BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210015-EI

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

VOLUME 8
PAGES 1625 - 1879

PROCEEDINGS: HEARING

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

DATE: Monday, September 20, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 7.)

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 20210015-EI** **Filed: June 21, 2021**

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
INCORPORATED

Jon C. Moyle, Jr.
Moyle Law Firm, P.A
The Perkins House
118 N. Gadsden St.
Tallahassee, Florida 32301
Telephone: 850.681.3828
Facsimile: 850.681.8788

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	DOCKET NO. 20210015-EI Filed: June 21, 2021

Table of Contents

LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
AEO	Annual Energy Outlook
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CDR	Commercial/Industrial Demand Reduction
CILC	Commercial/Industrial Load Control
CONE	Cost of New Entry
CPVRR	Cumulative Present Value Revenue Requirement
CT	Combustion Turbine
DSM	Demand Side Management
ECCR	Energy Conservation Cost Recovery
EIA	Energy Information Administration
Exelon	Exelon Generation Company LLC
F.A.C.	Florida Administrative Code
FIPUG	Florida Industrial Power Users Group
FPL or Company	Florida Power & Light Company
FRCC	Florida Reliability Coordinating Council
GSD	General Service Demand
GSLD	General Service Large Demand
Gulf Power	Gulf Power Company
kW / kWh	Kilowatt / Kilowatt-Hour
MDS	Minimum Distribution System
MISO	Midcontinent Independent System Operator, Inc.
MFRs	Minimum Filing Requirements
MW	Megawatt
NRC	Nuclear Regulatory Commission
O&M	Operation and Maintenance
ROE	Return on Equity
RSAM	Reserve Surplus Amortization Mechanism
SoBRA	Solar Base Rate Adjustment
St. Lucie	St. Lucie Nuclear Plant
TCJA	2017 Tax Cuts and Jobs Act
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; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

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. I have testified in Florida Power & Light Company's (FPL's) 2009, 2012 and 2016 rate cases. 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). FIPUG members purchase electricity from FPL. They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and significant interest in the outcome of this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A I am addressing the following issues:

- FPL's proposed Four-Year Rate Plan including the continuation of the Reserve Surplus Amortization Mechanism (RSAM) and 2024-2025 Solar Base Rate Adjustments (SoBRAs);
- Class Cost-of-Service Study (CCOSS);
- Class revenue allocation; and
- FPL's proposal to reduce the incentive payments to customers participating in two load management programs — Commercial/Industrial Load Control (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) — by 33%.

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

A Yes. My colleague, Ms. LaConte, will address FPL's proposed cost of capital, the mechanism to adjust rates to reflect a change in the federal corporate income tax rate, the recovery of costs associated with the retirement of Scherer Unit 4, and rate case expense amortization.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-14.**

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. One should not interpret the fact that I do not address every issue raised by FPL as support of its proposals.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Four-Year Rate Plan

- The proposed Four-Year Rate Plan would increase base revenues by $2.042 billion ($2.245 billion without continuing the RSAM) for the years 2022 through 2025.

- The 2022 and 2023 base rate increases would be based on two fully projected future test years. This practice eliminates regulatory lag.

- Various elements of the Four-Year Rate Plan, such as continuing the RSAM and the two SoBRA adjustments, would guarantee that FPL achieves at the top end of the return on equity (ROE) authorized by the Commission. The guarantee is the result of how FPL has used the RSAM in the past and the effect of authorizing the two proposed additional solar plant base rate increases in 2024 and 2025 without subjecting FPL to any earnings test.

- Eliminating regulatory lag, while enabling a utility to always achieve the highest authorized earnings substantially mitigates FPL's regulatory risk. Accordingly, if the Four-Year Rate Plan is approved, FPL's authorized ROE should be at or below the national average.

- Providing a utility guaranteed earnings is contrary to the regulatory compact. The regulatory compact provides the utility an *opportunity* to earn a reasonable return on the investments (not a *guarantee*) that are used and useful in providing electricity service and to recover reasonable and necessary operating expenses.

- The Commission should return to more traditional ratemaking practices by discontinuing use of the RSAM as proposed by FPL and rejecting the proposed 2023 base rate increase unless FPL files a complete set of updated minimum filing requirements (MFRs).

Reserve Surplus Amortization Mechanism

- The RSAM is a tool that can be used under certain very specific circumstances to temporarily mitigate the impact of large rate increases. The premise for using an RSAM is that the utility has a large surplus in its depreciation reserve based on the results of a contemporaneous depreciation study. The RSAM uses this surplus to reduce annual depreciation expense for a limited time period. However, once the surplus has been exhausted and normal depreciation expense is restored, rates will be higher. This is because (with RSAM) reducing depreciation expense results in higher net plant (than in the absence of an RSAM). Thus, the RSAM is not cost-free. In effect, the RSAM is a loan to customers (*i.e.,* temporarily lower base rates) that they will repay with interest at the utility's authorized cost of capital.

- FPL's current rates are higher because of the RSAM.

- FPL does not have a surplus depreciation reserve based on its 2021 Depreciation Study. The Study reveals a $437 million reserve *deficit*.

- The continuation of the RSAM is contingent on extending the lives of the St. Lucie Nuclear Plant (St. Lucie) and FPL's combined cycle gas turbine (CCGT) and solar units, and reverting to the depreciation parameters used in the 2016 Depreciation Study for certain transmission and distribution assets. However, the CCGT and solar life extensions are clearly hypothetical. FPL has offered no assurances that extending the lifespans of its CCGTs from 40 to 50 years and its solar plants from 30 to 35 years is either feasible or cost-effective.

- For example, a key assumption justifying the continuation of the RSAM in the 2016 rate case was extending the planned retirement date of Scherer Unit 4 from 2039 to 2052. In this proceeding, FPL is proposing to retire Scherer Unit 4 in 2022. Further, it is now demanding full recovery with a regulatory return on the unamortized plant balance, even though it used the Scherer 4 surplus depreciation to earn at the top end of its authorized ROE in every reporting period since the 2016 rates were implemented.

- FPL has misused the RSAM. Because of the RSAM, FPL was able to achieve actual earnings at the top end of its authorized ROE in nearly every reporting period since the RSAM was first implemented in the 2010 rate case. Thus, the RSAM has provided a windfall to FPL's shareholder. FPL could have instead used surplus depreciation to mitigate future costs, rather than boost shareholder earnings.

- The absence of an actual depreciation reserve surplus and FPL's past misuse of the RSAM mean that the continuation of the RSAM is no longer in the public interest. The Commission should reject the RSAM.

- Regardless of the disposition of the RSAM, it is probable that FPL will successfully obtain a 20-year life extension for the St. Lucie plant. Because a 20-year life extension will significantly reduce annual depreciation expense, the Commission should order FPL to create a regulatory liability commencing in the month following Nuclear Regulatory Commission (NRC) approval of the license extension. The St. Lucie regulatory liability would require FPL to retain the lower depreciation expense for the benefit of FPL's customers, rather than FPL's shareholder. The accumulated balance can be used to mitigate future base rate increases.

<u>Solar Base Rate Adjustments</u>

- The two proposed SoBRAs are single-issue or "piecemeal" ratemaking. Piecemeal ratemaking occurs when rates are adjusted outside of a general rate case. Thus, the amount of the SoBRA increases ignores whether any base rate increase is needed to allow FPL to earn its authorized return.

- It is unclear whether the Commission can approve the SoBRAs other than in a general rate case or separate stand-alone limited proceeding.

- The proposed solar projects are not necessary to meet a reliability need. FPL's sole justification for the proposed solar projects is that they are cost-effective; that is, they will result in lower rates. Accordingly, FPL has discretion about when to place these projects into service.

- The in-service date of the 2024 solar projects can be deferred to 2025 without jeopardizing reliability.

- The Commission should reject the 2024-2025 SoBRAs.

- Regardless of the disposition of the SoBRAs, the Commission should require FPL to provide guarantees that customers are realizing the benefits claimed by FPL. Such guarantees should include disallowing costs for failing to meet minimum annual capacity factor requirements and if the solar projects have not achieved the promised benefits as determined in a forensic analysis quantifying the costs actually incurred and the direct benefits actually provided by its various solar investments.

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

- Of the two CCOSSs FPL filed in this proceeding (a "Base" study and an "MDS" study), the MDS (minimum distribution system) study is the most accurate. However, there are significant flaws with FPL's MDS study.

- The first flaw is that the CCOSS is internally inconsistent. This is because FPL imputed the CDR/CILC incentive payments collected in the Energy Conservation Cost Recovery (ECCR) clause, rather than what would have been collected during the test year.

- The second flaw is the imputed incentives were not recognized in the CCOSS as an additional cost recoverable from customer classes. As a result, the earned rates of return derived in the CCOSS at present rates are overstated. FPL's earnings are the same with or without the incentive payments.

- The third flaw is that production and transmission demand-related costs were allocated to customer classes using the Twelve Coincident Peak (12CP) method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. FPL, however, is a strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.

• Unless these flaws are corrected, the CCOSS will not provide a reasonable basis for determining a proper cost-based revenue allocation.

• The first flaw can be corrected by imputing incentive payments using test-year billing determinants. This would increase the imputed incentives to $80.9 million.

• The second flaw can be corrected as follows:

  - Directly assign the $80.9 million of imputed incentive payments to the CILC, GSD, and GSLD customer classes.

  - Allocate the $80.9 million to all customer classes in a manner consistent with the allocation of production demand-related costs, because the incentive payments recognize the avoided production capacity-related costs attributable to the CDR/CILC load management programs.

• The third flaw can be corrected by using the Four Coincident Peak (4CP) method. The 4CP method is based on demands that occur coincident with FPL's summer period (June through September) demands. 4CP recognizes that it is the summer peak demands that primarily drive the need for new capacity additions to maintain reliability. The projected summer peaks are consistently 20% higher than the projected winter peaks. FPL also experiences its lowest reserve margins during the summer months. This is also when the transmission system experiences its lowest load carrying capability.

- FPL's MDS analysis should be adopted. MDS classifies a portion of the distribution network as a customer-related cost. This is consistent with the principles of cost causation; that is, it better reflects the drivers that cause a utility to incur these costs. MDS is also an accepted practice. For example, both Gulf Power Company (Gulf Power) and Tampa Electric Company (TECO) have used the MDS approach to setting rates.

- Regardless of whether MDS is approved, the separation of distribution network investment between primary and secondary voltage as used in FPL's MDS CCOSS should be approved because it provides a more consistent treatment between conductors (*i.e.,* overhead lines and underground conductors) and their corresponding support structures (*i.e.,* poles, towers, fixtures, and underground conduit) than in FPL's "Base" study.

- I have corrected FPL's MDS CCOSS and presented the results under both the 12CP and 4CP methods.

<u>Class Revenue Allocation</u>

- The Commission's long-standing policy has been to move all rates closer to cost using a proper CCOSS.

- FPL's proposed class revenue allocation should be rejected because it is derived from its highly flawed "Base" CCOSS. Base rates would more than double for some classes and increase by 180% for other classes. Former Gulf Power customers transferring to FPL's GSLD rates would experience greater rate shock than FPL's customers. By any definition, base rate increases of this magnitude would be rate shock and violate the principle of gradualism.

- Correcting the flaws with FPL's MDS CCOSS would substantially remove any rate shock. I present two alternative proposals based on the two corrected CCOSSs that I am sponsoring.

- A general rate case is the only venue in which gradualism can be properly applied. The principle of gradualism means placing reasonable limits on base rate increases to avoid rate shock.

- FPL's application of gradualism, however, fails to prevent rate shock because FPL uses total revenues, rather than base rate revenues, to measure the impact of a base rate increase. Total revenues include costs recovered in other cost-recovery mechanisms (*i.e.,* fuel and purchased power, energy conservation, environmental, capacity, and storm hardening). These cost recovery mechanisms are not at issue in this case.

- FPL is seeking four base rate increases. Therefore, measuring the impact of those proposed increases on base revenues is the proper way to measure the impact and to apply gradualism to mitigate rate shock.

- The proper application of gradualism would be to limit the increase to any customer class to not exceed 1.5 times the system average base revenue increase, and no class should receive a rate decrease.

CILC/CDR Monthly Incentive

- FPL is once again proposing drastic reductions in the incentive payments under the CILC and CDR load management programs. In this case, the proposal is a 33% reduction. In 2016, FPL proposed a 37% reduction.

- The incentive payments compensate CILC and CDR customers for agreeing to curtail load to alleviate any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the use of peaking generators. Curtailments can also occur when any Peninsular Florida utility experiences an emergency condition or shortage. There are no limits to the frequency and duration of the curtailments under the CILC program.

- FPL's proposal to reduce the incentive payments by 33% is judgmental. It is, in part, informed by FPL's observation that its projections of generation capital costs have declined and by the results of a production cost simulation model, AURORA, to measure the cost-effectiveness of the CILC/CDR programs over a 46-year study period (2022 to 2068).

- Notwithstanding that AURORA has never been used to measure the cost-effectiveness of any demand side management (DSM) program, the results would justify only a very small reduction in the monthly incentive for the CILC/CDR programs to remain cost-effective; certainly not 33%.

- The AURORA model results should be disregarded because it measures total production costs, which includes capital, fixed expenses, and variable costs, such as fuel. However, the CILC/CDR programs avoid capital and fixed expenses. Changes in variable costs are not relevant. In fact, the Commission has always used avoided generation capital costs to determine whether it is cost-effective to implement, expand, or close a load management program.

- Although FPL's projections of avoided generation capital costs may have declined, actual capital costs have either increased or remained relatively unchanged. Since 2012, the capital cost of capacity installed by FPL has increased from $676 per kW to $847 per kW. Further, the capital costs projected by the Energy Information Administration (EIA) in its Annual Energy Outlook (AEO) reports have also steadily increased since 2012. The Midwest Independent System Operator, Inc. (MISO) uses projected generation capital costs to determine the cost of new entry (CONE) in its annual Planning Resource Auctions. I have observed no discernable trend (up or down) in MISO's projected CONE prices since 2013.

- The intrinsic value of load management programs is the amount of generation capacity and the associated costs that have been avoided as a result of a utility providing non-firm service options, such as CILC and CDR. There is no dispute that these programs have allowed FPL to construct less generation capacity (approximately 977 MW based on maintaining a 20% reserve margin). Further, FPL has installed over 7,500 MW of capacity since 2012 at costs ranging from $379 per kW to over $1,600 per kW. On average, the installed costs of this capacity was $847 per kW ($667 per kW excluding the solar plants).

- By not having to firm-up the CILC/CDR load, FPL avoided at least $667 per kW of capital costs. This cost avoidance would translate into a net benefit of $9.78 per kW-month. The current CILC/CDR monthly incentive is $8.70 per kW-month.

- Even if FPL had constructed only combustion turbine (CT) units, the net benefit would be $9.00 per kW-month, which is higher than the current $8.70 per kW-month incentive.

- Based on evidence of the capital costs actually avoided, the current CILC/CDR monthly incentive should not be reduced by 33% as FPL is proposing.

2. FOUR-YEAR RATE PLAN

Q WHAT ARE THE KEY ELEMENTS OF FPL'S PROPOSED FOUR-YEAR RATE PLAN?

A The Four-Year Rate Plan would run from 2022-2025. The key elements of the plan are:

- Cumulative base revenue increases of $2.042 billion[1], consisting of two base rate increases using the fully-projected future test years 2022 and 2023 and two SoBRA increases in 2024 and 2025;
- The continuation of the RSAM;
- The continuation of the storm cost recovery mechanism as approved in FPL's 2016 rate settlement;
- Accelerating the amortization of unprotected excess accumulated deferred income taxes resulting from the 2017 Tax Cuts and Jobs Act (TCJA); and
- A mechanism to timely address possible changes in the federal corporate income tax rate.[2]

Q ARE ANY OF ABOVE COMPONENTS ESSENTIAL TO FPL'S FOUR-YEAR RATE PLAN?

A Yes. FPL witness, Robert Barrett, stated that three of the above components — continuation of the RSAM, the 2024-25 SoBRAs, and accelerated amortization of unprotected excess deferred income taxes — are essential to the Company's ability to commit to its Four-Year Rate Plan.[3]

---

[1] FPL's Petition lists total annual revenue increases of $1.108 billion to be effective January 1, 2022 and $607 million to be effective January 1, 2023, resulting in a cumulative increase of $1.715 billion. However, the $1.715 billion does not include the proposed 33% reduction in the CILC/CDR incentives, certain revenue adjustments and unbilled revenues.

[2] Petition at 2.

[3] Direct Testimony of Robert E. Barrett at 13.

Q HOW DOES THE FOUR-YEAR RATE PLAN COMPARE TO A TRADITIONAL RATE CASE?

A In a traditional rate case, a utility would request one base rate increase using a single test year. Further, when a fully projected future test year is used, it would be based on an approved corporate budget. In this case, however, only the projected 2022 test year is based on FPL's official corporate budget and per-books financial forecast, which were approved in the fall of 2020.[4] The projected 2023 test year is not based on an approved corporate budget. Further, FPL is not proposing to update the 2023 test year to reflect an approved corporate budget.[5]

Q IS IT A COMMON PRACTICE TO USE TWO FULLY PROJECTED FUTURE TEST YEARS IN A GENERAL RATE CASE?

A No.

Q SHOULD THE 2023 INCREASE BE APPROVED AS FILED?

A No. The 2023 increase should be rejected unless FPL files a complete set of updated MFRs.

Q ARE OTHER ASPECTS OF FPL'S FOUR-YEAR RATE PLAN INCONSISTENT WITH TRADITIONAL RATEMAKING?

A Yes. As previously stated, FPL is seeking two SoBRA increases. They would be implemented in 2024 and 2025. At this time, FPL estimates that each SoBRA would increase base revenues by an additional $140 million per year. The actual SoBRA increases would depend on the construction costs.

---

[4] FPL Response to FIPUG Interrogatory No. 29.

[5] FPL Response to FIPUG Interrogatory No. 33.

Q WHY IS FPL SEEKING TWO SOBRA INCREASES?

A The proposed SoBRA increases reflect FPL's plan to install 1,788 megawatts (MWs) of solar projects.[6]

Q WERE THE PROPOSED SOBRA REVENUE INCREASES DERIVED IN THE SAME MANNER AS THE 2022-2023 BASE REVENUE INCREASES?

A No. Unlike the 2022/23 base rate increases, the proposed SoBRAs would not be "needs based;" that is, they are not derived from a revenue requirements analysis. A revenue requirements analysis determines whether a base revenue increase is needed to provide FPL a reasonable opportunity to earn a reasonable return on the facilities that are used and useful in providing electricity to its customers.

It is unclear how the Commission can approve the SoBRAs because they would not be subject to the detailed investigation of FPL's earnings that typically occurs in a general rate case.

Further, this additional solar capacity is simply not needed. As discussed later, the Florida Reliability Coordinating Council (FRCC) projections reveal that Peninsular Florida will have sufficient reserve margins absent the planned solar projects.

Q ARE THERE ANY INCONSISTENCIES BETWEEN FPL'S PROPOSED FOUR-YEAR RATE PLAN AND TRADITIONAL RATEMAKING?

A Yes. The proposed Four-Year Rate Plan would virtually guarantee that FPL continues to achieve earnings at the top end of its authorized earnings range. Yet, as Ms. LaConte testifies, FPL's claimed revenue requirements are based on an excessive cost of capital. Specifically, FPL's proposed cost of capital is based on a "financial"

[6] Petition at 2.

capital structure consisting of 59.6% common equity and an 11.5% return on equity (ROE). As Ms. LaConte testifies, the proposed 59.6% financial common equity ratio is approximately 787 basis points higher than the national average equity ratio for investor owned electric utilities having a comparable "A" bond rating as FPL. Ms. LaConte also states that the proposed 11.5% ROE is 195 basis points higher than the national average ROE authorized by state regulatory commissions for vertically integrated electric utilities. If approved, FPL's pre-tax cost of capital would be the highest of any vertically integrated electric utility in the nation.

FPL's extremely high cost of capital is incompatible with a rate plan that would guarantee FPL's future earnings.

Q WOULD ALL FPL CUSTOMERS BE AFFECTED EQUALLY BY FPL'S FOUR-YEAR RATE PLAN?

A No. The proposed 2022-23 base rate increases would average 23.2%. However, FPL's larger customers, mainly Florida's businesses, would experience much more drastic increases: 59.4% for CILC customers; 42.4% increases for Rate GSLD customers. These increases are 2.6 and 1.8 times the system average increase. Former Gulf Power customers transferring to FPL's GSLD rates would receive even higher base rate increases. Base rate increases of this magnitude would result in rate shock and violate the principle of gradualism.

3. RESERVE SURPLUS AMORTIZATION MECHANISM

Q WHAT IS THE RSAM?

A The RSAM uses a surplus depreciation reserve to *temporarily* reduce the utility's future revenue requirements. Thus, one advantage of the RSAM is that it can mitigate short-term rate increases. Once a depreciation reserve surplus has been exhausted, the utility may require higher rates to maintain its authorized return.

For example, when FPL originally implemented the RSAM as a result of the 2010 Rate Order, the 2009 Depreciation Study revealed that the accumulated depreciation reserve was $1.2 billion higher than necessary to support timely capital recovery.[7] The Commission directed FPL to amortize $894 million of depreciation reserve surplus as a credit over the four-year period ending 2013.[8] Thus, the premise behind the RSAM is that the utility has a significant depreciation reserve surplus as determined in a contemporaneous depreciation study. As discussed later, FPL's 2021 Depreciation Study revealed a $437 million reserve *deficit*, not a surplus.[9]

Q IS THE RSAM A NORMAL FACET OF UTILITY RATEMAKING?

A No. Normally base rates are set to reflect the depreciation and dismantlement expenses as determined in contemporaneous depreciation and dismantlement studies. These studies provide the best information about the key depreciation parameters: lifespans, salvage value, removal cost and interim capital additions and retirements of each of the utility's long-lived assets. These parameters are subject to

---

[7] *In re: 2009 depreciation and dismantlement study by Florida Power & Light Company*, Docket No. 090130-EI, Order No. PSC-10-0153-FOF-EI at 199 (Mar. 17, 2010).

[8] *Id.* at 87.

[9] Direct Testimony of Ned A. Allis, Exhibit NWA-1 at 102.

change as circumstances warrant. For example, if a nuclear plant receives a 20-year extension to its operating life, it can significantly reduce the applicable nuclear depreciation rates. Thus, the RSAM might be warranted if a current depreciation study reveals a potential surplus using the best available information.

Q IS AN RSAM COST-FREE TO CUSTOMERS?

A No. Although RSAM would reduce depreciation expense in the near-term, future base rates would be higher because:

1. After the depreciation surplus has been exhausted, pre-RSAM depreciation expense would be restored, thereby raising base revenue requirements, and
2. Future rate base would be higher because RSAM slows down the build-up of the accumulated depreciation reserve.

Although FPL's Four-Year Rate Plan would temporarily mitigate base rate increases in 2022 and 2023, FPL customers would pay (and are currently paying) higher rates (now and) in the future.

Therefore, the RSAM is akin to loaning money to customers (in the form of lower base electric rates) in the short-term that customers will have to repay with interest at FPL's authorized cost of capital.

Q HAVE FPL CUSTOMERS PAID HIGHER ELECTRIC RATES BECAUSE OF THE RSAM?

A Yes. For example, in its Petition to initiate the 2012 rate case, FPL cited the cumulative impact of the RSAM approved in the 2010 Rate Order as accounting for $104 million of its proposed test-year revenue increase.[10] The RSAM was continued in both the 2012 and 2016 rate cases. Thus, FPL's rates are higher today because of the RSAM.

Q IF THE RSAM IS NOT COST-FREE, WHY DID THE COMMISSION APPROVE AN RSAM FOR FPL?

A The reasons supporting the RSAM are more aptly described in the Commission's Order[11]:

> We believe that the very presence of a reserve imbalance indicates the existence of intergenerational inequity. Based on what is known today, the life estimates of yesterday are now viewed as being too short. FPL has lengthened the life span estimates for its production plants. Net salvage estimates have changed. This does not mean however, that past life and salvage estimates were wrong. Disregarding the fact that settlements were reached in 2002 and 2005 that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of FPL's depreciation parameters was in Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, <u>In re: 1997 depreciation study by Florida Power & Light Company</u>. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.
>
> We agree with FPL that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase, thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase. At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that under present expectations more than enough has been

[10] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 120015-EI, Petition at 15-16 (March 19, 2012).

[11] *In re: Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI at 83 (Mar. 17, 2010).

> recovered, so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future. (quote footnotes omitted)

Q HAS FPL MAINTAINED A LARGE DEPRECIATION RESERVE SURPLUS SINCE THE 2010 RATE ORDER?

A No. In its 2016 rate case, FPL's Depreciation Study showed a $100 million reserve *deficit*.[12] Despite changing the depreciation parameters to *create* a $1 billion surplus,[13] the 2021 Depreciation Study filed in this rate case now shows a $437 million depreciation reserve deficit.[14] Thus the premise for continuing the RSAM no longer exists today.

Q HAVE ANY OF THE REVISED DEPRECIATION PARAMETERS FAILED TO MATERIALIZE?

A Yes. The $1 billion surplus reserve assumed that Scherer Unit 4 would be retired in 2052.[15] The 2016 Depreciation Study established a 2039 retirement date.[16] In this case, FPL is now proposing to retire Scherer Unit 4 in 2022. Thus, FPL reaped the benefit of the additional depreciation surplus caused by the assumed life extension of

---

[12] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 160021-EI, Direct Testimony and Exhibits of Ned W. Allis, Exhibit NWA-1 (Mar. 15, 2016). The amount was not affected by the Errata filed on Aug. 16, 2016.

[13] Docket No. 160021-EI, Order No. PSC-16-0560-AS-EI, *Order Approving Settlement Agreement* at 3 (Dec. 15, 2016).

[14] Direct Testimony of Ned Allis, Exhibit NWA-1 at 102.

[15] Docket No. 160021-EI, *Order Approving Settlement Agreement*, Attachment A, Exhibit D at 2 (Dec. 15, 2016).

[16] *Id.*, *Direct Testimony and Exhibits of Ned W. Allis*, Exhibit NWA-1 (Mar. 15, 2016). The amount was not affected by the Errata filed on Aug. 16, 2016.

Scherer Unit 4, but it is now seeking cost recovery of an even larger remaining balance of the unit, along with a full regulatory return on the unamortized balance, over ten years. FIPUG witness LaConte addresses FPL's Scherer Unit 4 cost recovery proposal.

Q IF THE CURRENT DEPRECIATION STUDY REVEALS A LARGE DEFICIT, HOW DOES FPL JUSTIFY CONTINUING THE RSAM?

A FPL proposes to continue the RSAM by, once again, changing the lifespans and other parameters that were derived in the 2021 Depreciation Study. These changes, and their estimated impacts, are summarized in Table 1.

Table 1
Depreciation Parameters Contributing To the Proposed RSAM[17]
($Millions)

Description	Lifespan Extension (Years)	2022 Impact	2023 Impact
St. Lucie Nuclear	20	$130.9	$133.4
Combined Cycle Gas Turbines	10	$120.8	$126.8
Solar Plants	5		
Other Assets	Various	$13.0	$10.8
Total		$238.7	$249.4

For example, FPL is assuming that St. Lucie would receive a 20-year extension of its operating license. Increasing St. Lucie's lifespan by 20 years, alone would lower the associated depreciation expense by $133.4 million in 2023. Similarly, FPL is

[17] Direct Testimony of Keith Ferguson, Exhibit KF-3(B) at 1.

proposing extended lifespans for its CCGTs and solar plants that would result in a further $120.8 and $126.8 million per year reduction in depreciation expense in years 2022 and 2023, respectively.

These *after-the-fact* changes to the lifespans developed in FPL's 2021 Depreciation Study are the drivers that would *transform* an otherwise large deficit in the accumulated depreciation reserve into a surplus.

Q ARE THE PROPOSED LIFESPAN EXTENSIONS SHOWN IN TABLE 1 REASONABLE?

A No, with one notable exception. First, there is no actual experience of a CCGT plant achieving a 50-year lifespan, or a utility scale solar plant achieving a 35-year lifespan. Second, decisions to extend the life of a CCGT will depend on whether the added capital investment to keep the plant running would be cost effective. However, with on-going improvements in generation technology that have dramatically improved the efficiency of CCGTs, it would be farfetched to assume that an existing CCGT (using current technology) would continue to be cost-effective for an additional 10 years.

To use an analogy, just because it may be feasible to drive a 20-year old car for another 20 years, this cannot be accomplished without incurring significant maintenance expense to replace worn out parts. At some point, the cost of buying a new car will be more than outweighed by the higher maintenance and lower gas mileage of the 20-year old car.

Second, I would note that FPL constructed and operated CCGTs in the 1970s. These plants have long since been retired and none were in operation for a period approaching 50 years.

Finally, with respect to solar plants, no utility-scale solar plant has achieved a 35-year lifespan. In fact, the industry considers a 30-35 year lifespan to be a stretch goal.[18]

Q YOU MENTIONED ONE EXCEPTION TO EXTENDING THE LIFESPANS DERIVED IN FPL'S 2021 DEPRECIATION STUDY. WHAT IS THAT EXCEPTION?

A FPL's proposal to extend the lifespan of the St. Lucie is more realistic because FPL successfully extended the lifespan of its Turkey Point Nuclear Plant from 60 to 80 years. Exelon Generation Company LLC (Exelon) also received approval for a 20-year extension of the operating license at its Peach Bottom Atomic Power Station. So, unlike CCGTs and solar plants, there is actual experience in the nuclear industry to extend the operating license by an additional 20 years. The license extensions that have been approved will result in both Turkey Point Nuclear Plant and Peach Bottom Atomic Power Station having 80-year lifespans.

Q DOES THE ST. LUCIE NUCLEAR PLANT EXCEPTION WARRANT CONTINUING THE RSAM?

A No. First, FPL has stated that it will not file a request with the NRC for an extended operating license until August 2021.[19] Based on FPL's experience with Turkey Point and Exelon's experience with Peach Bottom Atomic Power Station, the NRC process required 20 months from filing to approval. Thus, the outcome for St. Lucie will not be

[18] For example: https://www.greentechmedia.com/articles/read/europes-solar-market-grapples-with-35-year-plant-lifespans; https://www.paradisesolarenergy.com/blog/solar-panel-degradation-and-the-lifespan-of-solar-panels

[19] Direct Testimony of Keith Ferguson at 15.

known until sometime during the first quarter of 2023. FPL's RSAM proposal, however, assumes that it will receive the benefit of the 20-year operating license extension in 2022.

Q IS CONTINUING THE RSAM IN THE PUBLIC INTEREST?

A No. I have supported the RSAM when a utility demonstrated a significant depreciation reserve surplus in a current depreciation study. Absent a surplus, continuing the RSAM would not be in the public interest. Further, FPL has misused the RSAM. Since the RSAM was approved in the 2010 Rate Order, FPL has *managed* its earnings to consistently achieve a ROE at the upper end of the authorized range. For example, during the period 2010-2013, FPL used the RSAM to achieve an ROE at or slightly below 11% ROE in the vast majority of the reporting periods. Beginning in 2014 and continuing through 2017 FPL's achieved ROE was 11.5% in the vast majority of the reporting periods. Thereafter, FPL's achieved ROE has been 11.6%.[20]

Thus, FPL's shareholder has been the primary beneficiary of the RSAM because the RSAM has allowed FPL to consistently achieve very high earned ROEs. Had FPL opted to use the RSAM to achieve earnings at only the minimum or mid-point ROE, less of the Reserve Amount would have been exhausted. Any remaining Reserve Amount could have been used to mitigate future revenue requirements.

Q IS THERE ANY PRECEDENT FOR A UTILITY ACHIEVING THE MAXIMUM AUTHORIZED RETURN ON EQUITY?

A No. Most utilities struggle to earn their authorized returns. The RSAM guarantees

[20] FPL Response to FIPUG ROG No. 22.

that FPL will always earn the maximum authorized ROE. Under these circumstances, the RSAM has fundamentally changed the regulatory paradigm.

Q PLEASE EXPLAIN.

A The regulatory paradigm provides an opportunity for a utility to earn a reasonable return on its investments in the facilities that are used and useful in providing electric service to customers. The RSAM has clearly replaced the opportunity to earn with guaranteed earnings.

Q WHAT DO YOU RECOMMEND?

A The RSAM should not be continued. The premise behind the RSAM no longer exists because FPL does not have a substantial depreciation reserve surplus. In fact, the opposite is true; FPL has a substantial depreciation reserve *deficit*.

Q SHOULD THE COMMISSION TAKE ANY ACTION IN THE EVENT THAT FPL SUCCESSFULLY OBTAINS A 20-YEAR EXTENSION OF THE OPERATING LICENSE AT THE ST. LUCIE PLANT?

A Yes. As previously stated, it is probable that FPL will successfully obtain a 20-year life extension for the St. Lucie plant. Because a 20-year life extension will significantly reduce annual depreciation expense, the Commission should order FPL to create a regulatory liability commencing in the month following NRC approval of the license extension. The St. Lucie regulatory liability would require FPL to retain the lower depreciation expense for the benefit of FPL's customers, rather than FPL's shareholder. The accumulated balance can be used to mitigate future base rate increases.

4. SOLAR BASE RATE ADJUSTMENTS

Q WHY SHOULD THE COMMISSION REJECT THE PROPOSED SOLAR BASE RATE ADJUSTMENTS?

A The proposed SoBRAs are a form of single-issue or "piecemeal" ratemaking. Piecemeal ratemaking occurs when rates are adjusted outside of a general rate case. Adjusting base rates outside of a rate case, however, assumes that the utility experiences no changes in either base revenues or associated costs that would affect its earnings potential. This is in stark contrast to traditional ratemaking in which a utility is allowed to increase revenues, but only in the amount necessary to provide an opportunity to earn the authorized return on investment. Because the SoBRAs are not *needs-based*, FPL could continue to earn excessive returns.

Q DOES THE COMMISSION CONDUCT THE SAME INVESTIGATION IN A SOBRA FILING THAT IT CONDUCTS IN A GENERAL RATE CASE?

A No. Unlike in a general rate case, the Commission does not conduct a detailed investigation of a utility's earnings in a SoBRA filing. Thus, there is no independent analysis and no determination whether a specific revenue increase is needed to provide an opportunity to FPL to earn its authorized rate of return.

Q HAS FPL PROVIDED ANY ANALYSIS DEMONSTRATING THE NEED FOR THE TWO PROPOSED SOLAR BASE RATE ADJUSTMENT INCREASES?

A No.[21]

---

[21] FPL Response to FIPUG Interrogatory No. 21; Deposition of Robert E. Barrett (June 11, 2021).

Q IF THE SOBRAS ARE NOT NEEDS-BASED, CAN THEY BE APPROVED AS PART OF A FOUR-YEAR RATE PLAN?

A No. It is my (non-legal) understanding that the Commission cannot approve a change in a utility's base rates, except in a general rate case or through a separate stand-alone limited proceeding under Rule 25-6.0431, Florida Administrative Code (F.A C.) The latter procedure is designed to streamline a rate increase when a major asset is placed in service immediately after the test year and the inability to timely adjust base rates would have a demonstrably large impact on a utility's earned rate of return. The proposed SoBRAs do not meet either qualification. Further, they are integral to, rather than separate from, FPL's proposed Four-Year Rate Plan, not stand-alone limited proceedings.

Q YOU PREVIOUSLY STATED THAT PIECEMEAL RATEMAKING ASSUMES NO CHANGE IN THE UTILITY'S OTHER REVENUES AND OTHER COSTS. IS IT POSSIBLE THAT FPL'S FUTURE REVENUES COULD BE HIGHER AND FUTURE COSTS COULD BE LOWER?

A Yes. FPL continues to experience unprecedented customer and load growth. Sales growth generates additional base rate revenues. These additional revenues can offset future increases in costs.

Q DO INCREASES IN COSTS NECESSARILY REQUIRE HIGHER BASE RATES?

A No. Maintaining the integrity of the ratemaking process also means ensuring that rates are adjusted only when necessary. Just because a utility's costs may be increasing is not a sufficient reason to raise rates. To understand why, think of a rate as consisting of two components: (1) the amount of costs to be recovered and (2) the applicable billing units (e.g., kW, kWh) or sales. If costs increase but sales also increase by the same degree, rates should remain the same. It is only when the change in costs differs from the corresponding change in sales that rates should also change. When costs increase faster than sales, rates will increase, and vice versa. Further, the amount of a required rate increase is not driven solely by the change in costs. It will also depend on the relative change between costs and sales.

For example, if costs increase by 10 percent and sales increase by 6 percent, rates should increase by only 4 percent. Thus, it is critical to analyze both the changes in costs as well as impact of load growth and the resulting increase in revenues.

Q DOES FPL NEED THE SOBRA INCREASES?

A No. The proposed solar projects are not necessary to meet a reliability need. FPL's sole justification for the proposed solar projects is that they are cost-effective; that is, they will result in lower rates. Accordingly, FPL has discretion about when to place these projects into service. Even if FPL places the solar projects in service as planned, there is no evidence that FPL's costs are increasing faster than its increase in revenues due to load growth.

Q WHY DO YOU SAY THE SOLAR PROJECTS ARE NOT NEEDED FOR RELIABILITY?

A FPL is projecting it will have sufficient reserves even without the 2024 solar plant additions. This is demonstrated in **Exhibit JP-1**.

Q DID YOU MAKE ANY ADJUSTMENTS TO FPL'S PROJECTED RESERVE MARGINS?

A Yes. FPL has assumed that solar projects provide approximately 50% of their nameplate capacity during the summer peaks and zero capacity during the winter peaks. These assumptions are not supported by the facts. This is shown in **Exhibit JP-1**, page 2, which measures the power output of FPL's solar projects coincident with the monthly peaks since 2017. As can be seen, FPL's solar projects have contributed to both the summer and winter peaks. On average, the solar projects produced power at 57% of their nameplate capacity during FPL's monthly peaks since 2017. Therefore, I restated the installed capacity to reflect solar power output at 57% of nameplate in quantifying both the summer and winter peak reserve margins.

Q WILL DEFERRING THE IN-SERVICE DATES OF FPL'S SOLAR PROJECTS IMPACT RELIABILITY FOR PENINSULAR FLORIDA?

A No. The FRCC is projecting that summer reserve margins will be well-above the 20% reference level. The absence of 1,788 MW of solar capacity will not cause Peninsular Florida to fall below a 20% summer reserve margin. This is shown in **Exhibit JP-2**.

Q DO THE SOBRAS RAISE ANY OTHER CONCERNS?

A Yes. FPL has asserted that the solar projects are cost-effective. However, other than placing a cap on the construction cost, FPL has not provided any guarantee that customers will fully realize the benefits claimed by FPL. Because the solar projects are not designed to meet a capacity need, the Commission should require FPL to stand behind its promises by imposing performance standards and other requirements, such as a forensic analysis of the actual savings from the solar projects to ensure that the promised benefits have actually materialized. FPL is required to meet certain minimal performance standards for its thermal generating resources. Because the benefits of solar projects include lower energy costs, at a minimum, FPL should be subject to annual operating guarantees to ensure that energy savings benefits are indeed realized.

Q WHAT REQUIREMENTS SHOULD BE PLACED ON FPL TO DEMONSTRATE THAT ITS SOLAR PROJECTS HAVE PROVIDED THE PROMISED BENEFITS?

A FPL's solar projects should be required to provide energy at the capacity factor assumed by FPL in determining cost-effectiveness. Further, FPL should periodically provide forensic studies that quantify the direct costs and benefits provided by FPL's solar investments. The Commission should disallow cost recovery if FPL fails to meet either the performance guarantees or if the projected benefits have not been achieved.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject the two proposed SoBRA base revenue increases. Further, going forward with solar generating units, the Commission should require FPL to provide minimum performance guarantees and to provide a forensic analysis demonstrating that its solar investments have provided the promised benefits to customers.

5. CLASS COST-OF-SERVICE STUDY

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

A A CCOSS is an analysis used to determine each 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. Most of a utility's costs are incurred to jointly serve many customers. 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 two CCOSSs. FPL's "Base" study was provided in MFR Schedule E-1. FPL also filed an "Alternate" CCOSS.[22]

Q WHAT IS THE DIFFERENCE BETWEEN THE BASE AND ALTERNATE CLASS COST-OF-SERVICE STUDIES?

A The Alternate CCOSS used different methods to allocate the costs of FPL's distribution network. The distribution network includes plant investment FERC Account Nos. 364-367 and related expenses. The Alternate study used the Minimum Distribution System (MDS) to classify distribution network costs between demand and customer-related costs. It also provided a different separation between primary and secondary voltage distribution plant.

[22] Direct Testimony of Tara B. DuBose, Exhibit TBD-3.

Q WHICH STUDY IS PREFERABLE?

A As explained later, FPL's Alternate (*i.e.,* MDS) study is far preferable to the Base study. However, both the Base and MDS CCOSSs are flawed.

Q WHAT ARE THE FLAWS WITH FPL'S BASE AND MDS COST STUDIES?

A The flaws are:

- First, consistent with the Matching Principle FPL properly adjusted the base revenues of the non-firm classes (*i.e.,* CILC and GSD/GSLD) to "impute" the incentive payments paid to CILC/CDR customers. In doing so, FPL understated the adjustment because it used the incentive payments collected in the ECCR clause rather than repricing test-year non-firm base revenues at the firm rates. From a cost allocation perspective, the imputed incentive payments are a test-year proxy for the incentive payments that are ultimately recovered in the ECCR. By mixing the ECCR and test-year ratemaking, FPL's CCOSS is internally inconsistent.

- Second, FPL failed to allocate the imputed incentives as an additional cost recoverable from customer classes, and as a result, the earned rates of return derived in the CCOSS at present rates are overstated. FPL's earnings are the same with or without the incentive payments.

- Third, production and 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 strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.

Q HOW SHOULD THESE FLAWS BE CORRECTED?

A First, the incentive payments imputed to the non-firm classes should be quantified using *test-year* assumptions, and they should be allocated to customer classes as recoverable costs in determining the required base rate revenues. The test-year imputed incentive payments are $80.9 million. They should be directly assigned to the CILC and GSD/GSLD classes as shown in Table 2 below.

Table 2 Test-Year Incentive Payments ($000)	
Customer Class	**Amount**
CILC-1D	$34,410
CILC-1G	$1,150
CILC-1T	$14,410
GSD	$13,135
GSLD-1	$13,089
GSLD-2	$4,691
Total	$80,865
Source: **Exhibits JP-3** and **JP-4**	

The $80.9 million should be allocated to all customer classes as a production demand-related cost.

Second, 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) demands.

Correcting FPL's MDS study for these flaws would show that the CILC and most of the GSLD customer classes are currently providing rates of return that are much closer to, if not significantly above, parity. Thus, the CILC and GSLD classes should not receive drastically above-average base rate increases as FPL is proposing.

Q DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A Yes. FPL uses a proprietary model to generate its CCOSS. Thus, Intervenors cannot access the model either to conduct a full audit or to run alternative scenarios. FPL is one of the few utilities in the country that does not provide a working version of its CCOSS model in its general rate cases. Accordingly, the Commission should order FPL to provide a working version of its CCOSS in future rate cases.

Imputed Incentive Payments

Q DO FPL'S CLASS COST-OF-SERVICE STUDIES INCLUDE CUSTOMER CLASSES THAT RECEIVE BOTH FIRM AND NON-FIRM SERVICE?

A Yes. The customer classes defined in FPL's CCOSSs include customers who receive both firm and non-firm service. The CILC classes (*i.e.,* CILC-1D, CILC-1G, and CILC-1T) receive primarily non-firm service. Some of the customers in the GSD, GSLD-1, and GSLD-2 classes take non-firm service under the CDR Rider.

Q HOW ARE COSTS ALLOCATED TO THE NON-FIRM CLASSES?

A FPL allocates costs to the non-firm classes using the same methodologies and load data that is used to allocate costs to the firm classes. The entire CILC and GSD/GSLD class loads are included in the demand and energy allocation factors used to allocate production demand and energy-related costs. Thus, despite receiving non-firm service, the CILC and GSD/GSLD classes are not treated any differently from a cost allocation perspective as the firm customer classes.

Q DOES FPL MAKE ANY ADJUSTMENTS TO RECOGNIZE THE NON-FIRM NATURE OF THE SERVICE PROVIDED TO THE CILC AND GSD/GSLD CLASSES?

A Yes. FPL adjusted the test-year base revenues by imputing the incentive payments currently paid to the non-firm customers under the CILC and CDR programs. The imputed incentive payments reflect the additional base revenues that the non-firm classes would have paid if they were receiving firm service during the test year.

Q WHY IS IT APPROPRIATE TO ADJUST THE NON-FIRM CLASS BASE REVENUES BY THE IMPUTED INCENTIVE PAYMENTS?

A FPL's CCOSS assumes that both the firm and non-firm customer classes are receiving firm service. Consistent with the "Matching Principle" and to ensure that the CCOSS results are accurate, it is appropriate to impute the incentive payments paid to the non-firm classes so that the base revenues reflect the level these classes would provide if they were taking firm service. The Matching Principle means applying consistent assumptions in determining both revenues and costs. By imputing the incentive payments, both the revenues and allocated costs are based on consistent assumptions.

Q HOW SHOULD THE IMPUTED INCENTIVES BE DETERMINED?

A The imputed incentives should reflect the additional base revenues that the non-firm classes would have paid during the test year if they had received firm service under the otherwise applicable firm rate schedules. For example, if CILC-1T customers were receiving firm service, they would be priced under the GSLD-3 rate schedule. Similarly, if CILC-1D (CILC-1G) customers were receiving firm service, they would be priced under the GSLD-1 and GSLD-2 (GSD) rate schedules.

The imputed incentives would be quantified differently for the CDR Rider customers because they are already taking service on a firm rate schedule. Specifically, the imputed incentives would be the product of the CDR Monthly Incentive and the test-year interruptible billing demand.

Q DO YOU AGREE WITH THE APPROACH USED BY FPL TO DETERMINE THE COST TO SERVE THE NON-FIRM CLASSES?

A No. There are two significant problems with the way the non-firm classes (*i.e.,* CILC, GSD/GSLD) were treated in FPL's CCOSSs.

First, the imputed incentives reflect the incentive payments collected in the ECCR. This approach is internally inconsistent because the incentive payments collected in the ECCR are not based on adjusted test-year sales. The imputed revenues should be quantified using test-year assumptions.

Second, imputing the incentive payments should be earnings neutral. This is because FPL collects the same amount of base revenues irrespective of how the incentives are accounted for in a CCOSS. That is, from a cost-allocation perspective, the test-year imputed incentive payments represent additional costs to serve FPL's firm customers. Because the imputed incentive payments are production demand-related costs, they should have been allocated to customer classes in a similar manner as all other production demand-related costs. FPL, however, skipped this very important and essential second step. As a result, FPL overstated the earned rates of return at present rates.

Q DOES FPL USE A SIMILAR PROCEDURE TO ALLOCATE THE CURTAILABLE CREDITS IN ITS COST STUDIES?

A Yes. The cost of providing incentives to curtailable customers is recovered in base rates rather than through the ECCR as applies to the CDR/CILC incentives.

Q DOES IT MATTER THAT THE CDR/CILC INCENTIVES ARE RECOVERED IN THE ECCR AND NOT IN BASE RATES?

A No. The CCOSS measures how FPL's base rate costs should be allocated to each customer class. This process is independent of how the costs eligible for recovery in separate cost recovery mechanisms, such as the ECCR, are quantified and recovered.

Further, imputing test-year incentive payments preserves the Matching Principle, thereby ensuring the integrity of the CCOSS results. The fact that imputed revenues may reflect the incentives FPL recovers in the ECCR is irrelevant.

Q TURNING TO YOUR FIRST CONCERN, HOW SHOULD THE IMPUTED INCENTIVE PAYMENTS HAVE BEEN QUANTIFIED?

A FPL's CCOSS measures the cost to provide firm service for all customer classes. This includes the CILC customers whose service, in reality, is mostly non-firm. To be internally consistent and recognizing the fact that the CILC base revenues reflect the lower cost to provide non-firm service, the CILC and GSD/GSLD class revenues must be restated at the level these customers would have paid *during the test year* if they were taking service under one of the otherwise applicable firm rates (*e.g.*, GSD or GSLD). Thus, the first step should be to correct the amount of the imputed incentive payments to the non-firm classes by using test-year billing determinants.

Q HOW MUCH ADDITIONAL BASE REVENUES SHOULD BE IMPUTED TO THE NON-FIRM CUSTOMER CLASSES?

A **Exhibit JP-3** shows the derivation of the test-year imputed incentive payments. Specifically, I repriced the CILC revenues by applying the otherwise applicable firm rate schedule to the test-year CILC billing determinants.

For example, **Exhibit JP-3,** page 1 shows the derivation of the test-year incentive payments imputed to the CILC-1T class. The applicable firm service rate would be either GSLD-3 or GSLDT-3. Repricing CILC-1T at these rates would result in an imputed base revenue adjustment of approximately $14.41 million.

Exhibit JP-3, pages 2 and 3 provides a similar analysis for the CILC-1D class. As can be seen on page 3, approximately $34.41 million should be imputed to this class using test-year assumptions. The $34.41 million was derived by repricing CILC-1D on the GSLD-1 and GSLD-2 standard and Time-of-Use rates.

Exhibit JP-3, page 4 shows imputed base revenues of $1.15 million for the CILC-1G class. The $1.15 million adjustment was based on repricing the test-year CILC-1G billing determinants on GSD-1 and GSDT-1 rates.

Exhibit JP-4 quantifies the test-year imputed incentives for the GSD, GSLD-1, and GSLD-2 classes. The imputed incentives are the product of the current CDR Monthly Incentive ($8.70 per kW) and the test-year utility controlled demand. The resulting total CDR payments of $31 million should imputed to the GSD, GSLD-1, and GSLD-2 classes in the CCOSS. I would note that this amount is higher than the $29.3 million of CDR incentive payments that FPL imputed in its CCOSSs. The difference reflects test-year adjustments.

Q HOW SHOULD THE IMPUTED CILC/CDR INCENTIVES BE ALLOCATED?

A First, the test-year imputed CILC/CDR incentives quantified in **Exhibit JP-3** and **Exhibit JP-4** should be directly assigned to the CILC and GSD/GSLD class base revenues. Second, because the imputed incentives are the test-year proxy for the incentive payments, they should be allocated to customer classes using the production demand allocation factors. Further, as demonstrated below, the allocation should be based on the amount of firm load served by customer class.

Q CAN YOU ILLUSTRATE WHY THE IMPUTED INCENTIVES SHOULD BE ALLOCATED BASED ON THE AMOUNT OF FIRM LOAD SERVED BY CUSTOMER CLASS?

A Yes. **Exhibit JP-5** shows two different methods of allocating production plant and related costs to non-firm customers.

Method 1 excludes non-firm load from the CCOSS. The premise behind *Method 1* is that the utility does not install any production capacity to serve non-firm load. This is a reasonable premise because FPL removes non-firm load (including CILC and CDR) to quantify its summer and winter peak reserve margins. The reserve margins are the primary metric used to assess resource adequacy.

Method 2 reflects the basic approach that FPL used in its CCOSS (*i.e.,* to treat non-firm load as firm) except that the imputed incentive payments are allocated to the firm classes. As can be seen, the two treatments are mathematically equivalent, but only if the imputed incentive payments are allocated to firm loads, which FPL failed to do.

The illustration shows the allocation of $10,000 in production capacity costs to two equal size classes: A and B. Class A is comprised of only firm load, while Class B's load is 50% firm and 50% non-firm. The non-firm load provides $1,500 in revenue. *Method 1* allocates zero production capacity costs to interruptible customers (column 4, line 8). The non-firm revenues are used to lower the cost to provide firm service (columns 2 and 3, line 9). This results in allocating the $10,000 as follows: Class A

$5,667; Class B $4,333 ($2,833 plus $1,500), of which the firm load would be charged $2,833.

Method 2 treats non-firm load as firm. Thus, it imputes additional revenues to Class B, and these imputed revenues are allocated to both classes based on the amount of firm load. The imputed revenues are the difference between the revenues that the non-firm customers would have paid under the firm rates (or $2,500) and the actual non-firm revenues (or $1,500). Thus, in the illustration, the imputed revenues are $1,000. As can be seen on line 13, the $10,000 of production capacity costs is allocated as follows: Class A $5,667; Class B $4,333 ($2,833 + $1,500), of which firm Class B customers are allocated $2,833. However, this is the same allocation as if no production capacity costs were allocated to non-firm load in the first place (*i.e., Method 1*).

Q WHAT DO YOU CONCLUDE FROM THE EXAMPLE SHOWN IN EXHIBIT JP-5?

A First, the example demonstrates the application of the Matching Principle to correctly quantify and impute additional base revenues that reflect the differences in revenues under the non-firm and firm rate schedules during the test year. FPL's revenue adjustments were based on amounts recovered in the ECCR, which are clearly different than the test-year incentive payments.

Second, the example demonstrated that the imputed incentive payments must be reallocated to customer classes based on each class's firm load. This second step, which is missing from FPL's Base and Alternate CCOSSs, recognizes that the incentives paid to non-firm customers benefit firm customers.

Q HAVE YOU APPLIED THE APPROACH DEMONSTRATED IN EXHIBIT JP-5 TO FPL'S CLASS COST-OF-SERVICE STUDIES?

A Yes. **Exhibit JP-6** shows how test-year imputed incentive payments derived in **Exhibit JP-3** and **Exhibit JP-4** were directly assigned to the CILC and GSD/GSLD class base revenues (line 6). As can be seen, the test-year imputed incentive payments are $80.9 million. This compares to $74.5 million in FPL's CCOSSs.[23]

I then derived a firm production demand allocator by removing from FPL's 12CP allocation factors (line 7) the estimated non-firm load in the CILC and GSD/CILC classes (line 8). The test-year imputed incentive payments imputed to the CILC and GSD/GSLD classes were then reallocated to customer classes (line 11) based on each class's percentage of firm load (line 10).

Q HAVE YOU REVISED FPL'S MDS CLASS COST-OF-SERVICE STUDY WITH THE CORRECTIONS MADE TO THE QUANTIFICATION AND ALLOCATION OF THE TEST-YEAR INCENTIVE PAYMENTS?

A Yes. **Exhibit JP-7** is a corrected version of FPL's MDS CCOSS. In this study, the CILC, GSD, GSLD-1, and GSLD-2 class revenues were adjusted consistent with the methodology shown in **Exhibit JP-6** to recognize what the these customers would have been charged if they had been taking service on the otherwise applicable firm rate during the test year.

[23] MFR Schedule E-5, Test Consolidated With RSAM, line 6.

Q WHAT DO THE RESULTS OF YOUR CORRECTED MDS CLASS COST-OF-SERVICE STUDY DEMONSTRATE?

A Correcting quantification and allocation of the imputed incentive payments moves the CILC classes to either above or just below parity as shown on **Exhibit JP-7**, page 1, line 24. These are significant changes from FPL's Base study.

Allocation of Production and Transmission Costs

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

A FPL is proposing to use the 12CP and 1/13th average demand to allocate production plant and related costs. Effectively, this method allocates 92.3% (12/13ths) using the 12CP method and 7.7% (1/13th) on average demand. Average demand is equivalent to year-round energy usage. FPL uses 12CP to allocate transmission plant.

Q DO YOU HAVE ANY CONCERNS ABOUT THE 12CP METHOD?

A Yes. 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. Thus, giving substantial weighting to the non-summer months in allocating production and transmission costs ignores the reality that FPL is a strongly summer-peaking utility. This is demonstrated in **Exhibit JP-8**. As can be seen, there are substantial differences in FPL's monthly system peak demands. The demands during the summer months are consistently much closer to the annual system peak than the peak demands in the non-summer months. Based on FPL's projections, the summer peak demands are expected to be more than 20% higher than the expected winter peak demands.

Q IS SYSTEM RELIABILITY A MORE SIGNIFICANT CONCERN DURING THE SUMMER MONTHS?

A Yes. **Exhibit JP-1** showed that FPL's reserve margins are projected to be significantly lower during the summer months than in the winter months. This means that system reliability is being driven primarily by the projected summer peak demands. Further, transmission lines have less load carrying capability during the summer months. Accordingly, both production and transmission plant and related costs should be allocated to customer classes using a method that reflects summer period demands.

Q WHAT ALLOCATION METHOD WOULD RECOGNIZE THESE REALITIES?

A The 4CP method better reflects the realities that FPL is a strongly summer-peaking utility and that summer period demands are more critical to maintaining the reliability of the bulk power system.

Q HAVE YOU QUANTIFIED THE IMPACT OF USING 4CP RATHER THAN 12CP TO ALLOCATE PRODUCTION AND TRANSMISSION DEMAND-RELATED COSTS?

A Yes. **Exhibit JP-9** estimates the impact of using 4CP (instead of 12CP) on each class's revenue requirement. The 12CP and 4CP demand allocation factors are shown in columns 1 and 2, respectively. The impact was derived by comparing the allocated production and transmission demand-related costs in FPL's CCOSS (columns 3 and 4) to the corresponding allocations had 4CP been used instead of 12CP (columns 5 and 6). As can be seen in column 7, using the 4CP method would reduce the GSLD and CILC class revenue requirements by $32.7 million and $10.7 million, respectively.

Q WHAT DO YOU RECOMMEND?

A The Commission should require FPL to adopt the 4CP method to allocate production and transmission plant and related costs. FPL should also re-run its MDS CCOSS to allocate production and transmission demand-related costs using the 4CP method.

Minimum Distribution System

Q EARLIER YOU STATED A PREFERENCE FOR FPL'S MDS COST STUDY. WHY SHOULD FPL'S MDS COST STUDY BE USED FOR SETTING RATES IN THIS PROCEEDING?

A The MDS classifies a portion of the distribution network as a customer-related cost. This is in stark contrast to FPL's Base CCOSS, in which all distribution network costs are considered demand-related. 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 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 FERC Account Nos. 364, 365, 366, 367 and 368.

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:

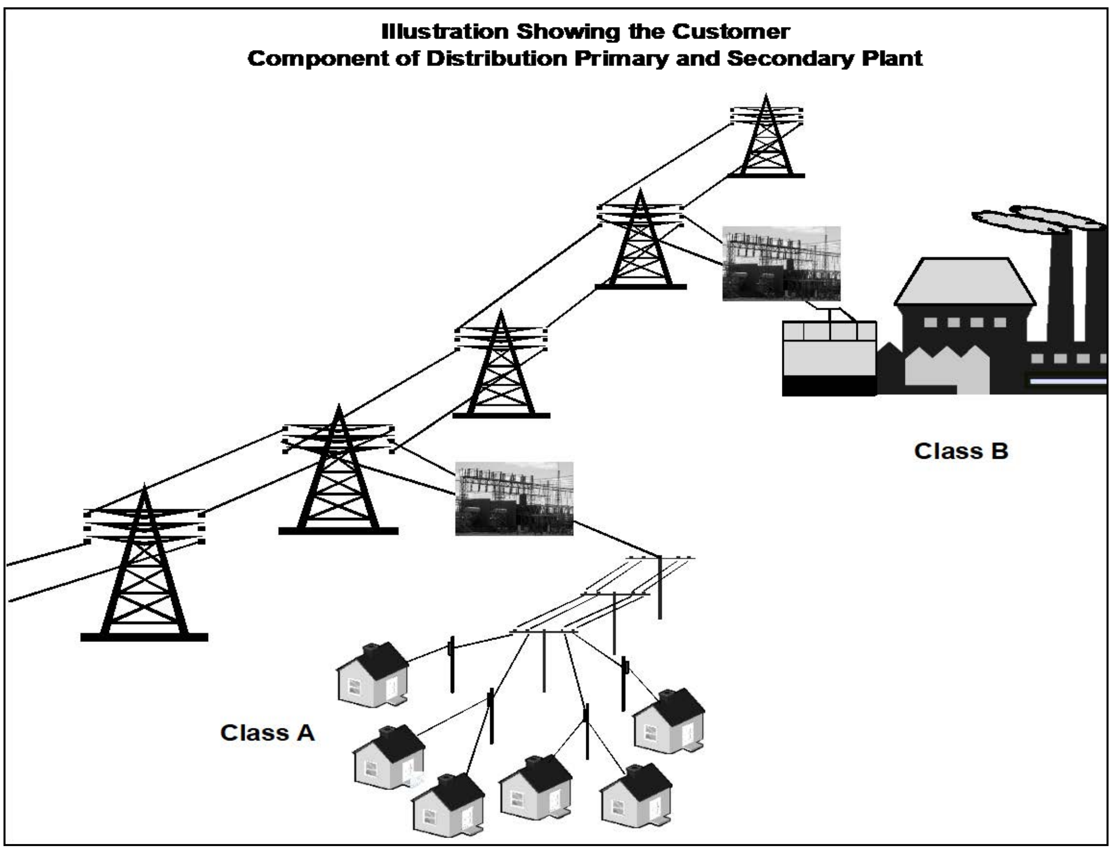
- Provide access to a safe, delivery-ready power grid (*i.e*., a customer-related cost); and
- Meet customers' peak electrical power needs (*i.e*., a demand-related cost).

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 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 the 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 it provides, electricity cannot flow to customers. Thus, this 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.

If FPL were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of distribution lines because they are required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced. Consider the diagram below, which shows the distribution network for a utility with two customer classes, A and B.



The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

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.[24]

Q WHAT DO YOU RECOMMEND?

A The Commission should approve the use of the MDS in setting base rates in this proceeding. Gulf Power and TECO use the MDS approach in setting base rates and the MDS methodology more fairly allocates costs between user groups. The MDS approach recognizes that there are additional customer-related costs to provide distribution service (other than the meter and service drop), and it allocates these costs based on the number of customers. MDS is consistent with cost causation, is an

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

accepted industry practice, and the Commission previously approved its use for Gulf Power and TECO.

<u>Primary/Secondary Voltage Separation</u>

Q WHY DOES A CLASS COST-OF-SERVICE STUDY DISTINGUISH BETWEEN THE SERVICE PROVIDED AT PRIMARY AND SECONDARY VOLTAGE?

A The vast majority of FPL's electricity sales are delivered at secondary voltage. The cost to provide secondary service is more expensive than the cost to provide primary or transmission service for two reasons. First, FPL has to invest in additional distribution facilities to transform voltage from transmission to primary and then from primary to secondary distribution. Thus, in contrast to primary service, secondary distribution service requires additional transformation. Second, more energy is lost when delivering energy at lower voltages (*i.e.*, secondary) than at higher voltages (*i.e.*, primary).

For these reasons, it is essential to accurately quantify the respective costs to provide primary and secondary distribution service. That process requires identifying the investments that are used to provide distribution service, both at primary and secondary voltages.

Q HOW MUCH DISTRIBUTION NETWORK INVESTMENT DID FPL ASSIGN TO PRIMARY AND SECONDARY DELIVERY?

A Table 3 summarizes how FPL separated network distribution between primary and secondary distribution in its Base CCOSS.

Table 3
Functionalization of Distribution Plant
FERC Account Nos. 364 - 367[25]
Base Study

Description	Account No.	Primary	Secondary
Poles, Towers, Fixtures	364	97.3%	2.6%
Overhead Conductors	365	81.6%	18.2%
Underground Conduit	366	91.8%	8.2%
Underground Conductors	367	87.3%	12.7%

The primary/secondary split was based on an analysis of retiring distribution plant.[26]

Q DO YOU HAVE ANY CONCERNS WITH HOW FPL SEPARATED PRIMARY AND SECONDARY DISTRIBUTION INVESTMENT?

A Yes. As shown in Table 3, 97% of FPL's investment in poles, towers and fixtures would be assigned to primary service and only 2.6% would be assigned to secondary service. However, only 82% of the overhead conductors (which are supported by the poles, towers and fixtures) were assigned to primary delivery and 18% were assigned to secondary delivery. Similarly, FPL assigned 91.8% of the underground conduit to primary even though a lesser share of the underground conductors (which are supported by the underground conduit) were assigned to primary. Thus, it appears that there are internal inconsistencies in how FPL separated the primary and secondary investments in these FERC Accounts.

---

[25] MFR Schedule E-10 (Test Year, Consolidated, With RSAM), Attachment 4.

[26] FPL Response to FIPUG Interrogatory No. 40.

Q DID YOU OBSERVE THE SAME PROBLEMS IN FPL'S MDS CLASS COST-OF-SERVICE STUDY?

A No. Table 4 summarizes the percentage of distribution plant assigned to Primary and Secondary in FPL's MDS CCOSS. The percentages of plant in FERC Account Nos. 364-367 assigned to primary are more consistent than in FPL's Base CCOSS. Thus, this study provides a more consistent treatment between the conductors (*i.e.,* overhead lines and underground conductors) and their corresponding support structures (*i.e.,* poles, towers, fixtures, and underground conduit) than in FPL's "Base" study.

Table 4
Functionalization of Distribution Plant
FERC Account Nos. 364 - 367[27]
MDS Study

Description	**Account No.**	**Primary**	**Secondary**
Poles, Towers, Fixtures	364	72.5%	27.5%
Overhead Conductors	365	84.9%	15.1%
Underground Conduit	366	87.7%	12.3%
Underground Conductors	367	88.0%	12.0%

Q WHAT DO YOU RECOMMEND?

A The Commission should approve the MDS for allocating distribution plant. However, should the Commission reject MDS, it should nevertheless adopt the primary/secondary separation in FPL's MDS CCOSS.

[27] Direct Testimony of Tara B. DuBose, Exhibit TBD-7.

6. 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 ARE THERE ANY EXTENUATING CIRCUMSTANCES THAT WARRANT PARTICULAR ATTENTION TO GRADUALISM IN THIS PROCEEDING?

A Yes. The economy is recovering from the COVID-19 pandemic. In this post-pandemic environment, the Commission should avoid imposing very large electric base rate increases at this time.

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 its cost to serve, 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 changes in revenues due to changes in sales will translate into offsetting changes in costs); and they encourage conservation (because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions).

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

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal.

Q DOES FPL'S PROPOSED CLASS REVENUE ALLOCATION FOLLOW THESE PRINCIPLES?

A No, not entirely. FPL's proposed class revenue allocation would move all rates much closer or immediately to cost based on the results of its Base CCOSS. As previously discussed, FPL's Base CCOSS is seriously flawed and, at a minimum, should incorporate the MDS and my recommended changes in the amount and allocation of the incentive payments. However, for FPL's largest customers who are in the GSLD and CILC rate schedules, FPL's proposed class revenue allocation would result in rate shock. This is shown in Table 5.

Q PLEASE EXPLAIN TABLE 5.

A Table 5 shows FPL's proposed base rate increases for the major customer classes in 2022 and the cumulative base rate increase through 2023. These increases are also expressed as a percentage of the retail average base rate increase (*i.e.,* the relative increase).

Table 5
FPL's Proposed Base Rate Increases
With RSAM[28]

Customer Class	2022 Increase		Cumulative 2023 Increases	
	Percent	Relative Increase	Percent	Relative Increase
Residential	10.6%	69%	17.4%	75%
GS/GSCU	14.1%	92%	21.8%	94%
GSD	24.4%	160%	34.0%	146%
GSLD	28.0%	184%	42.4%	183%
CILC	46.4%	305%	59.4%	256%
MET	19.3%	127%	27.5%	118%
Lighting (SL, OS)	8.5%	56%	10.9%	47%
Standby (SST)	4.4%	29%	6.2%	27%
Total Retail	15.2%	100%	23.2%	100%

For example, if the class's increase is equal to the retail average base rate increase, the relative increase would be 100%. A class that is receiving an above-system average increase would have a relative increase above 100, and vice versa for a class that receives a below-system average increase.

[28] MFR Schedule E-8 2022 and 2023.

As Table 5 demonstrates, the proposed 2022 base rate increases for the GSLD and CILC classes would be 184% and 305%, respectively, of the retail system average increase. The cumulative 2023 base rate increases would be 183% and 256%, respectively, of the retail system average increase.

By any definition, relative base rate increases of the magnitude FPL is proposing for the GSLD and CILC classes would be rate shock.

Q WOULD FORMER LARGE GULF POWER CUSTOMERS EXPERIENCE SIMILAR BASE RATE INCREASES AS CURRENT FPL CUSTOMERS?

A No. Former Gulf Power customers eligible for FPL's GSLD rate schedules would experience even higher base rate increases than similarly situated FPL customers. This is demonstrated in Table 6.

Table 6
Base Rate Increases With RSAM For Customers Transferring to FPL's GSLD Rate Schedules

Rate Schedule	Existing Utility	2022 Increase	Cumulative 2023 Increases
GSLD-1	**FPL**	24.1%	38.1%
	Gulf	162.4%	45.7%
GSLD-2	**FPL**	19.6%	33.6%
	Gulf	79.6%	67.2%
GSLD-3	**FPL**	21.6%	37.9%
	Gulf	37.5%	51.5%
FPL Customers		22.9%	37.0%
Gulf Power Customers		82.6%	50.9%

The proposed Transition Rider would mitigate but not eliminate the disparate base rate increases shown in Table 6.

Q HOW DO YOU RECONCILE THE IMPACTS SHOWN IN TABLES 4 AND 5 WITH FPL'S CLAIMS THAT IT IS FOLLOWING GRADUALISM PRINCIPLES?

A FPL's definition of gradualism is flawed because it is based on expressing the proposed *base* revenue increases as a percentage of the *total* revenues from each class. This is not an apples-to-apples comparison. Total revenues include base revenues as well as the revenues collected under FPL's five separate cost recovery mechanisms:

- Fuel and Purchased Power.
- Energy Conservation.
- Capacity.
- Environmental.
- Storm Protection.

However, the costs recovered in these cost recovery mechanisms are not directly impacted in a base rate case. Thus, FPL's definition of gradualism is inapt in this proceeding when only the base rates are at issue.

Q WHICH APPROACH (TOTAL REVENUE OR BASE REVENUE) BETTER MEASURES THE IMPACT ON CUSTOMER CLASSES?

A FPL is seeking four separate and distinct ***base*** rate increases in this application. Measuring the impact of those proposed increases on ***base*** revenues is the only proper way to measure the impact and to assess whether FPL's proposed class revenue allocation results in rate shock. Gradualism is not considered in any of the other cost-recovery mechanisms. Therefore, a general rate case is the only venue in which gradualism can be properly applied. Because a general rate case only addresses changes in base revenue, gradualism should be measured relative to base rate impacts.

Q HAVE YOU DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION BASED ON YOUR REVISED CLASS COST-OF-SERVICE STUDIES?

A Yes. **Exhibit JP-10** uses FPL's MDS study with the corrections to the level and allocation of the incentive payments. My recommendation would result in moving the major rate classes to cost. **Exhibit JP-11** uses FPL's MDS study, the 4CP method to allocate production and transmission demand-related costs, and the corrections to the level and allocation of the incentive payments. In both cases, no class would receive a decrease or an increase more than 1.5 times the system average base rate increase.

7. CILC/CDR MONTHLY INCENTIVE

Q WHAT IS THE CILC PROGRAM?

A CILC program is a non-firm tariff option in which customers agree to curtail load at FPL's direction. The curtailment conditions in the CILC tariff are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions 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. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.[29]

Further, under the Commission's Rules:

> (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.[30]

Thus, a CILC customer 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 CILC loads in assessing resource adequacy. Thus, CILC is a lower quality of service than firm power because it can be interrupted as described above. In exchange for an agreement to curtail load at FPL's control, CILC customers pay a lower base rate than firm customers.

---

[29] FPL Tariff, Commercial/Industrial Load Control Program, Fourth Revised Sheet No. 8.652 (Nov. 15, 2002).

[30] Rule 25-6.035 F.A.C.

Q HOW ARE CILC CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE FPL?

A The Load-Control On-Peak demand charge is a reduced rate that reflects the current value of non-firm capacity. The other applicable demand charges (*i.e.,* Firm On-Peak and Maximum Demand) recover the allocated transmission and distribution demand-related costs and are, thus, similar in concept to FPL's other firm rates.

Q WHAT IS THE CDR PROGRAM?

A Rider CDR is an optional rate available as follows:

> Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.[31]

As with CILC, non-firm load can be curtailed by FPL at any time (with some limitations) under a wide range of circumstances. The tariff states:

> <u>Control Condition:</u>
>
> The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions 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. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load

[31] FPL Tariff, Commercial/Industrial Demand Reduction Rider, Twenty-Second Revised Sheet No. 8.680 (Jan. 1, 2021).

Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.

Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.

Duration: The duration of a single Load Control Period will typically be three (3) hours and will not exceed six (6) hours. In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[32]

Q YOU PREVIOUSLY DESCRIBED HOW FPL PROVIDES NON-FIRM SERVICE UNDER RATES CILC AND RIDER CDR. APPROXIMATELY HOW MUCH NON-FIRM LOAD IS SERVED UNDER THESE TARIFF OPTIONS?

A The service provided under the CILC and Rider CDR tariff options account for about 814 MW.[33]

Q ARE THE CILC/CDR SERVICE OPTIONS THE ONLY NON-FIRM RATE OPTIONS OFFERED BY FPL?

A No. FPL provides approximately 1,800 MW of non-firm load. Thus, there are other load management programs besides CILC and CDR.

---

[32] *Id.,* Second Revised Sheet No. 8.681 (Mar. 30, 2004).

[33] Direct Testimony of Dr. Steven R. Sim at 17.

Q FPL IS PROPOSING TO REDUCE THE INCENTIVE PAYMENTS TO CILC AND CDR BY 33%. IS FPL PROPOSING TO REDUCE INCENTIVES PAID UNDER OTHER NON-FIRM LOAD OPTIONS IN THIS PROCEEDING?

A No, not to my knowledge.

Q HOW WOULD A 33% REDUCTION IN INCENTIVES PAID TO CILC AND CDR CUSTOMERS IMPACT BASE RATES CHARGED TO THESE CUSTOMERS?

A A 33% reduction in the incentive payments under the CILC program accounts for about $15.1 million of FPL's proposed base revenue increase to the CILC classes. This one change alone reflects about 30% of FPL's proposed 2022 base revenue increase to the CILC classes. Reducing the Rider CDR credits from $8.70 per kW to $5.80 per kW would account for about $9.2 million or approximately 1.8% of the base revenue increases allocated to the GSD and GSLD classes.[34]

These are in addition to the increases resulting from FPL's flawed CCOSSs, which were discussed previously.

Q WHAT IS THE BASIS FOR FPL'S PROPOSAL TO REDUCE THE INCENTIVES PAID TO CILC AND CDR CUSTOMERS?

A FPL witness, Dr. Steven R. Sim, stated that the 33% reduction was based, in part, on the analysis provided in his direct testimony; specifically, Exhibit SRS-2 which supplemented Dr. Sim's testimony in the 2019 Demand Side Management (DSM) Goals docket (Docket No. 20190015-EG). However, had FPL relied solely on Dr. Sim's new cost-effectiveness analysis, the reduction would have been approximately

[34] FPL MFR E05 Test Consolidated with RSAM.

3% rather than 33%. Thus, the decision to reduce the incentives by 33% was based in large part on judgment, something acknowledged by Dr. Sim during his deposition.[35]

Q HAVE YOU ANALYZED EXHIBIT SRS-2?

A Yes. Exhibit SRS-2 presents the results of a cost-benefit analysis using the AURORA production cost simulation model. The model projected system production costs over the period 2020 through 2068.[36]

System production costs include both fixed and variable costs. Fixed costs include the capital costs of future capacity additions and any incremental fixed operation and maintenance expenses. Variable costs include system-wide fuel costs and variable operation and maintenance expense. Thus, the cumulative present value revenue requirement (CPVRR) net benefit analysis FPL performed includes both fixed and variable costs.

Q HOW WAS THE AURORA MODEL USED TO DETERMINE THE NET BENEFITS OF THE CDR AND CILC PROGRAMS?

A FPL calculated the CPVRR net benefits using two AURORA model runs:

1. Assuming the continuation of the CDR and CILC programs (that provide approximately 814 MW of capacity); and
2. Without the CDR and CILC programs.

The difference between the CPVRR net benefits with and without the CDR and CILC programs is supposed to measure the long-term benefit of these programs to FPL's customers.

[35] Deposition of Steven R. Sim (Jun. 9, 2021).

[36] Direct Testimony of Dr. Steven R. Sim at 46.

Q BASED ON THIS ANALYSIS, WHAT INCENTIVE PAYMENT WOULD BE CONSIDERED COST-EFFECTIVE FOR FPL CUSTOMERS?

A The net benefits derived in Exhibit SRS-2 would support a monthly incentive payment of $8.45 per kW.[37] This is only a 3% reduction from the current incentive.

Q WHY THEN IS FPL PROPOSING TO REDUCE THE INCENTIVE PAYMENT TO $5.80 PER KW?

A FPL has assumed that the monthly incentive payments would increase as future base rates are implemented. Further, Dr. Sim asserted that capital costs would continue to decline in the future, thereby purportedly eroding the cost-effectiveness of the CDR and CILC programs.

Q ARE ANY OF THESE ASSUMPTIONS VALID?

A No. First, any decline in future capital cost should have already been recognized in the AURORA model runs. This is because the AURORA model calculates fixed and variable costs of new generation based on assumptions about future capital costs and commodity prices, among other assumptions. Second, FPL's assertion that the monthly incentive levels would increase in subsequent years is sheer speculation and would only occur (if at all) in a SoBRA increase. Finally, as discussed later, the current $8.70 per kW monthly incentive is more than cost-effective based on the costs that FPL has avoided due to the CDR and CILC programs.

[37] FPL Response to FRF Interrogatory No. 2.

Q IS FPL'S COST-EFFECTIVENESS ANALYSIS OF THE CDR AND CILC PROGRAMS VALID?

A No. The primary benefit of the CDR and CILC programs is to defer future capacity additions. However, the AURORA model quantifies both fixed (*i.e.,* capacity) and variable (*i.e.,* energy) costs. Thus, AURORA is the wrong tool to measure the cost-effectiveness of load management programs. Second, the analysis presented in Exhibit SRS-2 misconstrues the role of cost-effectiveness tests in setting rates.

Q PLEASE EXPLAIN.

A Determining the cost-effectiveness of a rate is different from determining whether a particular DSM or load management program should be offered or expanded. The former is a ratemaking issue, while the latter is a resource planning issue.

Q HOW IS RESOURCE PLANNING DIFFERENT FROM RATEMAKING?

A Resource planning is, by definition, forward looking; whereas ratemaking reflects past decisions and costs that have mostly been incurred in the past as well as the projected additional costs for the test year. Specifically, resource planning identifies the range of options that can allow a utility to meet its future needs at the lowest reasonable cost. In the context of non-firm service, resource planning can determine whether it is cost-effective to implement, expand, or close a particular option to new business.

Ratemaking addresses the recovery of costs associated with the utility's existing resources, which include both supply side and demand-side resources, once the Commission has determined that the resource is both prudent and reasonable. The costs of those resources are recoverable in rates. Importantly, the costs eligible for recovery in rates are not adjusted even if the resource may no longer be cost-effective. For example, if an existing CCGT is no longer cost-effective because it can no longer compete with other resource options, the utility is still allowed to recover those costs in rates because the Commission has deemed them to be prudent and reasonable.

When used in the context of evaluating non-firm service, the reasonableness of any non-firm rate can be assessed by determining whether the utility has actually avoided constructing new capacity and quantifying the costs associated with this avoided capacity. If the Commission determines that a non-firm rate option is no longer providing benefits to the general body of ratepayers, it can require the utility to close the rate to new business.

Q DO THE COMMISSION'S RULES ADDRESS COST-EFFECTIVENESS TESTS IN GENERAL?

A Yes. Cost-effectiveness is addressed in the Commission's rule on Non-Firm Electric Service.[38] Specifically:

> Purpose. The purposes of this rule are: to define the character of non-firm electric service and various types thereof; to require a procedure for determining a utility's maximum level of non-firm load; and to establish other minimum terms and conditions for the provision of non-firm electric service.

Q HOW IS COST-EFFECTIVENESS DEFINED?

A Cost-effectiveness is defined as follows:

> (c) "Cost effective" in the context of non-firm service shall be based on avoided costs. It shall be defined as the net economic deferral or avoidance of

[38] Rule 25-6.0438(2) F.A.C.

> additional production plant construction by the utility or in other measurable economic benefits in excess of all relevant costs accruing to the utility's general body of ratepayers.[39]

Q HOW ARE COST-EFFECTIVENESS TESTS USED?

A Cost-effectiveness tests are used in the conservation goals dockets to determine the maximum level of non-firm load; specifically, whether a new DSM or load management program should be implemented and/or whether an existing program should either be expanded or closed to new business.

Q HAS THE COMMISSION EVER USED A PRODUCTION COST SIMULATION MODEL TO EVALUATE COST-EFFECTIVENESS?

A No. In the past, the Commission has prescribed a model to evaluate the cost-effectiveness of DSM and load management programs. This model evaluated the avoided costs of capacity (and energy for DSM programs) and the estimated costs (*i.e.*, the incentives paid to participating customers). Thus, it was a targeted resource planning model. Importantly, the results informed the Commission whether it would be cost-effective to allow new participants into a specific program. If the model showed that a program was no longer cost-effective, the remedy was to close the program to new business.

[39] Rule 25-6-0438(3)(c) F.A.C.

Q IS REPLACING THE COMMISSION'S PRESCRIBED COST-EFFECTIVENESS MODEL WITH THE AURORA PRODUCTION COST SIMULATION MODEL PROBLEMATIC?

A Yes. As previously explained, the AURORA model captures not only changes in fixed costs, but also the variable costs associated with future resource plans. However, the primary benefit of the CDR and CILC load management programs is to reduce future capacity additions that result in lower fixed costs. Thus, FPL's use of the AURORA model introduces other variables besides the impact on future capacity additions and fixed costs that are unrelated to determine the cost-effectiveness of the CDR and CILC programs.

Q ARE THE BENEFITS DERIVED FROM THE AURORA MODEL ACCURATE?

A The accuracy of the AURORA model results cannot be verified without conducting a detailed audit. However, auditing the model would require obtaining a temporary user license at a significant cost. Given the statutorily-imposed time constraints, a general rate case is not a proper forum to fully vet a model that has never before been used to measure the cost-effectiveness.

Q ARE THERE ANY OTHER REASONS WHY THE COMMISSION SHOULD QUESTION THE RESULTS OF THE AURORA MODEL?

A Exhibit SRS-2 is based on just one AURORA model scenario. Other than including and then removing the CDR and CILC programs, no other scenarios were provided. Normally, resource planning models examine multiple scenarios that examine a wide range of assumptions, including different levels of load growth, inflation and commodity prices. Absent a robust analysis that considers a wide range of scenarios, it would be impossible to validate the model results even if there were sufficient time and available resources.

Q DR. SIM ASSERTS THAT DECLINING CAPITAL COSTS ARE A PRIMARY FACTOR BEHIND FPL'S JUDGMENT TO REDUCE THE INCENTIVE PAYMENTS BY 33%. WHAT IS THE BASIS FOR THIS STATEMENT?

A Specifically, Dr. Sim stated that, in 2009, FPL projected that the avoided unit would have a capital cost of $974 per kW. However, by 2019, FPL projected that the same avoided unit would have a capital cost of only $663 per kW. This is a 32% decrease.[40]

Q HAVE YOU SEEN EVIDENCE THAT GENERATION CAPITAL COSTS HAVE DECLINED AS DR. SIM'S ASSERTS?

A No. **Exhibit JP-12** shows the trends in generation capital costs. First, I have tabulated the overnight construction costs of CT generating units as compiled in the EIA's AEO reports dating back to 2013. As can be seen, the projected overnight costs in the most recent AEO report for 2021 are higher than the corresponding projected overnight construction costs in the 2013 AEO report.

Second, I have provided a history of the CONE prices published by MISO in its annual PRA. The CONE prices shown reflect the cost to construct a new CT in MISO local resource Zone 9, which includes Louisiana, Mississippi and Texas (along the

[40] *In re: Commission review of numeric conservation goals* (Florida Power & Light Company); Docket No. 20190015-EG, Direct Testimony of Steven R. Sim at 25-26 (Apr. 12, 2019).

Gulf Coast). As can be seen, the CONE prices have varied over time. However, there is no discernable decline (certainly not 32%) as suggested by Dr. Sim.

Q HAVE FPL'S GENERATION CAPITAL COSTS DECLINED?

A No. If capital costs are declining as Dr. Sim asserts, one would also expect that the capital costs of generation capacity additions would also be declining. However, FPL's installed generation capital costs have steadily increased since 2012. This is shown in **Exhibit JP-13**. FPL's most recent thermal capacity addition, the Dania Clean Energy Center, is expected to cost $762 per kW (line 12). Increasing capital costs, coupled with the fact that FPL's installed capacity costs have averaged $847 per kW (well above $663 per kW), further invalidates FPL's new cost-effectiveness analysis, which assumes a continued decline of capital costs.

Q DOES FPL'S PROPOSAL TO REDUCE THE CDR AND CILC INCENTIVES BY 33% RAISE ANY OTHER CONCERNS?

A Yes. Dr. Sim assumes that reducing the incentives to the levels that customers were paid in the distant past would have no adverse consequences; that is, customers would not be motivated to switch from non-firm to firm service. However, he has not provided any customer survey assessing potential customer impacts of a 33% reduction in the CDR and CILC incentives.

Q IS THERE ANY REASON TO BELIEVE THAT CUSTOMERS WOULD CONTINUE THEIR PARTICIPATION IN THE CDR AND CILC PROGRAMS IF THE INCENTIVES ARE REDUCED BY 33%?

A No. Non-firm service is not cost-free. Curtailments could occur at any time when capacity is insufficient throughout Peninsular Florida, not just in FPL's service territory. Thus, CDR and CILC participants have to incur costs to be able to safely curtail load when notified. Reducing the incentive payments by 33% substantially changes the customer's assessment of the risks and benefits of the programs. If the participants believe that the benefits of remaining on non-firm service will be substantially reduced and are no longer justified by the risks, as FPL is proposing in this case, they may decide to convert to firm service.

Q WHAT WOULD HAPPEN IF ALL THE CDR AND CILC LOAD WERE TO CONVERT FROM NON-FIRM TO FIRM SERVICE?

A FPL would have to install additional capacity to firm up the CDR and CILC loads. Assuming a 20% reserve margin, 814 MW of CDR and CILC non-firm load would require an additional 977 MW of capacity.

If that additional capacity had been installed over the period 2012 through 2021, FPL would have incurred an average installed cost of additional capacity of about $667 per kW (excluding solar capacity), as shown in **Exhibit JP-13**.

Using $667 per kW as the average installed cost of incremental capacity, the annual cost avoided by a transmission level customer taking non-firm service was approximately $9.78 per kW per month. The $9.78 per kW per month avoided capacity cost is derived on page 1 of **Exhibit JP-14**. It is based on FPL's test year carrying charges. This is higher than the current $8.70 per kW CDR Monthly Incentive.

Q **THE $667 PER KW AVOIDED CAPITAL COST ASSUMES THAT FPL WOULD HAVE INSTALLED THE SAME MIX OF THERMAL GENERATION TO FIRM-UP THE CDR AND CILC LOADS. WHAT IF FPL HAD INSTALLED COMBUSTION TURBINES INSTEAD OF CCGTS AND SOLAR PLANTS?**

A **Exhibit JP-14,** page 2 quantifies the avoided cost of non-firm capacity had FPL installed CTs during this period to firm-up the CDR and CILC loads. As can be seen, the corresponding annual revenue requirement avoided by a transmission level customer taking non-firm service was $9.00 per kW per month. This amount is also higher than the current CDR Monthly Incentive.

Q **HAVE THE CDR AND CILC PROGRAMS PROVIDED (AND CONTINUE TO PROVIDE) BENEFITS TO THE GENERAL BODY OF FPL CUSTOMERS?**

A Yes. The capacity costs avoided by providing non-firm service under the CDR Rider and CILC rate schedule exceed the incentive payments to these customers. Hence, from a ratemaking perspective, both the CDR and CILC programs are cost-effective.

Q **WHAT DO YOU RECOMMEND?**

A The Commission should reject FPL's proposal to drastically reduce the CDR credit. There is no evidence that capital costs have declined, certainly not by the magnitude estimated by Dr. Sim.

8. CONCLUSION

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

A The Commission should make the following findings:

- Reject the 2023 subsequent year increase unless FPL files a complete set of updated MFRs.
- Reject the continuation of the RSAM.
- Reject the 2024 and 2025 SoBRAs.
- Reject FPL's "Base" class cost-of-service study.
- Adopt FPL's minimum distribution system analysis, including the separation between primary and secondary investment, in allocating distribution network costs.
- Correct the three flaws in FPL's MDS class cost-of-service study as follows:
    - Adjust the imputed incentives to $80.9 million.
    - Directly assign the $80.9 million to the CILC, GSD, and GSLD customer classes as shown in Table 2 of my testimony.
    - Allocate the $80.9 million as a cost to all customer classes based on each class's proportion of firm load.
    - Use the 4CP (rather than the 12CP) method to allocate production and transmission demand-related costs.
- Reject FPL's proposed application of gradualism in determining its class revenue allocation.
- Approve a class revenue allocation based on the corrections to FPL's MDS study.
- Reject FPL's proposed 33% reduction to the CILC/CDR monthly incentive payments.

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 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, 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.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20165	Direct	MI	Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism	10/15/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design	10/1/2018

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Initial Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	9/27/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study; Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment	8/13/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surrebuttal	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge	8/8/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Revenue Requirements; Tax Cuts and Jobs Act; Riders	8/1/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/5/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation	6/26/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study; Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study; Revenue Allocation	5/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins	4/25/2018

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Surrebuttal	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins; Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM	11/21/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	10/3/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power Station	3/31/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues; Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas	3/3/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation	3/3/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015

APPENDIX C

Procedures and Key Principles of a CCOSS

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 (kWs). This includes production, transmission, and some distribution investment and related fixed 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 (kWhs). 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 several 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. Finally, customers who self-serve all or a portion of their power needs from BTMG will have dramatically different load characteristics than customers who purchase all or most of the power from the utility. Thus, they should be costed separately.

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 either primary distribution or primary substation customers. More investment is required to serve a primary distribution than a primary substation customer. 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 rate increase by Florida Power & Light Company	**DOCKET NO. 20210015-EI** **Filed: June 21, 2021**

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, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. 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. 20210015-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 21st day of June 2021.

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

(Whereupon, prefiled direct testimony of Billie S. LaConte was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 20210015-EI** **Filed: June 21, 2021**

DIRECT TESTIMONY AND EXHIBITS OF BILLIE S. LACONTE

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
INCORPORATED

Jon C. Moyle, Jr.
Moyle Law Firm, P.A
The Perkins House
118 N. Gadsden St.
Tallahassee, Florida 32301
Telephone: 850.681.3828
Facsimile: 850.681.8788

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 20210015-EI** **Filed: June 21, 2021**

Table of Contents

LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
CAPM	Capital Asset Pricing Model
DCF	Discounted Cash Flow
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
IOU	Investor Owned Utility
MRP	Market Risk Premium
ROE	Return on Equity
RSAM	Reserve Surplus Amortization Mechanism
S&P	Standard & Poor's
SoBRA	Solar Base Rate Adjustment

Direct Testimony of Billie S. LaConte

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte, 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

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

A I am an energy advisor and Associate at J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University. Since graduating in 1995, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. More details are provided in **Appendix A.** A list of my appearances is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Florida Power & Light Company (FPL). They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and significant interest in the outcome of this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A I am addressing the following issues:

- Cost of Capital;
- Scherer Unit 4 Retirement and JEA payment;
- Rate case expense amortization; and
- Income tax adjustment.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

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

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

A No. One should not interpret the fact that I do not address every issue raised by FPL as an endorsement of its proposals.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Cost of Capital

- FPL's proposed 11% cost of equity (before any performance incentive) is excessive relative to the returns authorized by other state regulatory commissions nationwide in rate case decisions since 2019 for vertically integrated electric investor-owned utilities. Authorized returns on equity (ROE) have averaged below 10% since 2013.

- On average, other vertically integrated, A-rated electric investor-owned utilities collectively had an average 51.73% financial equity ratio in 2020, which is 787 basis points lower than the equity ratio FPL is proposing in this case.

- FPL's capital structure is inefficient because it fails to employ an appropriate amount of leverage. Accordingly, for ratemaking purposes, the Commission should adjust FPL's common equity ratio so that it is more in line with the average of other vertically integrated A-rated electric investor-owned utilities and should not exceed 52%

- The 11% return on equity (ROE) (before any performance adder) recommended by FPL's ROE witness, Mr. Coyne, is based on improper application of widely used and accepted methods, as well as other methods, such as the Expected Earnings method, which is not widely used.

- Mr. Coyne's recommendation to select an ROE from the higher end of his recommended range due to FPL's level of risk compared to the companies in the proxy group is unnecessary. FPL's risk is less than the risk of the companies in the proxy group. Due to its excessive common equity ratio, FPL is less risky than the proxy company.

- A 59.6% financial equity ratio is clearly excessive in this case because FPL's proposed 11% cost of equity is 739 basis points more expensive than long-term debt. This excessive equity ratio results in a higher cost of capital and higher rates than a utility with a more leveraged capital structure.

Scherer Unit 4 Retirement and JEA Payment

- FPL proposes the early retirement of Scherer Unit 4. In the 2016 rate case, FPL proposed retiring the unit in 2039. Pursuant to the settlement, the retirement date was extended to 2052.

- Despite moving up the retirement date by 30 years, FPL proposes amortizing the remaining undepreciated balance of the plant over ten years, and earning a fully regulated return on the unamortized balance.

- FPL should recover the remaining plant balance through 2039, as established in the 2016 depreciation study. Further, because FPL has already monetized capital recovery of Scherer Unit 4 in the RSAM that was implemented in the 2016 rate case through earnings and because the asset is no longer used and useful, FPL should not earn a return on the unamortized balance.

- FPL has agreed to pay JEA a "Consummation Payment" of $100 million as part of its plan to retire Scherer Unit 4 early. FPL proposes to amortize the "Consummation Payment" over ten years and earn a fully regulated return on the unamortized balance.

- FPL customers did not benefit from JEA's portion of the Scherer Unit 4, and they should not be responsible for JEA's outstanding revenue bonds for Scherer Unit 4. Further, to the extent that the retirement of Scherer Unit 4 was prompted by a corporate goal to eliminate coal-fired generation, the JEA payment would clearly be a shareholder benefit.

Rate Case Expense Amortization

- FPL projects it will incur $5 million of rate case expenses in this proceeding. It proposes to recover the rate case expense over four years. It is also proposing to earn a return on the unamortized balance of these expenses in its claimed 2022 test year and 2023 subsequent year revenue requirements.

- FPL should only recover actual rate case expenses that it incurs through the conclusion of the hearing in this proceeding.

- FPL should not earn a return on the unamortized balance of the rate case expense regulatory asset. The proposed return unnecessarily inflates the rate case expenses and does not provide FPL with an incentive to control its rate case expenses. Therefore, FPL's proposal to earn a return on its rate case expenses should be rejected.

Income Tax Adjustment

- FPL proposes to adjust base rates if the federal corporate income tax rate increases. Such an adjustment is not necessary because the change in federal income tax may not occur. However, if the Commission approves FPL's proposal, should the federal corporate income tax rate decrease, then base rates should similarly be adjusted to reflect the lower income tax rate.

2. COST OF CAPITAL

Q WHAT ARE YOUR CONCERNS WITH FPL'S PROPOSED COST OF CAPITAL?

A My primary concerns are:

- FPL's proposed ROE is out-of-step with the electric utility industry. Even without the 50 basis point performance incentive, the proposed ROE of 11% is excessive relative to the ROEs authorized by other state regulatory commissions for electric investor-owned electric utilities (IOUs).
- FPL's common equity ratio is excessive as compared to the national average in 2020 and the average for A-rated vertically integrated electric utilities.
- Mr. Coyne's analysis is based on faulty assumptions, which inflate FPL's required return on equity (ROE). His analysis includes the improper application of widely accepted cost of equity methodologies. He also makes use of the Expected Earnings methodology, which is not widely accepted. Further, his assessment of FPL's risk relative to the companies in his proxy group is flawed.

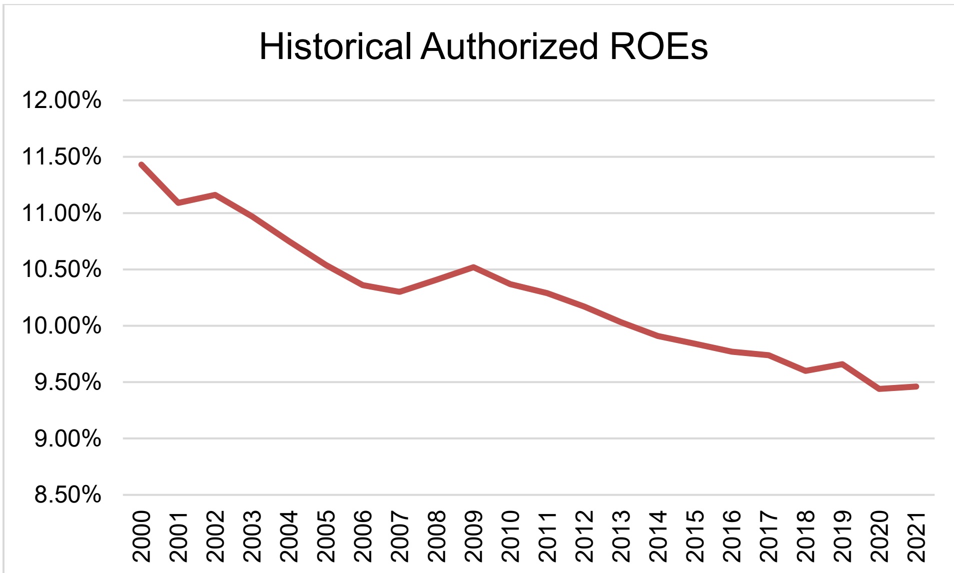
Trends in State Authorized ROEs

Q IS FPL'S PROPOSED ROE CONSISTENT WITH THE TREND IN THE NATIONAL AVERAGE ROE FOR ELECTRIC UTILITIES?

A No. The national average authorized ROE for vertically integrated electric utilities was 9.74% in 2019, and 9.55% in 2020, as reported by RRA. A copy of the RRA Report is provided in **Exhibit BSL-1**. These averages reflect the actual decisions from rate cases in Florida as well as decisions by other state regulatory commissions in general rate cases. As discussed later, this is a reasonable basis for assessing the trend in authorized ROEs.

Q WHY SHOULD THE COMMISSION GIVE SIGNIFICANT WEIGHT TO ROE DETERMINATIONS RESULTING FROM EVIDENTIARY RECORDS THAT ARE NOT A PART OF THIS PROCEEDING?

A The trend in utility authorized ROEs indicates that, in general, utilities' current risks are lower than in the past. The graph below shows the average historical authorized ROE for U.S. based electric utilities since 2000 through the first quarter of 2021.



The lower ROES are due, in part, to the lower risk-free cost of capital and the implementation of various cost recovery mechanisms and other enhancements that have reduced regulatory lag.

Q HOW DOES FPL'S REQUESTED ROE COMPARE TO THE NATIONAL AVERAGE ROE FOR ELECTRIC UTILITIES?

A FPL's requested 11.5% ROE (including the performance incentive) is 195 basis points higher than the average authorized ROE for vertically integrated electric utilities (9.55%) in 2020. The average authorized ROE for the first quarter of 2021 is 9.45%.[1]

[1] S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions – January – March 2021 (Apr. 28, 2021).

Q HOW WOULD FPL'S PROJECTED REVENUE REQUIREMENT BE AFFECTED IF THE COMMISSION SET FPL'S ROE AT THE RRA NATIONAL AVERAGE FOR 2020?

A FPL's projected revenue requirement would decrease by $697.6 million in 2022 and $752.1 million in 2023. The details of this calculation are shown in **Exhibit BSL-2** pages 1 and 2.

Capital Structure

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT FPL'S PROPOSED EQUITY RATIO IS EXCESSIVE?

A. Table 1 summarizes the average financial equity ratio of each vertically integrated electric IOU in the most recent rate case decided during the period 2016 through 2020.

Table 1
Average Authorized Financial Equity Ratios
2016 - 2020

Year	Average Common Equity Ratio
2016	50.43%
2017	50.94%
2018	49.83%
2019	51.99%
2020	50.99%

A *financia*l capital structure comprises debt and equity. This is in contrast to a *regulatory* capital structure, which may also include deferred taxes, customer deposits and deferred investment tax credits.

As shown above, the average common equity ratio in 2020 is more than 860 basis points lower than FPL's proposed equity ratio of 59.6%. FPL's proposed equity ratio is excessive, as compared to the national average equity ratio, and considering FPL's requested 11.5% ROE. For example, in 2018, Hawaiian Electric Company was authorized a 56.91% common equity ratio; however, the authorized return on equity was 9.5%, or 200 basis points lower than FPL's requested ROE. As discussed above, FPL's proposed weighted average cost of capital, based on its financial capital structure, is significantly higher than the national average.

Q IS FPL'S COMMON EQUITY RATIO HIGHER THAN OTHER A-RATED UTILITIES?

A Yes. Table 2 provides the average common equity ratio for A-rated utilities from 2016 through 2020. FPL's common equity ratio is significantly higher than the common equity ratios each year. FPL's proposed 59.6% financial common equity ratio is 787 basis points higher than the electric IOU average for A-rated utilities in 2020.

Table 2
Average Authorized Financial Equity Ratios
A-Rated Vertically Integrated Utilities
2016 - 2020

Year	Average Common Equity Ratio
2016	48.33%
2017	51.04%
2018	50.53%
2019	51.94%
2020	51.73%

Q ARE THERE ANY CONSEQUENCES OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?

A Yes. FPL's higher percentage of equity and lower percentage of debt in its capital structure lowers its financial risk. Furthermore, common equity is more expensive than debt. In this case, FPL is proposing an 11.5% cost of equity, but the proposed cost of debt would be only 3.61%, which is 789 basis points lower. A utility with too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the greater the benefits to FPL's shareholders and executives and the higher the rates all FPL retail customers will bear. FPL should not be rewarded for its overly conservative use of debt and high equity ratio.

Q WHAT IS THE IMPACT ON FPL'S REVENUE REQUIREMENT IF ITS COMMON EQUITY RATIO IS REDUCED TO THE NATIONAL AVERAGE COMMON EQUITY RATIO IN 2020 FOR A-RATED UTILITIES?

A If FPL's financial common equity ratio is reduced to 51.73%, its revenue requirement would be $419.8 million lower in 2022 and $446.6 million lower in 2023. The details are shown in **Exhibit BSL-3**, pages 1 and 2.

Q WHAT IS THE IMPACT ON FPL'S REVENUE REQUIREMENT IF ITS RETURN ON EQUITY AND COMMON EQUITY RATIO ARE REDUCED TO THE NATIONAL AVERAGE RETURN ON EQUITY AND COMMON EQUITY RATIO?

A If FPL's ROE is reduced to 9.55% and its financial common equity ratio is reduced to 51.73%, it revenue requirement would be $1,025 million lower in 2022 and $1,099 million lower in 2023. The details are shown in **Exhibit BSL-4**, pages 1 and 2.

Q WHAT DO YOU RECOMMEND REGARDING FPL'S COMMON EQUITY RATIO?

A I recommend that FPL's capital structure should be more in line with the average of A-rated electric IOUs. Accordingly, I recommend that FPL's equity ratio not exceed 52%.

Analysis of FPL's Requested ROE

Q HAS YOU REVIEWED FPL'S PROPOSED COST OF CAPITAL?

A Yes. FPL's proposed 6.84% cost of capital is summarized in Table 3 below.

Table 3
FPL's Proposed Cost of Capital
Test Year Ending December 31, 2022

Description	Percent of Capital	Cost	Weighted Cost
Long-Term Debt	31.37%	3.61%	1.13%
Customer Deposits	0.82%	2.03%	0.02%
Short-Term Debt	1.18%	0.94%	0.01%
Deferred Income Tax	10.62%	0.00%	0.00%
FAS 109 Deferred Income Tax	6.08%	0.00%	0.00%
Investment Tax Credits	1.89%	8.38%	0.16%
Common Equity	48.04%	11.50%	5.52%
Total	100.00%		6.84%

Source: MFR Schedule D-1a.

As Table 3 demonstrates, FPL is seeking an 11.5% ROE including the proposed 50 basis point performance incentive. Ignoring customer deposits, deferred income taxes, and investment tax credits, FPL's "financial" capital structure would consist of approximately 40.4% (short and long-term) debt and 59.6% equity.

Q WHAT IS THE FINANCIAL CAPITAL STRUCTURE?

A Financial capital structure comprises debt and equity only. Investors base their estimated returns on financial capital, not on non-financial, regulatory capital, such as deferred income taxes and customer deposits. The regulatory capital structure determines FPL's weighted average cost of capital (WACC) for regulatory purposes. Investors review the financial capital structure to determine their estimated return.

Q FPL WITNESS BARRETT CLAIMS THAT FPL'S WEIGHTED AVERAGE COST OF CAPITAL IS LOWER THAN THE NATIONAL WEIGHTED AVERAGE COST OF CAPITAL OF 6.9% OVER THE LAST THREE YEARS.[2] IS HE CORRECT?

A No. Mr. Barrett is making an apples to oranges comparison. Because FPL uses a regulatory capital structure, which includes zero cost of capital items, such as customer deposits and deferred income taxes, its weighted average cost of capital, 6.84%, is lower than utilities whose capital structure includes only debt and equity. FPL's weighted average cost of capital including only debt and equity is 8.04%, which is higher than national weighted average cost of capital.

Q ARE THERE OTHER UTILTIES THAT USE A REGULATORY CAPITAL STRUCTURE?

A Yes, but only a few. Utilities in Arkansas, Indiana, and Michigan also use a regulatory capital structure that include zero cost of capital items.

Q HOW DOES FPL'S WEIGHTED AVERAGE COST OF CAPITAL COMPARE TO UTILITIES IN THOSE JURISDICTIONS?

A FPL's requested 6.84% cost of capital is significantly higher than the weighted average cost of capital in states that use a regulatory capital structure. As shown in **Exhibit BSL-5**, the three-year average after-tax weighted average cost of capital for vertically

[2] Direct Testimony of Robert E. Barrett at 47-48.

integrated utilities that use a regulatory capital structure is 5.57%, compared to FPL's 6.84%, or 127 basis points lower than FPL.

Q IS FPL'S WEIGHTED AVERAGE COST OF CAPITAL ON A FINANCIAL BASIS SIGNIFICANTLY HIGHER THAN THE NATIONAL AVERAGE?

A Yes. As shown in **Exhibit BSL-6**, FPL's requested financial cost of capital is 8.04%, compared to the 2020 national average of 7.02%. On a pre-tax basis, FPL's cost of capital is 10.20%, compared to the 2020 national average of 8.68%. FPL's significantly higher weighted average cost of capital is due to its extremely high requested ROE of 11.5% and excessive common equity ratio of 59.6%. I will subsequently discuss each of these in more detail.

FPL's Cost of Equity Analysis

Q HOW DID FPL DETERMINE ITS ROE?

A Mr. Coyne's ROE analyses is based on four methodologies: the Discounted Cash Flow (DCF) method, the Capital Asset Pricing model (CAPM), a Risk Premium method, and the Expected Earnings method, using a proxy group of companies that are similar to FPL. **Appendix C** provides a description of the DCF, CAPM, and Risk Premium methodologies.

Q WHAT ARE THE RESULTS OF MR. COYNE'S ANALYSES?

A Mr. Coyne's analyses result in a range of 7.98% - 14.17%. However, he rejected his own analysis and estimated a range of 9.29% - 14.17%. Ultimately, Mr. Coyne recommended a range of 10.5% - 11.5%.[3] Based on his recommended range,

[3] Direct Testimony of James M. Coyne at 53, 64.

concerns regarding the DCF methodology, and observations regarding FPL's relative risk and flotation costs, he recommends an 11% ROE, or 11.5% ROE including the performance incentive.

Q WHAT DO YOU MEAN BY A PROXY GROUP?

A A proxy group is a group of companies involved in similar operations as FPL.

Q WHY IS A PROXY GROUP RELEVANT IN DETERMINING AN APPROPRIATE ROE?

A A proxy group is relevant because it provides a group of companies that are comparable in risk to FPL, hence estimating the cost of equity for the proxy group represents the economic opportunity costs that have an impact on the ROE for FPL.

Q DO YOU AGREE WITH THE GROUP OF COMPANIES THAT MR. COYNE INCLUDED IN HIS PROXY GROUP?

A Yes. The companies in Mr. Coyne's proxy group are comparable to FPL, based on Mr. Coyne's screening requirements, with which I agree.

Q WHAT ARE YOUR CONCERNS WITH MR. COYNE'S DCF ANALYSIS?

A Mr. Coyne rejected his DCF analysis. He stated:

> My primary conclusion is that the results of the DCF model understate the cost of equity for electric utilities under current market conditions and should not be used exclusively to establish the return for FPL in this proceeding.[4]

Based on this concern, Mr. Coyne excluded the results of his "Mean Low" estimates. As a result, Mr. Coyne's estimated DCF ROE is inflated by 61 basis points. The

[4] *Id*. at 54.

average DCF ROE excluding the Mean Low results is 9.83% and the average DCF ROE including the Mean Low results is 9.22%. Excluding the Mean Low results, thus, artificially inflates the ROE.

Q IS MR. COYNE'S DCF ANALYSIS REASONABLE?

A Yes. Although I agree that the DCF should be used in conjunction with other models to determine FPL's estimated return on equity, I disagree with Mr. Coyne's conclusion that the DCF results are not reliable and do not properly reflect current market conditions.

Further, Mr. Coyne's DCF analysis is based on reasonable assumptions including forecast earnings growth and expected dividend yields for the companies in his proxy group. The results of his DCF analysis are shown in Table 4.

Table 4
DCF Results

Stock Price Period	Mean Low	Mean	Mean High
30-Day Average	8.08%	9.33%	10.41%
90-Day Average	7.98%	9.23%	10.31%
180-Day Average	8.04%	9.30%	10.37%

Source: Direct Testimony of James M. Coyne at 53.

Based on my review, I conclude that the results are reasonable, and further, they should be used, in conjunction with other accepted methodologies, to determine FPL's ROE. Thus, the estimated DCF ROE should also include the Mean Low results.

Q DO YOU AGREE WITH MR. COYNE'S CAPM ANALYSES?

A No. Mr. Coyne's CAPM analysis uses betas calculated by Value Line and Bloomberg, a 2.80% forecast risk-free rate, and a forecast market risk premium (MRP).[5] His forecast MRP is based on the average of *projected* returns for Standard & Poor's (S&P) 500 Index using S&P's Earnings and Estimates report, Bloomberg Professional, and Value Line, using the DCF model to project the earnings. The average of his total market return is 15.75%.[6] Based on this market return, Mr. Coyne's estimated a 14.17% ROE.

While I agree with his use of a *forecast* MRP, Mr. Coyne failed to estimate the ROE using a *historical* MRP. Therefore, his estimated CAPM ROE is significantly overstated.

Q IS IT A COMMON PRACTICE TO ALSO USE THE LONG-TERM HISTORICAL MRP TO ESTIMATE THE CAPM ROE?

A Yes. A long-term estimate of the historical MRP is a commonly used method which is based on actual, historical MRPs over several decades and provides a reliable estimate of the expected MRP.

Q HAVE YOU CALCULATED THE ROE USING THE CAPM AND THE LONG-TERM HISTORICAL MRP?

A Yes. The historical MRP (1926-2020) is 7.15%, based on data from Ibbotson's *2020 SBBI Valuation Yearbook*.[7] Using Mr. Coyne's average beta of 0.88, and a 2.80%

---

[5] *Id.* at 57.

[6] *Id.* at 59.

[7] *In the Matter of the Application of DTE Gas Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Natural Gas, and for Miscellaneous Accounting Authority,* Case No. U-20940, Direct Testimony of Dr. Bente Villadsen at 44 (Feb. 12, 2021).

risk-free rate with the 7.15% MRP, the estimated ROE for FPL is 9.09%.[8]

$$2.80\% + 0.88 * 7.15\% = 9.09\%$$

The historical MRP provides a reasonable estimate of FPL's ROE and should be included in Mr. Coyne's analysis.

Q IS MR. COYNE'S RISK PREMIUM ANALYSIS VALID?

A No. Mr. Coyne's Risk Premium method estimates the ROE based on the historical relationship between allowed ROEs in electric utility rate cases and the risk-free rate at the time the ROEs were authorized, from 1992 through February 2021. Using this data, Mr. Coyne created a regression analysis to estimate the ROE. Mr. Coyne's regression analysis purports to demonstrate that there is an inverse relationship between the equity risk premium and interest rates. However, his regression analysis does not encompass other factors that could affect the equity risk premium, such as different Federal monetary and fiscal policies, or economic risk, such as employment, consumption and growth. These factors could have an impact on authorized ROEs due to their effect on market risk, which may cause regulators to adjust their authorized ROEs. The change in interest rates is one of many factors that may affect a utility's authorized ROE.

Q HAVE YOU REVISED DR. COYNE'S RISK PREMIUM ANALYSIS?

A Yes, using the data provided by Mr. Coyne, I used his long-term average equity risk premium of 6% and long-term risk free rate of 2.8% to derive an estimated ROE of 8.8%. The long-term risk premium estimate recognizes that the risk premium can

[8] Direct Testimony of James M. Coyne, Exhibit JMC-5.2.

fluctuate depending on market conditions and investor expectations. Therefore, using the average risk premium over this time-period is a reasonable method to estimate FPL's cost of equity.

Q WHAT IS MR. COYNE'S ESTIMATED ROE USING HIS EXPECTED EARNINGS METHODOLOGY?

A Mr. Coyne's Expected Earnings analysis estimates the ROE at 10.22%.[9] However, I disagree with the Expected Earnings methodology.

Q WHY DO YOU DISAGREE WITH THE EXPECTED EARNINGS METHODOLOGY?

A The Expected Earnings methodology is not a reliable method to estimate the ROE. It represents a forecast return on book equity and not a required return or cost of equity and therefore should not be relied upon to estimate FPL's ROE.

Q WHAT DO YOU MEAN BY THE ESTIMATED EARNINGS METHOD REPRESENTS A FORECAST ROE AND NOT A REQUIRED RETURN OR COST OF EQUITY?

A The Expected Earnings method uses forecasted earned returns on *book* equity. This is not a reasonable proxy for investors' expected *market* returns. It is a book accounting return and does not reflect investors' market expectations. FERC rejected the Expected Earnings method in a 2019 Order.[10] As explained by FERC:

> Because an investor cannot purchase a utility's common stock at book value and must instead pay the prevailing market price for common equity, the utility's expected earned return on book value is indicative of neither what

---

[9] *Id*. at 64.

[10] *Association of Businesses Advocating Tariff Equity et al. v. Midcontinent Independent System Operator, Inc. et al*, Docket Nos. EL 14-12-003 and EL 15-45-000, Opinion No. 569 at 104 (Nov. 21, 2019).

> an investor can expect to earn on an investment in the utility's common stock nor what return an investor requires to invest in the utility's common stock.

As such, Mr. Coyne's Expected Earnings method is not a reliable proxy for the estimated ROE for FPL and should be rejected.

Flotation Costs

Q WHAT ARE FLOTATION COSTS?

A Flotation costs include two components. The first component is the actual cost paid by a company to the underwriter for issuing the stock. The second is indirect and represents the potential dilutive impact due to the issuance of new stock.

Q HOW DO FLOTATION COSTS AFFECT THE ROE DETERMINATION?

A Flotation costs increase the ROE. For example, Mr. Coyne made an upward adjustment of 11 basis points to his estimated ROEs to account for flotation costs.[11]

Q DOES FPL INCUR FLOTATION COSTS?

A No. First, Mr. Coyne's estimate of flotation costs was based on the companies in his proxy group, not on any actual flotation costs incurred by FPL or expected to be incurred during the Four-Year Rate Plan. This is because FPL is a regulated utility that does not issue stock and therefore does not incur flotation costs. The flotation costs are incurred by FPL's parent company, NextEra Energy. Therefore, a flotation cost adjustment is not necessary.

[11] Direct Testimony of James M. Coyne at 83.

Q IF FPL IS RESPONSIBLE FOR NEXTERA'S FLOTATION COSTS, SHOULD THE COMMISSION APPROVE MR. COYNE'S FLOTATION COST ADJUSTMENT?

A No. As noted above, Mr. Coyne's flotation cost adjustment is not based on actual flotation costs incurred. If the Commission allows FPL to recover flotation costs, it should be based on a reasonable projection of flotation costs that FPL's parent company will incur during the Four-Year Rate Plan.

Impact of Correcting FPL's ROE Analysis

Q IF THE VARIOUS FLAWS IN FPL'S ROE ANALYSIS ARE CORRECTED, HOW WOULD THIS AFFECT FPL'S ESTIMATED ROE?

A Correcting the errors in Mr. Coyne's ROE analysis and excluding a flotation cost adjustment, it is clear that FPL's cost of equity does not exceed 9.59%. The derivation of 9.59% is shown in Table 6 below. It is based on the results of the restated DCF results and the revised CAPM and Risk Premium analyses.

Table 6
Revised ROE

Methodology	ROE
DCF Low	
30-day Average	8.08%
90-day Average	7.98%
180-day Average	8.04%
DCF Mean	
30-day Average	9.33%
90-day Average	9.23%
180-day Average	9.30%
DCF High	
30-day Average	10.41%

Table 6 Revised ROE	
Methodology	**ROE**
90-day Average	10.31%
180-day Average	10.37%
CAPM Projected MRP	14.17%
CAPM Historical MRP	9.09%
Risk Premium	8.80%
Average	9.59%

My revised ROE reflects the inclusion of Mr. Coyne's Mean Low DCF results, the projected and historical MRP, and the historical equity risk premium for electric utilities. Furthermore, a flotation cost adjust was excluded because FPL does not issue common stock.

Q WHAT IS THE IMPACT ON FPL'S REVENUE REQUIREMENT USING YOUR REVISED ROE?

A Replacing FPL's requested 11.5% ROE with the revised ROE of 9.59% reduces FPL's revenue requirement by $683.2 million in 2022 and $736.6 million in 2023. **Exhibit BSL-7** pages 1-2 provides the detailed calculations.

Q PLEASE SUMMARIZE YOUR CRITICISMS OF MR. COYNE'S ROE ANALYSES.

A Mr. Coyne relies on four methods to estimate FPL's ROE. His DCF analysis excludes his Mean Low results, which overstates his estimated DCF ROE.

His CAPM analysis excludes the historical MRP, which is a common method to estimate a utility's ROE. The exclusion of the historical MRP results inflates FPL's estimated ROE.

The Risk Premium method uses a regression analysis that only considers the impact of long-term interest rates on the equity risk premium. Other factors also affect the equity risk premium, such as Federal monetary policy. Ignoring other factors that may affect the equity risk premium produces inaccurate ROE estimates.

The Expected Earnings methodology is not a common method used to estimate the ROE for a regulated utility. As detailed above, the utility's expected earned return on book value is indicative of neither what an investor can expect to earn on an investment in the utility's common stock nor what return an investor requires to invest in the utility's common stock. Therefore, it should be rejected.

The flotation cost analysis is misplaced because FPL does not issue stock.

Risk Factors

Q IS FPL MORE RISKY THAN MR. COYNE'S PROXY GROUP COMPANIES?

A No. Mr. Coyne suggests that FPL's risk as it relates to the proxy group is higher and would support an ROE at the high end of his recommended range. These risk factors include FPL's capital expenditures program, its nuclear generation fleet, risk associated with storm damage and resulting outages, regulatory risk, and risk related to FPL's proposed Four-Year Rate Plan.

However, although its capital expenditure program is significant, FPL's risk related to the proxy group regarding the risk factors identified by Mr. Coyne is lower. For example, as noted by Mr. Coyne, over half of the companies in the proxy group have nuclear assets. Further, FPL is an above average nuclear operator, which credit rating agencies view as favorable. FPL has similar risk associated with storm damage, however, its regulatory risk is significantly below the proxy group's regulatory risk and the proposed Four-Year Rate Plan reduces its risk compared to the proxy group.

Q ARE ANY OF THE COMPANIES IN THE PROXY GROUP EXPOSED TO STORM DAMAGE AND OUTAGES?

A Yes. Several companies in the proxy group are exposed to storm damage and outages, such as tropical storms and hurricanes, severe thunderstorms, tornados, ice storms and in the case of Edison International, outages due to wildfires. FPL's risk regarding exposure to storms is similar to the proxy group's exposure to adverse weather events and, therefore, FPL's is not riskier than the proxy group regarding its exposure to storm damage and outages.

Q DOES FPL HAVE HIGHER REGULATORY RISK?

A No. FPL's regulatory risk is significantly below the companies in the proxy group. According to Regulatory Research Associates (RRA), the regulatory climate in Florida, as it relates the risk faced by investors, is significantly better than the regulatory climate in other states. As noted by RRA:

> Florida regulation is viewed as quite constructive from an investor perspective….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….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.[12]

Q HOW DOES FLORIDA'S REGULATORY RANK COMPARE TO OTHER STATES?

A Florida's regulatory rank is significantly above other jurisdictions. RRA's regulatory evaluation scale uses three categories, Above Average, Average, and Below Average. Within each category, it includes a ranking of 1, 2, or 3. According to RRA,

> An Above Average designation indicates that, in RRA's view, the regulatory climate in the jurisdiction is relatively more constructive than average, representing *lower risk* for investors that hold or are considering acquiring the securities issued by the utilities operating in that state.[13] (emphasis added)

Florida is ranked Above Average/2. Out of the 53 ranked jurisdictions, Florida is in the top 5. The proxy group of companies represent 47 regulated utilities. Out of those 47 regulated utilities, four have an RRA rank that is equal to Florida. The remaining 43 are ranked below Florida. This demonstrates that FPL has significantly less regulatory risk than the companies in the proxy group.

Q DOES THE FOUR-YEAR RATE PLAN INCREASE FPL'S RISK?

A No, quite the opposite. FPL's proposed Four-Year Rate Plan uses two forward looking test-years, 2022 and 2023. It also allows FPL to adjust its rates in 2024 and 2025 for solar based rate adjustments, which, as discussed in Mr. Pollock's testimony, is clearly piecemeal ratemaking. Piecemeal ratemaking allows a utility to implement a change in rates outside of a base rate case, while ignoring the utility's earnings. The SoBRAs

[12] S&P Global Market Intelligence, Regulatory Research Associates, RRA Evaluation (Apr. 29, 2021).

[13] S&P Global Market Intelligence, RRA Regulatory Focus, State Regulatory Evaluations (Aug. 19, 2020.

will mitigate FPL's risk because it will change rates on an expedited basis and outside the context of a traditional rate case in accordance with cost changes. Further, as noted by RRA, multi-year rate plans approved in Florida are supportive of the utility's financial health. The Four-Year Rate Plan does not increase FPL's risk relative to the companies in its proxy group, but reduces its risk.

<u>Financial Risk Factors</u>

Q DOES FPL HAVE SIGNIFICANT FINANCIAL RISK?

A No. FPL does not have significant financial risk for several reasons, including: (1) the use of multiple fully projected future test years; (b) piecemeal cost recovery clauses that allow rates to be adjusted outside of base rate cases; and (c) a regulatory commission that employs many constructive ratemaking practices.

Q DOES FPL CURRENTLY HAVE ANY ADJUSTMENT CLAUSES IN PLACE THAT REDUCE ITS VARIABILITY IN INCOME AND LOWER ITS FINANCIAL RISK?

A Yes, FPL currently recovers a number of its costs through various surcharges and cost recovery factors. These include the following adjustment clauses:

- Fuel and Purchased Power;
- Energy Conservation;
- Capacity;
- Environmental; and
- Storm Protection

FPL's adjustment clauses shift the risk of cost recovery from shareholders to customers. FPL is able to change its rates to recover costs on a current basis, which reduces regulatory lag and income variability.

Q HOW HAS THE RESERVE SURPLUS AMORTIZATION MECHANISM (RSAM) AFFECTED FPL'S FINANCIAL RISK?

A The RSAM has effectively removed FPL's financial risk because it has allowed FPL to earn its authorized ROE since 2010. Table 7 shows FPL's earned ROE without the RSAM and with the RSAM since 2010.

Table 7
Earned ROEs With and Without RSAM

Year	Without RSAM	With RSAM
2010	10.97%	11.0%
2011	9.69%	11.0%
2012	8.00%	11.0%
2013	10.12%	10.96%
2014	11.66%	11.5%
2015	11.57%	11.5%
2016	11.45%	11.5%
2017	5.91%	11.08%
2018	14.08%	11.6%
2019	13.05%	11.6%
2020	11.61%	11.6%

Source: Response to FIPUG First Set of Interrogatories No. 22, Attachment No. 1.

FPL has consistently earned its authorized ROE at the top of the range every year. In years where FPL earned below its authorized ROE, the RSAM was implemented to increase its ROE. The RSAM guarantees investors that FPL has lower risk and will likely earn its authorized ROE every year.

Q DOES THE SOLAR BASE RATE ADJUSTMENT MECHANISM REDUCE FPL'S RISK?

A Yes. The SoBRA allows FPL to make adjustments to its revenue requirement outside of a rate case, which is also another form of piecemeal ratemaking. Allowing additional adjustments to FPL's revenue requirement outside of a rate case, without a thorough review of all of its revenues and costs, reduces its income volatility and thus, reduces its financial risk.

Q HOW DOES LOWER FINANCIAL RISK IMPACT FPL'S EXPECTED COST OF CAPITAL?

A FPL's reduced financial risk lowers investors required return. Thus, investors' required return for FPL will be lower. Hence, the risk-reducing measures and the RSAM support a reduction to FPL's proposed ROE of 11% (excluding the 50 basis point performance incentive).

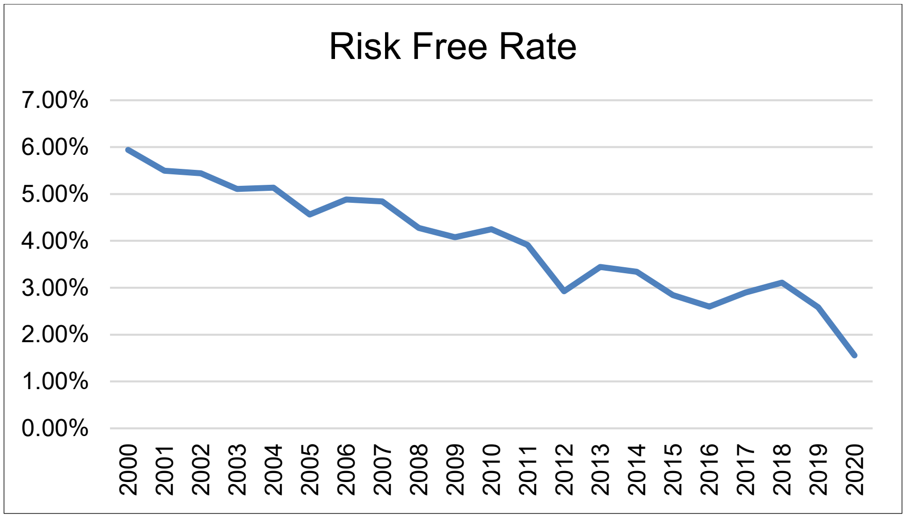
Risk-Free Cost of Capital

Q WHAT IS THE RISK-FREE COST OF CAPITAL?

A The risk-free cost of capital is represented by the yield on 30-year U.S. Treasury bonds. The 30-year U.S. Treasury bond interest rate is used because the term of the security should closely match the lifetime of the underlying assets.

Q HAS THE RISK-FREE COST OF CAPITAL CHANGED IN THE PAST TWENTY YEARS?

A Yes. The risk-free cost of capital is represented by the yield on 30-year U.S. Treasury bonds. The 30-year U.S. Treasury bond interest rate is used because the term of the security should closely match the lifetime of the underlying assets. As can be seen in the graph below, the risk-free cost of capital has steadily declined over the last 20 years.[14]



Q WHAT ARE THE IMPLICATIONS OF THE DECLINE IN THE RISK-FREE COST OF CAPITAL IN DETERMINING A FAIR AND REASONABLE ROE?

A All other things being equal, a declining risk-free cost of capital should translate into a correspondingly lower authorized ROE.

Q WHY DOES A DECLINING RISK-FREE COST OF CAPITAL SUPPORT A LOWER AUTHORIZED ROE?

A A lower risk-free rate, coupled with the risk premium, will produce a lower ROE. The risk premium measures the additional risk to a stock above the risk-free rate. This risk premium plus the risk-free rate is one methodology used to estimate a utility's ROE. A lower risk-free rate will reduce the estimated ROE.

---

[14] Calculated using data from U.S. Department of the Treasury, Resource center: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Q DOES FPL'S PROPOSED ROE REFLECT ITS LOWER RISK?

A No. FPL faces lower regulatory and financial risks than the proxy group. This is due to the very constructive regulatory environment and FPL's excessive equity ratio. The proposed Four-Year Rate Plan further reduces these risks because, as discussed by Mr. Pollock, it would guarantee that FPL earns at the top end of its authorized ROE due to the proposed extension of the RSAM. Further, the risk-free cost of capital continues to decline. Thus, even assuming no change in the risk premium associated with equity financing, the cost of equity is lower. For all of these reasons, FPL's requested ROE is clearly excessive.

Q WHAT DO YOU RECOMMEND?

A I am not recommending a specific ROE at this time. FPL's proposed 11.5% ROE is excessive compared to the revised ROE of 9.59% and the national average ROE in 2020 of 9.55%. Accordingly, I recommend that the Commission set FPL's ROE at or below the average of the authorized ROEs by other state regulatory commissions.

3. SCHERER UNIT 4 RETIREMENT AND JEA PAYMENT

Q PLEASE DESCRIBE SCHERER UNIT 4.

A Scherer Unit 4 is an 850 MW coal fired generating facility that is jointly owned by FPL (76.36%) and JEA (23.64%).[15]

Q IS FPL PLANNING TO RETIRE SCHERER UNIT 4?

A Yes. FPL proposes to retire its portion of Scherer Unit 4 as of January 1, 2022.[16] Per FPL:

> The modernization of FPL's generation fleet over the last decade…has increasingly pushed coal to the bottom of the dispatch stack. Ongoing capital costs and O&M obligations have rendered FPL's legacy coal plants as prime candidates for overall cost reduction efforts.17

The early retirement of Scherer Unit 4 is consistent with the Environmental, Social and Governance plans of FPL's parent company, NextEra. It also allows FPL to invest in new capacity, which benefits its shareholders.

Q CAN FPL RETIRE SCHERER UNIT 4 WITHOUT JEA'S APPROVAL?

A No. Without JEA's agreement to retire its share, FPL may not retire its portion of Scherer Unit 4 under the settlement obligation. FPL and JEA have a joint agreement with Georgia Power to jointly own Scherer Unit 4. FPL and JEA also own undivided interests in the common facilities of Scherer Unit 3 and Unit 4, as well as undivided

[15] Direct Testimony of Sam Forrest at 19.

[16] *Id*. at 21.

[17] *Id.* at 19-20.

interests in the Scherer common facilities related to Units 1-4. FPL and JEA also maintain their own coal stockpiles and a portion of the materials and spare parts.

Q WHAT IS FPL'S REMAINING UNDEPRECIATED BALANCE OF SCHERER UNIT 4 AND ITS COMMON FACILITIES?

A The remaining undepreciated balance of Scherer Unit 4 is $831 million.[18] FPL's proposal to recover these costs is to create a regulatory asset and amortize the balance over 10 years. The unamortized balance would earn a full return.

Q ARE THERE ANY OTHER COSTS ASSOCIATED WITH THE EARLY RETIREMENT OF SCHERER UNIT 4?

A Yes. In order to retire the unit early, FPL needed JEA to agree with its proposal. However, JEA has ongoing bond obligations related to its share of Scherer ownership and needs to pay off the bonds in the event of a retirement. The outstanding balance of the revenue bonds is approximately $100 million.[19] In order to retire the plant early, FPL negotiated with JEA a "Consummation Payment" of $100 million to satisfy the revenue obligations.

Q WHAT IS FPL'S PROPOSAL TO RECOVER THE "CONSUMMATION PAYMENT" FROM FPL CUSTOMERS?

A FPL proposal would create a regulatory asset for the "Consummation Payment" and amortize it over ten years. FPL would also receive a full return on the unamortized portion.

[18] Direct Testimony of Liz Fuentes at 21-22.

[19] Direct Testimony of Sam Forrest at 21.

Q ARE FPL CUSTOMERS OBLIGATED TO PAY THE "CONSUMMATION PAYMENT"?

A No. FPL customers should only pay FPL's share of the Scherer Unit 4 costs. FPL customers should not be responsible for JEA's $100 million outstanding revenue obligation bonds. FPL customers received the benefit of FPL's share of Scherer Unit 4, and JEA's customers received the benefit of JEA's share. Therefore, if Scherer Unit 4 is retired, FPL customers should only pay FPL's remaining undepreciated balance of the plant, or $831 million, and not the $100 million "Consummation Payment."

Q SHOULD FPL AMORTIZE THE REMAINING NET BALANCE OF SCHERER UNIT 4 OVER TEN YEARS?

A No. FPL should amortize the remaining plant balance over the original life of the plant, 2039. This was the retirement date established in FPL's 2016 Depreciation Study for Scherer Unit 4.[20] However, as a result of the settlement of FPL's 2016 rate case, the Scherer Unit 4 retirement date was extended to 2052.

Q SHOULD FPL EARN A RETUN ON THE REMAINING BALANCE OF SCHERER UNIT 4?

A No. Extending the retirement date of Scherer Unit 4 to 2052 allowed FPL, in part, to continue the RSAM. FPL subsequently monetized Scherer Unit 4 through lower depreciation expense to achieve earnings at the top end of its authorized ROE. Now

[20] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 160021-EI, Order Approving Settlement Agreement, Attachment A, Exhibit D at 2 (Dec. 15, 2016).

FPL seeks not only to retire the unit 30 years sooner, it is also asking to earn a return on the unamortized plant balance. Notwithstanding the "bait and switch" on the Scherer Unit 4 retirement date, FPL should not have two bites at the same earnings apple. It used the RSAM funds created in part by extending the life of Scherer plant to prop up its earnings and it should not be allowed recovery of an additional return on the remaining plant balance.

Q IS THERE ANY OTHER REASON WHY FPL SHOULD NOT EARN A RETURN ON THE REMAINING BALANCE OF SCHERER UNIT 4?

A Yes. When Scherer Unit 4 is retired on January 1, 2022, it will no longer provide service to customers; therefore, it will no longer be used and useful. If a plant is no longer used to provide service or is not capable of providing service, then a utility should not earn a return on that plant, because it is not providing a benefit to customers.

Q WHAT DO YOU RECOMMEND?

A The $100 million JEA "Consummation Payment" should be rejected. I recommend that the remaining undepreciated balance of Scherer Unit 4 be recovered through the original life of the plant, 2039, and FPL should not earn a return on the remaining net balance. The JEA "Consummation Payment" should be rejected. FPL customers are not responsible for JEA's outstanding revenue obligations regarding Scherer Unit 4 because FPL customers did not benefit from JEA's ownership portion of Scherer Unit 4.

4. RATE CASE EXPENSE AMORTIZATION

Q IS FPL SEEKING RECOVERY OF ITS RATE CASE EXPENSES IN THIS PROCEEDING?

A Yes. FPL is seeking recovery of $5 million of estimated rate case expenses it will incur in the current proceeding over four years.[21] In addition, it is requesting that the unamortized balance be included in rate base in the 2022 test year and the 2023 subsequent year.

Q SHOULD FPL RECOVER ALL OF ITS RATE CASE EXPENSES IN THIS PROCEEDING?

A Yes. However, the amount of the rate case expenses should be based on the actual rate case expenses incurred by the conclusion of the hearing in this proceeding. Any rate case expense incurred after the conclusion of the hearing in this proceeding should be recovered in FPL's next base rate case.

Q SHOULD FPL INCLUDE RATE CASE EXPENSES IN RATE BASE?

A No, FPL should not include rate case expenses in the 2022 test year or the 2023 subsequent year. Including rate case expenses in rate base would be detrimental to customers because FPL would also recover a full return on the unamortized balance, which would unnecessarily increase costs for customers. Further, allowing FPL to earn a return on its rate case expenses removes any incentive to control its costs and favors shareholders, not customers.

[21] Direct Testimony of Liz Fuentes at 18.

Q WHAT DO YOU RECOMMEND?

A I recommend that FPL recover its actual rate case expenses incurred through the conclusion of the hearing in this proceeding. The actual rate case expenses incurred may be recovered over four years; however, FPL should not include the unamortized portion of the balance in rate base in the 2022 test year or the 2023 subsequent year.

5. FUTURE INCOME TAX CHANGE PROPOSAL

Q HAS FPL PROPOSED AN ADJUSTMENT IF THE FEDERAL CORPORATE INCOME TAX RATE INCREASES DURING THE TERM OF THE FOUR-YEAR RATE PLAN?

A Yes. FPL proposes to adjust base rates if the federal corporate income tax rate increases. Within 90 days of the enactment of the new tax law, FPL will submit revised base rates to the Commission. If the tax rate change occurs after the new base rates are implemented, FPL will submit the calculation of the change in base rates to the Commission for a subsequent base rate adjustment.

Q HOW WILL FPL QUANTIFY THE REQUIRED CHANGE IN BASE RATES?

A FPL will provide two sets of MFR Schedules A-1, B-1, C-1 and D-1a for both the 2022 test year and the 2023 subsequent year adjustment. The updated schedules will reflect base rates using the current corporate income tax rate and base rates using the revised corporate income tax rate. If the corporate income tax rate changes after 2023, FPL will use the 2023 MFRs to determine the change in base rates.

Q IS THE INCOME TAX PROPOSAL NECESSARY?

A No. It is piecemeal ratemaking. However, if the Commission approves FPL's proposal, then it is allowing a change in base rates outside the context of a rate case. If that occurs, then the adjustment should occur only when the income tax change goes into effect and affects FPL's income tax expense.

Q SHOULD THE MECHANISM ALSO REQUIRE FPL TO REDUCE BASE RATES IF THE FEDERAL CORPORATE INCOME TAX DECREASES?

A Yes. Similar to the proposal to adjust base rates if the federal corporate income tax increases, FPL should be required to reduce base rates to reflect the lower income tax expense when the tax rate change has become effective.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission reject FPL's proposal because it is not needed at this time. If the Commission approves FPL's proposed base rate adjustment to reflect an increase in the federal corporate income tax rate, then it should also apply if the federal corporate income tax rate decreases. The adjustment should be made only after the new income tax rate goes into effect and actually affects FPL's income tax expense.

6. CONCLUSION

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A The Commission should accept the following recommendations:

- Reject FPL's proposed 11.5% ROE (including the performance incentive)
- Set FPL's ROE at or near the average of the ROEs authorized by state regulatory commissions.
- Reduce FPL's financial equity ratio to not exceed 52%.
- Reject FPL's proposed capital recovery schedule for Scherer Unit 4 and require FPL to amortize the remaining balance through 2039, the original remaining life of the plant, without a return on the unamortized balance.
- Disallow the $100 million "Consummation Payment" to JEA.
- Authorize the recovery of actual rate case expenses incurred through the conclusion of the hearing in this proceeding and disallow rate base treatment in the 2022 test year or the 2023 subsequent year.
- Reject FPL's proposed corporate income tax mechanism at this time as it is not necessary. If the Commission approves FPL's proposal, the mechanism should recognize both increases and decreases in the federal corporate income tax rate and that base rates are not adjusted until FPL experiences a change in income tax expense due to the tax rate change.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Billie S. LaConte

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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

A I am an energy advisor and am currently employed by J. Pollock, Incorporated as Associate Consultant.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts Degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University.

Upon graduation in May 1995, I joined Drazen Consulting Group, Inc. (DCGI). DCGI was incorporated in 1995 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. I joined J. Pollock in May 2015.

During my tenure at DCGI and J. Pollock my work has focused on revenue requirement issues, cost of capital (return on equity and capital structure), cost allocation, rate design, sales and price forecasts, power cost forecasting, electric restructuring issues, integrated resource plans, formula rate plans, asset management agreements and contract interpretation.

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 has included advising clients on economic and strategic issues concerning the natural gas pipeline, oil pipeline, electric, wastewater and water utilities. I have prepared cost allocation and rate design studies to provide timely support to clients engaged in settlement negotiations in electric and gas utilities, provided power cost forecasting studies to assist clients in project planning and negotiated contracts with electric utilities for standby services and interruptible rates. I have also prepared studies on electric and gas utilities' performance-based rates (PBR) and benchmarking programs to evaluate their success and to provide recommendations on methods to be used. I worked on contract interpretation to resolve contract disputes for several clients. I have provided financial and cost of service analysis for natural gas pipelines certificate approval from the Federal Energy and Regulatory Commission (FERC) and the Canadian National Energy Board (NEB). Additionally, I completed the Corporate Credit Rating Analysis course presented by Moody's Analytics.

I have worked on various projects located in many states and several Canadian provinces including Alberta, British Columbia, Saskatchewan, Nova Scotia and Quebec. I have testified before the state regulatory commissions of Arkansas, Georgia, Iowa, Louisiana, Michigan, Minnesota, Missouri, New Mexico, Pennsylvania, Texas and South Carolina, and the provincial regulatory boards of Alberta and Nova Scotia. I similarly have appeared before the St. Louis Metropolitan Sewer District Commission.

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 Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Return on Equity; Operation and Maintenance Expenses; Incentive Compensation	6/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Rate Design, Retired Plant, Expense Amortization	5/17/2021
PHILADELPHIA WATER DEPARTMENT	Philadelphia Large Users Group	Fiscal Years 2022-2023	Rebuttal	PA	Class Cost-of-Service Study; Stormwater Incentive Program	4/7/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	Early Plant Retirement; Excess Accumulated Deferred Federal Income Taxes; Self-Insurance Reserve; Imputed Capacity	3/31/2021
SHARYLAND UTILITIES, L.L.C.	Texas Industrial Energy Consumers	51611	Direct	TX	Rate-Case Expenses; Operation and Maintenance Expense; Transmission Cost of Service Refund Rider	3/8/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Surrebuttal	PA	Revenue Allocation; Rate Design	2/9/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Rebuttal	PA	Allocation of Distribution Mains; Revenue Allocation; Rate Design; Universal Service Fund Charge	1/19/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	12/22/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Surrebuttal (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	11/17/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Surrebuttal	PA	Rate Design; Regionalization and Consolidation Surcharge; Return on Equity	10/20/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	10/19/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (2020 Eval. Report)	AR	Historical Year Netting Adjustment; :Long-Term Debt Costs	10/5/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Rebuttal	PA	Rate Design	9/29/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Direct	PA	Regionalization and Consolidation Surcharges; Commercial Rate Design	9/8/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Financial Compensation Mechanism; Deferred Capital Spending Recovery Mechanism; Karn 1 & 2 Retention and Separation costs, return on equity, storm restoration deferral; PowerMIFleet Pilot Foundational Infrastructure Program; Conservation Voltage Reduction	7/14/2020
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Projected Year Capital Expenditures; Capitalization Policy; Projected Year Adjustments	7/2/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Return on Equity; Capital Structure; Debt Cost; Additional Surcharges and Deferred Regulatory Accounts	6/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Return on Equity; Statistical Analysis of Distribution Mains Allocation	5/5/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Return on Equity; Capital Structure; Long-Term Debt Cost	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Rebuttal	MI	Return on Equity	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Return on Equity; Operation and Maintenance Expenses	3/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20618	Direct	MI	Certificate of Convenience and Necessity	1/17/2020

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Alternate Rate Plan; Coal Combustion Residual Cost Recovery; Amortization of Retired Plant	10/17/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Tax Cuts and Jobs Act Impact; Projected Year Revenues; Projected Year BRORB; Grid Modernization; Advanced Metering Infrastructure Expense	10/4/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Surrebuttal	AR	SWEPCO's Formula Rate Review; Energy Cost Recovery Rider; Distribution Reliability Rider	9/24/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Direct	AR	SWEPCO's Formula Rate Review; Capital Structure; Distribution Reliability Rider; Arkansas Formula Rate Plans	7/16/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Formula Rate Plan, Capital Additions, Operation and Maintenance Expenses	7/2/2019
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Cross-Answering	LA	Fuel Tracking Mechanism	7/1/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Unprotected Excess Deferred Income Tax Rider; Incentive Compensation	6/6/2019
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Direct	LA	Fuel Tracking Mechanism	5/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Return on Equity	4/29/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Supplemental Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/23/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/12/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Return on Equity; Capital Structure; Project vs. Historical Test Year; Earnings Sharing Mechanism	4/5/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Excess Deferred Income Tax Rider; Post-Test Year Adjustments; Coal Ash Pond Closure Expense; End-of-Life Nuclear Costs; Regulatory Assets; Return on Equity and Equity Ratio	3/4/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Direct	AR	Gas Distribution Uprstream Services Contracting Process	2/12/2019
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Formula Rate Plan Tariff; Long-Term Debt Cost and Preferred Equity; Projeced Year Capital Additions; Historical Year Capital Additions	10/4/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Return on Equity	10/1/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Return on Equity, Capital Structure and Long-Term Debt Cost, Investment Recovery Mechanism Excess Sharing Mechanism	9/10/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Opposition	AR	Opposition to Settlement Agreement	8/3/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017; Forecast Revenues; Uncollectible Expense; Pipeline Integrity Assessment and Remediation Expense	7/2/2018

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-052	Surrebuttal	AR	Utility Restructuring Costs and Tax Effects	5/31/2018
PUBLIC SERVICE COMPANY OF NEW MEXICO	City of Farmington, New Mexico; Board of County Commissioners for San Juan County	17-00174	Direct	NM	Integrated Resource Plan; Future of San Juan Generation Station	5/4/2018
ENTERGY ARKANSAS, INC. and CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Electric Energy Consumers, Inc. and Arkansas Gas Consumers, Inc.	18-006	Direct	AR	Effect on Revenue Requirement due to 2017 Tax Cuts and Jobs Act	3/29/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U18424	Rebuttal	MI	Rate of Return	3/21/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	18-014-TF	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017 and Tax Adjustment Rider	3/19/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Rate of Return, Capital Structure	2/28/2018
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Surrebuttal	AR	Asset Management Agreement Proposal	1/12/2018
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Direct	AR	Asset Management Agreement Proposal	12/8/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/31/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Forecast Revenues, Cost of Debt, Revenue Requirement and Capital Additions	10/4/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Return on Equity	9/7/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Return on Equity, Capital Structure	8/10/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Rate of Return, Capital Structure, Labor Expense	7/3/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/24/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Rate of Return, Forecast Revenue, Capitalization	9/30/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Surrebuttal	PA	Return on Equity	8/31/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Direct	PA	Return on Equity	7/22/2016
NORTHERN STATES POWER	Xcel Large Industrials	15-826	Direct	MN	Return on Equity, Multi-Year Rate Plan	6/14/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Surrebuttal	AR	Return on Equity, Formula Rate Plan, Capital Structure	6/7/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Direct	AR	Return on Equity, Captial Structure	4/14/2016
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Rebuttal	MO	Return on Equity	1/19/2012
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Direct	MO	Return on Equity	11/17/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Supplemental	MO	Rate Model	9/16/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Surrebuttal	MO	Rate Increase, CIRP, Consent Decree	8/19/2011

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Rebuttal	MO	Rate Increase, CIRP, Consent Decree	7/18/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Surrebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	4/15/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Rebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	3/25/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Direct	MO	Return on Equity	2/8/2011
AMEREN UE	Missouri Energy Group	EO-2010-0255	Direct	MO	Prudence Audit of FAC Periods 1 and 2	11/22/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct - In Support	AR	Supporting the Proposed Settlement Agreement	5/11/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Surrebuttal	AR	Return on Equity	4/14/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct	AR	Return on Equity	2/26/2010
AMEREN UE	Missouri Energy Group	ER-2010-0036	Direct	MO	Energy Efficiency Costs	12/18/2009
AMEREN UE	Missouri Energy Group	ER-2008-0318	Surrebuttal	MO	Return on Equity	11/5/2008
AMEREN UE	Missouri Energy Group	ER-2008-0318	Direct	MO	Return on Equity, Off-System Sales	8/28/2008
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Long-Term Financial Plan, Capital Financing	5/2/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Surrebuttal	MO	Return on Equity, Interruptible Demand, Response Pilot	2/27/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Interruptible Rate	12/29/2006
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Return on Equity, Off-System Sales, Sharing Mechanism, 10% Cap on Residentials	12/15/2006
AMEREN UE	Missouri Energy Group	EA-2005-0180	Rebuttal	MO	Economic Analysis	1/31/2005
NOVA SCOTIA POWER INC.	Avon Valley Greenhouses	NSUARB-P-881	Direct	NS	Cost of Capital	10/12/2004
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Surrebuttal	MO	Working Capital, Return on Equity, Cost Allocation	12/5/2003
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Rebuttal	MO	Rate Design	11/10/2003
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Direct	MO	Return on Equity, Acquisition Adjustment, Cash Working Capital	10/3/2003
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Direct	MO	Revenue Requirement, Financial Planning	4/22/2003
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Surrebuttal	IA	Revenue Requirement, Return on Equity	9/19/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Capital Financing	8/13/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Captial Financiaing, Cost Allocation	7/28/2002
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Direct	IA	Revenue Requirement, Return on Equity	7/26/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Revenue Requirement, Capital Financing	7/10/2002

APPENDIX C

Return on Equity Methodologies

Discounted Cash Flow Method

Single Stage Discounted Cash Flow

The discounted cash flow model is used by investors to determine the present value of a stock, based on future cash flows (dividends), which are discounted by the stock's known return and its forecast growth.

The formula is:

$$P = \frac{D}{r-g}$$

Where:

P = current stock price
D = dividend yield
r = rate of return
g = growth rate

We can re-arrange the formula thus:

$$r = \frac{D}{P} + g$$

In other words, the expected return equals (1) the current dividend rate, plus (2) the expected growth in dividends. The expected growth in dividends is also measured by the expected growth in earnings.

The stock prices are based on the average stock closing prices, typically for the past 30 days. The average is used to ensure that the results reflect stock prices over a period of time that is not overly reliant on any particular events affecting stock prices on a given day and that represent capital market conditions over the past month

The growth rates are the forecast earnings per share growth rates for the next five years. The dividends are forecast figures and are adjusted to reflect any quarterly adjustments during the year.

Multi-Stage Discounted Cash Flow Methodology

A multi-stage DCF analysis uses three separate growth estimates or stages. The first stage measures the near-term growth rate based on the analysts' forecast earnings growth used in my constant growth DCF analysis. The second stage (intermediate-term) growth rates are linear interpolations of the first and third stage growth rates. The third stage (long-term) is the forecast of the long-term growth rate of gross domestic product (GDP). Using these inputs, the model calculates the required internal rate of return to meet these dividend growth rates, or the ROE.

The multi-stage method is used because analysts' growth rates for the first stage may not be sustainable over the long-term. The multi-stage model recognizes short-term growth (whether it be higher or lower than the long-term), but also accounts for a more realistic, long-term growth rate. Analysts' growth rates should be viewed in conjunction with other growth estimates to achieve a reasonable forecast of expected earnings.

The long-term growth in GDP is used because the underlying assumption is that mature, established companies can grow at a rate that is similar to, or lower than, the GDP growth rate. While some companies in the economy will grow faster than GDP for a while, this cannot happen consistently over a long period.

Capital Asset Pricing Model

The CAPM is a Risk Premium method that is used to estimate the ROE. It states that the expected return of a security equals the risk-free rate plus a risk premium. Simply put, investors require a premium over the risk-free rate if they are going to invest in a riskier security. The formula for the CAPM is:

*Expected ROE = Risk-Free Rate + β*Market Risk Premium*

The equity risk premium for a particular stock is the MRP times the stock's beta (β). The MRP is the difference between the return on the market on average (*i.e.*, the S&P 500) and the risk-free rate. Thus, it is the premium that reflects the risk on an average stock. Beta is the price volatility of that stock relative to the market as a whole. Thus, the risk premium for a *specific* stock equals the *average MRP* times the beta. Since utility stocks are lower risk than the average stock, the risk premium for a utility stock is lower than the average MRP. Multiplying the beta times the MRP gives the appropriate risk premium for the company (or group of comparable companies) being studied.

The risk-free rate is the projected yield on 30-year U.S. Treasury bonds. This rate is considered to be risk-free because the return is guaranteed by the U.S. government.

Two MRP estimates may be used, including the historical MRP estimate and a projected MRP. The historical MRP is based on historical data dating back to 1996. The projected MRP is based on the projected median three-to-five year price appreciation of the 1,700 stocks from Value Line and the projected median dividend yield over the next 12 months for all dividend paying stocks. The forecast annual return is based on the forecast annual growth rate of the stocks plus the forecast median dividend produces a projected annual return. The projected risk-free rate is deducted from the projected annual return to determine the projected MRP.

Beta measures the volatility of a security in comparison to the market as a whole. A beta equal to 1.00 means that a stock's price fluctuates exactly as the market as a whole. A beta higher than 1.00 implies that the stock's price is more volatile than the market; a beta less than 1.00 implies the stock's price is less volatile than the market. The standard formula for estimating beta is the covariance between a security's return and the return of the market divided by the variance of the market returns over a specified period.

Beta is typically based on the betas provided by Value Line. Value Line's method to estimate beta is based on "a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. Value Line then adjusts these Betas to account for their long-term tendency to converge toward 1.00."

Risk Premium Method

The Risk Premium method estimates the ROE for a utility as the sum of a bond yield plus a risk premium yield. The bond yield is the projected return on the long-term government bond plus the risk premium. The risk premium is a measure of the additional return an investor requires due to the additional risk of the security.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 20210015-EI** **Filed: June 21, 2021**

AFFIDAVIT OF BILLIE S. LACONTE

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

Billie S. LaConte, being first duly sworn, on her oath states:

1. My name is Billie S. LaConte. I am an Association of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. 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. 20210015-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.

Billie S. LaConte

Subscribed and sworn to before me this 21st day of June 2021.

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

(Whereupon, prefiled direct testimony of Tony M. Georgis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**)))**	**DOCKET NO. 20210015-EI**

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF THE FLORIDA RETAIL FEDERATION

JUNE 21, 2021

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Blvd, Suite 305, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Florida Retail Federation.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I have a Master of Business Administration degree from Texas A&M University, with specialization in finance. Also, I earned a Bachelor of Science in Mechanical Engineering from Texas A&M University. In addition to my undergraduate and graduate degrees, I am a registered Professional Engineer in the states of Colorado and Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am the Managing Director of NewGen's Energy Practice. I have more than 20 years of experience in engineering and economic analyses for the energy, water, and waste resources industries. My work includes various assignments for private industry, local governments, and utilities, including sustainability strategy, strategic planning, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research. I have been extensively involved in the development of unbundled cost of service ("COS") and pricing models during my career. A summary of my qualifications is provided within Exhibit TMG-1 to this testimony.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony to the Public Utility Commission of Texas and the Indiana Utility Regulatory Commission, as shown in my resume and record of testimony included as Exhibit TMG-1.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR DIRECT TESTIMONY?

A. Florida Power & Light Company ("FPL") has proposed a four-year program to increase its base electric rates by $1,995 million over the years 2022–2025, with the cumulative effect being an increase in customer bills of more than $6.5 billion over that period. FPL expressly ties that multi-year rate plan to a variety of special rate treatments and conditions, specifically including an unusual "Reserve Surplus Amortization Mechanism" proposal through which FPL will create a significant apparent excess depreciation reserve that FPL would then be authorized to use throughout the term of the rate plan to manage its regulated earnings to a target level set by FPL management (presumably at the top end of its allowed range).

The base rate revenue increases that FPL seeks in 2022 and 2023 amount to more than a 20% increase overall from current base rates. Significantly, FPL proposes to direct a disproportionate amount of the proposed increases in those years to its commercial service classes, some of whom would see base rate increases approaching or exceeding 40%. Rate increases of this level are incompatible with the concept of implementing gradual changes in rates to the extent practicable.

My testimony explains that FPL's cost of service study in this case systematically over-allocates utility production and transmission costs to non-firm interruptible service commercial and industrial customers. Also, the current and proposed Commercial Demand Reduction ("CDR") credit offset that FPL incorporates in its cost of service study is not valued correctly. The net result of this distorts FPL's cost of service results and the utility's proposed allocation of revenue increases among customer classes.

My testimony also explains why FPL should allocate distribution related costs using the Minimum Distribution System ("MDS") approach that the utility filed in this case but does not propose to employ. Overall, I recommend that the Commission resolve these issues collectively by directing FPL to adopt an equal percentage increase for all customer service classes for the 2022 and 2023 rate increases, if any, just as FPL proposes to apply its base rate increases for the years 2024 and 2025 for its proposed solar base rate adjustment ("SOBRA") investments.

Next, many commercial class customers receive service under interruptible tariff provisions that for decades have provided significant system reliability benefits to FPL and its firm service customers. In addition to the credits being undervalued within the cost of service study, FPL proposes to slash the credits provided for that interruptible service by one-third. Reducing the credits both exacerbates the rate and customer bill impacts for those interruptible customers and diminishes their incentive to continue to participate in the programs. I demonstrate that FPL has significantly understated the value of its Commercial/Industrial Load Control ("CILC") and successor CDR credit programs as well as why the credits associated with those programs should be increased.

My testimony does not propose specific adjustments to FPL's proposed 2022 and 2023 revenue requirement or the SOBRA increases proposed for 2024 and 2025. This should not be interpreted as endorsing in any sense the level of revenue increases that FPL proposes, which appear to be excessive in several significant respects. I do, however, explain why FPL's proposed Reserve Surplus Amortization Mechanism ("RSAM") misapplies basic depreciation concepts, is not in the public interest, and should not be adopted by the Commission.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- TMG-1 Resume and Record of Testimony of Tony Georgis
- TMG-2 CILC/CDR Credit Rider Embedded Valuation
- TMG-3 Select FPL Responses to FRF Interrogatories (Nos. 7 & 11)

III. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. My recommendations are as follows:

- **Interruptible Service Credits:**

  FPL's proposed reduction to the CDR and CILC credit should be rejected because the credit is undervalued today. FPL underestimates the reliability value provided by customers taking service under the terms of FPL's CILC tariff and participating in the CDR rider credit. The prevailing credits should be increased to $10.07 per kW-month and not reduced as FPL proposes.

- **Cost of Service and Revenue Allocation:**

  FPL's cost of service study incorrectly allocates generation and transmission costs to its interruptible non-firm commercial and industrial loads. This is inconsistent with the way in which FPL actually designs and constructs its system and incurs costs. FPL also does not adequately account for the value of CILC and CDR credit offsets in Schedule E-5 in the cost of service study. These errors distort the cost of service results and FPL's proposed allocation of revenue increases among customer classes.

  Due to the structural corrections necessary in FPL's cost of service analysis concerning FPL's allocation of fixed production and transmission costs to non-firm loads in addition to adjustments required to incorporate the MDS for allocating distribution-related costs, I recommend that any base rate revenue increase adopted by the Commission should be implemented through an equal percentage increase to all customer classes for each of the years of an approved base rate plan.

- **<u>Minimum Distribution System:</u>**

  The Commission should find that the MDS study and results should be included in the cost of service results because they better reflect the costs that customer classes impose on the system, improving eventual rate design and better aligning cost recovery with cost incurrence.

- **<u>The RSAM proposal should be rejected.</u>**

  The Commission should determine that FPL's RSAM proposal misapplies the purpose in depreciation studies of comparing booked depreciation to a theoretical reserve level. Any material reserve surplus determined after approval of all pertinent depreciation parameters (i.e., service lives, net salvage, and cost of removal) for FPL's regulated assets should be applied for consumer benefit (used to moderate current rates or applied to write down utility assets) rather than diverted to ensure earnings levels for FPL investors.

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS WHEN IMPLEMENTED?

A. The results of my recommendations are as follows:

- The CILC base bill percentage reduction is increased to 25% and the CDR credit increased to $10.07 per kW-month.
- An equal percentage increase approach is applied to revenue allocation to any revenue requirement increase approved in this proceeding.

IV. CILC/CDR VALUATION

Q. PLEASE DESCRIBE FPL'S CURRENT CILC/CDR PROGRAMS

A. The Commercial/Industrial Load Control ("CILC") rate and its successor Commercial Industrial Demand Reduction ("CDR") rider are the largest and most successful FPL demand side management ("DSM") programs for its commercial and industrial customers. Historically, these programs have been among the most cost-effective of all DSM programs implemented by FPL. Combined, they currently provide approximately 814 MWs of interruptible load controlled by FPL, which provides exceptionally reliable capacity value to FPL and all of its other customers.

The CILC rate incorporates an interruptible credit into the design of the rate and was the operative large customer interruptible rate for many years. This rate was closed to new customers in the year 2000. Customers participating in the commercial/industrial interruptible service program in subsequent years take service under an otherwise applicable rate schedule, typically GSLD or GSLDT, and receive the CDR credit to their demand charge.

Operationally, the CILC and CDR are identical in that both are interruptible by FPL on one hour notice for reliability purposes for up to six hours when needed to forestall a system emergency; capacity shortages (generation or transmission); or whenever, in FPL's sole judgement, actual or projected system load could require FPL to operate its generating units above their rated output (i.e., "peaking operation").[1] Moreover, in the event of an actual system emergency, the tariffs allow FPL to interrupt service to CILC/CDR participants on shorter notice (as little as 15 minutes, or even less if service to firm customers is threatened), and the interruption period may be longer than 6 hours.[2] Service interruptions under the programs by FPL can occur at any time of the year. FPL has complete control over the service interruption to participating customers and there is no opportunity for a participating customer to avoid, or "buy through," any service interruption that FPL elects to implement. In fact, there are significant penalties under the tariff and CDR rider for energy consumption above a customer's contracted level of firm demand during an interruption event, and FPL can terminate a customer's participation for such noncompliance.

The result of these rigorously defined tariff conditions is an extremely reliable emergency resource that may be available faster than any FPL peaking black-start supply resource. This resource is also dispersed throughout the FPL territory, so its availability is not limited by transmission constraints or other physical impediments.

In contrast, for peaking assets like the four combustion turbines being added to the Gulf service area, FPL needs to acquire or encumber land, construct and operate the generation facilities, recover a return on and of the assets, pay property taxes on the land and assets, pay salaries and benefits to the staff required for those facilities, build

[1] *See* the Control Conditions listed in the tariff.

[2] *See* the Duration Conditions listed in the tariff.

or upgrade substations and other equipment to interconnect with the grid, maintain spare parts inventory, make regulatory filings for air permits and other licenses, incur fuel and other operating costs, and contend with all issues affecting unit start up and delivery of output to load centers (e.g., generator availability, location, and transmission limits). For the interruptible resources participating in the CILC and CDR programs, FPL incurs none of those costs, emissions, or system impediments.

For resource planning purposes, FPL has not in the past and does not currently treat the full metered or measured loads of CILC and CDR customers as firm loads. This is routinely reflected in the FPL Ten Year Site Plan filings, which deduct commercial/industrial load management capacity values from the determination of Net Firm Demand upon which FPL calculates its capacity reserve margins and generation need determinations.[3] In short, CILC/CDR participants have, over several decades, provided a continuous source of system reliability benefits and cost savings to FPL and all firm service customers.

The participating customers receive a reduction in their monthly bills through a direct percent reduction of the base CILC bill (currently 22%), or a bill credit of $8.71 per kW-month for the portion of their CILC or CDR that is interruptible.[4]

Q. FPL PROPOSES TO REDUCE THE INTERRUPTIBLE SERVICE CREDIT APPLICABLE TO NON-FIRM CUSTOMERS TAKING SERVICE UNDER THE COMMERCIAL INDUSTRIAL LOAD CONTROL ("CILC") RATES

---

[3] See Schedules 3.1 and 7.1 of the FPL Ten Year Site Plans.

[4] Direct Testimony of Steven R. Sim at 17 (Sim Direct).

AND THE COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER ("CDR") BY ROUGHLY 33%. DO YOU AGREE WITH THE FPL PROPOSAL?

A. No. The credits applied for this interruptible service should be increased. FPL fully recognizes the continuing reliability value provided by its CILC/CDR interruptible customers and wants to retain all of the 814 MWs of capacity value that current participants provide, but argues incorrectly that the value of that service is declining. Capacity costs actually are not declining, and the reliability value of this interruptible load will only increase as FPL begins to place greater reliance on intermittent supply resources.

Q. PLEASE CONTINUE.

A. The CILC and CDR programs have allowed FPL to avoid or defer additional transmission and generation investments over the decades in which the programs have been in place and customers have been participating. FPL's generation and transmission systems are designed and constructed to meet expected net firm peak demands on the utility system, plus a reserve margin.

In Florida, the accepted capacity reserve margin is 20%.[5] Thus, the capacity benefit that CILC and CDR participants provide includes the dedicated customer load reduction plus the applicable reduction in reserve margin. For example, if 100MW were available for CILC and CDR, the actual benefit to FPL would be 120MW in their resource plan.

[5] The convention to apply a 20% reserve margin is not a rule requirement but has been implemented under a long-standing approach endorsed by the Commission. *See* the calculations on Schedule 7.1 of the FPL Ten Year Site Plan.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE CURRENT CILC AND CDR VALUATION PROPOSED BY FPL?

A. FPL does not propose any changes to how the CILC/CDR programs work that would make them less valuable to the network as a resource. It simply proposes to pay participants less for providing those benefits. Mr. Sim proposes to reduce the CDR incentive credit from $8.71 per kW-month to $5.80 per kW-month, a reduction of 33%, and to reflect a corresponding reduction in the credit incorporated in the CILC rate. He maintains that the benefits of the interruptible service programs, as well as all other DSM programs, has declined, as measured by FPL's AURORA resource modeling tool.

Q. COULD YOU FURTHER DESCRIBE FPL'S STATED REASONS FOR REDUCING THE CDR CREDIT?

A. Mr. Sim equates the historical CDR and CILC capacity value and customer participation to the cost-effectiveness of "open" DSM programs, or those DSM programs open to new participants and marginal new demand response capacity to FPL.[6] He describes how the AURORA optimization model used by FPL for integrated resource planning was used to estimate resource planning costs with and without the CILC/CDR resources available. FPL used the calculated difference in costs between an option with CILC and CDR and one without CICL and CDR interruptible capacity to quantify the ostensible economic benefit of the interruptible service demand reductions.

[6] Sim Direct at 19.

FPL did not, however, propose to reset the CDR credit based on the basic RIM cost-effectiveness measure (a RIM measurement of 1.0 indicates that program benefits match costs). Instead, FPL arbitrarily proposes to reduce the CILC/CDR credit to a level that is expected to result in a RIM test of 1.45, which is higher than all but one of the currently approved FPL DSM measures.[7] This produced the FPL proposed reduced CDR incentive credit of $5.80 per kW. I describe the flaws in FPL's assessment below.

A. COST OF SERVICE AND CILC RATE AND CDR CREDIT VALUE MISALIGNMENT

Q. HOW DOES FPL ALLOCATE GENERATION AND TRANSMISSION COSTS TO THE CILC AND CDR CUSTOMER-RELATED CLASSES?

A. FPL allocates demand costs associated with generation and transmission plant to the CILC and CDR-eligible customer classes based on their metered demand coincident with the 12 monthly peaks on the FPL system. In effect, all metered load is considered firm load.

Q. IS THERE ANY REDUCTION OR ADJUSTMENT IN THIS DEMAND ALLOCATOR AT THE SYSTEM COINCIDENT PEAKS TO RECOGNIZE INTERRUPTIBLE (NON-FIRM) CUSTOMER LOAD?

A. No, FPL does not adjust the customer class demand allocations to account for non-firm demand.[8] CILC and CDR customers and related customer classes are treated as firm

[7] Residential Load Management (on call) program has a RIM of 1.82 but yields a small fraction of the demand reduction benefits provided by the CILC/CDR programs. Docket No. 20200054, *Petition for Approval of Florida Power & Light Company's Demand-Side Management Plan*, 2020-2024 Demand-Side Management Plan at 7 (Feb. 24, 2020).

[8] *See* Exh. TMG-3 (FPL Response to FRF's Second Set of Interrogatories No. 11).

capacity customers, even though more than 814 MW of that coincident peak demand included in the cost allocations is interruptible and FPL does not design or construct firm capacity to serve that load.[9] This systematically over-allocates production costs to FPL's non-firm, interruptible customer classes.

Q. WHAT IS THE EFFECT OF FPL'S ALLOCATION OF CAPACITY COSTS TO CILC AND CDR CUSTOMER CLASSES ON THE ACTUAL METERED DEMAND, INCLUDING THE INTERRUPTIBLE CAPACITY, RATHER THAN THE FIRM CAPACITY AMOUNTS THAT ARE LOWER?

A. FPL's approach violates an essential purpose of a cost of service study, which is to assign and allocate a utility's embedded costs to customer classes based on how those customer classes impose costs on the system. For example, customers served at transmission voltages are not allocated distribution costs because they do not use the distribution system and do not cause distribution plant to be constructed. By the same token, the need for FPL's production plant is tied to net firm demand and excludes non-firm load, which receives a lesser quality of service. By allocating its production costs based on customer class metered demand, and not the lower firm capacity amount reduced for interruptible capacity, FPL over-allocates costs to the interruptible customer classes.

Q. PLEASE EXPLAIN FURTHER.

A. By allocating the full embedded generation costs to the CILC and CDR customer classes at the measured demand and failing to adjust for the non-firm amount of that peak demand in the allocation of costs, FPL's cost of service analysis misaligns cost

[9] *See* Exh. TMG-3 (FPL Response to FRF's First Set of Interrogatories No. 7).

causation with cost recovery. It should correct the analysis by crediting the full embedded cost value of the interruptible capacity back to the participating CDR and CILC customer classes, but FPL does not attempt this.

Embedded costs evaluated in the FPL cost of service study represent the accumulated historical and recent costs for FPL's generation and transmission system. FPL did not design its system or construct production assets to serve CDR and CILC customer interruptible loads. To properly match FPL embedded costs to those classes, such production costs should only be allocated to CILC and CDR firm loads, and not the interruptible component. This would properly align cost allocation with cost causation.

Q. WHAT ARE THE EMBEDDED COSTS FPL HAS INCURRED FOR GENERATION AND TRANSMISSION SERVICE AND THE RELATED UNIT COSTS FOR THOSE SERVICES?

A. Exhibit TMG-2 details the system-level total costs for generation and transmission services and translates those total costs to unit costs (i.e., per kW) based on the FPL system coincident peak billing determinants. I used FPL's coincident peak demand billing units to reflect the unit cost values during peak demand periods on the system because that best aligns with periods when the CILC and CDR services would most likely be activated by FPL.

Generation unit costs, based on the coincident peaks, are $14.49 per kW, and the transmission costs are $4.17per kW for the 2023 Test Year. Thus, the total unit cost for generation and transmission for the FPL system based on coincident peak demands is $18.66 per kW. When the 20% reserve margin is applied to this total it becomes $22.39 per kW. This amount fully reflects FPL's embedded cost of firm capacity and the on-going value to the system of the existing CILC/CDR interruptible load.

Q. IS THIS EMBEDDED UNIT COST MORE REFLECTIVE OF THE BENEFIT AND VALUE THE CILC AND CDR CUSTOMERS HAVE PROVIDED AND CONTINUE TO PROVIDE FPL THAN THE PROPOSED INCENTIVE BY MR. SIM?

A. Yes. If the forward-looking, marginal new resource basis proposed by Mr. Sim is used to value the CDR incentive, it will not match the historical and recent benefits FPL has realized with these customers for more than two decades. Adopting FPL's proposed reduced incentive for the CILC and CDR interruptible customer loads substantially under-states the value provided by those customers to FPL and firm service.

Q. DO YOU RECOMMEND THAT THE CDR CREDIT BE INCREASED?

A. Yes. As I explain below, looking at the expected change in capacity costs in the next four years, the CDR credit value should be increased to $10.07 per kW-month.

B. FUTURE COSTS OF FIRM CAPACITY

Q. MR. SIM STATES THAT A NUMBER OF UTILITY COSTS THAT COULD BE AVOIDED BY DSM BENEFITS HAVE BEEN TRENDING STEADILY

DOWNWARD FOR MORE THAN A DECADE AND WILL CONTINUE.[10] DO YOU AGREE?

A. No. While some DSM-related avoided costs may be declining as referenced in his testimony, the value of firm and dispatchable capacity resources has and is not. As seen in the following figures, the near-term projected costs for firm capacity are not steadily declining across the Eastern and Southern United States.

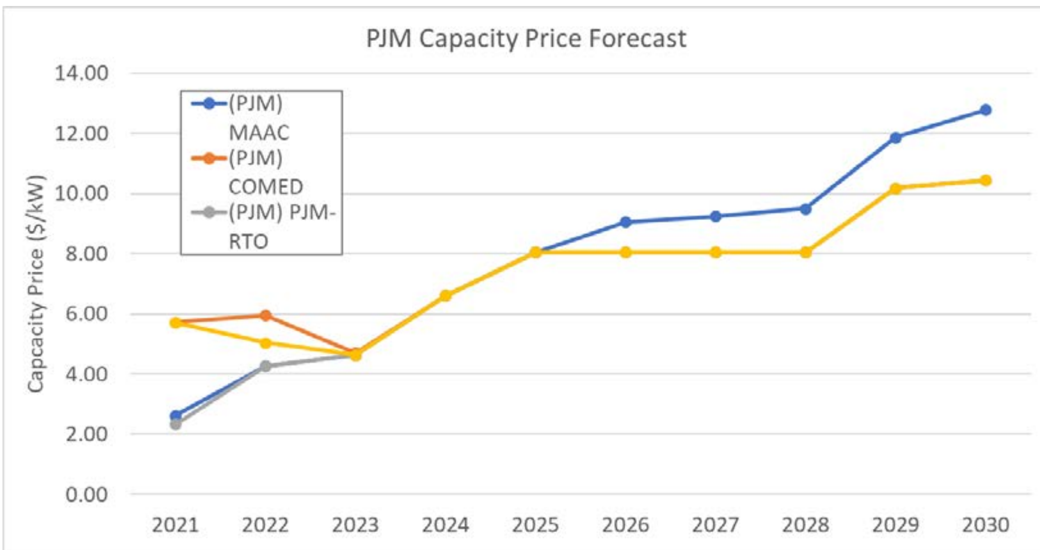


Figure 1: PJM Capacity Price Forecast [11]

[10] Sim Direct at 30.

[11] S&P Global Market Intelligence Power Forecast.

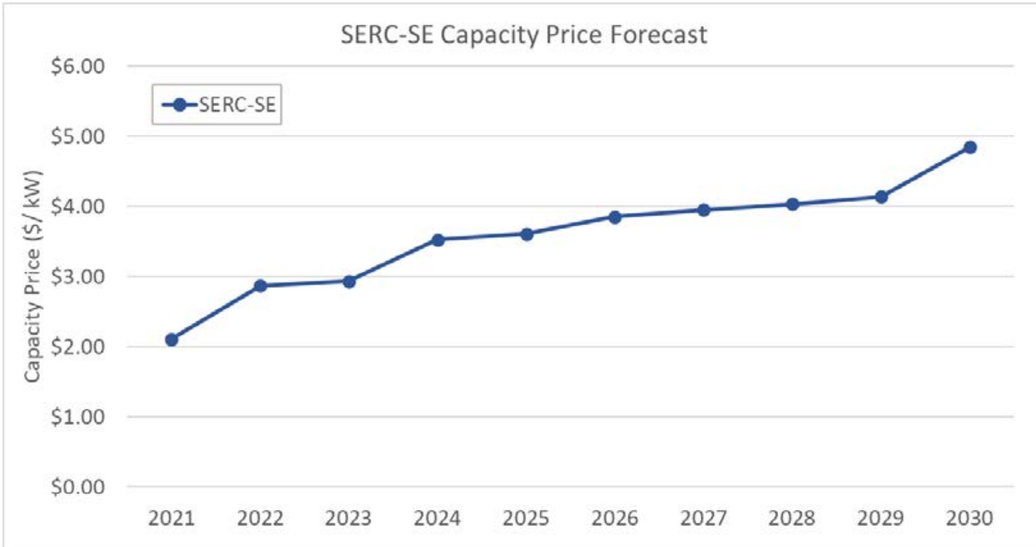


Figure 2: SERC-SE Capacity Price Forecast[12]

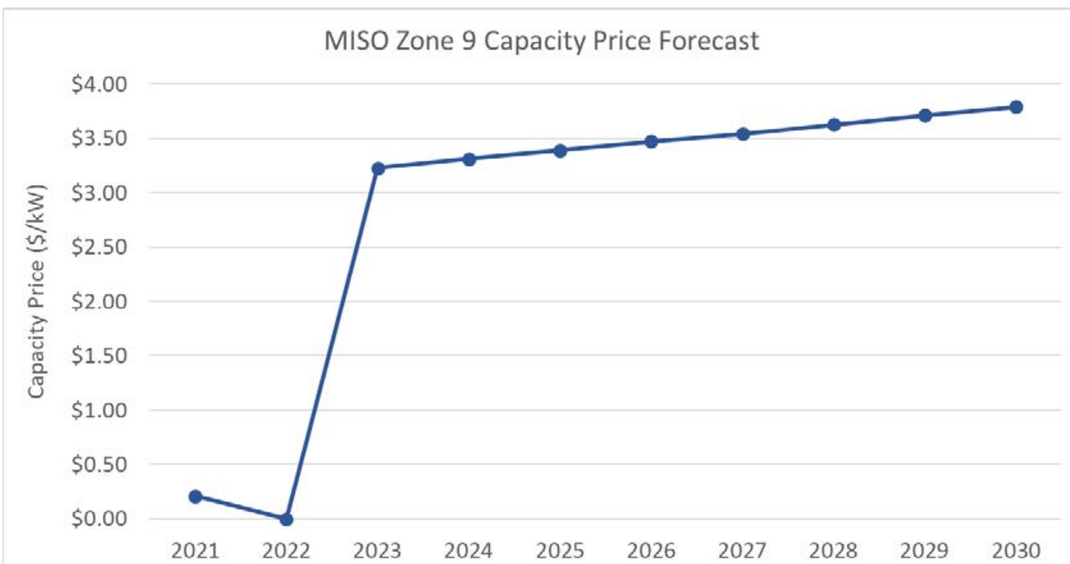


Figure 3: MISO Zone 9 Capacity Price Forecast[13]

---

12 S&P Global Market Intelligence Power Forecast.

13 S&P Global Market Intelligence Power Forecast.

Q. WHAT ARE THE PROJECTED COMPOUNDED ANNUAL GROWTH RATES FOR 2022 THROUGH 2025 IN EACH OF THESE THREE MARKET PROJECTIONS?

A. The compounded average annual growth rates are 17.2% for PJM, 5.9% for SERC-SE, and 1.6% for MISO zone 9. In each case, these projected costs for firm capacity are not decreasing, but increasing substantially. In SERC-SE, the SERC reliability subregion that includes Florida, the capacity costs are projected to increase by 5.9% per year from 2022 through 2025.

Q. WHY DID YOU CALCULATE THE AVERAGE ANNUAL GROWTH FOR YEARS 2022 THROUGH 2025?

A. I selected 2022 through 2025 for SERC-SE because that is a four year period that aligns with the FPL rate plan and Mr. Sim's methodology for calculating the proposed CILC/CDR incentive levels. Mr. Sim noted the setting of incentive levels for DSM programs should ensure the programs remain cost-effective for a minimum of four years.[14]

Q. USING MR. SIM'S METHODOLOGY, COULD THESE PROJECTIONS BE APPLIED TO CALCULATE THE CILC/CDR CREDIT VALUES IN FPL'S CALCULATION METHODOLOGY?

A. Yes. Following Mr. Sim's methodology of a forecasted trend in capacity values, the escalation rates seen in the above examples could be applied to the current CILC/CDR credit value to calculate a new value applicable during the period covered by the proposed FPL rate plan.

---

[14] Sim Direct at 31.

Q. WHICH OF THE ANNUAL GROWTH RATES DID YOU APPLY TO THE CURRENT CILC/CDR CREDIT VALUE?

A. As Florida is located in the SERC-SE reliability subregion, the firm capacity price forecast and subsequent escalation rates for that region were applied to the current CILC/CDR credit value.

Q. WHAT IS THE RESULT OF APPLYING THE ESCALATION RATES FOR CAPACITY TO THE CILC/CDR CREDIT?

A. Table 1 shows the annual CDR credit value when the average annual growth rate in SERC-SE is applied for 2022 through 2025.

Current	**2022**	**2023**	**2024**	**2025**	**Average (2022-2025)**
$8.71	$9.22	$9.77	$10.34	$10.95	$10.07

Q. WHAT IS YOUR RECOMMENDATION FOR THE VALUE OF THE CILC/CDR CREDIT?

A. Applying FPL’s methodology of projected changes in costs and value for capacity, the CDR credit should be increased to $10.07 per kW-month to reflect the average change in value over the four year proposed rate plan.

C. FPL RATE IMPACT MEASURE TEST VALUATION AND APPLICATION TO CILC AND CDR CREDIT

Q. FPL PROPOSES TO RE-SET THE CILC/CDR CREDIT TO A REDUCED LEVEL THAT WOULD PRODUCE A RIM OF 1.45. DO YOU AGREE WITH THAT APPROACH?

A. No. Even if the embedded benefits of interruptible service discussed above were disregarded, there is no rational basis for reducing the credit below a level that would yield a RIM measurement of 1.0. As stated previously, firm capacity costs are not expected to decline, but increase. Reducing the credits to achieve a RIM of 1.45 is inconsistent with expected market conditions for firm capacity costs.

D. CILC AND CDR CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CILC AND CDR VALUATION CONCLUSIONS.

Lowering the value of the CILC and CDR capacity as FPL proposes is inconsistent with the avoided embedded costs provided by the programs and current projections of firm capacity costs, as well as their on-going benefits provided to the FPL and its firm service customers. No credit reduction is warranted, and the credit should be increased.

It is not easier or cheaper to construct firm dispatchable capacity across the Eastern and Southern United States. Those costs are projected to increase, not decrease. At a minimum, FPL's proposal to exaggerate the reduction in the interruptible service credit by re-setting the credit using a RIM of 1.45 is arbitrary and completely unwarranted.

Considering further the heightened importance of reliable capacity resources as weather sensitive intermittent resources on the FPL system increase, FPL's proposal goes in exactly the wrong direction. The credit should not be reduced below the current level of $8.71 per kW-month but should in fact be increased to $10.07 per kW-month.

V. FPL'S COST OF SERVICE AND REVENUE ALLOCATION ERRORS

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING FPL'S COST OF SERVICE STUDY AND PROPOSED REVENUE ALLOCATION FOR ANY BASE RATE INCREASE?

A. As noted above, FPL's cost of service study allocates generation and transmission production costs among service classes based on the metered 12 monthly coincident peaks for the study period without regard for interruptible load on its system. This systematically allocates costs to those classes with interruptible load that FPL does not build generation to serve. FPL's tariff could not be clearer on that point. FPL has not and does not propose to account for service to its interruptible non-firm loads in its generation planning and construction (see the CILC tariff "Continuity of Service Provision"), and its Ten Year Site Plans exclude commercial and industrial load management when determining the Net Firm Demand upon which its capacity reserve margin and generation need determinations are based. FPL's cost of service study simply is inconsistent with these facts.

That basic mis-match distorts the results of the cost of service study, and, by extension FPL's proposed allocation of revenue increases among the service classes that is based on the cost of service study, including in particular the service classes for which it proposes to apply an above system average (1.5 times) increase.

Q. ON SCHEDULE E-5 OF ITS MFRS, FPL ADDS INTERRUPTIBLE REBATES BACK TO THE INTERRUPTIBLE CLASSES IN THE FORM OF A "CILC INCENTIVE OFFSET" TO THE CLASS SALES REVENUES. DOES THIS CORRECT THE BASIC ERROR IN THE COST OF SERVICE STUDY?

A. No. The cost of service study allocates FPL's embedded costs, and the CILC/CDR credit, while a negotiated level in recent years, is based on FPL's avoided costs. The CILC incentive offset on Schedule E-5 reflects the rebate level and not the embedded cost benefits of the interruptible service. From a rate-setting standpoint, it is always hazardous to mix embedded and avoided costs concepts. This misaligns embedded costs and marginal avoided costs concepts in an embedded cost of service by FPL.

Q. PLEASE EXPLAIN.

A. Because it is an embedded cost of service study, to correctly apply the value of the interruptible service programs, the credit offset approach that FPL employs in its study would need to reflect FPL's embedded production and transmission plant costs. As I explained above, that embedded value is approximately $22.39/kW-month, or well more than double the current rebate level that FPL applied on Schedule E-5. Consequently, the study still significantly over-allocates production costs to the service classes with interruptible service participants. This materially under-states the interruptible customer class rates of return shown in the cost of service study.

A. MINIMUM DISTRIBUTION SYSTEM METHODOLOGY AND APPLICATION

Q. PLEASE DESCRIBE THE MDS METHODOLOGY?

A. Distribution costs are driven by the utility's requirement to connect customers to the system no matter where they are located within its service area and the demand requirements those customers place on the system. The MDS method classifies costs as either customer-related or demand-related based on the concept of a minimum system. A minimum system simply represents that infrastructure cost required to connect a customer to the grid without further consideration of the customer's demand and energy requirements. This involves determining the minimum size of pole, conductor, transformer, and service drops required to simply connect to a customer premises. Once the minimum sizes of the distribution system components are determined, the value of the MDS plant is determined. This MDS portion of the total distribution plant is classified as customer-related and allocated to customer classes based on the number of customers. The remaining portion of the distribution plant is classified as demand-related and allocated to customers based on non-coincident peak demand allocation factors.

For example, if the total distribution plant value was $500 million and the MDS study calculated that $100 million was related to the minimum system, then 20% of the distribution plant would be classified as customer-related and allocated accordingly. The remaining 80% would remain classified as demand-related and allocated accordingly. Use of MDS represents a fair classification of distribution costs to customers because it recognizes that the physical location of the customer is an important driver of costs and these costs should be properly classified as customer-related.

Q. IS THE MDS METHODOLOGY FOR CLASSIFYING COSTS AN ACCEPTED INDUSTRY PRACTICE AND CLASSIFICATION METHODOLOGY?

A. Yes. The National Association of Regulatory Utility Commissioners recognizes and details the use and application of the MDS methodology.

Q. WHY SHOULD THE MDS BE APPLIED AND INCLUDED IN THE FPL COST OF SERVICE?

A. The MDS more accurately reflects the costs incurred by the utility to simply connect to customers. It calculates the minimum distribution component sizes for poles, transformers, and conductors to simply connect a customer's meter to the distribution substations to receive power. These distribution assets and infrastructure are required if the customer's peak demand is 10 kW or 0kW. As there is a certain level or amount of distribution assets and infrastructure required whether or not the customer is using any power, a portion of the distribution system costs should be classified as customer related. This customer portion of the distribution costs does not vary with the demand levels, it varies with the number of customers; thus, it should be classified as customer-related.

Q. SHOULD THE MINIMUM DISTRIBUTION SYSTEM (MDS) METHODOLOGY BE APPLIED AND ADOPTED WITH THE FPL RATE PROCEEDING?

A. Yes, it should be included in this and subsequent FPL rate proceedings. It should be included to better reflect the costs imposed on the system by each customer class. The MDS is a long-standing accepted methodology for classifying distribution costs as both customer and demand related. These costs are then allocated on customer and demand allocation factors to the customer classes.

Q. HOW HAS FPL APPLIED THE MDS TO THE PROCEEDING?

A. FPL included an MDS assessment for informational purposes but does not propose to apply the MDS approach in its cost of service analysis. The FPL-prepared MDS cost of service and MFRs are summarized in FPL witness Tara Dubose's Exhibit TBD-7 and TBD-8.

B. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CORRECTING FPL'S COST OF SERVICE STUDY AND PROPOSED REVENUE ALLOCATION?

A. From a bottom line perspective, the erroneous allocation of production costs to non-firm load and FPL's failure to incorporate the MDS approach both indicate that FPL's proposed allocation of above system average increases to its commercial and industrial service classes is not supportable. For the purposes of this case, rather than attempting to re-build the cost of service study from the ground up, I recommend that FPL apply an equal percentage increase to all customer classes for any base rate revenue increase that the Commission may authorize. This approach is appropriate under the circumstances and consistent with the revenue allocation that FPL proposes to apply in the years 2024 and 2025 for its SOBRA-related base rate increases.

VI. RESERVE SURPLUS AMORTIZATION MECHANISM (RSAM)

Q. FPL'S PROPOSED MULTI-YEAR RATE PLAN IS TIED TO ADOPTION, WITH MODIFICATIONS, OF THE RESERVE SURPLUS AMORTIZATION MECHANISM ("RSAM") APPROVED AS PART OF FPL'S 2016 RATE SETTLEMENT. DO YOU SUPPORT APPROVAL OF THE PROPOSED RSAM IN THIS CASE?

A. No. The proposed RSAM is not in the public interest and should not be approved.

Q. PLEASE EXPLAIN.

A. First, the dollars at issue with this mechanism involve the timing of recovery of utility assets from ratepayers through depreciation expense. The proposed RSAM permits FPL to manipulate the timing of charges to depreciation to manage its regulated earnings, and not to benefit consumers. In very brief terms, if FPL's earnings are below its selected target, the utility would implement adjustments to lessen depreciation expense (enhancing reported earnings) and increase its perceived excess depreciation reserve. This is not a zero sum game since this action would create a corresponding increase in rate base that would add to FPL's current return on investment while consumers will be charged higher depreciation in the future to ensure full recovery of the asset costs over time.

If, on the other hand, FPL's earnings looked to exceed its target, the process is reversed: FPL would book increased depreciation expense and lower the perceived reserve. This protects FPL and its shareholders against an excess profit-based rate reduction, but provides no consumer benefit at all.

Q. PLEASE CONTINUE.

A. The reserve surplus refers to a calculated excess in the theoretical depreciation reserve. The theoretical reserve is the calculated balance that would be in the reserve if the service life and net salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. When the actual reserve exceeds the theoretical reserve, it is considered a surplus. When the actual reserve is less than the theoretical reserve, it is considered a deficiency. Comparing the theoretical reserve to the booked amounts provides a general check upon completion of a depreciation analysis to ascertain that the timing of asset cost recovery remains basically on track. Lesser deviations are generally captured in subsequent filings where, as in Florida, the remaining life method is employed. When either a surplus or a deficiency is significant, a ratemaking correction is made to utility rates to keep asset recovery on track with expected service lives. In any event, over time utility ratepayers pay for the full prudently incurred cost of the assets eventually, and correcting a material reserve surplus or deficiency can best be seen as an adjustment in the timing of that recovery.

In its 2016 base rate case, FPL apparently had a substantial reserve surplus. Correcting this excess normally should produce a credit for current consumers in determining a base rate revenue requirement or additional debits to write-down other assets. Instead, the rate settlement produced the RSAM as one of its key features. The RSAM allowed FPL to debit or credit the reserve surplus as needed, in FPL's judgement, to maintain reported earned return on equity within its accepted range (i.e., within 100 basis points of its ROE midpoint range of 10.6%, or 11.6%).[15] Given the expanding level of FPL's rate base, that 100 basis points equates to an additional $360 million in revenue to FPL in 2022 for which there is no underlying cost justification.[16]

The existence of a material reserve surplus is evidence of a depreciation timing mis-match that should be corrected for consumer benefit, RSAM effectively converts the surplus into an earnings maximization mechanism benefitting shareholders. While the mechanism may have been justified in 2016 as part of the compromises and trade-offs inherent in a comprehensive rate settlement, there is no justification for it on its own merits.

Q. DO YOU HAVE OTHER OBSERVATIONS CONCERNING FPL'S PROPOSED RSAM IN THIS DOCKET?

A. Yes. The most obvious is that the RSAM mechanism requires funding through the presence of a large surplus reserve and in this case there is no reserve surplus of any kind. FPL's 2021 depreciation study, sponsored by FPL witness Ned Allis, does not show a reserve surplus, but instead shows a reserve deficiency of $437 million. Thus,

[15] In practice, the reserve amount is adjusted by manipulating the cost of the removal element of the depreciation reserve.

[16] Barrett deposition at p.86.

based on FPL's 2021 depreciation study and Mr. Allis' testimony, there is no foundational predicate for an RSAM at all.

Undaunted, FPL witness Keith Ferguson, proposes a series of plant service life extensions (Exh. KF-3 (B) that are at odds with Mr. Allis' recommendations and are designed to lower depreciation expense by $239 million in 2022 and $249 million in 2023. With these adjustments, when added to an expected 2021 reserve ending balance of $340 million, FPL manages to manufacture a reserve surplus of $1.48 billion that could be used for RSAM purposes.[17] Mr. Ferguson's proposed adjustments are intended solely to create an opportunity to employ the proposed RSAM and are withdrawn if that mechanism is not adopted.

This proposal raises serious issues. Deciding what reasonable service lives should be employed for key FPL production assets in the development of depreciation rates should clearly stand on its own merits. The presence of a depreciation reserve surplus or deficiency should be a fall-out of a sound depreciation analysis and not a designed target. As noted above, comparisons of the actual and theoretical reserves are a check on that process and not something to target as an outcome.

Mr. Allis and Mr. Ferguson each claim they have a reasoned basis for their proposals, but FPL clearly cannot have it both ways. The Commission should reject any effort to manufacture a reserve disparity not grounded in a sound analytical assessment.

[17] This adjustment correspondingly increases the rate base on which FPL earns a return compared to what would otherwise occur.

Q. PLEASE CONTINUE.

A. Regardless of the earnings level achieved, no benefits accrue to ratepayers under FPL's proposed RSAM. This is a fundamental flaw in the mechanism. FPL can debit depreciation expense (and credit the reserve) to hold reported earnings to the permitted high end of its range up to the maximum proposed level of $1.48 billion. If FPL's earnings position remained strong, it could then, other factors being equal, transition to an excess earnings position. In that circumstance, however, the FPL RSAM proposal would permit the utility to begin adjusting the amortization expense of other assets recorded on its Capital Recovery Schedule (Exhibit KF-4) sufficient to cover the full $512 million planned for the period 2022–2025, except the amortization schedule for those assets is already built into the proposed revenue requirements for 2022 and 2023.[18] The RSAM effectively prevents such earnings from being applied to further write down those assets to a period beyond the proposed term of the rate plan. Applying what would otherwise be considered excess earnings to asset write-downs should be among the first uses of a large reserve surplus, so the proposed RSAM treatment conflicts with accepted regulatory practice. In any circumstance in which the RSAM is applied to keep FPL reported earnings in the accepted range, some tangible consumer benefit is required as well by writing down a commensurate level of FPL's regulatory assets.

Finally, FPL proposes that the RSAM remain in effect after the proposed four year rate plan until base rates are re-set by the Commission. This more or less ensures that FPL

[18] *See* FPL Exhibit KF-4.

could not, at least in the foreseeable future, be found to be in an excess earnings situation.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO FPL'S RSAM PROPOSAL?

A. It is essential to recognize at the outset that consumers will eventually be charged in rates for the full prudently incurred costs of FPL's assets. Depreciation rates and corrections associated with a depreciation reserve surplus merely affect the timing of that recovery. The accounting treatments proposed through the RSAM manage utility earnings in the short term but can also skew the appropriate timing of asset recovery from consumers and create other rate issues down the line. With that in mind, I recommend that:

1. The Commission reject the RSAM proposal as unwarranted and not in the public interest.
2. If the final approved depreciation rates demonstrate that a substantial reserve surplus exists, I recommend that 50% of the excess be applied to reducing the base rate revenue requirement and 50% be applied to amortizing FPL assets listed on the Capital Recovery Schedule. This approach would be fair to rate payers and FPL.
3. If an RSAM is approved by the Commission, at least two adjustments are required to benefit consumers.
    a. Any RSAM credits to the reserve should be matched by an equal supplemental credit to assets on the Capital Recovery Schedule, reducing the amounts to be amortized in the future.

b. The Commission should direct that the RSAM expire at the end of proposed term of the rate plan (i.e., yearend 2025 under FPL's proposal or whatever term the Commission may lawfully fix).

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of John Thomas Herndon was inserted.)

IN RE: PETITION BY FLORIDA POWER & LIGHT COMPANY FOR RATE UNIFICATION AND FOR BASE RATE INCREASE, DOCKET NO. 20210015-EI

DIRECT TESTIMONY OF JOHN THOMAS HERNDON

ON BEHALF OF FLORIDIANS AGAINST INCREASED RATES, INC.

INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John Thomas Herndon, and my address is 9062 Eagles Ridge Drive, Tallahassee, Florida 32312.

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

A. In practical terms, I am self-employed as an independent contractor. After more than thirty years of service to two Florida governors, the Florida Legislature, the Public Service Commission, and other agencies in Florida's state government, as well as brief periods in consulting, I retired from full-time employment in 2005. Since that time, I have worked as an independent contractor, including service as a director and board member for several organizations and occasionally as a consultant on various matters, including utility issues.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Floridians Against Increased Rates, Inc., a Florida not-for-profit corporation and FAIR's members who are customers of FPL.

Q. Please summarize your educational background and professional experience.

A. I received a Bachelor of Arts degree in Interdisciplinary Social Services from the University of South Florida in 1968, and a Master of Social Work degree from Florida State University in 1972. Beginning in 1974, I held several positions of increasing responsibility in Florida state government, including service in the Florida Legislature as staff director of the Florida House of Representatives Appropriations Committee. After that I served six years as state budget director and later Deputy Chief of Staff and Chief of Staff for Governor Bob Graham. I then served as a Public Service Commissioner from 1986 until 1990, after which Governor Bob Martinez nominated me to serve as Director of the Florida Department of Revenue from 1990 to 1992. Governor Lawton Chiles appointed me as his Chief of Staff for three years, from 1992 until 1995. My career in Florida state government culminated with my serving six years as Executive Director of the State Board of Administration managing the state pension fund and other accounts. My professional experience also included two relatively brief periods, 1995-

1996 and 2002-2005, in which I provided governmental consulting and lobbying services to a range of clients. My résumé is provided as Exhibit JTH-1 to my testimony.

Q. Please describe your responsibilities and activities with respect to FAIR.

A. I am a director of FAIR. In that capacity, I participate in the usual range of decisions made by directors of non-profit corporations that work to promote the public interest. Pursuant to applicable law, I receive no compensation for my services as a director. However, I am compensated pursuant to an engagement agreement for my services as an expert witness in this proceeding.

Q. Are you testifying as an expert in this proceeding? If so, please state the area or areas of your expertise relevant to your testimony.

A. Yes. From my perspective as a former member of the Florida Public Service Commission, as the Executive Director of the Florida State Board of Administration, as the Director of the Office of Planning and Budgeting in the administration of Governor Bob Graham, and as the chief of staff for Governor Bob Graham and Governor Lawton Chiles, I am testifying as an expert regarding utility ratemaking, including appropriate rates of return on common equity for investor-owned electric companies such as Florida Power & Light Company ("FPL") and Gulf Power Company ("Gulf"); regarding the principles applicable to setting fair, just, and reasonable rates for electric utility customers; and regarding sound public policy, including public interest considerations applicable to promoting electric utility service and the Commission's role in setting utility rates.

Q. Have you previously testified in proceedings before utility regulatory commissions or similar authorities?

A. Yes. I testified before the Florida Public Service Commission ("Commission," "Florida PSC," or "PSC") in Docket No. 20080317-EI, a previous general rate case before the PSC involving Tampa Electric Company. In my career, I also testified many times regarding financial, investment, and policy issues before committees and subcommittees of the Florida Legislature and before the Florida Governor and Cabinet.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit JTH-1	Résumé of John Thomas Herndon;
Exhibit JTH-2	Florida PSC document titled "REVENUE REDUCTIONS AND INCREASES ORDERED BY THE FLORIDA PUBLIC SERVICE COMMISSION FOR CERTAIN INVESTOR-OWNED ELECTRIC AND NATURAL GAS UTILITIES, UTILITIES FROM 1960 TO PRESENT (All Utilities from 1968 to Present);

Exhibit JTH-3	Articles of Incorporation of Floridians Against Increased Rates, Inc.;
Exhibit JTH-4	FAIR Membership Application; and
Exhibit JTH-5	FPL's Proposed Rate Increases Over 2022-2025.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony in this proceeding is to provide the Commissioners with a brief description of FAIR and to share my professional opinions regarding the appropriate standards for setting allowed revenues or revenue requirements, for setting rates of return on common equity for rate-regulated electric companies in Florida, and ultimately, for setting the retail electric rates to be charged to FPL's customers at the conclusion of this case. I also address the need for the Commission to consider the overall public policy aspects of the Commission's decisions on the public interest, particularly in the real-world circumstances in which this rate case is being conducted. By that I mean, the disastrous impact of FPL's proposed rate increases during the recovery from the most devastating economic and related challenges that the United States and the world have faced since World War II.

Q. Please summarize the main points of your testimony.

A. FAIR is a Florida not-for-profit corporation that exists to inform the public regarding energy issues and to advocate by all lawful means for laws, rules, and government decisions – including decisions to be made by the Florida Public Service Commission – that will result in the retail electric rates charged by Florida's investor-owned electric utilities being as low as possible while ensuring that the utilities are able to provide safe and reliable electric service. In joining FAIR, the members request and authorize FAIR to represent their interests in having the lowest possible electric rates consistent with their respective utility providing safe and reliable service. While FAIR continues to recruit new members on an ongoing basis, as of the date on which this testimony is being filed, FAIR has more than 500 members. The substantial majority – approximately 80 percent – of FAIR's members are customers of FPL.

Pursuant to Florida law and fundamental principles of utility rate-making, the Commission is responsible to set a utility's allowed revenues (or "revenue requirements") and the utility's rates at levels that are fair, just, and reasonable to both the utility and its customers.

From the utility's perspective, fair, just, and reasonable rates are rates that provide the utility with revenues that are sufficient to cover all of its reasonable and prudent operating and maintenance ("O&M") costs, cover its reasonable costs of borrowing debt capital, and provide the utility with the opportunity to earn a return on a reasonable and appropriate amount of equity capital that is sufficient to attract the needed capital to finance its reasonable and prudent investments that are necessary to provide safe and reliable service.

From the perspective of customers, fair, just, and reasonable rates are rates that enable the utility to provide safe and reliable service, including earning a reasonable return on investment, but no more than that. This means that whatever the utility pays for materials, capital equipment, and borrowed capital should be no greater than the amount truly necessary to provide safe and reliable service.

FPL's requests in this case represent the largest rate increase request made by any Florida public utility in history, and if granted, these new rates would be the largest rate increases in Florida history. (My Exhibit JTH-2 is a copy of a PSC report of rate case decisions of the PSC; the largest previous request was FPL's request in Docket No. 20080677-EI, made in 2008 and decided in 2010.) FPL's requests are excessive to the degree that it is highly likely that FPL can provide safe and reliable service with no rate increase before 2023 at the earliest. It is my opinion, based on reviewing FPL's claims and the testimony of the intervenor witnesses in this case, including the other witnesses sponsored by FAIR, that FPL can recover all of its O&M costs, pay all of its borrowing (debt) interest costs, and earn a fair return on its equity investment if the Commission simply sets FPL's rates applying a rate of return on common equity ("ROE") close to the average currently and recently approved by other states' regulatory commissions to a capital structure that includes an average amount of equity capital ("equity ratio") compared to those currently and recently approved by other state commissions. A PSC decision on these principles and parameters will not harm FPL's financial integrity, and given the very low financial risks faced by Florida IOUs, an average return in Florida – vs. the same return in other states – will be viewed favorably by potential investors.

FPL's request of for a midpoint ROE of 11.50 percent, including its requested 50 basis point "ROE performance incentive," is excessive vs. the national average for vertically integrated electric utilities of 9.55 percent. FPL's proposed equity ratio of 59.6 percent is excessive vs. the national average for all electric utilities of less than 50 percent. FPL's proposed values are also greater than those supported by other witnesses in this case. Just these two factors taken together, if decided fairly by the Florida PSC, would reduce FPL's revenue requirement for 2022 by more than $1 billion. This means that in 2022, FPL could cover all of its labor, materials and supplies, and other O&M costs, cover all of its borrowing (interest) costs, and make all of its proposed investments, and still earn returns demonstrated by national experience to be fair and reasonable, with no rate increase at all! Another way of looking at FPL's financial conditions is to see how they fared using the existing rate plans. The answer is, they did very well as measured by any financial metric.

From the basic viewpoint of good public policy, FPL's requests for the largest rate increases in Florida history and for an equity return that is dramatically greater than relevant national averages on an inflated equity ratio that is also substantially greater than relevant national averages, are excessive and unnecessary. In the simplest terms, FPL wants to overcharge its customers by more than $1 billion annually. For FPL to make this request against the backdrop of its earning returns much, much greater than the national averages over the past three years defies logic. And finally, for FPL to make these requests in the context of Florida and the United States still recovering from the most devastating economic, public health, and related challenges that the United States and the world have faced since World War II, is plainly contrary to the public interest of Florida and Florida's citizens.

The Florida PSC should stand up for what its statutes require: the Commission should appropriately consider the public interest of all Floridians and set rates for FPL and its customers that will enable FPL to recover its costs and earn a fair return on reasonable investment, sufficient to provide safe and reliable service, no more and no less. The PSC should deny FPL's excessive requests.

BACKGROUND – FLORIDIANS AGAINST INCREASED RATES, INC.

Q. Please describe FAIR and its purposes.

A. FAIR is a Florida not-for-profit corporation that was formed in March of this year. FAIR's purposes are set forth in the corporation's Articles of Incorporation, which are included as Exhibit JTH-3 to my testimony. In summary, FAIR's purposes are to inform the public regarding energy issues and to advocate by all lawful means for laws, rules, and government decisions – including decisions to be made by the Florida Public Service Commission – that will result in the retail electric rates charged by Florida's investor-owned electric utilities being as low as possible while ensuring that the utilities are able to provide safe and reliable electric service.

Q. Who are FAIR's members?

A. Membership in FAIR is open to any customer, including both residential and business customers, of any Florida investor-owned utility, i.e., FPL, Duke Energy Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company. In joining FAIR, the members request and authorize FAIR to represent their interests in having the lowest possible electric rates consistent with their respective utility providing safe and reliable service. A copy of FAIR's basic membership application is included as Exhibit JTH-4 to my testimony.

Q. How many members does FAIR have?

A. As indicated above, FAIR is a relatively new organization. Thus, not surprisingly, FAIR has an ongoing membership recruitment program. As of the time that this direct testimony is being filed, FAIR has more than 500 members, including customers of FPL, Duke Energy Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company's electric division. FAIR's members include customers from residential and general service rate classes. The vast majority of FAIR's members – approximately 80 percent of the total membership as of this date – are customers of FPL.

BACKGROUND – REGULATORY PRINCIPLES

Q. From your perspective as a former Florida Public Service Commissioner, what do you believe are the primary policies and principles that should guide the PSC's decisions in this case?

A. In general, the fundamental principles of setting a utility's allowed revenues and rates are simple: the utility should be allowed to recover all of its reasonable and prudent operating and maintenance ("O&M") costs, its reasonable and prudent costs of borrowing debt capital (i.e., interest expense), and a reasonable return on its reasonably and prudently incurred investments necessary to provide safe and reliable service at the lowest possible cost. In this context, "reasonable and prudent" costs must be determined as those that are <u>cost-effective</u> as compared to available alternatives, and this principle applies equally to the cost paid for a length of power line, a power pole, the interest cost on a bond, the ROE rate <u>required</u> in objective and competitive capital markets to attract equity capital, and the amount of equity capital that the utility objectively <u>needs</u> in order to support its investments.

These fundamental principles are frequently referred to as a set of policies and principles known as the "Regulatory Compact." The "bargain" contained within this Regulatory Compact is that the utility enjoys a government-protected monopoly in its service area, in return for which it is allowed to recover its necessary costs incurred in providing safe and reliable service to its captive customers. This bargain is fair to utilities because it ensures that, assuming reasonable and sound management, the utility will recover its legitimate costs and earn a fair and reasonable return, and it is fair to customers because, properly followed, it will ensure that customers receive safe and reliable utility services, like electricity, which is generally regarded as a necessity, at the lowest possible cost. In this context, cost-effective means at the lowest cost available from functionally equivalent alternatives; if the utility overpays or attempts to charge rates based on such over-payments, the bargain is violated.

Q. How does this relate to utility rates?

A. The utility's rates must be fair, just, and reasonable (and not unduly discriminatory). Fair, just, and reasonable rates are those that allow the utility to recover its reasonable, legitimate costs incurred through cost-effective management and to recover a reasonable and cost-effective return on its investments, also evaluated on the basis of cost-effective financing and management. Rates that include expenses for materials or labor that could have been procured at lower cost, and rates that include excessive returns, are unfair, unjust, and unreasonable.

BACKGROUND – FPL'S RATE INCREASE REQUESTS

Q. Please summarize your understanding of FPL's requested rate increases in this case.

A. From FPL's petition filed on March 12, 2021, and from the letter submitted by FPL's president, Eric Silagy, to PSC Chairman Gary Clark on January 11, 2021, I understand FPL's requests to include the following:

1. An increase in FPL's general base rates of $1.108 billion per year to be effective on January 1, 2022;
2. An additional increase in FPL's general base rates of $607 million per year (on top of the $1.108 billion increase in 2022) to be effective on January 1, 2023; and

3. Additional increases in base rates for planned solar generation investments in 2024 and 2025. (The revenue requirements for FPL's planned solar expansions are not specified in FPL's MFRs or testimony, so I have omitted these amounts from further discussion here.)

Adding all of these requested increases together over the four-year period from 2022 through 2025 covered by FPL's requests, it appears that FPL is requesting that its customers pay approximately $6.25 billion in additional base rates over this period. My Exhibit JTH-5 shows a simple tabulation of these amounts, excluding any of the 2024 and 2025 solar rate increases.

Q. Do FPL's proposals include any other features that affect its customers rates?

A. Yes. FPL also proposes to implement a "Reserve Surplus Amortization Mechanism" (to which FPL applies the acronym "RSAM") that would impact at least the rates of future FPL customers. This RSAM proposal is discussed further below and more fully by another FAIR witness, Timothy J. Devlin, a Certified Public Accountant and former Executive Director of the PSC.

RETURN ON EQUITY

Q. What is meant by "return on equity" in the context of regulatory decisions determining a utility's allowed revenues and rates?

A. Given the monopoly enjoyed by electric utilities such as FPL, these utilities are generally regulated by government agencies and are entitled to recoup through their regulated rates prudently incurred costs for O&M, cost of borrowing debt capital, and a reasonable return on investment such that investors are willing to support the utility operations.

Q. What is the basic standard that a regulatory authority, such as the Florida PSC, should use in deciding what ROE to use in setting a utility's allowed revenue requirements and rates?

A. Consistent with the Regulatory Compact principles and the PSC's obligation to set fair, just, and reasonable rates, the basic standard is that the ROE should be sufficient to enable the utility to cover its O&M costs, borrowing costs, and prudently incurred investments that are necessary to provide reliable, safe, and adequate service to its customers. No more, no less!

Q. How would you go about evaluating a utility's ROE?

A. While there are other analytical methods used by ROE witnesses in cases such as this, as an investor and as a former investment manager of major public funds, I believe that it is also useful and meaningful to "ground truth" any such estimates against what can be observed in the real world as the ROEs that are used by other regulatory authorities and the experience of utilities subject to those other authorities' decisions in being able to fulfill their obligation to provide safe and reliable service.

I would review, as many observers do, reports such as the S&P Global Market Intelligence Report. I would then look at the rates approved by other commissions and authorities and observe how the utilities whose rates were thus determined or approved are functioning in the real world. In the simplest terms, if the utilities are providing safe and reliable service with rates set based on the reported values, then it is obvious that those values are sufficient to enable the utility to do its job and to recover a fair return to equity capital.

Note that all of this assumes, reasonably, that the utility is allowed to recover all of its reasonable O&M costs and all of its borrowing (interest) costs. One can then observe whether the utility is able to issue bonds, whether it has experienced a debt downgrade, whether it (or its parent) has been able to issue new stock, and whether it has any readily observable reliability issues, that is, whether it is, in fact, providing safe and reliable service.

Q. Where does FPL's requested midpoint ROE of 11.5 percent fall relative to national averages?

A. FPL's request is substantially higher than the national average of 9.55% approved by other states' regulatory bodies – public service commissions and public utility commissions – for vertically integrated electric utilities in 2020, and it is excessive by any measure.

Q. Do you believe that FPL is really asking that it be allowed to earn an ROE of 11.5 percent?

A. No. I believe that, by use of its proposed RSAM, FPL wants to earn an ROE of 12.5 percent, just as it has earned 100 basis points above the midpoint of its current ROE range for the past 30-plus months for which data are available. This pattern of FPL's use of the RSAM and earning hundreds of millions of dollars a year above the midpoint ROE is documented in the exhibits of FAIR's witness Tim Devlin.

Q. Do you believe that FPL needs an ROE of 11.5 percent in order to attract sufficient equity capital and debt capital to support the investments that are reasonable, prudent, and necessary to maintain reliable service?

A. No. I believe that FPL's requested ROE of 11.5 percent is far out of line with what would be required in any objective capital market.

Q. What are the consequences to customers?

A. Again referring to the fundamental principles of utility ratemaking, the Regulatory Compact, and the principle that rates must be fair, just, and reasonable, if the PSC were to set FPL's allowed revenue requirements and rates using an ROE rate greater than what is required to attract needed capital, FPL and the PSC would be violating the Regulatory Compact and causing customers to pay rates that are too high – i.e., in regulatory terminology, rates that are unfair, unjust, and unreasonable.

EQUITY RATIO

Q. What is meant by the "equity ratio" in electric utility rate cases like this one?

A. It is a financial metric based on the amount of debt a company has vs. the shareholder equity in the company.

Q. How does the equity ratio affect customer rates?

A. Rates are set to recover the utility's costs, including a fair and reasonable return on equity (common stock). In capital markets, the cost of equity capital – i.e., the ROE – demanded by common stock investors is greater than the interest cost on long-term debt. Since utilities generally need some balance of equity and debt to support their investments, the question or issue for regulatory commissions becomes what the appropriate balance is.

Keeping in mind that, adhering to the Regulatory Compact, the utility and its regulators should always be striving to ensure safe and reliable service at the lowest possible cost, the regulatory authority must consider and determine the appropriate balance. Since equity capital costs more than debt, a higher equity ratio will (within a broad range) result in higher customer rates than a lower equity ratio.

To give a simple example, if a utility pays 5 percent on its bonds and a pre-tax ROE of 14 percent on its equity capital, its weighted cost of capital will be 9.5 percent if it has a 50 percent equity ratio (i.e., if it finances its investments with 50 percent equity and 50 percent debt or bonds). On the other hand, if the utility uses 60 percent equity, its weighted cost of capital will be 10.4 percent. On a rate base of $10 billion, this would cost customers roughly $90 million a year more than if the utility were to use the 50-50 financing structure.

Q. Do you believe that FPL needs an equity ratio of 59.6 percent?

A. No! The national average equity ratio approved by other state commissions for electric utilities in 2020 was 49.69 percent, nearly twenty percent lower, and nearly ten full percentage points lower, than FPL's request. This demonstrates that, in an objective capital market, utilities do not need equity ratios like FPL's requested 59.6 percent to attract capital, cover their costs, and provide service.

From my perspective as a former member of the PSC and as a former manager of the State's major pension funds, I will simply say that FPL's requested equity ratio of 59.6 percent is excessive. This issue is addressed in witness Mac Mathuna's testimony, with due consideration to FPL's financial integrity and bond rating considerations, and he recommends an equity ratio of 55 percent. Even though that is higher than current national averages, I would not object to that value.

FPL'S PROPOSED "RESERVE SURPLUS AMORTIZATION MECHANISM"

Q. What is FPL's proposed "Reserve Surplus Amortization Mechanism," or "RSAM?"

A. The RSAM as employed by FPL is the functional equivalent of a specialized depreciation reserve amortization scheme. According to the testimony that I have seen, the basic mechanism of FPL's RSAM arose from settlement agreements in 2010, 2012, and 2016; as far as I can tell, it was never specifically voted on as a separate litigated issue by the Florida PSC. FPL should be required to explicitly detail how it has used the RSAM in the past and how it proposes to utilize it going forward.

As employed by FPL, FPL can debit the RSAM or "Reserve Surplus" account in its discretion to offset amortization expense, which increases book earnings, and it can use any amount available in the RSAM account to achieve earnings up to the top of its ROE range. If FPL is allowed to use up a depreciation surplus of any amount, e.g., the $1.48 billion surplus proposed by FPL, such that that surplus is fully depleted at the end of the four-year period, then FPL's customers as of that time will be deprived of the rate-reduction benefits that the surplus would provide when applied to FPL's future rate base. Whatever the amount of FPL's rate base might be in the future, if FPL is allowed to use up the surplus, then FPL's rate base in its next rate case would be $1.48 billion greater than if the surplus were not used up, and FPL's future customers would be saddled with the capital costs – return on equity and interest cost – of that much greater rate base. This is clearly intergenerational inequity!

To emphasize this point, customers create any depreciation surplus by over-paying depreciation expense over time. Standard regulatory accounting and ratemaking practice is to flow back this customer-created value to the utility's customers; although there are sometimes arguments over the term of the amortization period (e.g., 4 years vs. 20 years), the value is always flowed back to customers. FPL's proposal, in stark contrast, would keep up to the entire $1.48 billion of customer-created value for FPL and its shareholder.

Q. Is this RSAM proposal appropriate?

A. At a minimum, it is not appropriate as proposed by FPL. I have reviewed the testimony of FAIR's witness Tim Devlin on this subject, and I agree with Mr. Devlin that it is not appropriate. I further agree that, if any RSAM-type proposal is to be allowed in this case, FPL's ability to use it should be capped to only amounts necessary for FPL to achieve its midpoint ROE, which is the fair and reasonable return to FPL's equity investor. Anything more than that is taking customer-created value away from customers, and any such practice is unfair, unjust, and unreasonable.

SERVING THE PUBLIC INTEREST

Q. What is the Florida PSC's basic statutory mandate?

A. As articulated by the Florida Legislature in Section 366.01, Florida Statutes, the PSC's basic statutory mandate is as follows:

> The regulation of public utilities as defined herein is declared to be in the public interest and this chapter shall be deemed to be an exercise of the police power of the state for the protection of the public welfare and all the provisions hereof shall be liberally construed for the accomplishment of that purpose.

As a non-lawyer and former PSC Commissioner, I believe that this means what it says: the PSC is charged by the applicable Florida Statutes with carrying out its duties to protect the public welfare of the citizens of the state.

Q. From your perspective as a former Public Service Commissioner, as a former staff director for committees of the Florida Legislature, as a former policy and budget director and chief of staff to two Florida governors, and as a lifelong citizen of Florida, what does the "public interest" mean to you?

A. I believe that the "public interest" means the public welfare generally, and this includes considerations of the overall health of the Florida economy and the welfare of all citizens. With respect to a specific utility such as FPL, including both the historical FPL and the new, combined FPL including Gulf Power Company, this means at least the welfare of all of the people served and directly affected by the utility's service. This includes considerations of the economic impacts of a utility's rates and rate increase requests on individuals, households, and businesses. To be completely clear, I am not advocating in any way that low-income customers should be subsidized by a utility's other customers or by the utility's shareholders, but I am saying that the PSC must consider the overall impacts on the Florida economy and on all customers.

In present-day, real-world circumstances, the PSC must recognize that many Floridians, Florida households, and Florida businesses are still struggling toward recovery from the impacts of the COVID-19 pandemic.

Q. Considering all of the circumstances confronting Florida and Floridians at the present time, what opinions, if any, do you have regarding whether FPL's proposed rate increases are consistent with the public interest of Florida and her citizens?

A. I believe that FPL's rate increase requests are excessive and contrary to the public interest. Particularly considering the amounts of equity returns that FPL hopes to harvest from its captive customers, FPL's requests are harmful to the Florida economy and to Floridians because they would, if allowed by the PSC, drain several billion dollars away from customers and give that money to FPL's shareholder, NextEra Energy. The requested increases are demonstrably and observably excessive compared to the returns – due both to an excessive ROE and an excessive equity ratio – that have been recently and currently approved by other state regulatory commissions, which tells the PSC that FPL can obtain needed capital at costs much, much less than what it is asking in this case.

As a side note, FPL requests a 50 basis point "ROE performance incentive" for what it claims is superior performance better than its peers. I would hope that FPL strives for superior performance as a matter of routine operation. Further, FPL's proposal is not an incentive at all - they are really asking for a reward for past behavior. Their behavior going forward will not in any way be incentivized by giving them a higher ROE. Their requested ROE performance incentive should be rejected.

Q. What, if anything, should the PSC do with respect to these public interest concerns in this case?

A. Again being perfectly clear, FPL should be allowed to recover its legitimate O&M and debt costs. If a length of power line costs $10 a foot, then that's what FPL should be allowed to recover in its rates. If an experienced line-worker's fair compensation is $90,000 a year, plus benefits and overtime premiums where applicable, then that's what FPL should be allowed to recover.

When it comes to FPL's equity costs, however, the PSC often applies a "range of reasonableness," typically framed as a range of 100 basis points below to 100 basis points above a defined midpoint. The PSC also frequently discusses a reasonable range for an ROE in deciding on that midpoint. In today's real world conditions facing Floridians, if the PSC recognizes that the "reasonable range" of ROEs is probably somewhere between 8.5 percent and 10.0 percent, given the national averages clustered around 9.5 percent, the PSC should act <u>in the public interest</u> to set rates using a value in the low end of any range of reasonableness.

This result would fulfill the PSC's statutory mandate to regulate in the public interest and to promote the public welfare by keeping spending power in the pockets of customers rather than unnecessarily transferring it to FPL and NextEra.

And the PSC must remember again that this assumes that FPL will be allowed to recover all of its O&M and debt costs, and to make all of whatever rate base investments the PSC deems reasonable and prudent. Any argument advanced by FPL that it would not have sufficient funds to provide reliable service, to make needed investments, to restore service following a hurricane, or any other such assertion, is a complete red herring. This principle of promoting the public interest by keeping spending power in customers' pockets for the health of the Florida economy and the welfare of those customers, while providing returns that are within a range of reasonableness as determined by reference to objective national averages is exactly what the PSC should be doing.

SUMMARY AND RECOMMENDATIONS

Q. Please summarize your opinion regarding FPL's requested rate increases.

A. In closing, it is my opinion that FPL has generally fulfilled its mission to provide safe, reliable, and reasonably priced energy services within the revenue parameters of its current rate plan, and no further rate increase is necessary!

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Nancy H. Watkins was inserted.)

IN RE: PETITION BY FLORIDA POWER & LIGHT COMPANY FOR RATE UNIFICATION AND FOR BASE RATE INCREASE, DOCKET NO. 20210015-EI

DIRECT TESTIMONY OF NANCY H. WATKINS, C.P.A.

ON BEHALF OF FLORIDIANS AGAINST INCREASED RATES, INC.

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Nancy H. Watkins, and my address is 610 South Boulevard, Tampa, Florida 33606.

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

A. I am employed by Robert Watkins & Company, P.A., as a Certified Public Accountant. I am also a director and vice president of Robert Watkins & Company.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Floridians Against Increased Rates, Inc., a Florida not-for-profit corporation, and its members who are retail customers of Florida Power & Light Company ("FPL").

Q. Please summarize your educational background and professional experience.

A. I received a Bachelor of Arts in Business Administration degree with a major in Accounting from the University of South Florida College of Business in 1982. I have worked continuously for Robert Watkins & Company, P.A. since its founding in January, 1980. I have performed all aspects of public accounting including tax, auditing, management advisory services, and accounting and review services. My primary scope of practice at this time is compliance and control systems for tax exempt entities with a focus on 501(c)(4) public policy organizations and political organizations, which include candidates, political parties and political action committees. A copy of my résumé is provided as Exhibit NHW-1 to my testimony.

Q. Please describe your responsibilities and activities with respect to FAIR.

A. I am the Treasurer of FAIR. In that capacity, I perform the usual range of functions and services that the treasurer of a not-for-profit corporation would normally perform. Robert Watkins & Company has an engagement agreement to perform accounting services for FAIR, and it is through that engagement agreement that I am compensated for my services at our usual and customary rates. FAIR and Robert Watkins & Company have agreed that my membership verification analysis services and related testimony in this proceeding will also be provided within the scope of our existing engagement agreement.

Q. Do you hold any professional licenses or certifications that are relevant to your testimony in this proceeding?

A. Yes, I am a Certified Public Accountant in the State of Florida. I received my certification in 1983. I am also a Professional Registered Parliamentarian pursuant to the certifications of the National Association of Parliamentarians and the American Institute of Parliamentarians. I have been a credentialed parliamentarian since 2007.

Q. Have you previously testified in proceedings before utility regulatory commissions or other regulatory authorities?

A. I have not testified before a utility regulatory commission but have testified before other governmental regulatory bodies.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit NHW-1	Résumé of Nancy H. Watkins;
Exhibit NHW-2	Articles of Incorporations of Floridians Against Increased Rates, Inc.;
Exhibit NHW-3	Membership Roster of Floridians Against Increased Rates, Inc. at June 15, 2021;
Exhibit NHW-4	Sample Form of FAIR Membership Application (Paper); and
Exhibit NHW-5	Sample Form of FAIR Membership Application (Electronic).

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I was asked and engaged by FAIR to conduct a verification of FAIR's members as to their existence, their status as to whether they intentionally joined FAIR, and their status as customers of Florida electric utilities whose rates are regulated by the Florida Public Service Commission ("Commission" or "PSC"). Accordingly, the purpose of my testimony in this proceeding is to provide the Commission with a description of FAIR's membership composition, based on the verification that I performed of the membership, and to provide my findings regarding FAIR's membership numbers, composition, and the utilities that serve FAIR's members.

Q. Please summarize the main points of your testimony.

A. As stated in its Articles of Incorporation, FAIR is a Florida not-for-profit corporation that exists to inform the public regarding energy issues and to advocate by all lawful means for laws, rules, and government decisions – including decisions to be made by the Florida PSC – that will result in the retail electric rates charged by Florida's investor-owned electric utilities being as low as possible while ensuring that the utilities are able to provide safe and reliable electric service. Membership in FAIR is open to any customer, including individuals and business customers, of any Florida electric utility whose rates are regulated by the Florida PSC; those utilities include Florida Power & Light Company ("FPL"), Duke Energy Florida ("DEF"), Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company's ("FPUC") electric utility divisions.

I reviewed FAIR's membership roster and a sample of the membership applications, including samples of the paper or "hard" copies of membership applications that were submitted by some of FAIR's members and also of the electronic membership applications by which members also joined FAIR. I also contacted a large sample of the members listed on FAIR's membership roster by email to determine whether their membership information in our roster was accurate that: (1) they are customers of an investor-owned Florida electric utility, (2) if so, of what utility they are a customer, and (3) that they intended to join FAIR. Effectively, this was a verification of the accuracy of FAIR's membership roster to confirm that the members are real people or businesses, that they intended to join FAIR, and that each is a customer of the utility indicated on the member's application.

The results of my verification analysis confirm that the members on FAIR's roster are real individuals and businesses, that they intended to join FAIR, and that FAIR's membership records accurately reflect that the members are customers of the utilities indicated in the records. The membership roster shows that the substantial majority, approximately 80 percent, of FAIR's members are customers of FPL.

FLORIDIANS AGAINST INCREASED RATES, INC.

Q. Please describe FAIR and its purposes.

A. FAIR is a Florida not-for-profit corporation that was formed in March of this year. FAIR's purposes are set forth in the corporation's Articles of Incorporation, which are included as Exhibit NHW-2 to my testimony. In summary, FAIR's purposes are to inform the public regarding energy issues and to advocate by all lawful means for laws, rules, and government decisions – including decisions to be made by the Florida PSC – that will result in the retail electric rates charged by Florida's investor-owned electric utilities being as low as possible while ensuring that the utilities are able to provide safe and reliable electric service.

Q. Please explain your understanding of the term "investor-owned utility" as used in your testimony.

A. As an initial part of my verification, I looked to the PSC's website for relevant information. In that search, I observed, on page 1 of a PSC publication titled "Facts & Figures of the Florida Utility Industry 2021," which I accessed through the PSC's website at the address http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Factsandfigures/April%202021.pdf, that the PSC describes its regulatory authority over investor-owned electric companies as encompassing "all aspects of operations, including rates and safety" while noting that its authority over municipal and cooperative utilities is "limited" to certain aspects that do not include those utilities' rates. At pages 3, 4, and 10 of this publication, the PSC identifies the investor-owned utilities as the five companies that I listed above as being those whose rates are regulated by the PSC.

Q. Who are FAIR's members?

A. Membership in FAIR is open to any customer, including both residential and business customers, of any Florida investor-owned electric utility, i.e., Florida Power & Light, Duke Energy Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company.

FAIR'S MEMBERSHIP – VERIFICATION AND CONCLUSIONS

Q. Please describe the verification process that you employed to evaluate FAIR's membership.

A. Recognizing that my testimony would be filed in this case on June 21, 2021, I began by obtaining FAIR's membership roster as of June 15, 2021. A copy of this roster is provided as Exhibit NHW-3 to my testimony. I then reviewed the roster to familiarize myself with the data contained in it and to decide how to proceed. On June 15, 2021, FAIR's membership roster included 516 members. Although I chose the June 15 roster for my sampling and verification analysis, I also reviewed FAIR's membership roster as of June

17, 2021; the June 17 roster included 550 members, and FAIR's membership continues to grow.

I decided that, based on the total reported membership as of June 15 of 516 members, that a sample of 220 members would be sufficient to provide acceptable accuracy to confirm that the results of my sample would fairly and accurately represent the underlying characteristics of FAIR's membership. A sample size of 220 for a population of 516 is calculated to determine a result with a 95% confidence interval with a 5% margin of error, which means the statistic will be within 5 percentage points of the real population value 95% of the time. A sample size of 291 increases the confidence interval to 99% with a margin of error of 5%.

In considering how large a sample to study, given the ease of technology available, I chose to sample the entire population of FAIR's members who had given their email address in order to verify the existence and accuracy of the information on file. Only nine of the 516 members failed to provide an email address or phone number and time did not permit confirmation by U.S. Postal Service mail, thus they were excluded from the sampled population. The resulting sample size of 507 was further reduced after distribution of emails due to 8 being ultimately not deliverable. The remaining 499 sample size able to be tested produces a 99% confidence level that the margin of error in the entire population is approximately 1%. I also reviewed a sample of the applications that FAIR had received in pdf format and a sample of those submitted electronically (online). A copy of the pdf format of the application is included as Exhibit NHW-4, and a copy of the electronic format of the application is included as Exhibit NHW-5 to my testimony.

Q. Please provide a summary of your verification results.

A. Of the 499 members that I sampled, three replied that they did not intend to join FAIR; one of those was the website tester, who apparently joined inadvertently when performing his or her tests. From these data, I conclude that, as of June 15, 2021, FAIR had 513 members who intended to join FAIR and that those members are served by the utilities indicated on their membership applications.

Q. Based on your sampling and verification process, what are your conclusions regarding FAIR's total membership, its customer composition, and what proportion or percentage of that total membership are customers of FPL?

A. Based on my verification findings, it is my opinion that, as of June 15, 2021, which is the date of the roster that I verified, FAIR's membership roster fairly and with reasonable accuracy, represents FAIR's membership, with the following summary characteristics:

1. As of June 15, 2021, FAIR had 513 members who intended to join FAIR.

2. Of the total, there were 511 residential customers and 2 business customers.

3. Of the total on June 15, 420 were customers of FPL, which is approximately 82% of the total membership population. Also included in FAIR's membership were 72 customers of Duke Energy, 20 with FPUC, 3 with Tampa Electric Company, and 1 with Gulf Power.

As stated above, a copy of the roster as of June 15 and as verified is included as Exhibit NHW-3 to my testimony.

SUMMARY OF TESTIMONY

Q. Please summarize the main points of your testimony.

A. I conducted an appropriate verification, based on an appropriate sample size, of FAIR's members to determine (1) whether the members are real persons and business entities; (2) whether they intended to join FAIR; and (3) by what utilities they are served. My findings confirm that the members of FAIR are real people and businesses, that they intended to join FAIR consistent with the purposes stated on the membership application, and that the vast majority – more than 80 percent – of FAIR's members are customers of Florida Power & Light Company.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Melissa Whited was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power and Light Company	**DOCKET NO. 20210015-EI**

DIRECT TESTIMONY OF

MELISSA WHITED

ON BEHALF OF

THE CLEO INSTITUTE AND VOTE SOLAR

JUNE 21, 2021

TABLE OF CONTENTS

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics, Inc., located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics (Synapse) is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison.

I have 12 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker in numerous industry conferences, including as a panelist for the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and the 2018 Annual Meeting. I have sponsored testimony before the Georgia Public Service Commission, the Colorado Public Utilities Commission, the Rhode Island Public Utilities Commission, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, and the Federal Energy Regulatory Commission. My CV is attached as Exhibit MW-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the CLEO Institute and Vote Solar.

Q What is the purpose of this testimony?

A My testimony demonstrates that FPL's proposal has failed to provide adequate safeguards for its low-income customers who are struggling with the impacts from COVID-19, unaffordable bills, and a warming climate. In my testimony, I document how FPL's disconnection practices have exacerbated inequities and that FPL's proposal will do little to address affordability or resilience. I propose several possible solutions to help protect FPL's most vulnerable customers, improve affordability, and enhance resiliency.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are as follows:

1. Many vulnerable customers reside in FPL's territory. One-third of the population in the counties served by FPL/Gulf Power earn less than 200% of the federal poverty level,[1] and an estimated 1.4 million FPL customers live in energy poverty.
2. FPL's average residential electric bills are 13th *highest* of the 50 mainland investor owned utilities with the most residential customers, contradicting FPL's claims that its customers' bills are among the lowest in the country.
3. The Company's proposed 18% rate increase over a four-year period worsens the high energy burdens already faced by its vulnerable customers, exacerbating socio-economic disparities these communities face.
4. FPL/Gulf have not done enough to address the energy burdens of their customers or vulnerability to a warming climate and extreme weather events such as more severe hurricanes. Instead:

[1] Florida Department of Health, Division of Public Health Statistics & Performance Management, http://www.flhealthcharts.com/ChartsReports/rdPage.aspx?rdReport=NonVitalIndRateOnly.DataViewer&cid=461.

- FPL/Gulf prematurely resumed customer disconnections in the fall of 2020, well before the conclusion of the pandemic, and the disconnection rates for both FPL and Gulf Power have far exceeded the disconnection rates of Tampa Electric and Duke Energy Florida. Unlike most other jurisdictions, FPL does not protect customers from disconnections when weather conditions are hazardous.
- FPL's performance in the area of energy efficiency – a key strategy for helping customers manage their energy bills – is second-worst in the nation.

5. FPL's proposal does not remedy these problems. Although FPL asks ratepayers to fund considerable investments in grid hardening and the latest monitoring technologies, it does little to help customers cope with outages once the grid goes down, or to help customers reduce their energy consumption through energy efficiency. It also contains no additional protections for customers facing disconnection – even though disconnections can be life-threatening.

In sum, FPL must do more to help its customers reduce their energy burden, avoid disconnection, and become more resilient in the face of climate change.

Q Do you have any recommendations to offer the Commission?

A Yes. Based on my findings, I offer the following four recommendations:

1. The Commission should reject FPL's proposed "performance incentive" of 50 basis points and instead adopt performance incentive mechanisms

focused on specific policy goals, such as reducing customer disconnections and improving energy efficiency programs.

2. FPL should expand customer protections against disconnections during emergencies (e.g., when preparing for or recovering from major storms), and when temperatures are hazardous.
3. FPL should implement innovative programs designed to improve resilience at schools, such as through expanded energy efficiency offerings, solar plus storage solutions, and school bus vehicle-to-grid pilots that could provide back-up power.
4. FPL should develop other low-income programs, such as a low-income rate discount or percentage of income payment plan.

3. FPL HAS FAILED TO ADEQUATELY ADDRESS CUSTOMERS NEEDS

Q What is your overall assessment of FPL's proposal?

A Under FPL's proposal, residential bills are set to increase by more than 18% by 2025.[2] At the same time, many Florida communities are struggling to recover financially from COVID-19 and are facing growing burdens of extreme weather events, higher temperatures, and sea level rise due to climate change. These impacts are not distributed equally – it is the most vulnerable customers who will be hardest hit by FPL's rate increase and who will experience the worst effects of

[2] Direct Testimony of FPL Witness Tiffany C. Cohen, Exhibit TCC-3, page 1 of 5 shows that a residential customer using 1,000 kWh/month will see his or her bill increase from $99.05 in 2021 to $117.06 in 2025.

the pandemic and climate change. FPL must do more to help vulnerable customers reduce their bills through energy efficiency, avoid disconnection, and adapt to climate change.

Q Please explain what you mean by "vulnerable customers."

A Vulnerable customers are those who have fewer resources to respond to external stressors (such as pandemics or higher electricity bills) or who are more susceptible to impacts from climate change (including bearing the brunt of increasingly severe hurricanes). These customers may include lower-income customers,[3] marginalized communities, and customers with health conditions that leave them highly dependent on electricity for their health and safety.

Vulnerable customers are more likely to face difficulties paying their bills due to higher electricity rates and are therefore at greater risk of disconnection. Climate change further compounds the challenges faced by these customers, as they have less capacity to prepare for and cope with the increasing frequency and severity of storms, higher temperatures, sea level rise, and related impacts on their health and the local economy.[4] In order to improve equity, FPL should be prioritizing actions that enable vulnerable customers to better withstand

---

[3] As discussed later in my testimony, low-income customers pay a higher percentage of their total income towards electric bills; when customers pay more than 6 percent of household income on electric bills (or 10 percent if using electricity for heating), these households are described as "energy burdened".

[4] U.S. Global Change Research Program. *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*. Washington, DC. 2018.

emergencies (including natural disasters and pandemics), manage their bills, and become more resilient in the face of climate change.

Q How will FPL's proposal impact vulnerable customers?

A FPL's proposed rate increase, driven in part by its proposal to reward itself with a 50-basis point performance incentive for "superior performance," is unwarranted and out of touch with the struggles that its customers are facing to make ends meet, avoid disconnection, and manage the impacts of climate change. Instead of patting itself on the back, FPL should be acknowledging and addressing the heavy energy burden faced by its customers by (1) taking immediate steps to reduce customer disconnections; (2) improving its energy efficiency programs; (3) facilitating resilience by expanding customer access to customer-sited generation and storage for backup power; and (4) designing innovative low-income programs. Performance incentives should only be provided to FPL for demonstrating substantial improvements in these areas.

Q Why do you contend that there is an urgent need to address energy burden?

A One-third of the population in the counties served by FPL/Gulf Power earn less than 200% of the federal poverty level, according to 2019 census data.[5] These customers tend to spend a disproportionate share of their incomes on energy costs.

---

[5] Florida Department of Health, Division of Public Health Statistics & Performance Management, http://www.flhealthcharts.com/ChartsReports/rdPage.aspx?rdReport=NonVitalIndRateOnly.DataViewer&cid=461.

In 2019, the Greenlink Group estimated that 1.4 million FPL customers live in energy poverty – defined as having electricity bills that exceed 6% of their household income or total energy bills that exceed 10% of their income.[6] When customers must spend such a large portion of their incomes to meet their energy needs, they must make difficult trade-offs, such as choosing whether to refill their medications or heat or cool their homes, even when temperatures reach dangerous levels.[7]

Q How has the pandemic affected customer energy burdens?

A Since the start of the COVID-19 pandemic in 2020, the number of households living in energy poverty has certainly increased. While Florida's economy has improved in recent months, unemployment is still much higher than it was before the pandemic. In the counties served by FPL and Gulf Power, nearly 150,000 more individuals were unemployed in March 2021 relative to March 2019. Further, customers who had fallen behind in their utility bills must now struggle to repay past due balances in addition to new energy bills, or face disconnection.

Q Has FPL taken adequate steps to make electricity bills more affordable, protect vulnerable customers, and facilitate resilience?

A No, FPL's efforts fall far short in addressing energy burdens in four ways:

---

[6] Florida PSC Docket No. 20190061-EI, Direct testimony of Matt Cox, PhD on behalf of Vote Solar.

[7] Chip Berry et al., *One in three U.S. households faces a challenge in meeting energy needs,* U.S. EIA (Sept. 19, 2018), https://www.eia.gov/todayinenergy/detail.php?id=37072.

1. First, FPL/Gulf have not only resumed customer disconnections well before the conclusion of the pandemic, but have done so aggressively. The Company's rate of disconnections is far higher than either Tampa Electric (TECO) or Duke Energy Florida (Duke), and the percent of customers disconnected without restoration by FPL/Gulf is also much greater than TECO or Duke.[8] FPL/Gulf should not be rewarded with a bonus return on equity (ROE) while an unreasonable share of its customers go without service.
2. Second, while FPL/Gulf touts its low electricity rates, customers still pay relatively high electricity bills compared to customers served by other utilities, in part due to FPL's abysmal energy efficiency offerings. FPL/Gulf must take steps to help its customers, particularly its low-income customers, implement more energy efficient measures to better manage their bills.
3. Third, while FPL is investing heavily in hardening its grid, the Company should also be assisting communities cope with the inevitable outages after major storms, such as through backup power systems for schools that serve as emergency shelters.
4. Fourth, low-income customer assistance programs, other than LIHEAP, are small and inadequate. FPL should propose new programs or low-income

[8] Based on an analysis of disconnection data provided by the utilities in customer impact data related to COVID-19, as filed in Docket 20200000 and Docket 20210000, and number of residential customers from U.S. EIA Form 861 (2019).

rates that help to alleviate the energy poverty faced by so many of its customers.

Disconnections

Q Please explain your concerns with FPL/Gulf's disconnection practices.

A While FPL's temporary cessation of disconnections offered vital short-term relief for customers during the first six months of the pandemic, the Company resumed disconnections in October of 2020 (FPL) and November of 2020 (Gulf) and has vigorously continued to disconnect customers throughout the winter and spring. I have several concerns with the Company's practice in this area.

First, I believe it was premature for FPL/Gulf to resume disconnections in the fall of 2020. The majority of states (35) mandated suspensions of utility disconnections, while the states without mandatory suspensions all enacted some form of voluntary moratorium.[9] Thus while I support FPL/Gulf's initial suspension of disconnections, I do not believe that the Company's actions went beyond the measures taken in most jurisdictions, nor are their actions aligned with the Company's claim that it delivers "superior customer service."

In contrast, many jurisdictions extended COVID-based disconnection moratoria well beyond October, and in fact some jurisdictions continue to keep such moratoria in place. The National Energy Assistance Directors Association

[9] National Energy Assistance Directors Association, *Summary of State Utility Shut-off Moratoriums due to COVID-19*, October 19, 2020, available at https://neada.org/utilityshutoffsuspensions/.

reports that more than half of the U.S. population was protected by a COVID or winter-season based disconnection moratorium through March of 2021.[10] Even now, Washington D.C., New York, and Virginia have maintained their disconnection moratoria due to COVID.[11]

Second, the disconnection rates for both FPL and Gulf Power have far exceeded the disconnection rates of TECO and Duke. As shown in the graph below, FPL disconnected nearly 2.5% of its residential customers in December, and its disconnection rates have been more than double TECO and Duke's throughout the spring.[12]

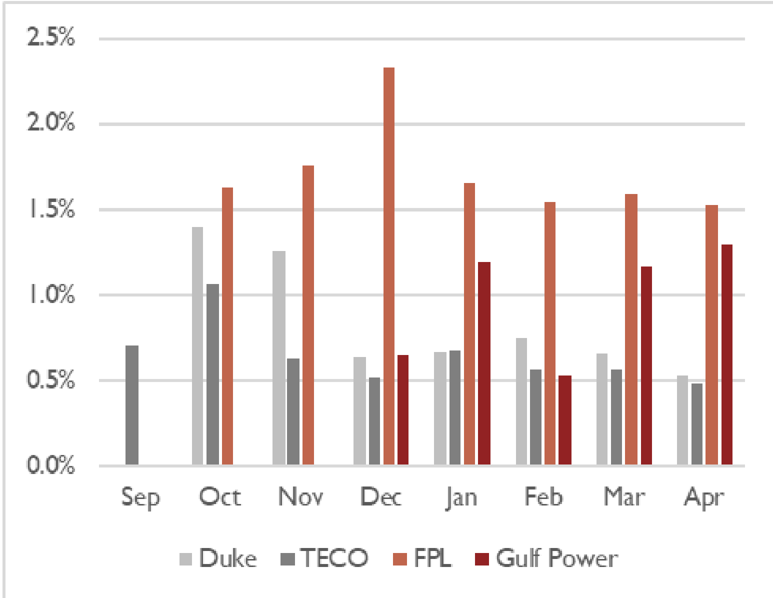
---

[10] National Energy Assistance Directors Association, *Winter and COVID-19 Utility Shut-off Moratoriums*, March 15, 2021, available at https://neada.org/wintercovid19moratoriums/.

[11] Washington, D.C. has suspended utility disconnections for nonpayment, as reported by the Mayor's office, https://coronavirus.dc.gov/utilityhelp; New York State Public Service Law prohibits utilities from disconnecting for nonpayment during the pandemic and continues until the COVID-19 state of emergency is lifted or expired, or at least by December 31, 2021, and thereafter for 180 days for customers who have experienced a change in financial circumstances due to the COVID-19 state of emergency, https://www3.dps.ny.gov/W/AskPSC.nsf/All/D3BB77AFE92D6FFF852585EE0051A13E?OpenDocument; Virginia prohibits disconnections until the Governor determines that the prohibition does not need to be in place or until at least 60 days after the declared state of emergency ends, Virginia House Bill 5005 (the Commonwealth of Virginia Budget, Section 4-14, Enactment 7(a), as of November 18, 2020), available at https://budget.lis.virginia.gov/item/2020/2/HB5005/Chapter/4/4-14.00/.

[12] Utility customer impact data related to COVID-19, as filed in Docket 20200000 and Docket 20210000. http://www.floridapsc.com/ClerkOffice/DocketFiling?docket=20210000.

Figure 1. Residential Customer Disconnection Rates



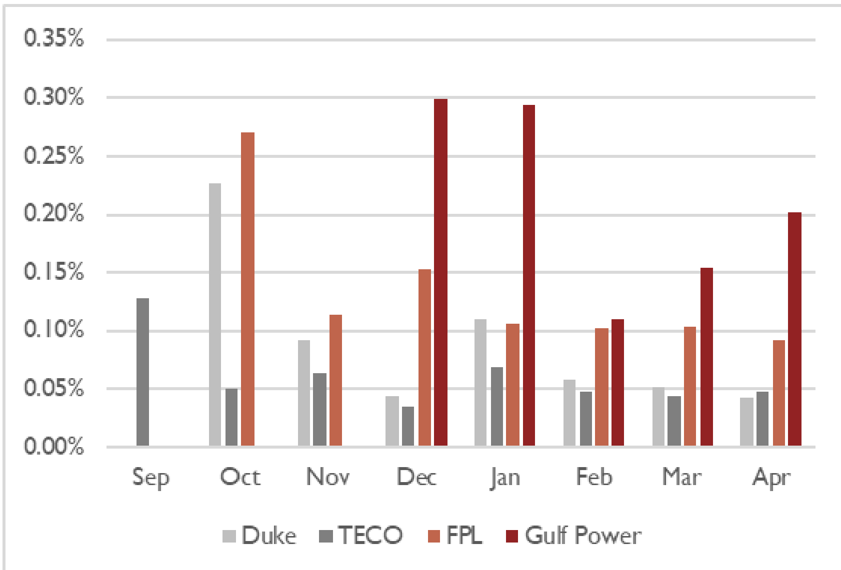
Source: Analysis of disconnection data provided by the utilities in customer impact data related to COVID-19, as filed in Docket 20200000 and Docket 20210000, and number of residential customers from U.S. EIA Form 861 (2019).

Q Has FPL provided customers with payment arrangements or other assistance to avoid disconnection?

A FPL states that it has assisted customers with payment arrangements and special programs "to provide additional relief and avoid disconnection." However, the percentage of customers disconnected calls into question the effectiveness of the Company's efforts to mitigate the hardship faced by customers who have fallen behind on their bills during the pandemic.

Further, once FPL and Gulf Power customers have been disconnected, they are much more likely to remain disconnected. The figure below shows that in virtually every month, the percentage of customers disconnected and not reconnected was higher for FPL and Gulf Power than TECO or Duke Energy. In fact, based on the customer impact data submitted by the utilities, residential customers of Gulf Power are nearly five times less likely to have their service restored than TECO customers.

Figure 2. Percentage of Residential Customers Disconnected without Reconnection



Source: Analysis of disconnection data provided by the utilities in customer impact data related to COVID-19, as filed in Docket 20200000 and Docket 20210000, and number of residential customers from EIA Form U.S. 861 (2019).

Q What do you conclude with respect to FPL's disconnection practices?

A FPL's President and CEO Eric Silagy claims that the Company's "philosophy and approach… begins with delivering superior customer service and reliability."[13] The Company's rate of disconnections implies otherwise, however. FPL/Gulf's high rates of disconnections – even during the height of the pandemic – indicate

---

[13] Docket No. 20210015-EI, Silagy Direct Testimony, p. 6, lines 13-14 (filed March 12, 2021).

that the Company lacks either the imagination or the incentive to find more effective ways of addressing energy affordability.

Q How do disconnections impact customers?

A Electricity service can mean the difference between life and death for customers. According to U.S. Energy Information Administration (EIA), already before the pandemic, nearly 20 percent of households reported "reducing or forgoing necessities such as food and medicine to pay an energy bill," and 11% of households "reported keeping their home at an unhealthy or unsafe temperature."[14]

These impacts became even more acute during the pandemic when customers were advised to remain home and schools converted to virtual classrooms. A customer shut off from electricity during the pandemic could mean that their children would lose access to education, and that they would need to move in with friends, relatives, or public shelters, potentially exposing them to COVID. A recent paper by the National Bureau of Economic Research reports that COVID-19 infections rates could have been reduced by 8.7% and deaths by

[14] U.S. Energy Information Administration, "One in three U.S. households faces a challenge in meeting energy needs." September 19, 2018. Available at https://www.eia.gov/todayinenergy/detail.php?id=37072.

14.8% had utility disconnection moratoria been in place nation-wide from the start of the pandemic.[15]

Although FPL states that, "We strive to do the right thing before we are ordered, or even asked, to do so,"[16] so far it has failed to do enough to ensure that electricity customers remain connected to vital electricity services. As I explain in greater detail later in my testimony, FPL should significantly expand its disconnection protection policies.

Q FPL states that its incremental bad debt expense has increased by $28.5 million since the start of the pandemic.[17] Would reducing disconnections increase bad debt expense and thus rates for all customers?

A Possibly, but only if customers are unable to pay the amount owed through an arrearage management plan, and if the bad debt is funded solely through ratepayer funds. An alternative would be for shareholders to shoulder all or a portion of the bad debt expense. Given that the Company's return on common equity in May 2021 was 11.60%[18] and that FPL's net income increased by more than $300

---

[15] Kay Jowers et al. Housing Precarity & the COVID-19 Pandemic: Impacts of Utility Disconnection and Eviction Moratoria on Infections and Deaths Across US Counties. National Bureau of Economic Research, Working Paper No. 28394. January 2021, p. 11. Available at https://www.nber.org/system/files/working_papers/w28394/w28394.pdf

[16] Docket No. 20210015-EI, Silagy Direct Testimony, p. 16 (filed March 12, 2021).

[17] FPL Response to CLEO/Vote Solar's First Set of Interrogatories No. 33, attached as Exhibit MW-2.

[18] FPL Rate of Return Surveillance Report for March 2021, filed on May 14, 2021. Available at https://www.floridapsc.com/UtilityRegulation/SurveillanceReports?compcode=EI802.

million between 2019 and 2020,[19] it would be reasonable for shareholders to fund some or all of the outstanding bad debt expense.

<u>Energy Efficiency and Affordability</u>

Q FPL has relatively low electricity rates. Does this mean that electricity is affordable for FPL's customers?

A No, electricity rates are not the same as electricity bills. Although two utilities could have the same electricity rates, customers could pay substantially different bills due to differing usage levels.

Q FPL Witnesses Silagy[20] and Reed[21] claim that FPL has the lowest residential bill of the largest investor-owned utilities. Is this an accurate claim?

A No. These comparisons are made assuming that customer energy usage levels are the same when they are not.[22] To compare the actual bills that customers pay across utilities, I used data from the U.S. Energy Information Administration's 2019 Form 861 for various utility groups. First, I analyzed average residential bills for the 50 mainland investor owned utilities with the largest number of

---

[19] NextEra Energy, Earnings Conference Call, Fourth Quarter and Full Year 2020, January 26, 2021, slide 8. Available at http://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/reports-and-fillings/quarterly-earnings/2020/Q4/4Q%202020%20Slides%20v%20F.pdf.

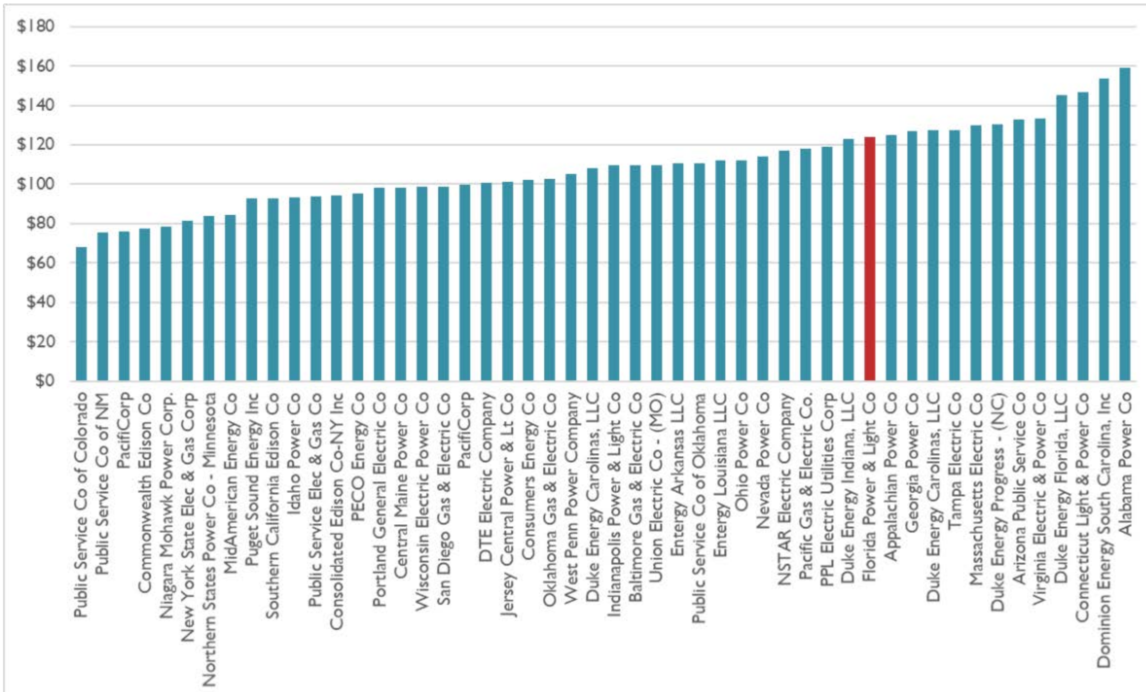
[20] FPSC Docket No. 20210015-EI, Silagy Direct Testimony, p. 6, lines 7-9 (filed March 12, 2021).

[21] FPSC Docket No. 20210015-EI, Reed Direct Testimony, page 11, lines 1-6 (filed March 12, 2021).

[22] *See* FPSC Docket No. 20210015-EI, Silagy Direct Testimony, Exhibit ES-3, which compares bills for customers assuming usage of 1,000 kWh.

residential customers. Of these utilities, FPL's average residential bill was 13th highest, as shown in the following figure.

Figure 3. Average Residential Monthly Bill (2019)



Q Why are the average bills for FPL customers higher than in most other jurisdictions?

A Electricity bills are generally higher in FPL's territory because electricity usage is higher than in many other utilities' territories. There can be numerous reasons for differing usage levels, but one key reason is utility investment in energy efficiency. Energy efficiency programs are an important way in which utilities can help customers reduce their usage and better manage their bills. Without such programs, customers may not have the knowledge, time, or funds to seek out and implement energy efficiency measures on their own. Compared to other utilities, FPL's energy efficiency efforts are limited. For 2020, the American Council for an Energy Efficient Economy (ACEEE) ranked FPL 51st out of 52 utilities.[23]

ACEEE reports that FPL's energy efficiency savings total just 0.06% of sales – well below the national average of 1.03% and the Southeast regional average of 0.47%.[24]

Q What are the consequences of under-performing in providing energy efficiency programs?

A The consequences of such low investments in energy efficiency put FPL customers at a disadvantage daily, since they end up paying higher bills than necessary. This has been particularly detrimental during the pandemic when many residents have been forced to stay home, rather than going to school or work, thereby increasing the energy burden for customers even further.

---

[23] Grace Relf, Emma Cooper, Rachel Gold, Akanksha Goyal, and Corri Waters. 2020 Utility Energy Efficiency Scorecard. ACEEE. February 2020.

[24] York, Dan and Charlotte Cohn. "Unrealized Potential: Expanding Energy Efficiency Opportunities for Utility Customers in Florida." ACEEE. January 2021. Available at https://www.aceee.org/sites/default/files/pdfs/expanding_ee_opportunities_in_florida.pdf.

Innovation for Addressing Resilience and Affordability

Q Has FPL implemented innovative programs to address customer energy burdens and resilience?

A No. FPL prides itself on being an "innovative industry leader"[25] and developing "innovative and industry leading ideas,"[26] but its efforts appear to largely be focused on utility investments and operations, such as grid hardening measures and adopting the latest technology to monitor the grid (such as deploying drones and robotics for inspections).[27] While these efforts may help to minimize outages, as acknowledged by FPL President and CEO Eric Silagy, "there is no such thing as a hurricane-proof electric grid."[28] When severe weather takes out power to the grid, vulnerable customers are often unable to evacuate and depend on critical facilities (including shelters) maintaining power. It is vital that these facilities have backup power, such as through customer-sited solar plus storage, to help communities deal with widespread power outages. FPL's proposal is focused primarily on utility-scale storage solutions, which will not be effective when a major outage occurs.

---

[25] FPSC Docket No. 20210015-EI, Silagy Direct Testimony, p. 21 (filed March 12, 2021).

[26] *Id*. at p. 17.

[27] *Id*.

[28] Ostrowski, Jeff. "Hurricane Dorian: FPL chief says 'significant destruction' possible." The Palm Beach Post. September 1, 2019. Available at https://www.palmbeachpost.com/news/20190901/hurricane-dorian-fpl-chief-says-ldquosignificant-destructionrdquo-possible.

Low-Income Assistance Programs

Q What forms of energy assistance programs are available to low-income customers in FPL/Gulf's territory?

A The federally-funded LIHEAP program is the largest program available to low-income customers of FPL/Gulf. FPL reports that in 2020, $29 million in LIHEAP funding was received.[29] In addition, FPL's "Care to Share" program helps customers who are experiencing temporary financial difficulties. In 2020, $1 million of assistance was provided through this program.[30] FPL has also offered temporary programs that provide credits to customers, including a bill relief credit for customers impacted by COVID[31] and the Low-Income Credit Program, which is designed to expire on December 31, 2021.[32]

Q Are these programs effective in reaching low-income customers?

A Unfortunately, these programs only reach a very small subset of low-income customers. According to the Company, the LIHEAP program served less than 65,000 customers in 2020,[33] and Care to Share provided assistance to fewer than 3,000 customers. During COVID, the Company reports that 112,000 residential

[29] FPL Response to CLEO/Vote Solar 1st Interrogatories No. 40, attached as Exh. MW-5.

[30] *Id*.

[31] FPL Response to CLEO/Vote Solar 1st Interrogatories No. 37, attached as Exh. MW-4.

[32] FPL Response to CLEO/Vote Solar 1st Interrogatories No. 39, attached as Exh. MW-3.

[33] *Id*.

and commercial customers took advantage of FPL's bill relief credit offer, and 63,000 customers are eligible for the Low-Income Credit Program. However, both the bill credits and low-income credits are temporary programs.

Based on recent numbers, fewer than 70,000 residential customers can be expected to receive assistance through LIHEAP and Care to Share. In contrast, one-third of the population in the counties served by FPL/Gulf Power earn less than 200% of the federal poverty level,[34] and an estimated 1.4 million FPL customers live in energy poverty.[35] In other words, only about five percent of the customers who need assistance receive it through these programs.

Q Has FPL proposed new programs or rates to reach more customers with high energy burdens?

A No, I am not aware of any proposals by FPL in this rate case that would address a large portion of customers with high energy burdens.

[34] Florida Department of Health, Division of Public Health Statistics & Performance Management, http://www.flhealthcharts.com/ChartsReports/rdPage.aspx?rdReport=NonVitalIndRateOnly.DataViewer&cid=461.

[35] Florida PSC Docket No. 20190061-EI, Direct testimony of Matt Cox, PhD on behalf of Vote Solar.

4. SOLUTIONS

Performance Incentive Mechanisms

Q What should be done to enhance customer protections and reduce customer energy burdens?

A I recommend that the Commission adopt performance incentive mechanisms related to energy efficiency and customer disconnections, and that protections against disconnections during hazardous temperatures, storms, and other emergencies be expanded.

Q Is your recommendation to adopt a performance incentive mechanism consistent with the Company's proposal to implement a 50-basis point ROE adder for superior performance?

A No. The Company's proposal for a 50-basis point reward is inappropriate as it is not tied to specific, Commission-approved metrics, targets, or goals. In contrast to the utility's proposal, performance incentive mechanisms ("PIMs") establish a well-defined set of metrics with associated targets and financial implications (i.e., penalties or rewards) tied to achieving specific targets. I recommend that the Commission reject the Company's proposal for a broad 50 basis point ROE adder and instead adopt PIMs tied to specific public policy goals.

Q What steps should be followed when establishing performance incentive mechanisms?

A As described in the report *Utility Performance Incentive Mechanisms: A Handbook for Regulators*,[36] the key steps for establishing a PIM are as follows:

1. Articulate the policy goals that the PIM is to achieve and assess any current utility incentives or disincentives for achieving these goals in the current regulatory context.
2. Identify the performance area(s) that warrant additional attention.
3. Establish specific, measurable performance metrics with reporting requirements for measuring progress toward the goal(s).
4. Establish performance targets to provide utilities with clear messages regarding the level of performance expected by regulators.
5. Establish penalties and rewards, as needed to provide direct financial incentives for maintaining or improving performance.

Q Please elaborate on your recommendation for a PIM related to utility disconnections.

A While I recognize that FPL has made efforts to enroll customers in Arrearage Management Plans (AMPs), clearly additional effort is needed in this area due to

[36] Whited, Melissa, Tim Woolf, and Alice Napoleon. 2015. *Utility Performance Incentive Mechanisms: A handbook for regulators*. Prepared for the Western Interstate Energy Board by Synapse Energy Economics. Available at https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

the large percentage of customers disconnected by FPL/Gulf. The specific solutions to address this issue will require the time and attention of FPL management and customer service staff, and care should be taken to minimize increases in bad debt expense. Because this can be a difficult, multifaceted issue, I suggest that the Commission implement a PIM that would provide FPL with a small financial incentive for reducing both bad debt and customer disconnections.

Q Do you also recommend that the Commission adopt PIMs that address energy efficiency?

A Yes. While I understand that specific energy efficiency targets are set in the Florida Energy Efficiency and Conservation Act (FEECA) docket,[37] I recommend that the Commission implement energy efficiency performance incentive mechanisms that would only reward FPL for substantial improvements in the delivery of energy efficiency programs, particularly for low-income customers. For example, FPL should fund emergency relief energy efficiency for customers in arrears, similar to the commitment that Duke Energy Florida recently made.[38]

In designing performance incentive mechanisms for energy efficiency, I note that financial rewards directly based on program spending, such as a rate of return on program costs, provide the wrong incentive to utilities. Such incentives

---

[37] *In re: Commission review of numeric conservation goals (Florida Power & Light Company)*, FPSC Docket No. 20190015-EG.

[38] *In re: Duke Energy Florida, LLC's Petition for a limited proceeding to approve 2021 settlement agreement, including general base rate increases*, Docket No. 20210016-EI, Memorandum of Understanding filed April 23, 2021.

encourage the utility to earn more by spending more (either by increasing rate base or by increasing program costs). For this reason, I recommend establishing PIMs that are tied to the net benefits provided to customers from energy efficiency programs, or for significantly expanding energy efficiency access to customers with high energy burdens.

Expanded Disconnection Moratoria

Q What do you recommend with respect to expanding utility disconnection protections?

A As I have explained, electricity is a vital service, especially during times of crisis. More must be done to ensure that customers who need it most are not disconnected, particularly when doing so could be life-threatening. Therefore, I recommend that FPL commit to suspending disconnections during emergencies (e.g., when preparing for or recovering from major storms), and when temperatures are hazardous. Such protections were recently agreed by Duke Energy Florida in the Memorandum of Understanding filed in Docket No. 20210016-EI,[39] and have been widely adopted across the United States.

---

[39] *Id.*

Q What other jurisdictions have adopted seasonal or temperature-based moratoria on disconnections?

A Approximately 75% of states have some form of seasonal or temperature-based disconnection moratoria in place, as reported by the US Department of Health and Human Services.[40] For example, Arkansas, Georgia, Illinois, Maryland, Minnesota, Missouri, New Jersey, Oklahoma, and Rhode Island are reported to prohibit disconnections during periods of excessive heat. As climate change leads to record-breaking heat, FPL should implement similar protections to help protect its vulnerable customers against unnecessary heat-related deaths. Likewise, customers should have access to life-saving electricity when major storms are imminent to enable these customers to prepare as well as possible, and for a reasonable time after storms hit to enable recovery.

Innovation in Resilience and Affordability

Q Has FPL implemented innovative programs to address customer energy burdens and resilience?

A No. As I noted earlier, although FPL prides itself on being an "innovative industry leader"[41] its efforts are largely be focused on utility investments and operations,

[40] The archived table of states with disconnection moratoria is available at https://web.archive.org/web/20210318034213/https://liheapch.acf.hhs.gov/Disconnect/SeasonalDisconnect.htm.

[41] FPSC Docket No. 20210015-EI, Silagy Direct Testimony, p. 21 (filed March 12, 2021).

such as grid hardening measures and adopting the latest technology to monitor the grid.[42]

I recommend that FPL look beyond its own operations and seek new ways to partner with its customers. In particular, I recommend that FPL target programs that address resilience and affordability for public schools.

Q Why do you recommend that FPL target programs for public schools?

A Schools are a prime candidate for utility programs because:

- School electricity bills represent a major cost for state taxpayers, with annual energy expenditures surpassing $500 million.[43]
- Schools serve as the primary source of public shelter during hurricanes, comprising 97 percent of statewide hurricane shelter space.[44] Vulnerable customers are more likely to use these shelters, as they tend to be less able to travel long distances and afford private accommodations (e.g., hotels). Thus, ensuring that these facilities have power, even when the rest of the grid is down, would provide enhance equity by improving customers' ability to withstand increasingly severe storms.

---

[42] *Id*.

[43] Florida Department of Education. Florida School District Annual Energy Cost Information, District Annual Financial Reports, 2017-2018. Available at http://www.fldoe.org/core/fileparse.php/5599/urlt/1718AnnualEnergy.pdf.

[44] Florida Division of Emergency Management. 2018 Statewide Emergency Shelter Plan, January 31, 2018, p. 1-4. Available at https://www.floridadisaster.org/globalassets/dem/response/sesp/2018/2018-sesp-entire-document.pdf.

- Some schools have adopted 100% clean energy goals (such as Miami). Expanding energy efficiency and customer-sited renewable energy options would help these schools meet their commitments to clean energy.[45]

Q What recommendations do you have for innovative programs aimed at enhancing resilience and affordability at schools?

A I recommend that FPL set ambitious goals for expanding its energy efficiency and demand response offerings to schools to reduce energy bills, and for implementing onsite renewable energy with storage to provide islandable back-up power for community resilience. For example, FPL should set a goal to ensure that by 2030, all schools that are able to accommodate it have installed on-site solar with battery storage for resilience purposes, and a related goal to reduce school building energy consumption by 25 percent. In addition, FPL should investigate ways that electric school buses could potentially help provide backup power in emergencies. FPL could structure this offering as a shared savings mechanism between participating schools, the utility and other customers. In order to ensure cost-effectiveness, the utility should issue a request for proposals (RFP) to obtain pricing from other qualified vendors, rather than the utility simply using such a program to expand its rate base.

---

[45] Harris, A. and C. Wright. "'For our children's sake': Miami Dade schools commit to 100% clean energy by 2030." Miami Herald, April 21, 2021. Available at: https://www.miamiherald.com/news/local/education/article250811844.html.

Additional Low-Income Protections

Q What other forms of energy assistance do you recommend for low-income customers?

A Separate low-income rates or programs for low-income customers can provide immediate assistance to these households. For example, a Percentage of Income Payment Plan (PIPP) caps a customer's bill at a set percentage of their income. Such programs have been adopted in Ohio, Illinois, and Colorado.[46] Some utilities offer separate rates for low-income customers or a percentage discount on the customer's bill. For example, California's CARE program provides low-income customers with a 30-35 percent discount on their electric bill,[47] and qualified customers of Massachusetts' investor-owned utilities are provided with a discounted electricity rate. For National Grid, this discount is currently equal to 32 percent.[48] PIPP legislation was recently passed in Virginia, capping eligible customers' monthly electric payments at six percent of household income, with options for customers to further reduce their bills through participation in

---

[46] In Ohio, a PIPP is available to customers whose income is at or below 150% of the federal poverty level (https://www.duke-energy.com/home/billing/special-assistance/percentage-of-income); in Illinois, customers receive assistance to help cover electricity bills greater than 6% of their income (https://www.illinoislegalaid.org/legal-information/setting-utilities-percentage-income-payment-plan) and in Colorado, the PIPP program is available to customers who have a household income at or below 185 percent of the current federal poverty level (https://dora.colorado.gov/press-release/puc-issues-emergency-rules-to-expand-utility-programs-for-low-income-customers-during).

[47] California Public Utilities Commission: CARE/FERA Programs, https://www.cpuc.ca.gov/lowincomerates/.

[48] National Grid Service Rates, Low-Income (R-2) rate, available at https://www.nationalgridus.com/MA-Home/Rates/Service-Rates.

weatherization or energy efficiency programs and energy conservation education programs.[49] FPL should commit to seeking a similar program for its low-income customers.

Q Does this conclude your testimony?

A Yes, it does.

[49] *An Act to amend and reenact §§ 56-576 and 56-585.6 of the Code of Virginia, relating to electric utilities; Percentage of Income Payment Program.* Available at: https://lis.virginia.gov/cgi-bin/legp604.exe?212+ful+HB2330ER

(Transcript continues in sequence in Volume 9.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 21st day of September, 2021.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024