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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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

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

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.

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[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.

<u>Class Cost-of-Service Study</u>

- 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.

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]

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[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:

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[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.

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[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.

<u>Production Plant</u>

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
<u>The Annual System Peak: 2022 – 2027</u>

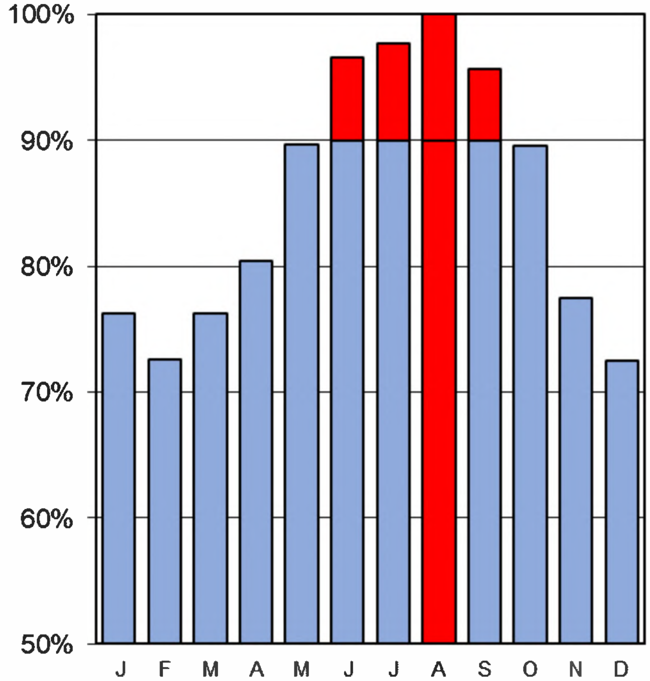

Figure 1 clearly demonstrates that FPL's peak demand loads occur in the summer months. 12CP would only be appropriate if FPL's loads were relatively flat and/or non-seasonal.

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.

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[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.

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[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

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[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.

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[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.

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

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[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:

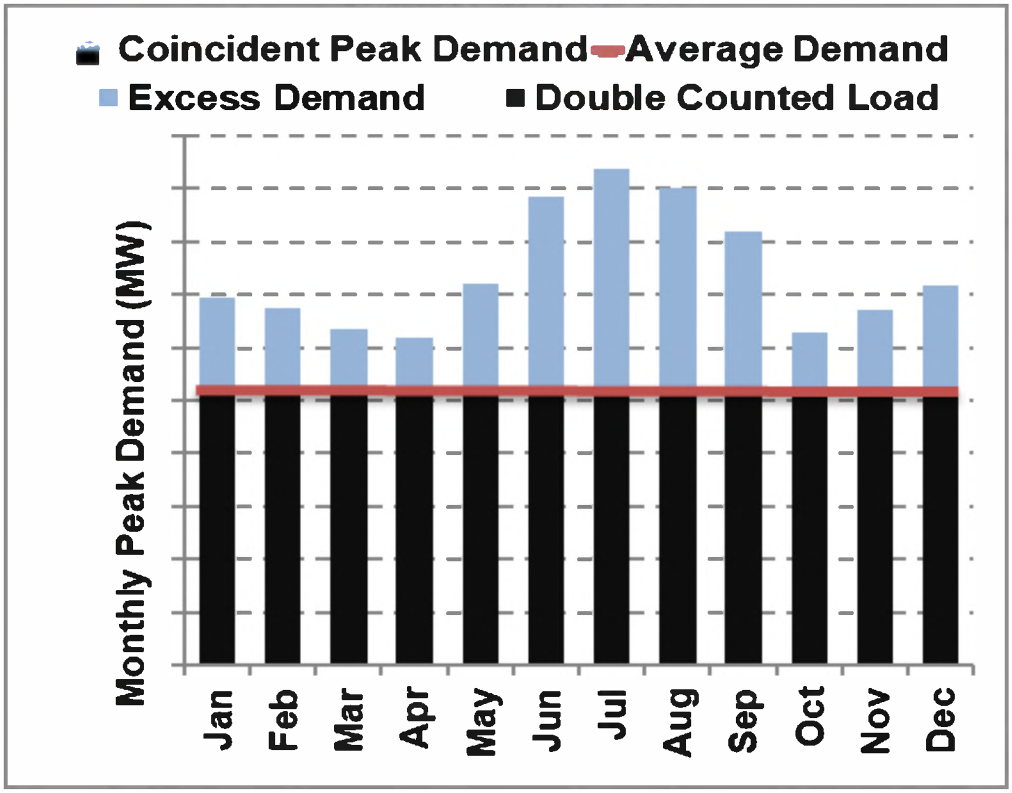
> The examiners find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as 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:

> 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.

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[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.

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:

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[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.

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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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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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by Jeffry Pollock

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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

APPENDIX B
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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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.

FLORIDA POWER & LIGHT COMPANY

Authorized Return on Equity for Vertically Integrated Electric Investor-Owned Utilities
In Rate Cases Decided in 2023 Through May 2025

Line	Utilitiy	Authorized ROE	Date
		(1)	(2)
1	Consumers Energy Co.	9.90%	1/19/2023
2	Minnesota Power Entrprs Inc.	9.65%	1/23/2023
3	Cheyenne Light Fuel Power Co.	9.75%	1/26/2023
4	Duke Energy Progress LLC	9.60%	2/9/2023
5	Southwestern Electric Power Co	9.50%	2/17/2023
6	Upper Peninsula Power Co.	9.90%	3/24/2023
7	Liberty Utilities (CalPeco Ele	10.00%	4/27/2023
8	Northern States Power Co.	9.25%	6/1/2023
9	MDU Resources Group	9.75%	6/6/2023
10	Northern IN Public Svc Co. LLC	9.80%	8/2/2023
11	Entergy Texas Inc.	9.57%	8/3/2023
12	Duke Energy Progress LLC	9.80%	8/18/2023
13	Green Mountain Power Corp.	9.58%	8/23/2023
14	Tucson Electric Power Co.	9.55%	8/25/2023
15	Avista Corp.	9.40%	8/31/2023
16	Alaska Electric Light Power	11.45%	8/31/2023
17	Public Service Co. of CO	9.30%	9/6/2023
18	MDU Resources Group	9.65%	9/21/2023
19	Duke Energy Kentucky Inc.	9.75%	10/12/2023
20	Southwestern Public Svc Co.	9.50%	10/19/2023
21	NorthWestern Energy Group	9.65%	10/25/2023
22	Public Service Co. of OK	9.30%	11/3/2023
23	Madison Gas & Electric Co.	9.70%	11/3/2023
24	Northern States Power Co.	9.80%	11/9/2023
25	Wisconsin Power and Light Co	9.80%	11/9/2023
26	PacifiCorp	9.35%	11/28/2023
27	DTE Electric Co.	9.90%	12/1/2023
28	The Empire District Electric C	9.70%	12/7/2023
29	PacifiCorp	10.00%	12/14/2023
30	Duke Energy Carolinas LLC	10.10%	12/15/2023
31	Portland General Electric Co.	9.50%	12/18/2023
32	Pacific Gas and Electric Co.	10.70%	12/22/2023
33	San Diego Gas & Electric Co.	10.65%	12/22/2023
34	Southern California Edison Co.	10.75%	12/22/2023
35	Nevada Power Co.	9.52%	12/26/2023

Source: S1 Capital IQ.

FLORIDA POWER & LIGHT COMPANY

Authorized Return on Equity for Vertically Integrated Electric Investor-Owned Utilities
In Rate Cases Decided in 2023 Through May 2025

Line	Utilitiy	Authorized ROE	Date
		(1)	(2)
36	Idaho Power Co.	9.60%	12/28/2023
37	Public Service Co. of NM	9.26%	1/3/2024
38	Kentucky Power Co.	9.75%	1/19/2024
39	UNS Electric Inc.	9.75%	1/30/2024
40	Virginia Electric & Power Co.	9.70%	2/28/2024
41	Consumers Energy Co.	9.90%	3/1/2024
42	Arizona Public Service Co.	9.55%	3/5/2024
43	Monongahela Power Co.	9.80%	3/26/2024
44	AES Indiana	9.90%	4/17/2024
45	Indiana Michigan Power Co.	9.85%	5/8/2024
46	Duke Energy Carolinas LLC	9.94%	6/20/2024
47	Indiana Michigan Power Co.	9.86%	7/2/2024
48	Dominion Energy South Carolina	9.94%	8/8/2024
49	Duke Energy Florida LLC	10.30%	8/21/2024
50	Green Mountain Power Corp.	9.97%	8/26/2024
51	Interstate Power & Light Co.	9.87%	9/17/2024
52	Sierra Pacific Power Co.	9.74%	9/18/2024
53	Idaho Power Co.	9.50%	9/23/2024
54	Upper Peninsula Power Co.	9.86%	9/26/2024
55	Upper MI Energy Rsrc Corp.	9.86%	10/10/2024
56	Pacific Gas and Electric Co.	10.28%	10/17/2024
57	San Diego Gas & Electric Co.	10.23%	10/17/2024
58	Southern California Edison Co.	10.33%	10/17/2024
59	Minnesota Power Entrprs Inc.	9.78%	10/24/2024
60	Appalachian Power Co.	9.75%	11/20/2024
61	Oklahoma Gas and Electric Co.	9.50%	11/26/2024
62	Tampa Electric Company	10.50%	12/3/2024
63	PacifiCorp	9.50%	12/19/2024
64	WI Public Service Corp.	9.80%	12/19/2024
65	Wisconsin Electric Power Co.	9.80%	12/19/2024
66	Portland General Electric Co.	9.34%	12/20/2024
67	Avista Corp.	9.80%	12/20/2024
68	Otter Tail Power Co.	10.10%	12/30/2024
69	Virginia Electric & Power Co.	9.95%	1/14/2025
70	Public Service Co. of OK	9.50%	1/15/2025
71	Puget Sound Energy Inc.	9.90%	1/15/2025

Source: S2 Capital IQ.

FLORIDA POWER & LIGHT COMPANY

Authorized Return on Equity for Vertically Integrated Electric Investor-Owned Utilities In Rate Cases Decided in 2023 Through May 2025

Line	Utilitiy	Authorized ROE	Date
		(1)	(2)
72	Bear Valley Electric Svc Inc	10.00%	1/16/2025
73	DTE Electric Co.	9.90%	1/23/2025
74	Duke Energy Indiana, LLC	9.75%	1/29/2025
75	Southern IN Gas & Electric Co.	9.80%	2/3/2025
76	Florida Public Utilities Co.	10.15%	3/4/2025
77	Black Hills Colorado Electric	9.40%	3/12/2025
78	Consumers Energy Co.	9.90%	3/21/2025
79	PacifiCorp	9.38%	4/25/2025
80	Public Service Co. of NM	9.45%	5/15/2025
81	Average	9.81%	

Source: S3 Capital IQ.

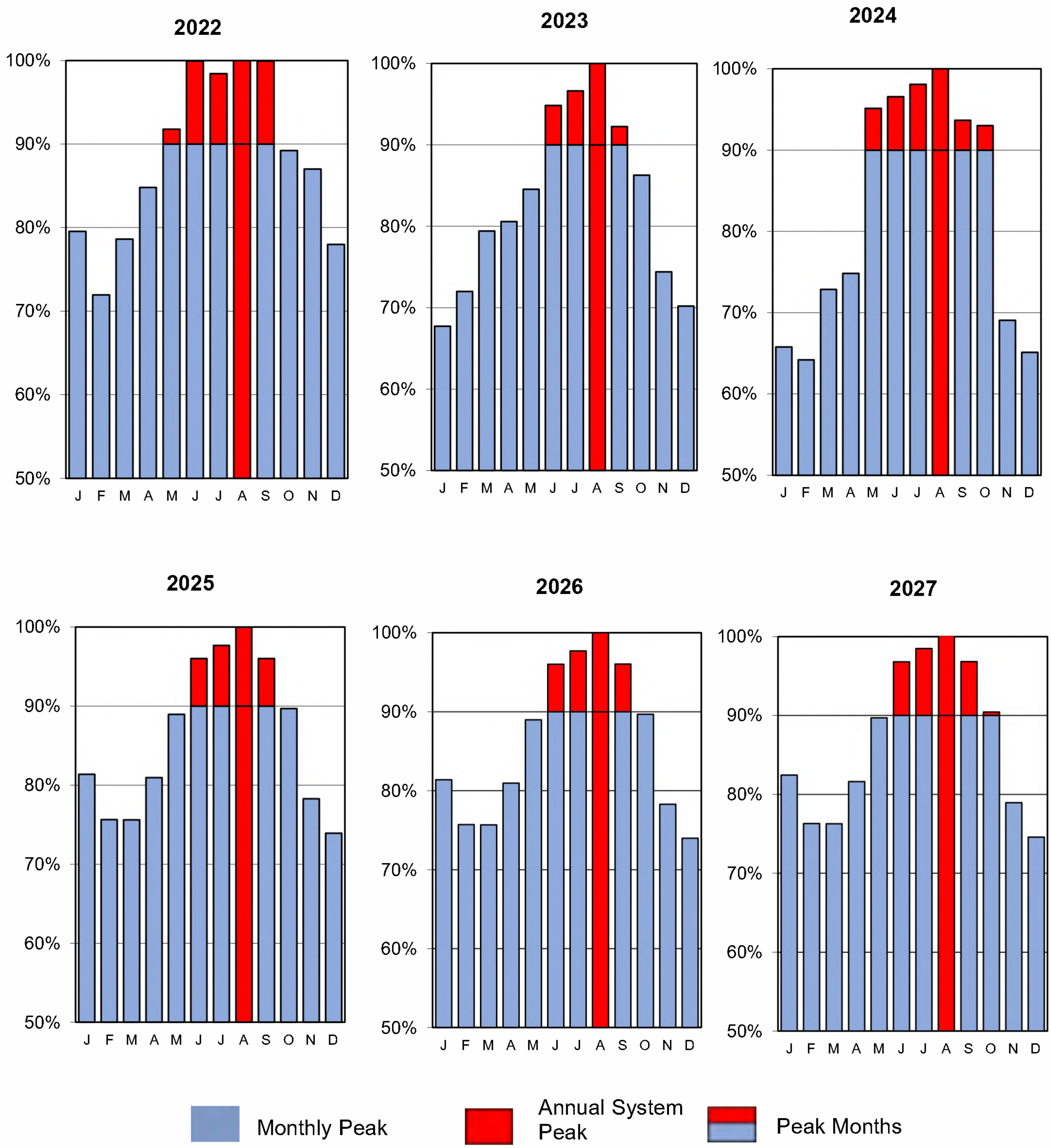
FLORIDA POWER & LIGHT COMPANY

Authorized Common Equity Ratio for Vertically-Integrated Electric Investor-Owned Utilities With "A" Moody's Credit Ratings

Line	Utility	Moody's Credit Rating	Authorized Equity Ratio
		(1)	(2)
1	Madison Gas and Electric	A1	56.1%
2	Georgia Power	A3	56.0%
3	Public Service Company of Colorado	A3	55.7%
4	Alabama Power	A1	55.0%
5	Tampa Electric Company	A3	54.0%
6	Oklahoma Gas and Electric	A3	53.5%
7	Mississippi Power	A3	53.1%
8	Duke Energy Indiana	A2	53.0%
9	Duke Energy Florida LLC	A3	53.0%
10	Duke Energy Carolinas LLC	A2	53.0%
11	Duke Energy Progress	A2	53.0%
12	Northern States Power Minnesota	A3	52.5%
13	Northern States Power Wisconsin	A3	52.5%
14	Indiana Mich Power Company	A3	51.2%
15	Consumers Energy	A1	50.0%
16	Portland General Elecric	A3	50.0%
17	**Average**		**53.2%**
18	**FPL**	**A1**	**59.6%**

Docket No. 20250011-EI
Montly Peak Demands
Exhibit JP-3, Page 1

FLORIDA POWER AND LIGHT COMPANY
Monthly Peak Demands as a Percent of the Annual System Peak Demand for the Years 2022 through 2027



FLORIDA POWER & LIGHT COMPANY
Summary of FIPUG's Revised Class Cost-of-Service Study
at Present Rates
Forecast Test Year Ending December 31, 2026
(Dollar Amounts in $000)

Line	Customer Class	Rate of Return	Relative Rate of Return	Interclass Subsidy*
		(1)	(2)	(3)
1	**CILC-1D**	5.54%	91%	$5,002
2	**CILC-1G**	6.05%	99%	$22
3	**CILC-1T**	6.64%	109%	($1,783)
4	**GS(T)-1**	7.17%	118%	($55,878)
5	**GSCU-1**	9.97%	164%	($520)
6	**GSD(T)-1**	5.37%	88%	$106,277
7	**GSLD(T)-1**	5.14%	84%	$45,176
8	**GSLD(T)-2**	4.76%	78%	$21,080
9	**GSLD(T)-3**	6.17%	101%	($115)
10	**MET**	7.28%	119%	($369)
11	**OS-2**	3.47%	57%	$553
12	**RS(T)-1**	6.31%	104%	($100,747)
13	**SL/OL-1**	7.04%	115%	($14,887)
14	**SL-1M**	8.47%	139%	($236)
15	**SL-2**	8.44%	138%	($287)
16	**SL-2M**	11.09%	182%	($143)
17	**SST-DST**	20.29%	333%	($94)
18	**SST-TST**	15.52%	255%	($3,050)
19	**TOTAL RETAIL**	6.10%	100%	$0

* A positive amount means that a class is being subsidized. A negative amount means that a class is subsidizing other classes.

FLORIDA POWER & LIGHT COMPANY
FPL Proposed Class Revenue Allocation
Forecast Test Year Ending December 31, 2026
(Dollar Amounts in $000)

		Present Sales Revenues			Proposed Increase			
Line	Customer Class	Base Revenues	Clause Revenues	Sales Revenues	Base Revenues	Clause Revenues	Total	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CILC-1D	$83,739	$102,416	$186,155	$37,408	$124	$37,532	20.2%
2	CILC-1G	$4,001	$4,086	$8,087	$1,609	$4	$1,613	19.9%
3	CILC-1T	$32,344	$54,870	$87,214	$18,873	$81	$18,954	21.7%
4	GS(T)-1	$711,160	$423,195	$1,134,355	$25,284	($18)	$25,266	2.2%
5	GSCU-1	$2,348	$1,542	$3,890	$85	$2	$87	2.2%
6	GSD(T)-1	$1,672,374	$1,288,244	$2,960,618	$445,542	$545	$446,088	15.1%
7	GSLD(T)-1	$519,887	$460,000	$979,887	$151,438	$376	$151,814	15.5%
8	GSLD(T)-2	$166,005	$165,695	$331,700	$52,060	$167	$52,226	15.7%
9	GSLD(T)-3	$31,515	$35,361	$66,876	$9,726	$47	$9,773	14.6%
10	MET	$4,270	$3,064	$7,334	$592	$1	$593	8.1%
11	OS-2	$1,983	$1,011	$2,994	$454	$2	$456	15.2%
12	RS(T)-1	$5,899,121	$3,619,108	$9,518,229	$811,213	($1,432)	$809,781	8.5%
13	SL/OL-1	$184,516	$21,129	$205,645	$18,440	$87	$18,527	9.0%
14	SL-1M	$1,520	$1,702	$3,222	$244	$6	$250	7.8%
15	SL-2	$1,810	$1,504	$3,314	$196	$2	$198	6.0%
16	SL-2M	$551	$311	$862	$19	$1	$20	2.3%
17	SST-DST	$177	$4,349	$4,526	$5	$0	$5	0.1%
18	SST-TST	$7,066	$4,004	$11,070	$232	$5	$237	2.1%
19	TOTAL RETAIL	$9,324,387	$6,191,590	$15,515,977	$1,573,420	$0	$1,573,420	10.1%
	Sources	E-5; E-13a	OPC POD 14 MFRS RATES	(1) + (2)	E-5; E-13a	$139 MM Purchased Capacity & CILC/CDR Payments	1.5x Average	15.2%

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	$24,882	29.7%	24.9%	($4,031)	$0	$20,851	24.9%	$104,590
2	**CILC-1G**	$4,001	$847	21.2%	21.2%	$0	$49	$896	22.4%	$4,897
3	**CILC-1T**	$32,344	$4,592	14.2%	14.2%	$0	$427	$5,019	15.5%	$37,363
4	**GS(T)-1**	$711,160	$32,381	4.6%	4.6%	$0	$6,445	$38,826	5.5%	$749,986
5	**GSCU-1**	$2,348	($418)	-17.8%	0.0%	$418	$0	$0	0.0%	$2,348
6	**GSD(T)-1**	$1,672,374	$437,809	26.2%	24.9%	($21,388)	$0	$416,421	24.9%	$2,088,795
7	**GSLD(T)-1**	$519,887	$155,508	29.9%	24.9%	($26,056)	$0	$129,452	24.9%	$649,339
8	**GSLD(T)-2**	$166,005	$59,812	36.0%	24.9%	($18,477)	$0	$41,335	24.9%	$207,340
9	**GSLD(T)-3**	$31,515	$4,835	15.3%	15.3%	$0	$305	$5,141	16.3%	$36,656
10	**MET**	$4,270	$143	3.4%	3.4%	$0	$38	$181	4.2%	$4,451
11	**OS-2**	$1,983	$1,187	59.8%	24.9%	($693)	$0	$494	24.9%	$2,477
12	**RS(T)-1**	$5,899,121	$815,117	13.8%	13.8%	$0	$57,203	$872,319	14.8%	$6,771,440
13	**SL/OL-1**	$184,516	$11,967	6.5%	6.5%	$0	$1,861	$13,828	7.5%	$198,344
14	**SL-1M**	$1,520	($110)	-7.2%	0.0%	$110	$0	$0	0.0%	$1,520
15	**SL-2**	$1,810	($132)	-7.3%	0.0%	$132	$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	($3,413)	-48.3%	0.0%	$3,413	$0	$0	0.0%	$7,066
19	**TOTAL RETAIL**	$9,324,387	$1,544,765	16.6%		($66,329)	$66,329	$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%	

FLORIDA POWER & LIGHT COMPANY
Size Thresholds Applicable to Very Large Load Customers

Line	State	Utility	Minimum Capacity (MW)	Date
			(1)	(2)
1	Kentucky	Kentucky Power Co.	150	3/18/2025
2	North Carolina	Duke Energy Carolinas	100	5/7/2024
3	Georgia	Georgia Power Co.	100	1/23/2025
4	Missouri	Evergy Missouri Metro, Inc	100	7/13/2023
5	Maryland	Maryland PSC	100	5/20/2025
6	Missouri	Ameren Missouri	100	Pending
7	West Virginia	Appalachan/Wheeling Power Co.	100,150*	3/25/2025
8	Indiana	Indiana Michigian Power Co.	70,150*	2/19/2025
9	South Carolina	Santee Cooper	50	4/25/2025
10	Utah	Rocky Mountain Power	50	4/25/2025
11	Oregon	Pacific Gas & Electric Co.	50	3/28/2025
12	Wyoming	Rocky Mountain Power	50	Pending
13	Mississippi	Entergy Mississippi, LLC	30	12/1/2018
14	Ohio	AEP Ohio	25	Pending
15	Virginia	Virginia Electric and Power Co.	25	Pending
16	South Dakota	Montana-Dakota Utilities Co.	10	9/1/2024
17	North Dakota	Montana-Dakota Utilities Co.	10	10/27/2022

* Individual Site/Aggregated Capacity .