Nuclear) and Non-Fuel Nuclear Production O&M per Nuclear MWh Produced (if applicable).

In addition to the "per customer" and "per MWh" measurement used in other metrics, the overall merit-order ranking for Transmission O&M also takes into account Transmission O&M expenses per mile of transmission line.

Figure 14: Transmission O&M[20]
Transmission O&M
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8		8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Please discuss how the Combined Company compares to its peers in controlling Distribution O&M expense.

A. The Combined Company has shown excellence in controlling its Distribution O&M expenses. The Combined Company is ranked in the top quartile of the Straight

[20] Combined metric ranking is for average of three metric rankings including: Transmission O&M per Customer, Transmission O&M per MWh, and Transmission O&M per Mile of Transmission Line.

Electric Group, first in the Florida Utility Group, and either second or first in the Large Utility Group for each of the past 10 years.

Figure 15: Distribution O&M[21]
Distribution O&M
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Please discuss how the Combined Company compares to its peers in controlling A&G expense.

A. The Combined Company is consistently a top performer in controlling A&G Expenses. The Combined Company has been among the top five performers in the Straight Utility

[21] Combined metric ranking is for average of two metric rankings including: Distribution O&M per Customer and Distribution O&M per MWh.

Group, the top performer in the Florida Utility Group, and a top-three performer in the Large Utility Group for each of the past 10 years.

Figure 16: A&G Expense[22]
A&G Expense
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Please discuss how the Combined Company compares to its peers in controlling Customer expense.

A. The Customer Expense metric includes customer account expenses, customer service and informational expenses and sales expenses. In terms of controlling customer expenses, the Combined Company is the top performer in the Florida Utility Group and

[22] Combined metric ranking is for average of two metric rankings including: A&G Expense per Customer and A&G Expense per MWh.

Large Utility Group for the past eight years since 2016 and is in the top quartile of the Straight Electric Group for the past nine years since 2015.

Figure 17: Customer Expense[23]
Customer Expense
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4		4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7		7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28

Lower Cost

Combined Company Rank Order

Q. Please discuss how the Combined Company compares to its peers in controlling Uncollectible expense.

A. The Combined Company's Uncollectible Expense as a percent of total sales revenues is in the top quartile of the Straight Electric Group for eight of the past ten years and is the top performer in the Florida Utility Group for each of the last 10 years. In the Large

[23] Combined metric ranking is for average of two metric rankings including: Customer Expense per Customer and Customer Expense per MWh.

Utility Group, the Combined Company is the top performer for eight of the past 10 years and ranked second and fourth best for the remaining two years as shown in Figure 18 below. The low Straight Electric Group rank of 19th in 2020 is attributable to the COVID-19 pandemic and proactive steps the Company took to help customers during that time.

Figure 18: Uncollectible Expense
Uncollectible Expense per Sales Revenue
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7		7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Lower Cost

Combined Company Rank Order

Q. Please discuss the Days Sales Outstanding metric and how the Combined Company compares to its peers.

A. Days Sales Outstanding is a measure of the average level of accounts receivable in relation to total electricity sales over a year and is calculated as the ratio of Customer Accounts Receivable to Total Electricity Sales multiplied by 365 days. Regarding this

metric, the Combined Company performs in the first or second quartile in both the Straight Electric Group, as shown in Figure 19 (below), and the Large Utility Group. In the Florida Utility Group, the Combined Company has been the best performer since 2014.

Figure 19: Days Sales Outstanding

Days Sales Outstanding
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Fewer Days Outstanding

Combined Company Rank Order

Q. Please discuss the Labor Efficiency metric and how the Combined Company compares to its peers.

A. Labor Efficiency is a combined metric that includes Salaries, Wages, Pension and Benefits on a per employee and per customer basis, as well as employees per customer. The Combined Company has demonstrated consistently strong performance in these areas. The Combined Company is routinely in the top quartile in the Straight Electric

Group, the top performer in the Florida Utility Group throughout the past 10 years and either the first- or second-best performer in the Large Utility Group since 2018.

Figure 20: Labor Efficiency[24]
Labor Efficiency
Straight Electric Group Rankings

More Efficient ↑

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Combined Company Rank Order

Q. Please discuss the Gross Asset Base metric and how the Combined Company compares to its peers in this metric.

A. The Gross Asset Base metric is an average of Total Utility Electric Plant per customer and Total Utility Electric Plant per MWh sold. A company with a lower Gross Asset Base metric value has spent less total gross capital investments per customer or per

[24] Combined metric ranking is for average of three metric rankings including: (1) Employees per Thousand Customers, (2) Salaries, Wages, Pensions, and Benefits per Customer, and (3) Salaries, Wages, Pensions, and Benefits ($000) per Employee.

MWh sold, indicating greater capital efficiency compared to a company with a higher metric value. As shown on pages 30 and 31 of Exhibit JJR-7, the Combined Company's level of Gross Asset Base per customer and per kWh of retail sales has exhibited strong performance, ranking in the first quartile in the Straight Electric Group in seven of the ten years examined. In the Large Utility Group, the Combined Company has been either the first-, second-, or third-best performer over the past ten years.

Figure 21: Gross Asset Base[25]
Gross Asset Base
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Lower Cost ↑

Combined Company Rank Order

[25] Combined metric ranking is for average of two metric rankings including: Gross Asset Base per Customer and Gross Asset Base per MWh.

Q. Please discuss how the Combined Company compares to its peers in regards to the Additions to Plant per New Customer metric.

A. The Additions to Plant per New Customer metric is calculated as annual additions to Total Electric Plant in Service as reported in each company's FERC Form 1 divided by the positive change in number of customers from prior year. While not all plant additions are attributable to new customers, a utility with a lower Additions to Plant per New Customer metric value typically meets new customer demand with lower cost capital investments, compared to a utility with a higher metric value. The Combined Company's Additions to Plant per new customer has generally been in the first or second quartile of the Straight Electric and Large Utility Groups, indicating that the Combined Company has been effective at controlling its costs per new customer

Figure 22: Additions to Plant Per New Customer

Additions to Plant per New Customer
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Lower Cost

Combined Company Rank Order

Q. How does the Combined Company compare in the overall rankings for these cost efficiency metrics?

A. As shown in Exhibit JJR-4, the Combined Company was the top performer in the Straight Electric Group, Florida Utility Group and the Large Utility Group each year between 2014 and 2023, as shown in Figure 23, below.

As Gulf and FPL have continued to work to incorporate the benefits of having merged into a single company and integrate into a single electric power system, more operational and maintenance improvement initiatives, merger synergies, and power system dispatch and resource planning synergies are being realized.

It should be noted that these results are based entirely on the ranking of the performance metrics without consideration of the Situational Assessment.

Figure 23: Overall Cost Efficiency Ranks[26]
Cost Efficiency Overall Rank
Straight Electric Group Rankings

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1st Quartile	1	1	1	1	1	1	1	1	1	1
	2	2	2	2	2	2	2	2	2	2
	3	3	3	3	3	3	3	3	3	3
	4	4	4	4	4	4	4	4	4	4
	5	5	5	5	5	5	5	5	5	5
	6	6	6	6	6	6	6	6	6	6
	7	7	7	7	7	7	7	7	7	7
2nd Quartile	8	8	8	8	8	8	8	8	8	8
	9	9	9	9	9	9	9	9	9	9
	10	10	10	10	10	10	10	10	10	10
	11	11	11	11	11	11	11	11	11	11
	12	12	12	12	12	12	12	12	12	12
	13	13	13	13	13	13	13	13	13	13
	14	14	14	14	14	14	14	14	14	14
3rd Quartile	15	15	15	15	15	15	15	15	15	15
	16	16	16	16	16	16	16	16	16	16
	17	17	17	17	17	17	17	17	17	17
	18	18	18	18	18	18	18	18	18	18
	19	19	19	19	19	19	19	19	19	19
	20	20	20	20	20	20	20	20	20	20
	21	21	21	21	21	21	21	21	21	21
4th Quartile	22	22	22	22	22	22	22	22	22	22
	23	23	23	23	23	23	23	23	23	23
	24	24	24	24	24	24	24	24	24	24
	25	25	25	25	25	25	25	25	25	25
	26	26	26	26	26	26	26	26	26	26
	27	27	27	27	27	27	27	27	27	27
	28	28	28	28	28	28	28	28	28	28
	29	29	29	29	29	29	29	29	29	29

Lower Cost

Combined Company Rank Order

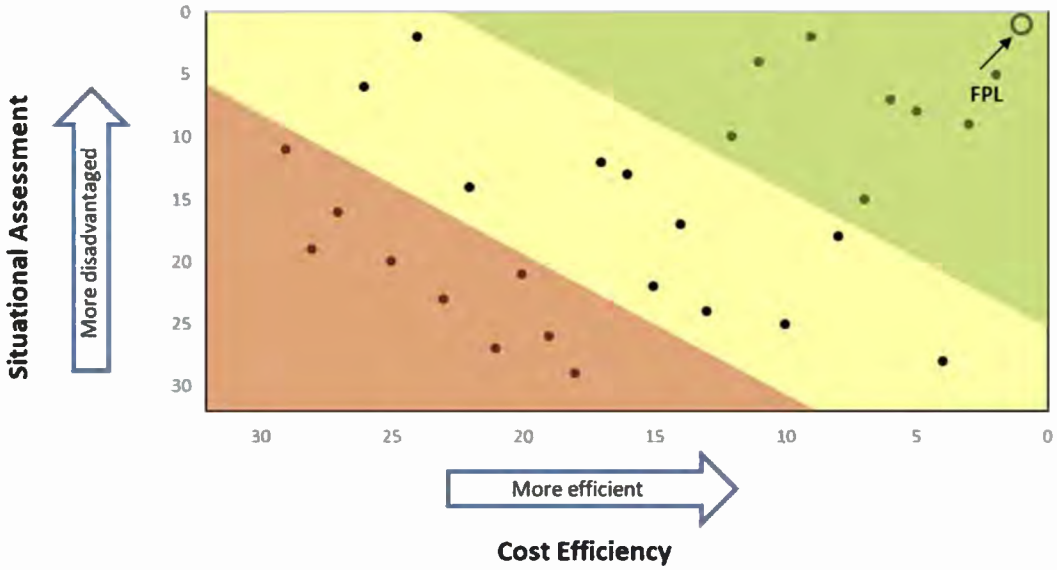
Q. Have you considered both the results of your situational assessment and your analysis of cost efficiency in your overall benchmarking of FPL's and Gulf's performance?

A. Yes. Exhibit JJR-12 (page 1 of 3), which is also shown in Figure 24 below, does just that, combining the cost efficiency rankings and the situational assessment rankings for 2023. Similar comparisons for 2022 and 2021 are provided in Exhibit JJR-12, pages 2

[26] Combined metric ranking is for average of rankings across the 11 Cost Efficiency metric groups listed in JJR-7, page 2 of 32.

and 3. When viewed together, a bandwidth around the diagonal line running from the upper left corner to the lower right corner (shown in the middle band on the chart) reflects the utilities whose productivity is generally consistent with the challenges identified in the situational assessment. The further away (either above or below) a utility's performance is from this line, the more exceptional its performance is (either exceptionally good or exceptionally poor). As shown in Exhibit JJR-12, the Combined Company's performance has been extraordinarily good during the study period, and the Combined Company outperformed all of its Straight Electric Group and Florida Utility Group peers on a basis that considers both absolute productivity measures and the relative challenges it faced. In addition, Exhibit JJR-13 shows the Combined Company's overall rank for situational assessment and cost efficiency in 2023, as well as the rank for each metric. These statistics, taken together, demonstrate that the Combined Company can be described as the best performing utility in the nation in terms of operational efficiency.

Figure 24: The Combined Company's 2023 Combined Situational Assessment and Cost Efficiency Rankings in Straight Electric Group[27]



Service Quality and System Reliability

Q. Please discuss the context in which you benchmark the Combined Company's service quality and system reliability.

A. In looking at economic efficiencies, it is easy to assume that all of the companies are created equal in terms of safety, reliability, and other important operational standards, but that is not the case. If a utility's management decides to launch major service quality initiatives, these initiatives may well have attendant costs, but the cost impact may also be offset by service improvement. To examine these issues, I have analyzed FPL's trends and performance for SAIDI, SAIFI and CAIDI distribution reliability

[27] Exhibit JJR-12

metrics. The Combined Company's reliability data are integrated beginning in 2022, and therefore I have calculated a weighted average of FPL's and Gulf's separate reliability data by year-end customer count for the years 2014 through 2021 to create ten years of comparable Combined Company data. These results are presented in Exhibit JJR-5.

Q. Please discuss SAIDI and how the Combined Company compares to its peers.

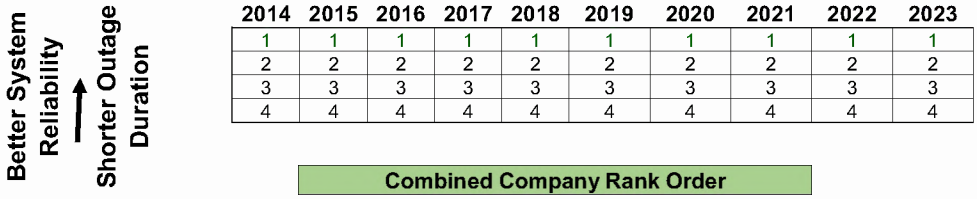
A. SAIDI is the system average outage duration for each customer served. As shown on page 9 of Exhibit JJR-5 and in Figure 25 below, the Combined Company has been the top performer among Florida investor-owned utilities[28] in reducing its distribution outage durations for all ten years from 2014 through 2023. Over the last five years since 2019, the Combined Company's average outage duration for each customer served was only 46 minutes[29], compared to Florida investor-owned utilities' average[30] of 106 minutes. In addition, the Combined Company has worked to lower its outage durations; for example, in 2023, the Combined Company's SAIDI was 43 minutes, a 34 percent decrease compared to the Combined Company's 2014 average SAIDI of 66 minutes.

[28] Reliability comparisons are made only to other Florida investor-owned utilities because my reliability benchmarking analysis relied upon publicly available data as published in FPSC reports. Florida investor-owned utilities are required to report reliability statistics to the FPSC using a 1-minute threshold to determine what is considered an "outage," with certain allowable exclusions (e.g., planned outages, outages that are the result of named storms tornados, and extreme weather or fire events that cause EOC openings).

[29] The Combined Company's 5-year average uses FPL and Gulf averaged SAIDI data for 2019, 2020, and 2021 and integrated FPL and Gulf data for 2022 and 2023.

[30] Excluding the Combined Company. Including Florida Public Utilities.

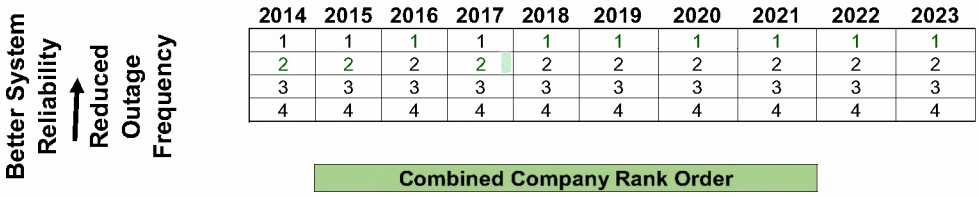
Figure 25: SAIDI
SAIDI
Florida Group Ranking



Q. Please discuss SAIFI and how the Combined Company compares to its peers.

A. SAIFI is the average frequency of interruptions for each customer served. As shown in Figure 26 below, the Combined Company has ranked as the first or second top performer in the past ten years. In 2023, the Combined Company's SAIFI was 0.62, a 37 percent decrease compared to the Combined Company's 2014 average SAIFI of 0.98.

Figure 26: SAIFI
SAIFI
Florida Group Ranking



Q. Please discuss CAIDI and how the Combined Company compares to its peers.

A. CAIDI is calculated as SAIDI divided by SAIFI and reflects the average restoration time for an interruption. As shown in Figure 27 below, the Combined Company has been the best performer among Florida investor-owned utilities[31] with the lowest average distribution outage duration in the last ten years. In 2023, the Combined

[31] Excluding the Combined Company. Including Florida Public Utilities.

Company's CAIDI was 69 minutes, approximately 20 minutes less than the Florida investor-owned utility average in 2023.

Figure 27: CAIDI

CAIDI
Florida Group Ranking

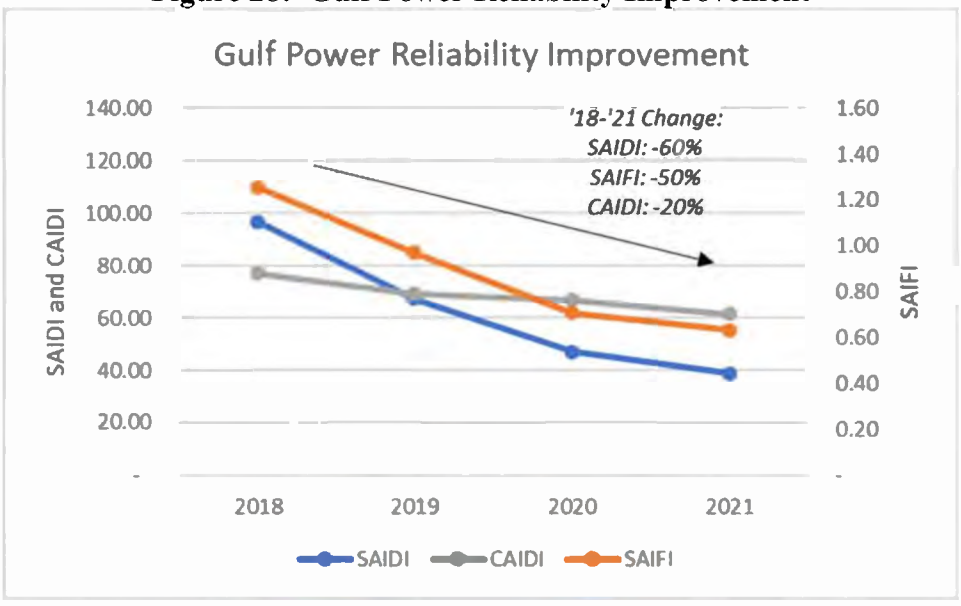
Better System Reliability ↑ Shorter Outage Duration

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	1	1	1	1	1	1	1	1	1
2	2	2	2	2	2	2	2	2	2
3	3	3	3	3	3	3	3	3	3
4	4	4	4	4	4	4	4	4	4

Combined Company Rank Order

When looking at Gulf's reliability metrics separately, all of Gulf metrics improved significantly following the acquisition in 2019. Gulf's SAIDI metric improved by 60 percent, SAIFI improved by 50 percent, and CAIDI improved by 20 percent between 2018 and 2021, as shown in Figure 28 below.

Figure 28: Gulf Power Reliability Improvement



Q. Has the Combined Company's service quality and system reliability ranking been impacted in any way as a result of the Combined Company's cost control activities?

A. No. The Combined Company is a top performer in service quality and system reliability compared to other Florida investor-owned utilities. Across all three reliability indices, the Combined Company's metrics ranked the best among Florida investor-owned utilities in 2022 and 2023. The Combined Company has performed well in quickly restoring service to customers in the event of outages with the lowest average outage duration each year from 2018 through 2023.

Operational and Emissions Performance

Fossil/Solar Plant Operational Performance

Q. Please discuss the heat rate performance of FPL's fossil generation fleet and any associated cost savings.

A. Heat rate is a measure of a power plant's efficiency or more specifically, how much thermal energy from fuel is required to produce one kWh of electricity. A lower heat rate value indicates a more efficient plant. The Combined Company has improved the average heat rate of its fossil/solar generation fleet by 15 percent since 2013. The average heat rate of the Combined Company's fossil/solar fleet in 2023 was 6,505 Btu/kWh compared to an industry average of 9,218 Btu/kWh, which indicates that the industry average heat rate is 42 percent less efficient than that of the Combined

Company's fossil units. At current gas prices, this efficiency advantage translates to $838 million in 2023 alone in fuel cost savings.[32]

Q. Please discuss the Equivalent Availability Factor metric performance of the Combined Company's fossil generation fleets.

A. As shown on page 3 of Exhibit JJR-5 and in Figure 29 below, the Combined Company's fossil generation fleet has consistently outperformed its peers in terms of power plant availability. Between 2014 and 2023, the Combined Company's average Fossil Equivalent Availability Factor averaged 92.1 percent compared to an industry peer average of 83.5 percent.[33]

Figure 29: Fossil Equivalent Availability Factor

Fossil - Equivalent Availability Factor										
Annual Values										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FPL + Gulf Combined	89.2	91.9	93.3	90.5	91.4	92.0	93.5	92.8	93.2	93.4
Industry Average	85.0	85.1	84.5	83.9	83.2	83.6	84.1	82.2	81.5	82.0

Q. Please discuss the Equivalent Forced Outage Rate metric performance of the Combined Company's fossil generation fleets.

A. As shown on page 4 of Exhibit JJR-5 and in Figure 30 below, the Combined Company's fossil units have performed exceptionally well compared to the industry on this metric. In the 10 years between 2014 and 2023, the Combined Company's performance was better than the industry average for all 10 years. Throughout this

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[32] Calculated based on delivered fuel prices and megawatt hours generated in 2023. For heat rate comparisons, I have used ABB's Velocity Suite database of non-nuclear generating units across the United States. FPL's heat rate calculation includes all FPL non-nuclear units. For the industry heat rate savings calculation, I used 2023 Florida Gas Transmission Z3 spot gas prices.

[33] For fossil plant reliability metrics (including Equivalent Availability Factor and Equivalent Forced Outage Rate), data comes from NERC. The peer group consists of industry NERC-reporting, large, fossil steam and combined cycle fleets (typically with greater than 5,000 MW of owned capability).

period, the Combined Company's average Equivalent Forced Outage Rate averaged just 1.2 percent compared to an industry peer average of 8.9 percent.[34]

Figure 30: Fossil Equivalent Forced Outage Rate

Fossil - Equivalent Forced Outage Rate										
Annual Values										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FPL + Gulf Combined	0.73	1.16	1.15	2.18	1.22	1.22	0.59	1.86	0.80	0.83
Industry Average	7.89	7.32	7.73	9.04	9.27	8.40	9.00	9.93	10.94	9.77

Nuclear Plant Operational Performance

Q. Please discuss the Capacity Factor metric performance of FPL's nuclear generation fleet.

A. The capacity factor of FPL's nuclear units has been above the industry average for the most recent four years, and above the industry average in seven of the last ten years. FPL's nuclear generation fleets has improved its average capacity factor by five percentage points since 2014.

Q. Please discuss the Equivalent Availability Factor metric performance of FPL's nuclear generation fleet.

A. As shown on page 6 of Exhibit JJR-5, the U.S. nuclear industry's average equivalent availability factor has improved over time, and as the industry improves its overall performance, so does FPL. FPL's nuclear generation fleet has operated above the industry average equivalent availability factor during the past two years, and within two percent of industry averages in all of the past nine years. In 2015, 2017, and 2019, FPL's nuclear units had an equivalent availability factor[35] within two percent of

[34] Ibid, with industry average excluding the Combined Company.

[35] Nuclear reliability data are not publicly available. I have relied on the Company for data pertaining to nuclear Forced Loss Rate, Nuclear Equivalent Availability Factor, and the Nuclear Industrial Safety Accident Rate.

industry averages. In 2016 and 2018, FPL operated above industry averages. Compared against its own performance over time, FPL's nuclear generation fleet has improved its equivalent availability factor by four percentage points since 2014.

Q. Please discuss the Forced Loss Rate metric performance of FPL's nuclear generation fleet.

A. The Forced Loss Rate is a secondary performance metric to the Equivalent Availability Factor metric. Reported by nuclear unit, the industry's Forced Loss Rate has ranged from 0.0 percent to a maximum of 48.32 percent over the past ten years. As shown on page 7 of Exhibit JJR-5, FPL's nuclear forced loss rate, a measure of how well important plant equipment is maintained and operated, has averaged 2.1 percent, which is close to the industry average of 1.8 percent over the last ten years.

Q. Please discuss the Nuclear Industrial Safety Accident Rate metric and performance of FPL's nuclear generation fleet.

A. The nuclear industrial safety accident rate tracks the number of accidents that result in lost work time, restricted work, or fatalities per 200,000 work hours. Reported by nuclear unit, the nuclear industrial safety accident rate has ranged from 0.0 to a maximum of 0.43 over the past ten years. As shown on page 8 of Exhibit JJR-5, FPL has outperformed its peers in this metric in three out of the last five years. For the past ten years since 2014, FPL's Industrial Safety Accident Rate has averaged 0.03 compared to an industry average of 0.04.

Q. What conclusions have you reached regarding the Combined Company's fossil and nuclear plant operational performance?

A. The Combined Company's superior performance on the cost efficiency benchmarks has not occurred at the expense of fossil or nuclear plant performance. As in years past, the Combined Company has achieved above average results, with no concerning trend.

Q. Please describe the emission metrics used to benchmark the Combined Company's emission profiles.

A. Given concerns over air emissions in Florida and nationwide, I calculated the Combined Company's approximate 2023 level of sulfur dioxide, nitrogen oxides and carbon dioxide emitted in pounds per MWh relative to a peer group.

Q. How did you determine which electric companies to include in the emission peer group that you used to benchmark the Combined Company's emission profiles?

A. I created a dataset of comparable companies whose energy generation was at least 30 percent of the Combined Company's 2023 generation level. Exhibit JJR-14 shows that the Combined Company's net generation in 2023 was 146,408 GWh. There were eight utility companies with at least 30 percent of the Combined Company's figure (the Industry group). I also separately considered Duke Energy Florida and Tampa Electric Company, the Florida utilities that own regulated generation assets.

Q. How does the Combined Company compare to its peers regarding air emissions?

A. The Combined Company's performance in terms of greenhouse gas emissions is exceptional. In 2023, the Combined Company emitted an average of 616 pounds of carbon dioxide per MWh compared to a peer group average of 779 pounds per MWh. The Combined Company emitted 0.11 pounds of nitrogen oxides per MWh compared

to a peer group average of 0.37 pounds per MWh. In addition, the Combined Company's sulfur dioxide emissions of 0.005 pounds per MWh are approximately 3 percent of the peer group's generation weighted average emission rate of 0.19 pounds per MWh.[36]

Q. What is the Combined Company's effect on the emissions profile of the state of Florida?

A. The Combined Company's generating stations have a profoundly strong effect on the emissions profile of the state of Florida. Excluding the Combined Company's units from the state's average generation-weighted carbon emission rate would raise the average carbon intensity of Florida generation (in pounds per MWh) by approximately 33 percent. Nitrogen oxide emissions per MWh would be approximately 80 percent higher, and sulfur dioxide emissions would be 210 percent higher without the effect of the Company's stations.

Q. Are there benefits associated with the Combined Company's commitment to a clean energy portfolio that are not reflected in base rates?

A. Yes. While the Combined Company's investments in making its fossil-fueled generating portfolio significantly more efficient are reflected in the Combined Company's base rates, the savings associated with this improved efficiency are ultimately reflected in lower fuel and environmental compliance costs, which are recovered through separate adjustment clauses outside of base rates.

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[36] In each of these emissions comparisons, FPL is compared to the generation-weighted average of proxy group emissions.

Level of Rates

Q. Are there characteristics of Florida regulation that have helped enable the Combined Company to outperform comparable utilities in cost efficiency despite facing significantly greater situational challenges compared to its peers in the industry?

A. Long-term rate solutions have been a hallmark of Florida regulation over the last 25 years, providing a significant degree of stability and certainty that otherwise would not have been possible. As such, Florida utilities generally average much longer intervals between rate cases than other utilities in the U.S. For example, going back to 1980, the state of Florida achieved the sixth-longest stay-out duration between base rate case filings out of the 50 states.[37] Additionally, the Combined Company, on a company basis since 1980, averages 1,899 days between rate case filings, compared to the nationwide utility median of 717 days.

Q. How have the Combined Company's rate levels compared to Southeastern U.S. Group and Florida Utility Group peers?

A. Compared to electric utilities in the Southeastern U.S. Group, the Combined Company has achieved rate levels that are highly favorable, especially when one considers the large rate impacts that hurricanes and tropical storms have had on the Combined Company's rates. As shown on page 1 of Exhibit JJR-6, in every year of my analysis,

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[37] Rate case data sourced by S&P Global Market Intelligence. Rate case stay-out calculated as time duration, in days, between the filing date and the company's previous filing date in that state. These durations were then averaged for all cases in that state since 1980. Stay-out durations in Florida averaged 1,824 days, ranking 6th-longest amongst all states. FPL also ranks 6th when considering time between the initial rate case filing and last authorized increase.

the Combined Company's typical residential bill was in the two best quartiles among the Southeastern U.S. Group.

The Combined Company average rates have traditionally been lower compared to rates charged by peer companies in Florida and the broader Southeastern U.S. Region for the residential and commercial rate classes, and close to, if not lower than, its peers for the industrial rate class. To benchmark the Combined Company's rates, I calculated the Combined Company's historical rates in comparison to the average of other electric utility peer companies' rates in Florida and the Southeastern U.S. Region using data compiled by S&P Global Market Intelligence from EIA Form 861 from 2014 through 2023. Results of my rate comparison[38] are shown in Exhibit JJR-6, pages 2 through 4 and are summarized as follows:

- In 2023, the Combined Company's residential rate was $0.003 per kWh more than the average rate for the Southeastern U.S. Group and $0.026 per kWh less than the average rate for the Florida Utility Group. This anomalous year was the product of FPL needing to implement a storm surcharge of $0.015/kWh for residential customers (a temporary increase of 11.1% beginning in April, 2023) to fund the unrecovered repair costs from Hurricanes Ian and Nicole. In addition, fuel under-recovery from 2022 affected 2023 bills, resulting in an additional $0.00758/kWh surcharge for residential customers. Putting aside this anomalous year, between 2014 and 2022, the Combined Company's residential

[38] Where applicable, I excluded the Combined Company from industry average calculations.

rate has been less than both Southeastern U.S. Group and Florida Utility Group average residential rates in every year. Since 2014, the Combined Company has maintained a residential rate, that was, on average, 5.3 percent less than the Southeastern U.S. Group average and 11.8 percent less than the Florida Utility Group average. Based on the Combined Company's total volume of 70,006 GWh of annual residential usage in 2023, the Combined Company's less expensive residential rates over these ten years (on average) translates to $1.133 billion in annual savings over the Florida Utility Group average residential rate. In other words, the Combined Company's residential customers would have paid $1.133 billion dollars more annually, on average, if they did not benefit from the Combined Company's favorable rates.

- The Combined Company's commercial customers received similarly favorable rates in 2023 compared to Florida utility peers. In 2023, the Combined Company's commercial customers paid on average $0.018 per kWh less than the Florida Utility Group average rate, translating to $933 million in annual savings, based on the Combined Company's total volume of 52,849 GWh of annual commercial usage in 2023.

- In 2023, the Combined Company's industrial customers paid on average $0.017 per kWh less than the Florida Utility Group average rate, translating to $79 million in annual savings, based on the Combined Company's total volume of 4,600 GWh of annual industrial usage in 2023.

- In addition, the Combined Company has consistently maintained a proven track record of providing substantial savings to its residential and commercial classes. In total for the past ten years since 2014, the Combined Company's residential savings total $11.40 billion over the Florida Utility Group average rates and $4.58 billion over the Southeastern U.S. Group. The Combined Company's commercial savings for the same period total $5.18 billion over the Florida Utility Group rates and $0.03 billion over the Southeastern U.S. Group rates. These figures demonstrate that the Combined Company's residential and commercial customers have substantially benefited from the Combined Company's lower rates over the past ten years.

Figure 31: The Combined Company Annual Residential Bill Savings

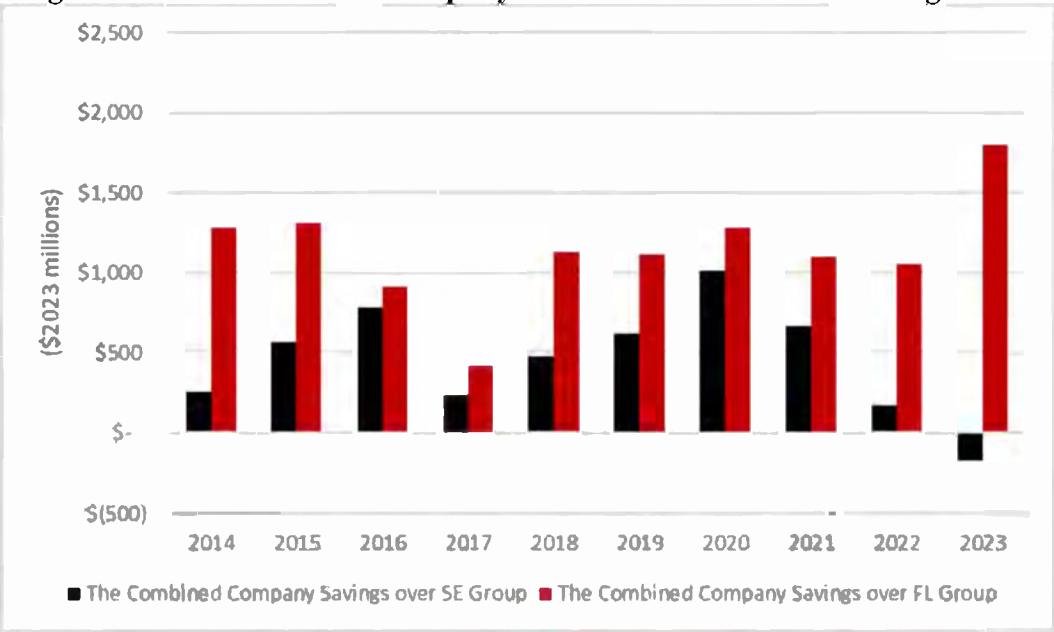


Figure 32: The Combined Company Annual Commercial Bill Savings

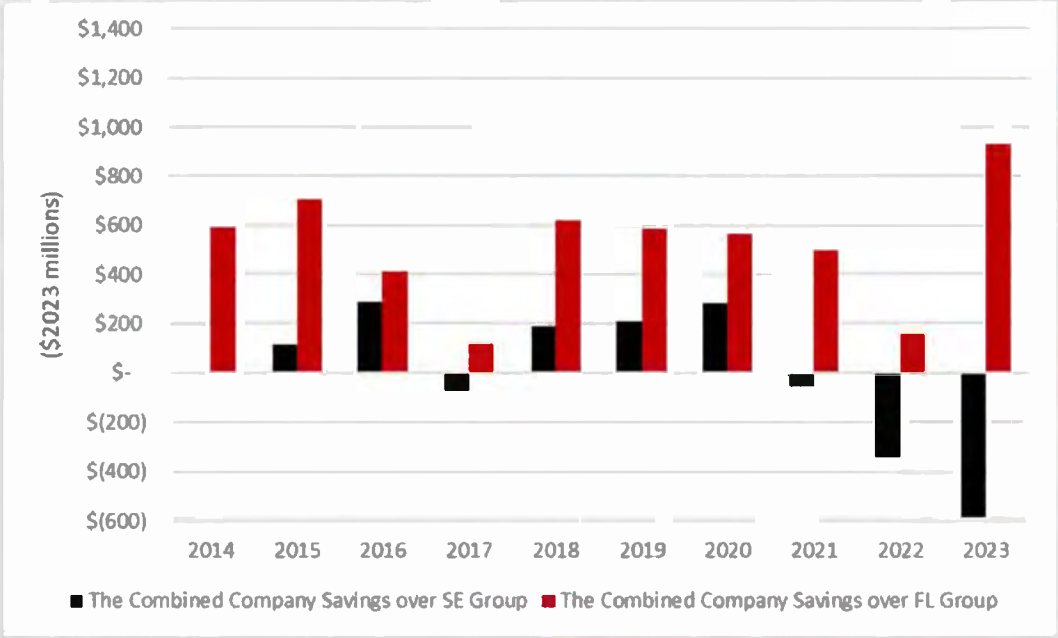
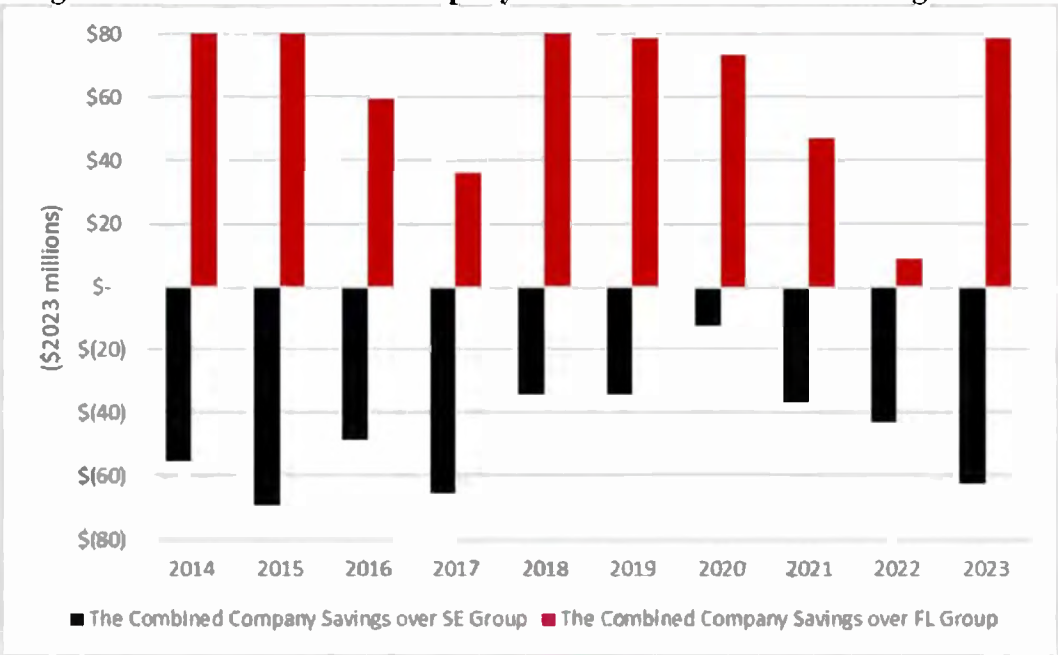


Figure 33: The Combined Company Annual Industrial Bill Savings



Q. Have the Combined Company's cost control activities and low rates led to a decrease in service quality or system reliability?

A. No. In fact, when comparing the Combined Company to the Southeastern U.S. Group's typical residential bills as well as CAIDI, SAIDI, and SAIFI, the Combined Company is among the top performers. Exhibit JJR-15, as well as Figures 34, 35, and 36 below, show the results of combining the 2024 Average Bills and the 2023 CAIDI, SAIDI, or SAIFI for the Southeastern U.S. Group respectively.[39] When compared to the Southeastern U.S. Group, no utility has achieved the Combined Company's level of reliability, or better, at a lower cost than that achieved by the Combined Company. In particular, the Combined Company had the most reliable SAIDI and SAIFI measures, the fifth-most reliable CAIDI measures, and had the lowest 2024 average bill of all the utilities in the Southeastern U.S. Group.[40]

[39] As of the date of this pre-filed testimony, these are the most recent values for each metric. The source of 2024 average residential bill data is The Edison Electric Institute, Typical Bills and Average Rates Report, Summer and Winter Averages, Residential 1000kWh. The source of CAIDI, SAIDI, and SAIFI data is EIA, IEEE Standard data, without Major Event Days. EIA IEEE Standard reliability data for Alabama Power Company and Virginia Electric & Power Company (Virginia and North Carolina) was not available.

[40] Average of 2024 summer and winter bill data from The Edison Electric Institute, Typical Bills and Average Rates Report, Residential 1000kWh.

Figure 34: 2024 Average Bill vs. 2023 CAIDI Rankings in Southeastern U.S. Group

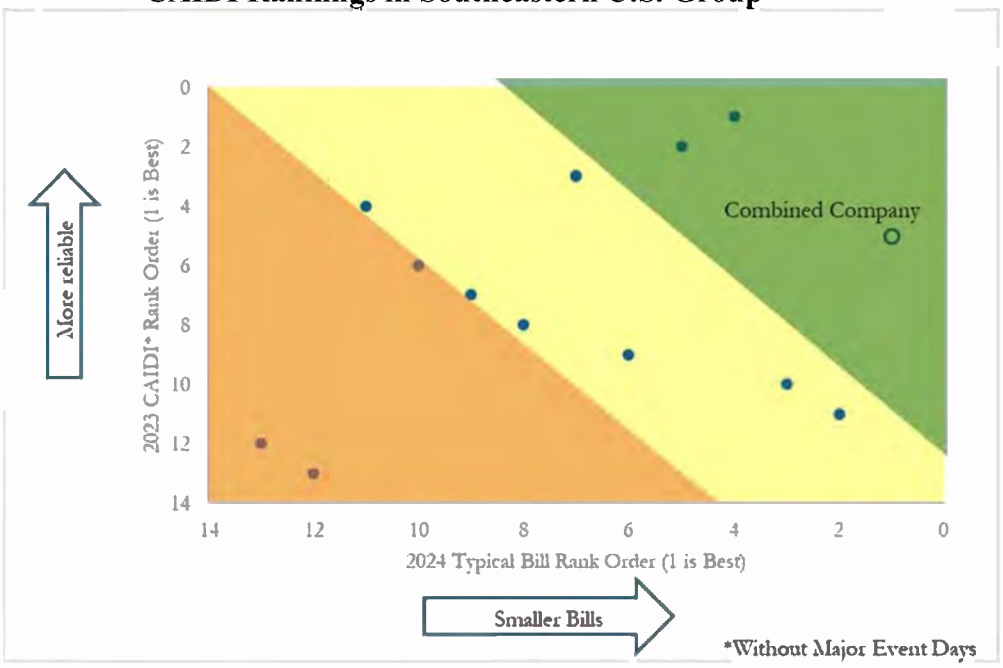


Figure 35: 2024 Average Bill vs. 2023 SAIDI Rankings in Southeastern U.S. Group

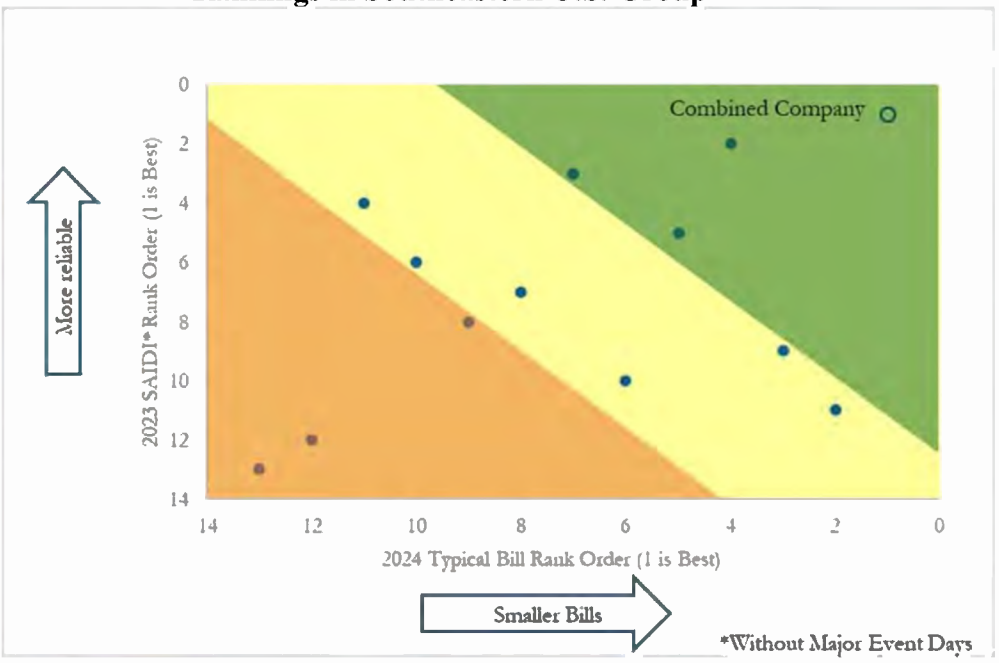
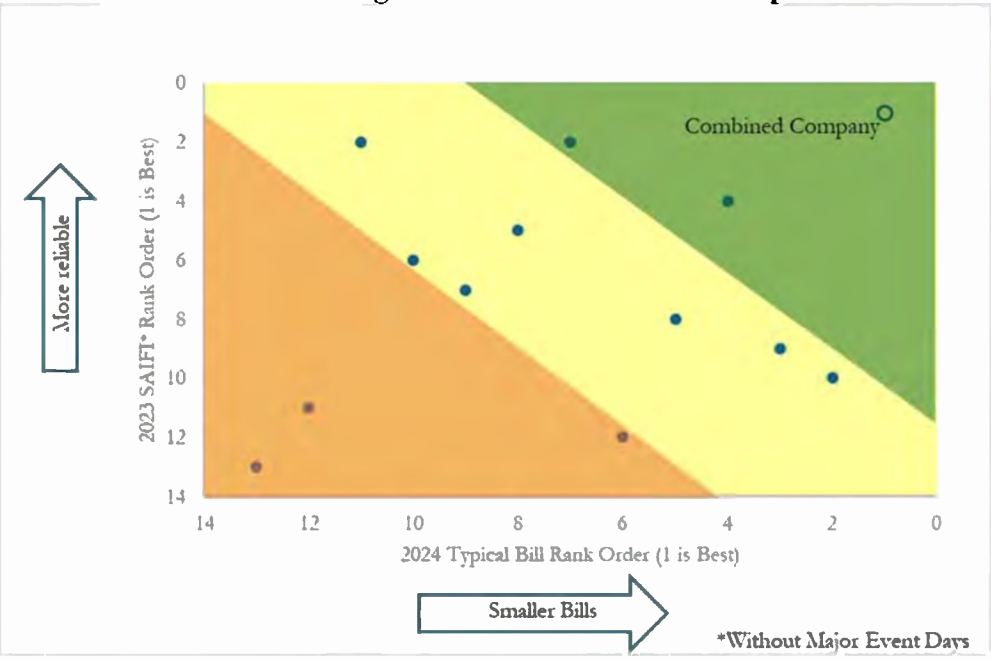


Figure 36: 2024 Average Bill vs.
2023 SAIFI Rankings in Southeastern U.S. Group



The Combined Company has demonstrated superior performance in many areas of reliability, as well as in financial and operational efficiency, which provides customers significant savings for very highly reliable service. These benefits to customers are the result of focused efforts by the Company and are enhanced by FPL's strong operational record which provides very substantial benefits to its customers.

Benchmarking Conclusions

Q. What are the conclusions from your cost and operational benchmarking regarding the Combined Company's performance relative to the peer groups?

A. The Combined Company has performed exceptionally well in comparison to its peers. In particular:

- The Combined Company has ranked as the top overall performer of the 29 companies in the Straight Electric Group in every year for the past 10 years.

- The Combined Company has ranked as the top (out of three) overall Florida utility in each of the past 10 years.
- The Combined Company has ranked as the top overall large utility (out of 12) in each of the past 10 years.
- The Combined Company has outperformed comparable utilities in cost efficiency despite facing significantly greater situational challenges compared to its peers in the industry.

The Combined Company's exceptional performance has resulted in significant economic and reliability benefits for its customers. For 2023 alone, if the Combined Company had been merely an average performer:

- The Combined Company's non-fuel operational and maintenance costs charged to customers would have been $2.9 billion higher than actual costs
- The Combined Company's annual fuel costs charged to customers would have been $838 million higher than actual costs
- The Combined Company's customers would have experienced approximately 131 percent worse reliability on average over the last five years with an average interruption duration of 106 minutes, rather than the Combined Company's actual average duration of 46 minutes.

SUMMARY

Q. Please summarize the major points of your direct testimony.

A. The results of my benchmarking analysis show that the Combined Company has consistently and substantially out-performed similarly sized companies, making even more improvements since acquiring Gulf, across a wide array of financial and operational metrics including:

- cost efficiency,
- service quality and system reliability,
- operational performance including emissions, and
- rate level.

The Company has achieved these results in spite of the fact that it faces a greater than average set of challenges (i.e., "degree of difficulty") from exogenous factors that impact a utility's ability to achieve top performance and macro-economic trends that put significant cost pressures on the Combined Company. The Combined Company has done an exceptional job of controlling costs and achieving high levels of service for its customers while continuing to improve, notwithstanding the fact that Gulf had historically less favorable cost and operational performance.

As a result of FPL's long-term planning strategy and superior management performance, FPL's customers have benefited from strong service reliability and historically lower rate levels compared to the rates of other electric utilities in Florida and the broader Southeastern U.S. Region. FPL has consistently demonstrated strong

fiscal responsibility, producing billions of dollars of savings for its customers, and has provided highly reliable, increasingly clean and efficient electric service at consistently affordable rates.

Q. Does this conclude your direct testimony?

A. Yes.

ERRATA SHEET

WITNESS: JOHN R. REED
DIRECT TESTIMONY DATED FEBRUARY 28, 2025

Page	Line	Change
19	12-13	Replace "Accumulated Depreciation as a Percent of Gross Plant" with "Five-Year Additions to Utility Plant as a Percent of Gross Plant"

C16-2119a

BY MS. MONCADA:

Q And, Mr. Reed, along with that testimony, you also had 15 exhibits, is that right, JJR-1 through JJR-15?

A That is correct.

Q And were those prepared under your direction or supervision?

A Yes, they were.

MS. MONCADA: Mr. Chairman, these have been identified on staff's list as 84 through 98.

CHAIRMAN LA ROSA: Okay.

BY MS. MONCADA:

Q Mr. Reed, did you prepare a summary of the topics covered in your direct testimony?

A Yes, I did.

Q Would you please provide that to the Commission?

A Certainly.

I have conducted an analysis of FPL's and the former Gulf Power's Company's financial and operation performance over the past 10 years through the use of a benchmarking study, including the review of macroeconomic and service area economic drivers that have contributed to the company's requested rate increase.

My benchmarking analysis shows that FPL has consistently and substantially out-performed similarly sized companies across a wide array of financial and operational metrics, including cost efficiency, service quality, system reliability, operational performance and rate level. The company has achieved these results in spite of the fact that it faces a greater than average set of challenges from exogenous factors that impact a utility's ability to achieve top performance. The company's exceptional performance has resulted in significant and -- significant economic and reliability benefits for its customers.

That's it.

Q Thank you.

MS. MONCADA: Mr. Reed is available for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

OPC, you are recognized for questioning.

MS. CHRISTENSEN: Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q Hello, Mr. Reed.

A Good morning.

Q Good morning.

I would ask you to open your testimony to page

four?

A I have that.

Q Okay. And on page four, you list exhibits you are sponsoring, correct?

A Page four, continuing on to page five, yes.

Q Okay. And looking at the list, I just want to confirm, you are not sponsoring any MFRs, are you?

A That is correct.

Q Let's look at the bottom of page five of your testimony. This is where you start discussing the purpose of filing your testimony, correct?

A Yes.

Q And isn't it correct that you were asked by FPL to conduct an analysis of FPL and the former Gulf Power Company's financial and operational performance over the past 10 years through the use of this benchmarking study?

A That's correct.

Q And you have done benchmarking studies for FPL in the past, correct?

A Yes, a number of them.

Q And isn't it true, the purpose of those benchmarking studies in the past was to justify a performance adder to increase the ROE, correct?

A In some rate cases, yes, there was a proposal

that accompanied my benchmarking, and that proposal was to provide an adder to the allowed return on equity.

Q And you would agree that a performance adder to the ROE has never been approved for FPL based on benchmarking, correct?

A That's correct. I think those cases were settled, but no explicit award was made for an adder.

Q And in this case, you do not say in your testimony that you are seeking to justify an increased performance adder to FPL's ROE, correct?

A No. The company did not seek a performance adder for the ROE despite the ongoing excellent performance.

Q And on page seven of your testimony, lines 14 through 17, you outline the metrics of this benchmarking -- that this benchmarking analysis is attempting to measure, is that correct?

A You are at page seven, line 14?

Q Yes. The cost efficiency, quality of service, system reliability, operational performance, including emissions and rate levels, that's essentially, in broad terms, what this benchmarking study was attempting to analyze?

A It includes those metrics, yes.

Q Okay. And you analyzed FPL's rate level as to

the total bill compared to a proxy group of companies you chose, correct?

A We looked at two items, the total bill and the average rate by customer class.

Q Okay. And that was based on a group of companies that you chose yourself?

A Yes, I think it was 12 companies from the southeast U.S.

Q Okay. And you would agree that FPL's management did not provide any guidance as to how to find or to measure affordability in your study, correct?

A That's correct. My decision on how I incorporated a consideration of affordability was my own. It wasn't driven by or dictated by the company.

Q And you own compared the total bills for FPL and the other companies that comprise your proxy group, correct?

A One slight correction, as I said, we looked at average rate by customer class and total bills --

Q Okay.

A -- and that was how we captured affordability. I should say we looked at that both across companies and across time.

Q Okay. And let's look at your Exhibit JJR-6, C16-2193.

A Yes, I have page one of that exhibit.

Q Okay. And this consists of four pages, correct?

A Correct.

Q But the first page shows the typical residential bill comparison, is that right?

A That is correct.

Q And typical bill is based on 1,000-kilowatt hour usage for residential customers --

A Correct.

Q -- is that right?

Is it correct that you used 1,000 kilowatts per hour for your comparison?

A Yes, that is correct.

Q And you would agree that if you look at these rates separately, the old Gulf territory would have had higher rates over the period of 2021 through 2024, correct?

A And higher, you mean higher than the average of FPL and Gulf?

Q Correct.

A Yes.

Q And you would agree that the total bill for FPL based on a combined basis shows that the total bill has increased by approximately $20 from 2015 through

2024, correct?

A Yes, I would say that's correct.

Q And that would be an approximately 75 percent increase for the winter months, and an 82 percent increase for the summer months on the typical customer bill, is my math correct?

A Could I have that number again?

Q Sure. If you take the total bill for the winter months in 2015 and you divide that by the increase -- or the total bill for the winter for 2024, that would be an approximately 75 percent increase over that time period?

A No, that's far in excess of the correct calculation.

Q Okay. And what would be the increase?

A It would be more in the nature of 35 percent --

Q Okay.

A -- over a ten-year period.

Q Okay. And then what would be the -- and how would you calculate that?

A For the winter of 2024, it was 136.7, $136.70. For the winter of 2015, it was $102.94. You divide the 136 by the 102, and subtract one, and that is the cumulative increase over 10 years.

Q Okay. And then if you could do the same calculation for the summer?

A That is 122.38 divided by 100.78, for a little less than 22 percent.

Q Okay. In looking at the total typical bill, you would agree that FPL is the largest of the electric utility companies in your proxy group, correct?

A When viewed as an operating company, yes. You will see in here that Duke has a number of operating companies that are included in the survey as well. Duke in aggregate is larger than FPL and Gulf in aggregate, but the individual operating companies are smaller than FPL.

Q Okay. And you would agree that the larger the customer base in the operating company, the more customers over which costs can be spread, thereby, reducing the impact of those costs relative to an individual customer, correct?

A Well, if you take a fixed amount of money and divide it by a larger number of customers, that has a larger base and you reduce the impact. But that assumes you are starting with a fixed amount of money that would be applied to both a smaller and larger company.

Q In other words, FPL, with its approximately six million customers, has what we call economies of

scale?

A It does. It makes good use of them.

Q And the total typical -- or the total typical bill was the only way in which you benchmark studied looking at affordability, correct? I think you said you also looked at rates, but total bill was the main comparison?

A We looked at both. Those are the two methods what we looked at affordability.

Q Okay. And then back on page 17 of your testimony, which is -- okay, on page 17, you used what you call a situational assessment to determine the relative advantages or disadvantages/challenges FPL has compared to your proxy group, correct?

A That is correct.

Q And you shows chose the metrics you used to make this assessment, correct?

A By this assessment, you mean the situational assessment?

Q Correct, that you chose the metrics you were going to make your assessment by.

A Yes, I chose these metrics based on my experience in conducting these studies in the past, and in my appearances before this commission five times before utilizing the same approach.

Q Okay. And based on your selected criteria, you determined that FPL combined is the most situationally challenged, correct?

A It faces, in aggregate, the greatest challenges of any of the 28 companies we included in our electric group.

Q And you would agree that your situational assessment is not a perfect means of capturing all the challenges or advantages of FPL combined in the peer group, correct?

A I would say there is no perfect methodology. This is the best that I am able to use. And as I said, it's been honed over roughly 40 years of use.

Q And you would agree that benchmarking, like many data points, it's tied to a specific point in time?

A It can be. In my case, it's not. In my case, it's tied -- it's presented here for the last 10 years, each of the last 10 years. In aggregate, my dataset that I have worked with FPL on spans almost 30 years.

Q Okay. On page 31, you talk about -- I am just waiting for you to get there.

A I am there. Yes.

Q Okay. On page 31, you talk about your financial and operational metrics regarding cost efficiencies, correct?

A Yes.

Q And then if we flip over two more pages to page 33, you say you account for the company's different sizes by looking at the expense per customer and expense per megawatt hour sold, correct?

A That is one of the ways that we accounted for different companies of different sizes. We developed the data on a unit cost basis per customer per megawatt hour sold.

We also selected proxy groups, or peer groups, actually five of them, that reflected similar sized companies. So we started by trying to define companies that were close, or as close as reasonably possible to FPL, and then calculated the data on a unit cost basis.

Q Okay. And you would agree the economies of scale that FPL enjoys due to its size would positively impact your cost efficiency measures, correct?

A It can if they are properly captured, and they have been properly captured by FPL.

Q And we discussed earlier, the larger the customer base, the lower the customer impact of an expense, correct?

A Of a fixed amount of expense. Larger companies don't necessarily achieve cost efficiencies, and larger customer bases don't necessarily reduce cost.

Q But generally speaking, you agree that the economies of scale do tend to lend themselves to lower cost per customer, correct?

A They provide opportunities, and in this case, those opportunities have been realized.

Q And you would also -- you also looked at the System Average Interruption Index, the Distribution System Average Interruption Frequency Index and the Customer Average Interruption Duration Index as your operational measures, is that correct?

A Yes, those are the reliability measures we used.

Q And you would agree that each of these measures will be reduced by the introduction of Florida's storm hardening and protection plan programs, correct?

A They should be. FPL's system hardening programs were meant to reduce the susceptibility of the system to storms and to improve the response rate, and I believe both of those have been achieved.

Q And you are aware that the Commission required the storm hardening since approximately 2007, right?

A I can't speak to whether the Commission required it. It has been in effect, I believe, since about 2007.

Q And since 2020, the Legislature required storm hardening plans, were you aware of that?

A Yes.

Q And would you agree that these programs are paid for by ratepayers through the Storm Protection Plan Clause?

A They are, and the benefits are reaped by ratepayers.

Q And you looked at operational and emissions performances of all of FPL compared to the proxy group, correct?

A Can have I that question again? I missed a word.

Q Certainly.

You looked at the operational and emissions performance of FPL compared to the proxy group, correct?

A Yes. I did.

Q Okay.

A Different proxy groups.

Q And your comparison is on page 62, figure 29 of your testimony. And you also have a table, figure 30 on page 63, where you compare FPL to the industry average peer group, correct?

A Those are two of the many tables that make that comparison, yes.

Q Okay. And this is the same equivalent availability factor shown in your Exhibit JJR-5 on page three, and the equivalent forced outage rate on page four of JJR-5?

A Yes, it should be.

Q Okay. Would you agree that the natural gas combined cycle plants will have better availability and performance than that of older natural gas plants or coal plants?

A Your question is the general category of natural gas combined cycle plants compared to similar older plants or coal plants?

Q Let me try the question again.

Would you agree that new natural gas combined cycle plants will have better availability and performance than older natural gas plants or coal plants?

A They will typically have better availability than coal plants. The comparison between new combined cycle and older combined cycle really depends on maintenance procedures for the older units. They aren't necessarily going to have higher availability.

Q Okay. But they generally tend to be more efficient and more heat -- have better heat rates, the newer models versus the older models?

A Yes. You are talking about gas-fired combined cycle plants. Yes, the newer models have been able to achieve lower heat rates, therefore, more efficiency in producing power from the fuel.

Q And you did not make any adjustments to account for different fuel mixes in your comparison of FPL to the industry average, is that correct?

A I am sorry, the industry average for what?

Q You did not make any adjustments to account for different fuel mixes in your comparison of FPL to the industry average regarding the -- this better performance, better availability in your comparison?

A No. We examined the fuel mix for each of the companies in the 28-company proxy group, and we did not see a need to make an adjustment for companies that were more heavily gas dependent or more heavily nuclear dependent or more heavily coal dependent, and we wanted to let the numbers speak for themselves.

Q And you would agree that the type of fossil generation can have an impact on availability, correct?

A Yes, as FPL, for example, has moved away from coal and to more gas-fired combined cycle and kept high-performing nuclear, its availability has improved. That's consistent with the shift in resource mix that it's chosen.

Q Okay. And then on page 75 of your testimony?

A Yes.

Q Okay. You make the claim that if FPL had been an average performer, it would have cost customers 2.9 billion for the combined company's nonfuel operation and maintenance costs in 2023, is that correct?

A Did you say cost or saved?

Q Combined nonfuel operational and maintenance cost in 2023.

A My statement is that if the company had been an average performer, its nonfuel O&M costs would have been 2.9 billion higher in 2023. So the company's excellent performance saved customers about 2.9 billion just on O&M costs.

Q Okay. So basically you took the fuel group average nonfuel O&M costs, substituted that for the combined FPL and Gulf company costs scaled up for the number of customers and megawatts, is that correct?

A Scaled up for the number of customers and megawatt hours, yes.

Q Okay. And then -- and on page 61, lines 18 through 62, and then through the top of page 62, line two, you also make the claim that if FPL had been an average performer, it would have cost customers 838 million for the combined companies' fuel in 2023,

correct?

A Yes. Stated another way, the company saved approximately 838 million in fuel costs as compared to an average performer.

Q Okay. And you did not include an exhibit to show either of these calculations?

A It's stated -- described in footnote 32, for example, the calculation on page 61.

Q Okay. And you --

A If you give me just a moment to go back and --

Q Sure.

A -- verify that.

Q Certainly.

A So over the two metrics, nonfuel O&M and fuel, if we turn to Exhibit JJR-11, page one of two.

Q Does this show the calculation?

A This shows the two data points that go into the calculation --

Q Okay.

A -- for the three data points, and then the calculation is described in the testimony.

Q Okay.

A In the case of fuel cost savings, JJR-11, page two of two, actually provides the calculation.

Q Okay. And that's for the fuel cost savings

only?

A Correct.

Q Okay. And one final question. You would agree that customers have paid for FPL's new more efficient fleet, correct?

A Yes, I would describe all of the prudently incurred costs as being included in customer rates, and what I have shown is the customers have derived substantial benefits through FPL's choices in implementing those investments.

Q Okay. I have no further questions. Thank you.

CHAIRMAN LA ROSA: Thank you.

FEL?

MR. MARSHALL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MARSHALL:

Q Good morning, Mr. Reed.

A Good morning.

Q When you refer to a typical residential bill across utilities in your testimony, you are referring to a bill at 1,000 kilowatt hours of usage?

A Correct.

Q Would you agree, in a cost-based ratemaking regime, revenue requirement is one component and billing

determinants are the other component?

A In deriving rates? Yes.

Q And if your revenue requirement is unchanged, and billing determinants go down because usage has dropped, then unit rates would go up?

A Your assumption was that the total revenue requirement doesn't go down despite the fact that consumption went down? Yes, under that hypothetical, that's correct.

Q And under that hypothetical, bills would, you know, almost certainly not go up, but the 1,000-kilowatt-hour bill would increase, is that right?

A As compared to what? I have lost your question.

Q As to what it had been before. Before it -- we had a revenue requirement, then billing determinants because usage dropped, went down, and we agreed that unit rates would go up in that situation?

A What you are saying to me is that consumption has gone down, yet you are not going to adjust the typical bill calculation. You are going to still use 1,000 kilowatt hours for the calculation.

I don't understand the logic of that, but if you were to ignore the drop in consumption for the purposes of the calculation while recognizing it in the

revenue requirement, yes, that would produce an inconsistent result, but that is the result it would produce.

Q If we could go to page 70 of your testimony, figure 31.

A I am there.

Q 2023 for this figure was the most recent year you had data available, is that right?

A Yes. That's correct.

Q And this shows that compared to the southeast group, that FPL residential customers actually paid more per year compared to the average rate in the southeast group?

A Not for year, but for half a year.

Q Okay. That was for half a year in 2023?

A Yes, based upon a storm surcharge that took effect for that period of time, that is the result for half a year.

Q Is that the first half of the year of 2023 -- or what half of the year was that?

A Winter.

Q Winter, okay.

Is there a place where you clarify that that figure is just regarding winter?

A Give me just a moment. Yes. Page -- Exhibit

JJR-6, page one of four. And if you look at the very last column, you will see winter '24 and summer '24. And you see that while FPL's rank was fifth for winter, it improved to first for summer. So it was the least expensive utility in the comparison group for the last period of our observation period. It was the most economical. But with the surcharge that took effect in the winter of '24, it was fifth.

Q Maybe I am confused, but I thought this figure 31 only went up through 2023?

A Okay. Same answer. Let me go back to -- what page is that chart on we were looking at?

Q Page 70.

A Yes. I am sorry. Let me correct my answer on page 70.

The comparison in the black box is not for half the year. It is for the year, but it's for half the group. It is for the southeast group. And the red bar, which is for the Florida group, is the rest of the comparison. And you are correct, it's through '23. And for '24, the numbers improved significantly.

Q If we could go to master page E58865?

A I am sorry, you will have to tell me what that is.

Q That's a direction to the Clerk so it should

pop up on your screen, and then this is going to be a demonstrative, so --

CHAIRMAN LA ROSA: If you look at the screen there to your right, it's the same item being displayed behind us, and then you have control to it through your mouse.

BY MR. MARSHALL:

Q Were you able to open that Excel sheet?

A I have it, yes.

Q And if you could go to the tab SNL revenue and -- well, let me -- a foundational question.

This is one of your workpapers, correct?

A It appears to be, yes.

Q And if you go to the tab SNL revenue and volume, I know most of this is redacted, but the last line on row 4,944 is not. Can you tell me, without revealing confidential information, the kind of information contained on this tab?

A I am sorry, I am still getting to the bottom of the page.

Q No worries.

A And what was your question?

Q Can you tell me what -- I mean, we have a row of information here at the bottom for FPL and Gulf combined. Can you tell me what those numbers at the

bottom row mean without revealing confidential information?

A Let's begin with this is the workpaper for Exhibit JJR-6. What's used from that dataset that's redacted is the revenue and megawatt hours for FPL and Gulf combined. Those two are divided to produce a rate, and then that rate is used to calculate a typical bill.

Without having the column headings, I can't tell you --

Q If it helps, there should be a red binder next to you that will have the unredacted column headings. And that will be under tab 356B. That one, yes. CEL 356B.

A And I am sorry, you are saying 356E as in echo?

Q B as in bravo. I am sorry.

A B as in bravo, okay.

MS. MONCADA: Mr. Marshall, do you have a rough page number? It's a long exhibit, I think.

MR. MARSHALL: It is, but I think the first page should have the column headings, which would hopefully alleviate any confusion.

MS. MONCADA: Thank you.

MR. MARSHALL: So just page one.

THE WITNESS: Yes, I am sorry, your question,

again, was what?

BY MR. MARSHALL:

Q Without revealing confidential information, can you tell us, you know, the numbers we have on the Excel sheet that are unredacted, the meaning of what those numbers are for FPL and Gulf combined?

A They appear to be the residential electric revenue for the total company in thousands of dollars, and they are for the 10 years from 2023 to 2014.

Q Would you agree, then, that looking at these numbers, that the residential revenue for FPL and Gulf combined jumped starting in around 2022?

A Yes. I should say that is because of the reporting basis that included Gulf.

Q Did you not combine FPL and Gulf together before 2022, is that --

A That's correct. They were added together manually. This data stream picks up off of Form 1s, so it was in that period of time that both companies were reported together on a Form 1, as opposed to through separate Form 1s.

Q Turning to the metrics that you looked at, you didn't look at a metric that included rate base per customer or per megawatt hour, is that right?

A That's correct, per se. Not rate base. We

did gross plant in lieu of rate base as a measure of capital efficiency.

Q And if we go to figure 8 in your testimony on page 29, would you agree that FPL has had relatively high as compared to other electric utilities' capital expenditures in adding utility plant?

A This is a different metric at page 29, figure 8. These are the additions of plant over a five-year period compared to customer growth. So this shows on average how much additional plant you need.

Actually, this is additions to utility plant over a five-year period of time. So this is meant to be a measure of the age of the plant of the company. Is it essentially an older system or a newer system?

So I would agree that this has higher additions to plant, therefore, it is a newer system on average than most of them. It's either first, second or third out of the peer group. So it tends to be among the newest of the systems because of the need for significant customer additions as the customer base grows.

Q Would you agree that all things being equal, new plants generally require less O&M and than old plants?

A Not necessarily true for generation.

Generation tends to be, O&M is based on hours of operation. It should be true to a certain degree for transmission and distribution plant that maintenance costs are reduced in the early years of operation.

Q If we could next go to master number E58864? And if we go to the tab data, which it looks like we are at.

This is another one of your workpapers, correct, Mr. Reed?

A Yes, it is. And I am sorry, what tab are we supposed to be on?

Q Data.

A Okay.

Q And you have a column on the right, CV -- in column CV, do you see that, for the past five years, gross additions to utility plant?

A Yes.

Q And does that play a role in the discussion were just having about that figure 8?

A Yes.

Q And if we go down to column CV, row 866. Row 866 would be FPL and Gulf combined for 2023, is that right?

A Yes, that appears to be correct.

Q And does that show that there has been almost

$40 billion in gross additions to utility plant in the last five years?

A Yes.

Q And two columns over to the left, in column CT, it says, five-year CAGR total retail electric volume, is that right?

A Yes. That's correct.

Q Can you tell me what that means?

A It is the compound annual growth rate over a five-year period in the number of megawatt hours sold.

Q And so for FPL and Gulf combined, was that rate 0.78 percent?

A And you are talking about specifically for 2023?

Q Yeah.

A Yes, that appears to be correct.

Q Switching topics slightly. On page nine, line 10 of your testimony, you refer to FPL's lower energy consumption per customer, is that right?

A That's correct. That's a measure of one of the exogenous factors that makes achieving favorable rates and favorable cost levels more of a challenge on FPL's system.

Q And this is referring to the fact that that FPL has a higher proportion of residential customers on

its system as compared to other electric utilities?

A That's fashioner partially correct, yes.

Q And you haven't looked at the energy consumption of FPL's residential customers compared to that of the other utilities?

A Not directly. The consumption of energy for residential customers compared to other utilities is more a function of weather, of heating load and cooling load, in that jurisdiction compared to Florida. It's not really a function of any controllable factor that would be able to be controlled by FPL's management.

Q It you also haven't looked at FPL's energy efficiency performance as compared to other electric utilities?

A No, that wasn't part of our objective.

Q You did look at the rate case frequency, is that right, as part of your testimony?

A It was, yes.

Q And if we could next go to master page number E58867?

Do you have the Excel sheet in front of you?

A I do.

Q And this is your workpaper regarding rate case frequency?

A That's correct.

Q And you have Florida as the sixth longest period of all 50 states between actual rate case filings? That's on the tab state ranking.

A That's correct.

Q With a -- am I reading that correctly, that's an average of 1,824 days between filings?

A What line is that on?

Q 14, of the state ranking tab.

A Yes. That's correct. I am not sure of the observation date of that number, but that's correct.

Q And that would be about five years?

A Yes.

Q If we go over to the rate case frequency tab and scroll down to Florida Power & Light. It should be in the -- around row 261, starting.

A I am there.

Q And my question is this: Is that the average -- for Florida Power & Light, you see that there is a 7,029 day number in column M cell row 265?

A I am sorry, could you give me that number and reference again?

Q 7,029 day number in column M, row 265.

A Yes, I see the number.

Q Would that be the number of days between, represented between that 1990 and 2009 FPL rate case

filing?

A It appears to be, yes.

Q And so that number would have been taken into account in your average, and would help drive that average up, is that right?

A It would have been included in the average. The average went back to 1980, and that average, over that period of time, was 1,899 days.

Q Thank you, Mr. Reed.

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

CHAIRMAN LA ROSA: Great. Thank you.

FAIR?

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: FEIA?

MR. MAY: No questions.

CHAIRMAN LA ROSA: Walmart?

MS. EATON: No questions.

CHAIRMAN LA ROSA: FEA?

CAPTAIN RIVERA: No questions. Thank you.

CHAIRMAN LA ROSA: FRF?

MR. BREW: No questions.

CHAIRMAN LA ROSA: FPL?

MR. MOYLE: No questions for FIPUG.

CHAIRMAN LA ROSA: Oh, sorry.

MR. MOYLE: That's all right.

CHAIRMAN LA ROSA: I forgot where we were. FIPUG.

Staff?

MR. STILLER: No questions.

CHAIRMAN LA ROSA: Commissioners, are there any questions of the witness?

Seeing no questions, back to FPL.

MS. MONCADA: No redirect.

We would ask that Mr. Reed's exhibits, which have been identified on the CEL as 84 through 98 be entered into the record.

CHAIRMAN LA ROSA: Seeing no objections? Seeing none, so moved.

Anything else that needs to be moved into the record?

Okay. Mr. Reed, thank you very much for your testimony.

MS. HARPER: Excuse me, Mr. Chair, I am sorry. I just wanted to clarify the records to move -- I am sorry the exhibits we are going to move into the record. I have 29 through 43, is that correct?

MS. MONCADA: If there was a mistake in my numbering, that sounds right.

MS. HARPER: Just wanted to make sure. Okay.

Thank you.

MS. MONCADA: Thank you.

MS. HARPER: Sorry to interrupt.

CHAIRMAN LA ROSA: No. No. Thank you. So moving 29 through 43 into the record, no objections? Seeing none, then so moved.

(Whereupon, Exhibit Nos. 29-43 were received into evidence.)

CHAIRMAN LA ROSA: You are still excused, Mr. Reed.

THE WITNESS: Thank you for accommodating me.

CHAIRMAN LA ROSA: No problem. Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: We are going to move -- we are going to take a quick break, but we are going to move, and, staff, correct me if I am wrong, to FRF's witness next, or do we have a different order?

MR. STILLER: I believe we are going next to FRF, Mr. Georgis.

MR. BREW: Yes.

CHAIRMAN LA ROSA: Excellent. Great. So we will come you to after a break.

It is 10:26. Let's reconvene here at 10:35, so a 10-minute break, 10:35.

Thank you.

(Brief recess.)

(Transcript continues in sequence in Volume 17.)

CERTIFICATE OF REPORTER

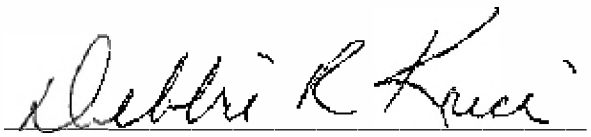
STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 29th day of October, 2025.



DEBRA R. KRICK
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