Dianne M. Triplett
DEPUTY GENERAL COUNSEL

June 24, 2024

VIA ELECTRONIC MAIL

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

Re: Docket 20240025-EI, Petition for Rate Increase by Duke Energy Florida, LLC

Dear Mr. Teitzman,

On June 11, 2024, the Florida Industrial Power Users Group ("FIPUG") submitted its confidential testimony and exhibits for Jeffry Pollock to Duke Energy Florida, LLC ("DEF") for review. On June 11, 2024, DEF filed its Notice of Intent to Request Confidential Classification regarding same.

DEF has reviewed Mr. Pollock's testimony and exhibits and determined it does not contain confidential information.

Enclosed for filing is the Direct Testimony and Exhibits of Jeffry Pollock.

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/mh
Attachments

299 First Avenue North (33701) ▪ St. Petersburg, Florida
Phone: 727.820.4692 ▪ Email: dianne.triplett@duke-energy.com

CERTIFICATE OF SERVICE

Docket No. 20240025-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 24th day of June, 2024, to the following:

/s/ Dianne M. Triplett
Dianne M. Triplett

Jennifer Crawford / Major Thompson / Shaw Stiller
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
JCrawfor@psc.state.fl.us
MThompso@psc.state.fl.us
SStiller@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Jon C. Moyle, Jr. / Karen A. Putnal
Moyle Law Firm, P.A.
FIPUG
118 North Gadsden Street
Tallahassee, Florida 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com

Tony Mendoza / Patrick Woolsey
Sierra Club
2101 Webster Street Suite 1300
Oakland, CA 94612
tony.mendoza@sierraclub.org
patrick.woolsey@sierraclub.org

Sari Amiel
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
sari.amiel@sierraclub.org

Walt Trierweiler / Charles J. Rehwinkel / Mary Wessling / Austin Watrous
Office of Public Counsel
111 W. Madison St., Rm 812
Tallahassee, FL 32399
rehwinkel.charles@leg.state.fl.us
trierweiler.walt@leg.state.fl.us
watrous.austin@leg.state.fl.us
wessling.mary@leg.state.fl.us

Bradley Marshall / Jordan Luebkemann / Hema Lochan
Earthjustice
LULAC & FL Rising
111 S. Martin Luther King Jr. Blvd.
Tallahassee, Florida 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org
hlochan@earthjustice.org
flcaseupdates@earthjustice.org

Robert Scheffel Wright / John T. LaVia, III
Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper, P.A.
Florida Retail Federation
1300 Thomaswood Drive
Tallahassee, Florida 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

Peter J. Mattheis / Michael K. Lavanga / Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew, PC
NUCOR
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

James W. Brew / Laura Wynn Baker / Sarah B. Newman
Stone Mattheis Xenopoulos & Brew, PC
PCS Phosphate-White Springs
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
jbrew@smxblaw.com
lwb@smxblaw.com
sbn@smxblaw.com

William C. Garner
Law Office of William C. Garner, PLLC
SACE
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

Nikhil Vijaykar
Keyes & Fox LLP
EVgo Services, LLC
580 California St., 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

Lindsey Stegall
EVgo Services, LLC
11835 W. Olympic Blvd., Ste. 900E
Los Angeles, CA 90064
Lindsey.Stegall@evgo.com

Frederick L. Aschauer, Jr., Esq.
Allan J. Charles, Esq.
Lori Killinger, Esq.
Lewis, Longman & Walker P.A.
AACE / Circle K / RaceTrac / Wawa
106 East College Avenue, Suite 1500
Tallahassee, Florida 32301
fAschauer@llw-law.com
acharles@llw-law.com
lkillinger@llw-law.com
jmelchior@llw-law.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	DOCKET NO. 20240025-EI Filed: June 11, 2024

CONFIDENTIAL INFORMATION REDACTED

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 Duke Energy Florida, LLC	**DOCKET NO. 20240025-EI** **Filed: June 11, 2024**

Table of Contents

LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
2021 Settlement	2021 Settlement Agreement in Docket No. 20210016-EI
AD	Average Demand
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CDM	Cost Duration Model
CS	Curtailable Service
CT	Combustion Turbine
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress
FIPUG	Florida Industrial Power Users Group
Gulf Power	Gulf Power Company
IS	Interruptible Service
ITC	Investment Tax Credit
IOU	Investor-Owned Utility
kW / kWh	Kilowatt / Kilowatt-Hour
MDS	Minimum Distribution System
MFR	Minimum Filing Requirement
MW / MWh	Megawatt(s) / Megawatt-Hour
O&M	Operation and Maintenance

Term	Definition
Proposed Solar Projects	DEF's 14 Proposed Solar Facilities
PTC	Production Tax Credit
ROE	Return on Equity
RRA	Regulatory Research Associates
TECO	Tampa Electric Company
TOU	Time-of-Use

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Duke Energy Florida, LLC. (DEF). 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 substantial interest in the issued raised in and outcome of this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A First, I present an overview of DEF's proposals, including the three proposed test years and the primary cost drivers for the proposed base revenue increases. Second, I address the following specific issues:

- Class cost-of-service study (CCOSS);
- Class revenue allocation; and
- Rate design.

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

A Yes. My colleague, Mr. Ly, will address the cost-effectiveness of DEF's 14 "Proposed Solar Projects," including the conditions that the Commission should impose if these projects are approved.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-5**.

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

A No. In various places, I use DEF's proposed revenue requirement to illustrate certain cost allocation and rate design principles. However, these illustrations, in no way, provide an endorsement of DEF's revenue requirement or any other proposals on issues not addressed in my testimony.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Overview

- DEF is proposing to adjust base rates using three separate, forward-looking, test years. This proposal is unprecedented and overreaching. The Commission has never allowed a utility to propose three consecutive base rate increases in a single proceeding. More typically, base rates have been set for just one test year, while subsequent-year adjustments have been allowed to provide for cost-recovery of specific asset additions that were projected to occur following the rate case test year.

- Setting rates based on three future test years is highly speculative and presupposes that DEF can accurately forecast plant additions, sales, revenues, and expenses nine months before the first set of rates are implemented. However, DEF had to correct an error in its sales and revenue forecasts for each test year, which reduced DEF's proposed revenue deficiency by $53.3 million in 2025. Furthermore, DEF also adjusted its expected retirement date for Steam Anclote Units 1 and 2, reducing depreciation expense by $32 million. These changes clearly demonstrate how even shorter-term projections can be inaccurate.

- The Commission should reject DEF's 2026 and 2027 test years and set rates for just 2025. To the extent DEF has specific asset additions that will be placed in service subsequent to 2025, these additions may be reflected in subsequent-year adjustments, but only if the plant additions have actually been placed in service (*i.e.*, are used and useful) and providing DEF is not overearning.

- DEF's proposed base revenue increase and subsequent-year adjustments are being driven by $2.7 billion of rate base additions and related costs (*i.e.,* operation and maintenance (O&M), depreciation, and property taxes), and higher cost of capital, which is primarily driven by an increase in the return on equity (ROE) from 10.10% under the Settlement Agreement (2021 Settlement) which resolved DEF's last rate case in 2021 to 11.15%.[1]

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[1] *In re: Petition for Limited Proceeding to Approve 2021 Settlement Agreement, Including General Base Rate Increases, by Duke Energy Florida, LLC.*, Docket No. 20210016-EI, Amendatory Order, Attachment A 2021 Settlement Agreement at 3-4 (Jun. 28, 2021). See also, *In Re: Petition for Limited Proceeding to Implement Return on Equity Trigger Provision of 2021 Settlement Agreement, by Duke Energy Florida, LLC.*, Docket No. 20220143-EI, Order Implementing Duke Energy Florida, LLC's Return on Equity Trigger (Oct. 21, 2022).

- Approximately $1.6 billion of plant additions are for the 14 Proposed Solar Projects. As Mr. Ly testifies, the cost-effectiveness of the Proposed Solar Projects is highly questionable.
- DEF's proposed 11.15% ROE is 137 basis points higher than the 9.78% average ROE authorized by state regulatory commissions nationwide for other vertically-integrated electric investor-owned utilities (IOUs) in rate case decisions in 2023 and through May 2024.
- Florida is viewed as a very constructive regulatory environment for IOUs. Further, a large percentage (52% in 2024) of DEF's annual revenues are collected in various cost recovery mechanisms that allow rates to be adjusted outside of base rate cases. Thus, it is clear that DEF faces significantly less regulatory risk than many of its peer IOUs. Accordingly, the lower regulatory risk should be reflected in the ROE authorized for DEF.

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

- DEF is proposing to set rates using a CCOSS that allocates production plant using the Twelve Coincident Peak (12CP)+25% Average Demand (AD) method and transmission plant using the 12CP method.
- Neither the 12CP+25% AD nor the 12CP methods reflect the reality that DEF is largely a summer-peaking utility with an occasional secondary winter peak. The summer and winter peak demands drive the need to install capacity to maintain system reliability.
- 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. If system planners installed capacity sufficient to serve the average of 12 monthly peak demands, DEF would not be able to serve all of its load during the peak periods.
- DEF asserts that allocating 25% of production on AD recognizes the role energy is given in generation facility planning, including DEF's plan to have installed a total of 37 utility scale solar plants through the 2025-2027 test periods. Besides the fact that 25% is arbitrary and unsupported, it is questionable whether the 14 Proposed Solar Projects are cost-effective. Further, solar plants comprise but one component of an integrated generation fleet that is designed to match supply and demand in real time. There is no basis to distinguish how solar plants are allocated to customer classes than any other generating resource.

- Production and transmission plant and related expenses should be allocated using the Four Coincident Peak (4CP) method. 4CP recognizes that DEF is a summer-peaking utility with a secondary winter peak. The summer months are also when the transmission system experiences its lowest load carrying capability.
- DEF classifies its distribution network system as 100% demand related. However, a portion of the distribution network should be classified as a customer-related cost using a process referred to as Minimum Distribution System (MDS). This is consistent with the principles of cost causation; that is, when DEF installs a distribution network, it does so, in part, to provide the voltage support and the readiness to serve new customers, irrespective of the amount of power and energy they will consume. Thus, MDS better reflects the drivers that cause a utility to incur these costs.
- MDS is an accepted practice. It was approved for both Gulf Power Company (Gulf Power) and Tampa Electric Company (TECO) in their last rate cases. Additionally, TECO is supporting MDS in its pending rate case.
- Production tax credits (PTCs) were allocated in the same manner as plant in service. However, unlike investment tax credits (ITCs), which reduce production capital costs, PTCs are earned for every megawatt-hour (MWh) generated by a DEF-owned solar project. Accordingly, PTCs should be allocated on an energy basis.
- Similarly, investment tax credits were allocated on plant in service, even though these tax credits are applicable only to production plant.
- DEF did not conduct a distribution loss study in this filing. The distribution loss factors for primary service were assumed to be 1% higher than the corresponding transmission losses. All of the residual losses were attributed to secondary distribution.
- DEF used the same loss factors by delivery voltage for both peak demand and energy. However, respecting the laws of physics, peak demand loss factors should be higher than energy loss factors.
- Accordingly, I have replaced DEF's demand and energy loss factors by delivery voltage with the corresponding loss factors developed by TECO in its pending rate case. TECO's loss factors are based on a distribution loss study and, further, the demand loss factors are appropriately higher than the corresponding energy loss factors.

Class Revenue Allocation

- DEF has followed the Commission's long-standing policy to move all rates closer to cost, subject to gradualism.
- However, DEF ignored the impact of its proposed 25% and 40% reductions in the Demand Credits applicable to Curtailable and Interruptible customers, respectively, in apportioning the proposed base revenue increases. As a result, the base rates for Curtailable and Interruptible customers would more than triple (over 200%) under DEF's proposal. Increases of this magnitude are overly abrupt, thereby violating reasonable gradualism constraints, and would impose an undue burden on these customers.
- The proper application of gradualism is 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.

Rate Design

- DEF is proposing minor updates to the time-of-use (TOU) rating periods, including renaming the "Super Off-Peak" period to Discount period. However, the proposed On-Peak Demand charges do not provide a strong incentive to shift load to lower cost periods because the Mid-Peak Demand charges also apply to demands during both the On-Peak and Off-Peak periods, while the Base Demand charge applies to demand in all hours. Thus, DEF's proposed TOU rates are time-varying in name only.
- The design of DEF's TOU rates is based on a flawed "Cost Duration Model" (CDM). The CDM spreads production/transmission plant-related costs and marginal energy costs to each hour throughout the year. Thus, it identifies the hours when costs are the highest (*i.e.,* On-Peak period) and the lowest (*i.e.,* Discount period).
- However, because the CDM spreads all production/transmission plant-related costs over all 8,760 hours in a typical year, which is contrary to cost-causation principles, the on-peak price signals are significantly diluted.
- The proposed Discount period would provide significantly lower pricing for a very limited period: six hours during the non-winter months and three hours during the winter months. Most customers could not avoid paying On-Peak and Mid-Peak Demand charges, even if they were able to shift most of their work hours to the Discount periods.

- The inability to avoid additional Demand charges would be a major disincentive for large electricity consumers who operate 24x7 to shift load away from high-cost periods.
- TOU rating periods have to be both practical, reflect time-varying costs, and send proper price signals that encourage customers to shift loads to lower-cost periods. DEF's proposed TOU periods do not meet these criteria, and the Commission should require DEF to redesign them.

2. OVERVIEW

Q HAS DEF IMPLEMENTED BASE RATE INCREASES RECENTLY?

A Yes. DEF implemented three base rate increases pursuant to the 2021 Settlement. The last of these increases was implemented just this year. Over the three years, the cumulative base revenue increase was 8.0%.

Q WHAT BASE RATE INCREASES IS DEF PROPOSING TO IMPLEMENT IN THIS PROCEEDING?

A DEF is proposing three base rate increases as shown in Table 1. Also shown are the three increases from the 2021 Settlement.

Table 1
Revenue Increases
($000)

Year	Amount	Percent
2021 Settlement		
2022	$67,246	2.8%
2023	$48,933	1.9%
2024	$79,199	3.1%
2024 Rate Case		
2025	$594,017	20.4%
2026	$97,678	2.8%
2027	$130,965	3.6%
Total	$822,660	28.3%

Sources:
Docket No. 20210016-EI, Amendatory Order.
Docket No. 20210016-EI, 2021 Settlement Updated C Schedules.
Docket No. 20240025-EI, Schedule E-13a, at 1-3.

As Table 1 demonstrates, the cumulative impact of the three proposed base revenue increases would be approximately $823 million, or 28.3%.

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

A DEF expects to add nearly $2.7 billion of rate base through 2027.[2] These additions include:

- 14 new solar projects: $1.6 billion;[3]
- 105 MW of two-hour battery energy storage systems: $194 million;[4] and
- Efficiency improvements to DEF's combined-cycle gas turbine (CCGT) fleet: $116 million.[5]

Additionally, DEF is proposing higher depreciation and dismantling expenses and a much higher cost of capital. This includes an increase in ROE from 10.2% to 11.15% ROE.[6] ***The 95-basis points of higher ROE accounts for, about $110 million of the proposed $823 million (three-year) base revenue increase.***

Q WHAT ARE YOUR PRIMARY CONCERNS WITH DEF'S RATE INCREASE PROPOSAL?

A First, DEF's proposal to implement three consecutive base rate increases derived from three separate fully-projected forward test years is unprecedented and overreaching. Second, the Proposed Solar Projects will dramatically increase DEF's rate base, yet

2 MFR Schedule B-1 at 1; DEF's 2024 Electric Forecasted Earnings Surveillance Report, Schedule 2 at 1.

3 Direct Testimony of Vanessa Goff at 4, 10.

4 Direct Testimony of Hans Jacob at 3, 5, 7.

5 Direct Testimony of Reginald D. Anderson, Exhibit RDA-4.

6 Direct Testimony of Adrien M. McKenzie at 3.

DEF has provided no assurances that the projects will even achieve the projected benefits or that the projected benefits will actually flow-through to customers. Third, DEF's proposed 11.15% ROE is excessive compared to the returns authorized for other vertically integrated electric IOUs in light of the fact that Florida has a much lower-risk regulatory environment than the vast majority of state regulatory commissions.

Proposed Three Test Years

Q ARE DEF'S THREE PROPOSED TEST YEARS CONCERNING?

A Yes. Setting rates based on three future projected test years is highly speculative and presupposes that DEF can accurately forecast plant additions, sales, revenues, and expenses numerous months before the first set of rates are implemented. In fact, an example of why this is problematic has already occurred: DEF prepared its sales and revenues forecast in February and March of 2023, 21 months before the 2025 test year. However, DEF had to correct an error in its sales and revenue forecasts for the 2025, 2026, and 2027 test years, which reduced DEF's proposed revenue deficiency by $53.3 million in 2025, $47.1 million in 2026, and $56.8 million in 2027.[7] In addition, DEF also adjusted its depreciation expense to correct its expected retirement date assumptions for Steam Anclote Units 1 and 2 from 2029 to 2042, thereby reducing depreciation expense by $32 million.[8] These corrections demonstrate how even short-term projections can be inaccurate.

[7] DEF Response to Staff ROG 1-2.

[8] DEF Response to OPC ROG 6-139.

Q IS THERE ANY PRECEDENT FOR USING THREE FULLY PROJECTED FORWARD-LOOKING TEST YEARS TO SET RATES FOR THREE CONSECUTIVE YEARS IN A SINGLE PROCEEDING?

A No. DEF claims that there is Commission precedent and refers to the 2017 Settlement and the 2021 Settlement, which included multiple year rate increases. While I am not an attorney, the 2021 Settlement specifically and plainly states that neither the Settlement or any of its terms shall have any precedential value.[9] DEF was not able to cite any fully litigated case whereupon three fully projected forward-looking test years were approved by the Commission.

Q IS IT REASONABLE TO SET RATES FOR THREE FUTURE YEARS IN ONE RATE CASE INVESTIGATION?

A No. The Test Year Rule states that:

> (1) At least 60 days prior to filing a petition for a general rate increase, a company shall notify the Commission in writing of its selected test year and filing date. This notification shall include:
>
> (a) An explanation for requesting the particular test period. If an historical test year is selected, there shall be an explanation of why the historical period is more representative of the company's operations than a projected period. If a projected test year is selected, there shall be an explanation why the projected period is more representative than an historical period;[10]

DEF did not provide a comparison of the 2026 or 2027 test years to the 2023 historical test year purportedly explaining why these years are more representative of its operations than the historical test year. Furthermore, comparing a test year that is three or four years past the historical year would be impracticable and unreliable.

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[9] Docket No. 20210016-EI, *Amendatory Order*, Attachment A 2021 Settlement Agreement at 25 (Jun. 28, 2021).

[10] Fla. Admin. Code Rule 25-6.140(1)(a).

Q WHAT DO YOU RECOMMEND?

A The Commission should reject DEF's 2026 and 2027 test years and set rates for just 2025. To the extent DEF has specific asset additions that will be placed in service after 2025, these additions may be reflected in future subsequent-year adjustments, but only if the plant additions have been placed in service and providing DEF is not overearning.

Proposed Solar Projects

Q PLEASE SUMMARIZE THE PROPOSED SOLAR PROJECTS WHICH ARE DISCUSSED IN DETAIL BY MR. LY.

A The 14 Proposed Solar Projects represent about 1,050 megawatts (MW) of *nameplate* capacity. DEF projects to commission six projects in 2025, four projects in 2026, and the remaining four projects in 2027.[11] DEF estimates that the 14 Proposed Solar Projects (including land) would cost $1,524 per kilowatt (kW). Through 2023, DEF had installed 1,186 MW of solar capacity at an average cost of $1,368 per kW.[12] Therefore, when DEF completes installation of the Proposed Solar Projects, it will have commissioned 2,235 MW (nameplate) of solar projects representing a total investment of over $3.2 billion or $1,441 per kW.

Q WHAT ARE YOUR SPECIFIC CONCERNS ABOUT THE FUTURE SOLAR PROJECTS?

A DEF asserts that the Proposed Solar Projects would save $1.2 billion in fuel costs over

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[11] DEF acknowledged during the deposition of its witness Vanessa Goff that some of these projects may be delayed.

[12] S&P Capital IQ; DEF Response to OPC ROG 7-167.

their expected 30-year lives and generate another $621 million in PTCs.[13] However, Mr. Ly has determined that DEF has overstated the projected fuel cost savings because it has assumed unreasonably high natural gas prices. Further, absent the PTCs, the 14 Proposed Solar Projects would not be cost-effective.

Q WHAT DO YOU RECOMMEND?

A It is essential to condition approval of these projects by imposing a construction cost cap and performance guarantees to ensure that customers actually receive the benefits projected. These recommendations are discussed fully in Mr. Ly's testimony.

Return on Equity

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

A DEF's proposed 11.15% ROE is excessive when compared to the ROEs authorized by state regulatory commissions in rate cases decided in 2023 and 2024 for vertically-integrated electric IOUs. A list of authorized ROEs for vertically-integrated electric IOUs in electric rate cases decided in 2023 and through May of 2024 is provided in **Exhibit JP-1**. As can be seen, the average authorized ROE by state regulators is 9.78% for the period.

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

A No. First, the regulatory climate in Florida is very supportive of the Florida electric IOUs which translates into lower risk for investors. This directly reflects the Commission's ratemaking policies, which include the use of forward-looking, future

[13] Direct Testimony of Benjamin M. H. Borsch, Exhibit BMHB-3.

test years and multi-year rate plans, timely cost recovery as reflected in both interim rate increases and in the various cost recovery clauses that allow rates to be adjusted outside of a rate case, allowing a return on construction work in progress, and authorizing securitization for storm damage and other major events. These risk-lowering policies are described in a 2021 assessment of Florida regulation conducted by Regulatory Research Associates (RRA) which ranked Florida above 46 other states for investor supportiveness by giving it a score of Above Average/2. RRA stated:

> ***Florida regulation is viewed as quite constructive from an investor perspective*** by Regulatory Research Associates, a group within S&P Global Commodity Insights. In recent years, ***the Florida Public Service Commission has issued a number of decisions, most of which opted 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-opted equity returns have tended to exceed industry averages when established, and ***the commission utilizes forecast test years and frequently authorizes interim rate increases. As a result, utilities are generally accorded a reasonable opportunity to earn the authorized returns.*** In addition, a constructive framework is in place for new nuclear and integrated gasification combined cycle coal power plants that allows a cash return on construction work in progress for these investments outside of the base rate case process. Whether any of the state's electric utilities will proceed with the construction of nuclear power plants in the foreseeable future remains questionable given the challenges such projects posed for utilities in neighboring states in recent years. State law permits the electric utilities to securitize certain nuclear generation retirement or abandonment costs, and one of the state's major companies has done so. ***Mechanisms are in place that allow utilities to reflect in rates, on a timely basis, changes in fuel, purchased power, certain new generation, conservation, environmental compliance, purchased gas and other costs. Additionally, the state has been very proactive in providing utilities cost-recovery mechanisms for costs related to major storms. Additionally, in 2019 the state opted a Storm Protection Plan Cost Recovery Clause that allows utilities to seek more timely recovery of storm hardening investments outside a general rate case.*** RRA currently accords Florida regulation an Above Average/2 ranking. (Section updated 4/29/21)[14] (emphasis added)

[14] RRA Assessment of the Florida Public Service Commission.

The Commission's ranking remains at Above Average/2.[15] Only one state regulatory commission, Alabama, is ranked higher than the Florida Commission.

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

A As can be seen in Table 2, DEF collected 53% of its annual sales revenues from under each of the five currently-effective cost-recovery mechanisms in 2023, and projects it will continue to collect between 44% and 52% in years 2024 and 2025.

Table 2
Percent of Revenues Collected Under the Various Commission-Approved Cost Recovery Mechanisms

Mechanism	2023	2024	2025
Fuel	36%	41%	34%
Energy Efficiency	2%	2%	2%
Capital Cost Recovery	7%	5%	2%
Storm Protection	2%	2%	5%
Storm Cost	6%	2%	-
Total Cost Recovery	53%	52%	44%

Source: MFR Schedule C-2.

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

A No. There is no appreciable regulatory lag in setting base rates. The Commission is required to render a decision within eight months after a base rate case is filed. However, because the Commission has authorized the use of a fully projected future test year, the rates approved by the Commission and placed in effect during the test

[15] RRA Regulatory Focus, RRA State Regulatory Evaluations – Energy at 5 (Mar. 1, 2024).

year will exactly recover the projected test-year cost to serve – unless, of course, actual sales, investment, and expenses vary from the utility's projections. Further, the Commission has consistently allowed utilities to propose subsequent-year adjustments that provide for cost recovery of specific assets placed in service after the rate case test year. Thus, there is virtually no regulatory lag in recovering the costs of future plant additions.

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

A The absence of any appreciable regulatory lag in setting base rates also reduces DEF's regulatory risk. This, coupled with this Commission's other supportive ratemaking policies (*i.e.,* future test year, the ability to adjust rates outside of a base rate case through separate cost recovery mechanisms) demonstrate how DEF's regulatory risk is no higher (and arguably lower) than most other regulated vertically integrated electric IOUs. Therefore, the lower regulatory risk should translate into a lower ROE than the other electric IOUs regulated by less supportive commissions.

3. CLASS COST-OF-SERVICE STUDY

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

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

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

A Yes. DEF filed CCOSSs for each of the three proposed test years utilizing two different methodologies. DEF's preferred study uses the Twelve Coincident Peak (12CP) and 25% Average Demand (AD) cost allocation method (*i.e.,* 12CP+25% AD).[16] DEF also filed a CCOSS using the 12CP and 1/13th AD (*i.e.,* 12CP+8%) method.[17]

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

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

[16] Direct Testimony of Marcia J. Olivier at 35.

[17] *Id.*

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

A The flaws are:

- First, the 12CP+25% AD method is not consistent with cost-causation principles because it allocates costs to all hours of the year. Further, it is based on an unspecified and subjective assessment of the purported benefits associated with more capital intensive (solar) plants and a flawed and incomplete application of Capital Substitution theory. Capital substitution erroneously assumes that the sole purpose of more capital-intensive power plants is to lower fuel costs, rather than meet expected peak demand. Further, the same theory is not applied to the allocation of fuel costs and, thus, it suffers from a lack of fuel symmetry. 12CP+25% AD also suffers from double-counting. For these reasons, many state regulatory commissions, including Florida, have rejected allocation methods similar to 12CP+25% AD.
- Second, transmission demand-related costs were allocated to customer classes using the 12CP method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. DEF, however, is a strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.
- Third, DEF failed to recognize that a portion of the distribution network is a customer-related cost. This failure stands in stark contrast to the practices of DEF's affiliates in both North and South Carolina that specifically recognize a customer-related portion of distribution network costs, a practice that is both accepted and consistent with cost-causation principles.
- Fourth, DEF allocated PTCs and ITCs on plant in service. However, PTCs are earned for every MWh generated by a solar project. Thus, they would be more appropriately allocated on an energy basis. ITCs are available only for certain production assets. Accordingly, ITCs should be allocated the same as production plant.
- Finally, the demand and energy losses used in DEF's CCOSS are not based on an actual distribution loss study. DEF derived the distribution loss factors using meter adjustments, which understate the distribution losses. Further, DEF assumed that the demand and energy losses are the same. Reflecting the laws of physics, demand losses should be higher than energy losses.

Q HOW SHOULD THESE FLAWS BE CORRECTED?

A First, production and transmission demand-related costs should be allocated to customer classes using the 4CP method. The 4CP method is based on demands that occur coincident with DEF's summer period (June through September) demands.

Second, a portion of DEF's distribution network should be considered a customer-related cost, rather than 100% demand, as is consistent with the MDS methodology.

Third, PTCs should be allocated on an energy basis, and ITCs should be allocated on production plant.

Fourth, to provide a proper representation of both demand and energy losses by delivery voltage, I replaced DEF's loss factors with the demand and energy loss factors used by TECO in its pending rate case.

Production Plant

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

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

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

A DEF witness Marcia Olivier asserts that the 12CP+25% AD method recognizes the role energy is given in generation facility planning. She cites the 23 DEF utility scale solar plants in service by December 2024 and DEF's plans to install 14 additional solar facilities in the 2025-2027 test periods.[18] She states these (and other DEF baseload generation) projects:

> …have a higher up-front capital cost, but the benefits to customers are primarily related to the cost of fuel, which is apportioned on an energy basis. Therefore, a larger portion of the Company's production capacity costs should be apportioned in the same manner as the customer realizes the benefits, *i.e.*, on an energy basis. [19]

Q DO YOU AGREE WITH HER ASSERTION?

A No. First and foremost, the use of 12CP to allocate costs to a utility that has strong summer and winter peak demands is contrary to cost causation. The seasonal peak demands are summarized in Figure 1 on the following page. Figure 1 clearly demonstrates that DEF's loads are highly seasonal. 12CP would only be appropriate if DEF's loads were relatively flat and/or non-seasonal. The specific problems with 12CP are discussed later.

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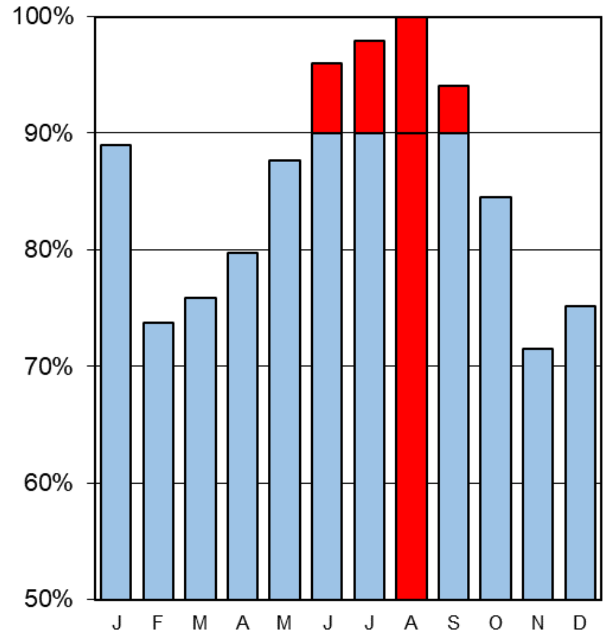
[18] *Id.* at 36.

[19] *Id*.

Figure 1
Monthly Peak Demands as a Percent of
The Annual System Peak: 2020 – 2025



Second, in stark contrast to peak demand methods (such as 1CP, 2CP, 4CP, and to a much lesser extent, 12CP), the 12CP+25% AD method is not consistent with cost-causation principles. Further, Ms. Olivier's assertion that DEF's production plant is caused by energy consumption is both misleading and inaccurate.

Third, unlike baseload (combined cycle gas turbine) plants, DEF's solar plants can operate only on sunny days. They are not physically capable of serving load in any given hour. Whereas DEF's combined cycle gas turbine plants have operated at capacity factors ranging from 35% to 75% over the past five years, DEF's solar plants have operated at less than a 28% capacity factor.[20] Thus, while solar plants are capital intensive, it is improper to characterize them as baseload energy resources. At best, solar plants are an intermittent energy resource.

[20] S&P Capital IQ.

Fourth, based on the information provided in Exhibit BMHB-3, although DEF projects that these projects will produce fuel cost savings, the DEF solar projects are only cost-effective when factoring in the taxpayer subsidized PTCs. Stated differently, but for the PTCs, the 14 Proposed Solar Projects would not be cost-effective. However, PTCs are effective only during the first 10 years of commercial operation. Once the PTCs have expired, the costs of the solar projects will likely exceed the benefits over their 20-year remaining lives.

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

Q DO AFFILIATES OF DEF USE THE 12CP+25% AD METHOD TO ALLOCATE PRODUCTION PLANT COSTS TO RETAIL CUSTOMER CLASSES?

A No. For example, in the most recent rate cases in North Carolina, DEF affiliates – Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) – used the Average and Excess method. In South Carolina, although DEP and DEC used the 12CP method to allocate production plant, they did not classify or allocate any production plant costs to energy as DEF is proposing.

Q DO THE DEF AFFILIATES OPERATING IN NORTH AND SOUTH CAROLINA FACE A MUCH DIFFERENT PLANNING ENVIRONMENT THAN IN FLORIDA?

A No. Both DEP and DEC have been retiring older fossil fuel plants and installing new natural gas combined cycle gas turbine (CCGT) plants, while also building out the infrastructure to support renewable energy projects.

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

A Capital Substitution overlooks four realities:

- The need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate the portion of production plant that Ms. Olivier considers to be demand related does not recognize the peak demands that drive capacity needs. Moreover, allocating the remainder of production plant based on energy ignores the important role of load-following capabilities.
- Fuel savings are not a cost driver. All new plants save fuel costs due to improvements in generation technology, not because they are more capital intensive. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lowest overall cost — not solely to lower fuel costs.
- CCGTs have become the technology of choice, not because they have lower fuel costs, but because they can provide flexible load-following capabilities needed to balance loads and resources in real time and meet operating reserve requirements. These capabilities are essential to keeping supply and demand in constant balance, particularly as more intermittent resources are added to the system.
- An energy allocation assumes all hours are critical to the choice of generation. However, capacity factor, which measures how often a power plant is dispatched to produce energy, does not determine the type of capacity to install. Thus, allocating investment to all hours is contrary to cost causation.

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

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

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

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

Q HOW IS THIS EXAMPLE RELEVANT TO MS. OLIVIER'S COST ALLOCATION METHODOLOGY?

A Ms. Olivier's cost allocation methodology assumes that all energy production matters; that is, the higher the capacity factor, the larger the portion of investment that should be allocated on a pure energy basis. This ignores the reality that the breakeven capacity factor between baseload and peaking plants likely occurred at a much lower (less than 10%) capacity factor. Thus, the baseload plants would be the lowest cost alternative if they are expected to operate at any capacity factor above the breakeven capacity factor. Whether a baseload plant operates at a 40%, 60%, or 80% capacity factor would not alter the decision. Thus, the operating capacity factor is irrelevant.

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

A Yes. This Commission has previously rejected the Equivalent Peaker method because it "…implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours past the break-even point.[21]

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

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

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

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public

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

Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s. In one such case the Commission adopted the Examiner's Report which cited the lack of fuel symmetry in rejecting capital substitution, an energy-based allocation method. Specifically:

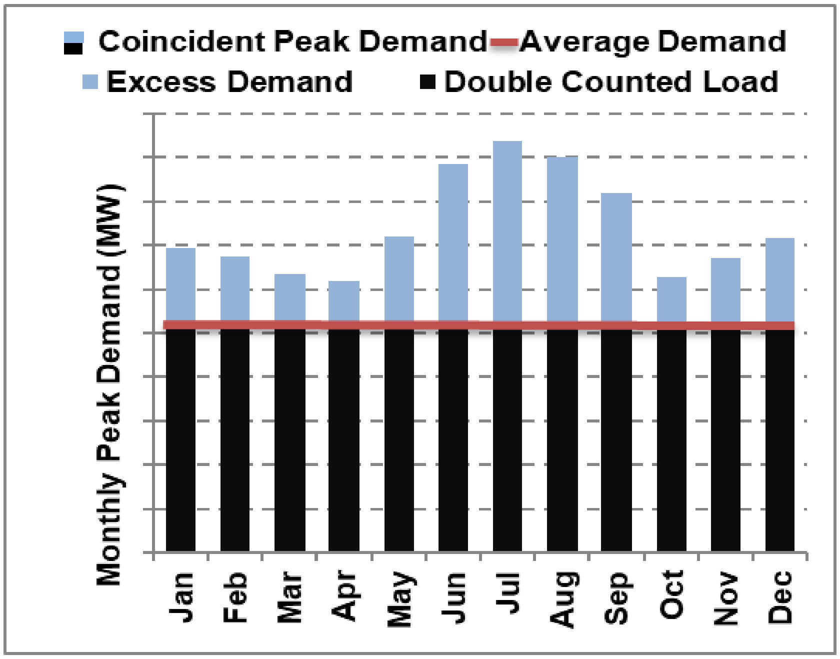
> The examiners find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal…the high load factor classes, which will bear higher cost responsibility for base load units, will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[22]

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

A Yes. The 12CP+25% AD method also suffers from a "double-counting" problem. Double-counting can occur when plant-related costs are allocated partially on a CP basis and on an average demand (or energy) basis. Average demand is annual energy consumption divided by 8,760 hours. It is also a component of coincident peak demand. This is illustrated in Figure 2 on the following page for a hypothetical summer-peaking utility.

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

Figure 2
12CP+25% AD Method



Average demand is equivalent to the black shaded area of the chart. Peak demand is represented by the combined black and blue shaded areas. In other words, the combination of average demand and 12CP demand allocators used in the 12CP+25% AD method results in double-counting energy usage: once in the average demand allocator and a second time in determining each class's 12CP demand.

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

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

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4 CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and thus "double dipping" is taking place.[23]

Q WHAT DO YOU RECOMMEND?

A The Commission should reject the 12CP+25% AD method because it is not consistent with cost causation, it is an oversimplification of utility system planning principles, and it suffers from the fuel symmetry and double-counting problems as described herein. By allocating demand-related costs primarily based on energy, thereby over-allocating costs to energy-intensive customer classes, such an approach would also have negative impacts on competitiveness and economic development.

Transmission Plant

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

A DEF uses 12CP to allocate transmission plant.

Q WHAT ARE YOUR CONCERNS WITH THE 12CP METHOD?

A As previously noted, 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

[23] *Id.* at 236.

weighting to the non-summer months in allocating production and transmission costs ignores the reality that DEF is a strongly summer-peaking utility. This is demonstrated in **Exhibit JP-2**.

As can be seen, there are substantial differences in DEF's monthly system peak demands. Historically, the demands during the summer months have consistently been much closer to the annual system peak than the peak demands in the non-summer months.

Q IS DEF PROJECTING TO REMAIN SUMMER PEAKING?

A No. DEF is currently projecting a winter peak.[24]

Q IS THERE AN AUTHORITY THAT SUPPORT YOUR OPINION THAT 12CP IS NOT AN APPROPRIATE METHOD FOR DEF?

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

> This [the 12CP] method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky.[25]

Clearly, DEF's annual load shape is spiky and its monthly peaks do not lie within a narrow range. This was demonstrated in **Figure 1** and **Exhibit JP-2**. Accordingly, 12CP does not reflect cost causation.

[24] DEF's Amended Ten-Year Site Plan 2024 – 2033 at 2-15 and 2-18 (Apr. 22, 2024).

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

Q WHAT ALLOCATION METHOD WILL RECOGNIZE THESE REALITIES?

A The 4CP method better reflects the realities that DEF has been a strongly summer-peaking utility with a growing winter peak. The peak demands during these periods are more critical to maintaining the reliability of the bulk power system.

Q WHAT DO YOU RECOMMEND?

A The Commission should require DEF to adopt the 4CP method to allocate production and transmission plant and related costs. Recognizing the increasing importance of the winter peak, the 4CP method should include the months January, June, July, and August.

<u>Distribution Network Costs</u>

Q WHAT ARE DISTRIBUTION NETWORK COSTS?

A The electric distribution network consists of DEF'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 HOW IS DEF PROPOSING TO CLASSIFY AND ALLOCATE DISTRIBUTION NETWORK COSTS?

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

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

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

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

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

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

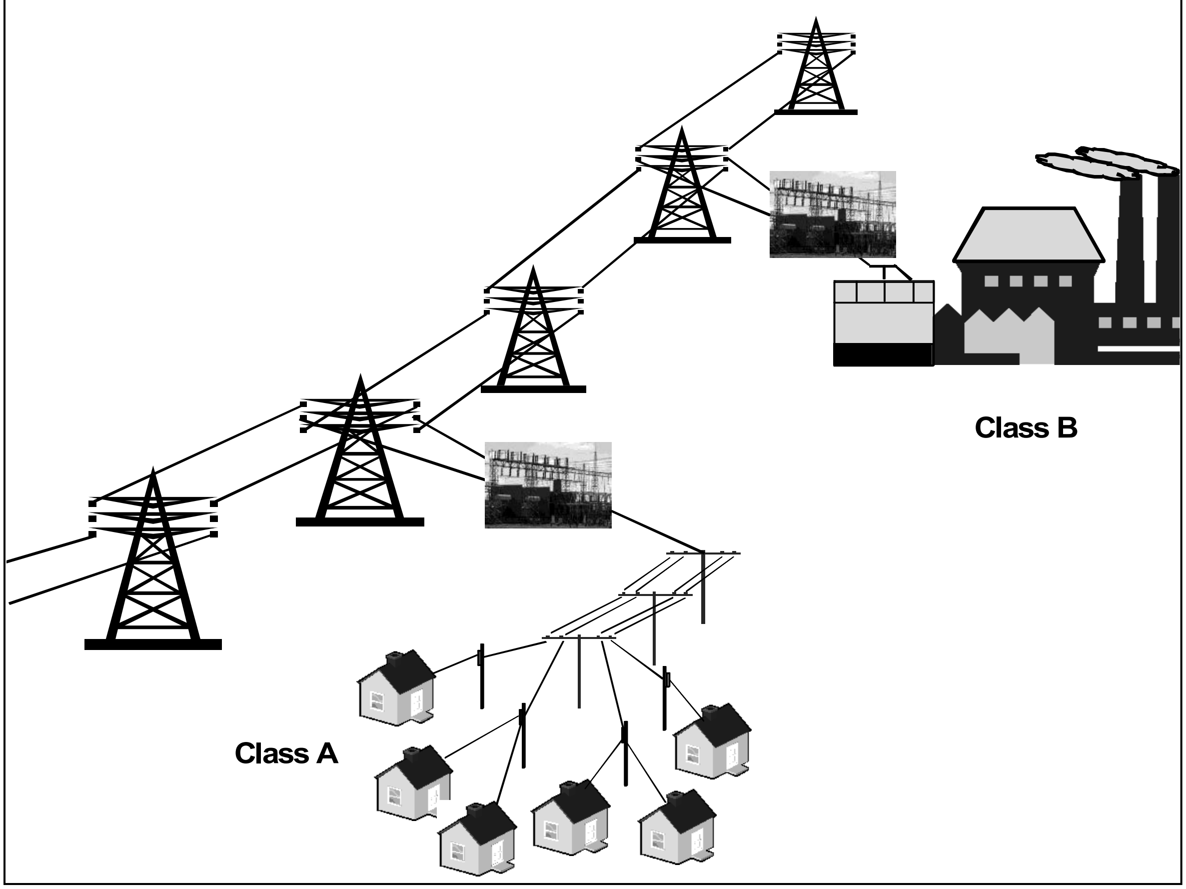
Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage support, which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence of the customer.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

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

A Although the distribution network is sized to meet expected peak demand, it must also provide direct connection to the customer while providing the necessary voltage support to allow power to flow to the customer. Absent a distribution network and the voltage support 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 DEF 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.

Illustration Showing the Customer Component of Distribution Primary and Secondary Plant



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.[26]

Q IS CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND A CONSISTENT PRACTICE WITHIN THE DUKE ENERGY SYSTEM?

A No. DEF affiliates, DEC and DEP, classify a significant portion of distribution network costs as customer-related. The customer-related cost classifications are summarized in Tables 3 and 4.

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

Table 3
Customer-Related Portion of Secondary Distribution Network Costs

FERC Account	DEC NC	DEP NC	DEC SC	DEP SC
364: Poles, Towers & Fixtures	14%	19%	15%	21%
365: Overhead Conductors	43%	32%	41%	41%
366: Underground Conduit	80%	73%	72%	54%
367: Underground Conductors	44%	73%	41%	54%
368: Line Transformers	100%	0%	60%	0%

Sources: Docket No. E-7, Sub 1276, Docket No. E-2, Sub 1300, DEP Docket No. 2022-254-E, DEP Docket No. 2023-388-E

Table 4
Customer-Related Portion of Primary Distribution Network Costs

FERC Account	DEC NC	DEP NC	DEC SC	DEP SC
364: Poles, Towers & Fixtures	49%	62%	51%	60%
365: Overhead Conductors	46%	39%	54%	43%
366: Underground Conduit	78%	70%	69%	50%
367: Underground Conductors	42%	70%	32%	50%
368: Line Transformers	0%	0%	0%	0%

Sources: Docket No. E-7, Sub 1276, Docket No. E-2, Sub 1300, DEP Docket No. 2022-254-E, DEP Docket No. 2023-388-E

As Tables 3 and 4 demonstrate, DEF's affiliates recognize that a significant portion of distribution network costs are customer-related.

Q DOES ANY OTHER FLORIDA UTILITY RECOGNIZE A CUSTOMER-RELATED COMPONENT OF DISTRIBUTION NETWORK COSTS?

A Yes. In its 2021 rate case, TECO agreed to implement a customer-related portion of the distribution network. TECO is proposing to continue this practice in its pending 2024 rate case.[27]

[27] *In re: Petition for Rate Increase by Tampa Electric Company,* Docket No. 20240026-EI, Prepared Direct Testimony and Exhibit of Jordan Williams at 14.

Q HAS DEF CONDUCTED A STUDY IDENTIFYING THE CUSTOMER-RELATED PORTION OF ITS DISTRIBUTION NETWORK COSTS?

A Yes. DEF conducted a MDS study and identified the customer-related costs for FERC Account Nos. 364, 365, 366, 367, and 368 as shown in Table 5.

Table 5
Customer-Related Costs from
DEF's Minimum Distribution System Study

FERC Account	Percentage
364: Poles, Towers & Fixtures	65%
365: Overhead Conductors	56%
366: Underground Conduit	52%
367: Underground Conductors	55%
368: Line Transformers	68%

Source: DEF Response to FIPUG ROG 2-36.

Q WHAT DO YOU RECOMMEND?

A DEF's CCOSS should be revised to recognize a customer-related component of distribution network costs consistent with the classifications shown in Table 5.

Recognizing a customer-related cost more fairly allocates distribution costs between rate classes. It also 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. Thus, it is consistent with cost causation, is an accepted industry practice, and this Commission previously approved its use for TECO.

Demand and Energy Loss Factors

Q DO YOU HAVE ANY CONCERNS WITH THE LOSS FACTORS USED BY DEF IN ITS CLASS COST-OF-SERVICE STUDY?

A Yes. There appears to be two fundamental problems.

First, losses are a function of electrical current, and current is highest during peak periods. Accordingly, the (peak) demand losses *should* be higher than the corresponding energy losses. Despite the physics behind the variable losses incurred by electric utilities, the energy loss factors used by DEF in this proceeding (which measure the average losses incurred over all 8,760 hours) are the same as the corresponding peak demand loss factors for all delivery voltages. This is demonstrated in Table 6.

Table 6
Duke Energy Florida
Delivery Efficiency Factors

Voltage	Demand	Energy
Secondary	0.957172	0.957172
Primary	0.975237	0.975237
Transmission	0.985237	0.985237

Source: MFR Schedule E-10.

A delivery efficiency factor is the inverse of a loss factor. The higher the delivery efficiency factor, the lower the loss factor, and vice versa.

Second, DEF derived the loss factors for primary distribution voltage by subtracting 1% from the corresponding transmission loss factors. All of the remaining losses were attributed to secondary distribution voltage. Thus, DEF did not conduct an actual distribution loss study. Had DEF conducted a distribution loss study, it is possible that the loss factors for both primary and secondary distribution voltages would be higher.

Q WHAT IS THE BASIS FOR YOUR ASSERTION THAT A DISTRIBUTION LOSS STUDY WOULD HAVE REVEALED HIGHER LOSS FACTORS TO PROVIDE SERVICE AT PRIMARY AND SECONDARY DISTRIBUTION VOLTAGES?

A In its pending rate case, TECO conducted a distribution loss study. The results of TECO's loss analysis are summarized in Table 7.

Table 7
Tampa Electric Company
Delivery Efficiency Factors

Voltage	Demand	Energy
Secondary	0.935585	0.947848
Primary	0.962361	0.975070
Transmission	0.980071	0.986991

Source: Docket No. 20240026-EI, MFR Schedules E-11 and E-19b.

As Table 7 demonstrates, TECO's demand losses are higher than the corresponding energy losses. Further, the losses for primary and secondary distribution voltages appropriately reflect the higher losses incurred to deliver electricity to customers taking service at these voltages.

Q WHAT DO YOU RECOMMEND?

A DEF's peak demand and energy and loss factors are clearly understated for primary and secondary distribution voltages. Accordingly, I recommend replacing DEF's loss factors with the demand and energy loss factors by delivery voltage that TECO is using in its pending rate case, as shown in Table 7.

The Commission should order DEF to conduct a full-scale distribution loss study for its next rate case. Preferably that study should be reviewed by all parties prior to the filing of DEF's next rate case.

<u>Revised CCOSS</u>

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

A Yes. **Exhibit JP-3** shows the derivation of the 4CP demand allocation factors. **Exhibit JP-4** is a revised CCOSS using 4CP (instead of 12CP+25% AD) for production and 4CP (instead of 12CP) for transmission. In addition, PTCs were allocated on an energy basis. As discussed earlier, PTCs are earned for every MWh generated from DEF's owned solar projects. Thus, allocating PTCs on an energy basis would better reflect cost causation than DEF's proposal, which spreads PTCs on plant in service.

4. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

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

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

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

Q WHAT IS THE PRINCIPLE OF GRADUALISM?

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

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

A Yes. Cost-based rates are fair because each class's rates reflect 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 SHOULD GRADUALISM BE MEASURED RELATIVE TO BASE REVENUES OR TOTAL REVENUE?

A Gradualism should be measured on base revenues. This is because only base revenues are subject to change in this proceeding. Total revenues include base revenues as well as the revenues collected under DEF's five separate cost recovery mechanisms:

- Fuel;
- Energy Efficiency;
- Capital Cost Recovery;
- Storm Protection; and
- Storm Cost.

None of these cost recovery mechanisms are subject to change in a base rate case. Further, gradualism is not considered in any of the cost-recovery mechanism. A general rate case is the only venue in which gradualism can be properly applied.

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

Q ARE THE PROPOSED BASE RATE INCREASES IN THIS PROCEEDING THE ONLY INCREASES THAT CUSTOMERS WOULD EXPERIENCE?

A No. In its pending conservation goals proceeding, DEF is proposing to reduce the Demand Credits applicable to Curtailable Service (CS) and Interruptible Service (IS) by 25% and 40%, respectively.

Q DOES DEF INCLUDE THE IMPACT OF REDUCING THE CURTAILABLE AND INTERRUPTIBLE SERVICE DEMAND CREDITS IN THIS PROCEEDING?

A No.

Q HOW WOULD THE 25% AND 40% REDUCTIONS IN THE CURTAILABLE AND INTERRUPTIBLE SERVICE DEMAND CREDITS IMPACT BASE RATES CHARGED TO THESE CUSTOMERS?

A The proposed reductions would generate additional revenue of $21.1 million from CS and IS customers.[28] These increases were ignored by DEF in determining the base revenue increases by customer class. Specifically, DEF is proposing base revenue increases of $22.9 million (30%) for CS and IS customers in 2025. Thus, if the CS and IS credits are reduced as DEF is proposing, and DEF receives its requested 2025 base revenue increase, CS and IS customers would experience base revenue

[28] MFR Schedule E-13c; MFR Schedule E-14; Rate Schedule CS-2 and Rate Schedule IS-2. See also, *In Re: Commission Review of Numeric Conservation Goals (Duke Energy Florida, LLC)*, Docket No. 20240013-EG, Direct Testimony of Tim Duff at 22 (Apr. 2, 2024).

increases of 213%. Not only would the combined rate increases violate the principle of gradualism, they would have a deleterious impact on the cost competitiveness and sustainability of the affected customers.

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

A Yes. **Exhibit JP-5** uses FIPUG's 4CP/MDS CCOSS with the revised loss factors and PTC/ITC allocations, as discussed previously. My recommendation would result in moving a majority of rate classes to a relative rate of return of 1.01, which is just slightly above parity. Consistent with gradualism, the LS Energy class would receive no increase because it is already providing a rate of return that exceeds DEF's proposed system average rate of return, and no class would receive a base revenue increase higher than 1.5 times the 19.3% system average base revenue increase. For purposes of this illustration, I have assumed no change in either the CS or IS Demand Credits. Should the CS and IS Demand Credits be reduced, the impact should be recognized in limiting the combined revenue increases to not more than 1.5 times the system average base revenue increase.

5. RATE DESIGN

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I address DEF's proposed TOU rating periods.

Q HOW SHOULD RATES BE DESIGNED?

A Rate design is an extension of the cost allocation process. Also referred to as "intraclass" allocation, rate design determines how the costs allocated to each customer class are recovered from the customers within the class. Thus, rates should be designed consistent with the methodologies used to allocate costs in the CCOSS.

Further, the purpose of rate design is to establish charges that reflect cost while also sending proper price signals to encourage customers to respond in an appropriate manner. A rate design that fails to either provide proper price signals or meaningful opportunities for customers to respond to price signals is not only not cost-based, it will also discourage customer engagement. The proposed TOU rating periods and price signals in DEF's TOU rate schedule achieve neither objective.

Q WHAT CHANGES IS DEF PROPOSING TO THE TIME-OF-USE RATING PERIODS?

A DEF is proposing only minor changes in the TOU rating periods. The current and proposed TOU rating periods are summarized in Table 8 on the following page.

Table 8
Time of Use Periods

Period	Present	Proposed
On-Peak (Year-round)*	6 p.m. to 9 p.m.	
On-Peak (Winter)*	5 a.m. to 10 a.m.	
Discount (Non-Winter)	12 a.m. to 6 a.m.	
Discount (Winter)	N/A	12 a.m. to 3 a.m.
Winter Months	Dec. Jan. Feb.	

* Weekdays excluding holidays.
Source: Direct Testimony of Matthew Chatelain at 11-12

As Table 8 shows, only slight revisions are being made to the TOU periods. Other than renaming the Super Off-Peak period to “Discount” period, DEF is proposing to add a second discount period in the winter months to encourage EV charging.

Q WHY DO YOU BELIEVE THAT DEF’S TIME-OF-USE RATING PERIODS ARE NOT COST-BASED?

A As discussed in further detail subsequently, DEF’s TOU rating periods were developed using a Cost Duration Method (CDM) that allocates the vast majority of production and transmission plant-related costs to hours other than DEF’s peak period demands. The impact of this costing philosophy is evident in the proposed Mid-Peak Demand charges in DEF’s IST-2 rate schedule. Table 9 on the following page summarizes the proposed IST-2 Demand charges.

Table 9 Interruptible Service – Transmission < 230 kV			
Charge	**Proposed Rate**	**Mar – Nov.**	**Dec. – Feb.**
On-Peak	$2.75	6 p.m.–9 p.m.	5 a.m.-10 a.m. 6 p.m.–9 p.m.
Mid-Peak	$5.28	6 a.m.–12 a.m.	3 a.m.–12 a.m.
Base Demand	$1.86	All Hours	All Hours
Discount Hours	$1.86	12 a.m.–6 a.m.	12 a.m. –3 a.m.
Source: Rate Schedule IST-2.			

As Table 9 demonstrates, the Mid-Peak Demand charges would account for the vast majority of the total Demand charges recovered under Schedule IST-2. Even if a manufacturing customer were to completely avoid On-Peak hours, the Demand charges would not be significantly reduced. This is because the Mid-Peak Demand charges would apply during both On- and Off-Peak hours. Further, because they are too narrowly defined, there would be little opportunity for manufacturing customers to shift load to the lower cost Discount period. This is demonstrated in Table 10.

Table 10 Number of Hours in DEF's Proposed Schedule IST-2 TOU Rating Periods			
Period	**Mar – Nov.**	**Dec. – Feb.**	**Total**
On-Peak	573	512	1,085
Off-Peak	4,359	1,399	5,758
Discount	1,644	273	1,917

As Table 10 demonstrates, DEF's proposed Schedule IST-2 is not a legitimate TOU rate because the prices are essentially unchanged for the vast majority of the hours in a typical year. This is because the Discount period (which is the only period that the proposed On-Peak and Mid-Peak Demand charges would not apply in Schedule IST-2) constitutes only 1,917 (22%) of the hours in a typical year. Further, the proposed On-Peak Demand charge is small relative to the proposed Mid-Peak Demand charges. Thus, DEC's TOU rating periods fail because they would send the same price signal during the vast majority (78%) of the hours.

Q WHAT IS THE JUSTIFICATION FOR THE TIME-OF-USE RATING PERIODS AND PRICING DIFFERENTIALS?

A DEF witness, Matthew Chatelain, states that the TOU rating periods and pricing are supported by the CDM.[29]

Q PLEASE EXPLAIN THE COST DURATION METHOD.

A The CDM was used to define how production and transmission plant-related costs and marginal energy costs vary by time-of-use. As discussed in Mr. Chatelain testimony, plant related costs are allocated to time periods during which system assets are used, regardless of the circumstances. Specifically, the costs for assets used during all hours are allocated to all hours, while the costs for assets used during peaking hours are more concentrated in those hours.[30]

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[29] Direct Testimony of Matthew Chatelain at 13.

[30] *Id*.

Q HOW WAS THE COST DURATION MODEL USED TO DETERMINE THE TIME BEARING NATURE OF PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?

A Production plant-related costs were spread to *all* hours based on net peak load, which is the difference between the total (*i.e.,* gross) load served and the amount of utility scale solar generation. Transmission plant-related costs were spread to *all* hours based on gross load. As the hourly load increases, the CDM allocates a proportionally larger share of plant-related costs to that hour. Because it spreads costs to all hours, regardless of the circumstances, the CDM clearly understates the costs assigned to on-peak hours. Only [redacted]% of production and transmission plant-related costs were allocated to the hours in which the net and gross system loads, respectively, are projected to be 90% or higher of the annual system peak. This result clearly demonstrates that the CDM essentially apportions costs to each hour based on the relative load in each hour, rather than the extent in which the load in a particular hour impacts system reliability or causes DEF to incur high energy costs. Accordingly, CDM is a usage-based, rather than a cost-based, model.

Q IS IT REASONABLE TO SPREAD PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS TO ALL 8,760 HOURS IN A TYPICAL YEAR?

A No. The CDM ignores cost causation because the amount of production and transmission facilities must be capable of serving the expected system peak demands, while providing an ample cushion to ensure that DEF can serve its firm loads *at all times*. Spreading these costs to all hours based on usage, rather than to peak periods, is also fundamentally inconsistent with DEC's CCOSS, which has historically allocated costs, in significant part, based on each customer class's coincident peak demand.

Further, DEF has provided no evidence that production and transmission plant-related costs are caused by loads in all 8,760 hours of the year. In fact, this assumption is demonstrably untrue for production plant, as previously discussed.

Q WHAT DO YOU RECOMMEND?

A The current TOU rating periods and pricing differentials should be retained. Further, the Commission should order DEF to develop a new TOU rate design in collaboration with the Commission Staff and other interested parties.

6. 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 2026 and 2027 test years.
- Adopt a lower ROE that reflects DEF's reduced regulatory lag and financial risk.
- Adopt the 4CP method of allocating production and transmission plant.
- Adopt a Minimum Distribution System analysis in allocating distribution network costs.
- Reject DEF's allocations of production tax credits and investment tax credits.
- Adopt FIPUG's recommendation to allocate production tax credits on an energy basis and investment tax credits on production plant.
- Reject DEF's loss factors.
- Adopt FIPUG's recommended demand and energy loss factors by delivery voltage.
- Require DEF to conduct a full-scale distribution loss study in its next rate case.
- Require DEF to completely revise the TOU rating periods and pricing.

Q DOES THAT CONCLUDE YOUR TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, 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
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Cross-Rebuttal	TX	Distribution Load Dispatch Expense; Residential Class MDD; LCUST Allocation Factor; Call Center Cost Allocation; Wholesale Distribution Service for Battery Energy Storage System	6/7/2024
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/6/2024
DOMINION ENERGY SOUTH CAROLINA, INC.	South Carolina Utility Energy Users Committee	2024-34-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/5/2024
DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240013-EG	Direct	FL	Curtailable General Service; Interruptible General Service	6/5/2024
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Direct	TX	Transmission Operation and Maintenance Expense; Property Insurance Reserve; Class Cost-of-Service Study; Rate Design; Tariff Changes	5/16/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Cross-Rebuttal	TX	Turk Remand Refund	5/10/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Surrebuttal	SC	Class Cost-of-Service Study; Revenue Allocation and Rate Design	4/29/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Direct	TX	Turk Remand Refund	4/17/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/8/2024
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	55378	Direct	GA	Deferred Accounting; Additional Sum; Specific Capacity Additions; Distributed Energy Resource and Demand Response Tariffs	2/15/2024
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

APPENDIX C

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.

Authorized Return On Equity For Vertically Integrated Electric Utilities
In Rate Cases Decided in 2023 and 2024

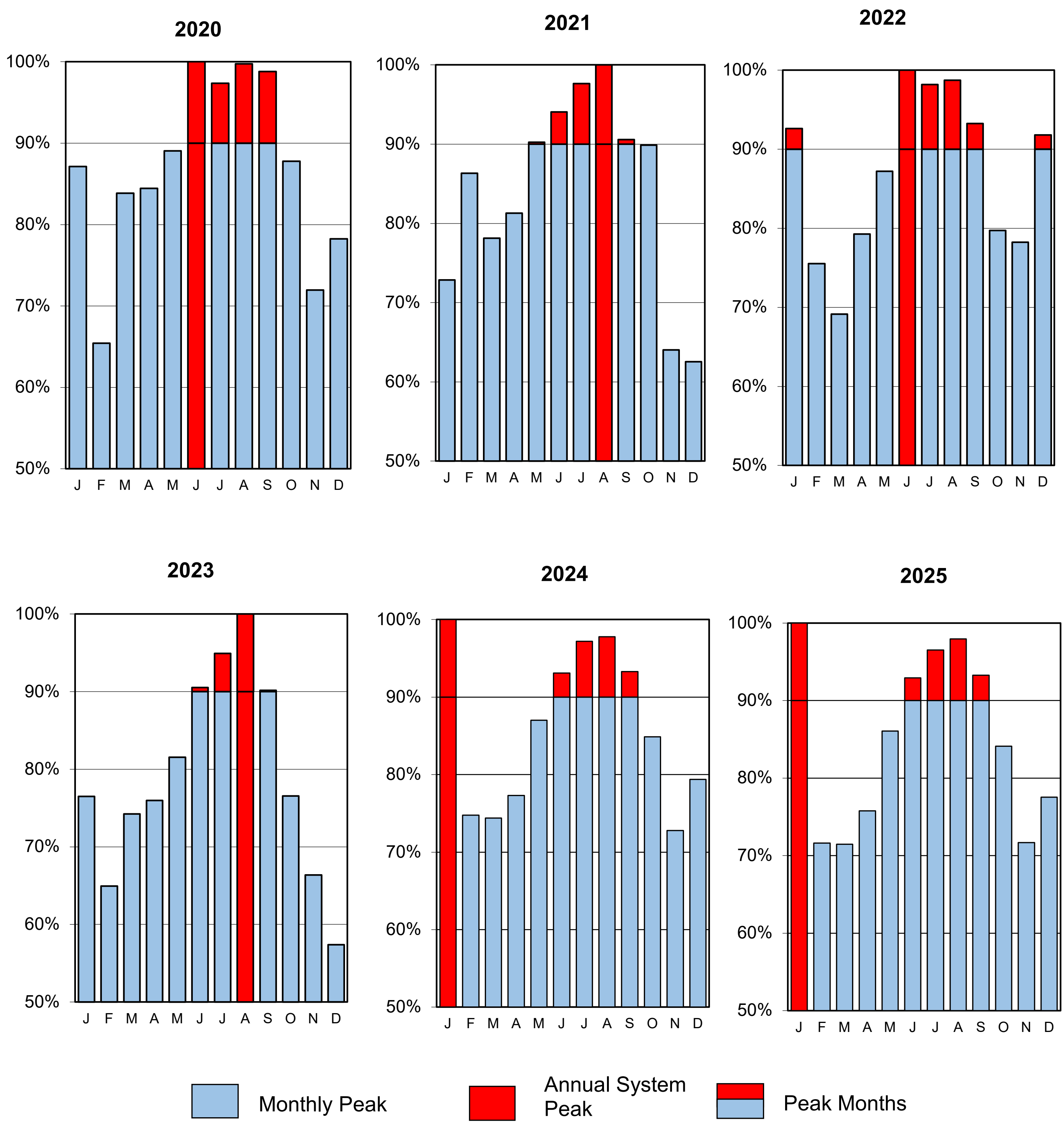
Line	State	Company	Docket	Date Decided	Return on Equity (%)
1	Michigan	Consumers Energy Co.	C-U-21224	1/19/2023	9.90
2	Minnesota	Minnesota Power Entrprs Inc.	D-E-015/GR-21-335	1/23/2023	9.65
3	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-214-ER-22	1/26/2023	9.75
4	South Carolina	Duke Energy Progress LLC	D-2022-254-E	2/9/2023	9.60
5	Louisiana	Southwestern Electric Power Co	D-U-35441	2/17/2023	9.50
7	Michigan	Upper Peninsula Power Co.	C-U-21286	3/24/2023	9.90
8	California	Liberty Utilities (CalPeco Ele	A-21-05-017	4/27/2023	10.00
9	Minnesota	Northern States Power Co.	D-E-002/GR-21-630	6/1/2023	9.25
10	North Dakota	MDU Resources Group	C-PU-22-194	6/6/2023	9.75
11	Indiana	Northern IN Public Svc Co. LLC	Ca-45772	8/2/2023	9.80
12	Texas	Entergy Texas Inc.	D-53719	8/3/2023	9.57
13	North Carolina	Duke Energy Progress LLC	D-E-2 Sub 1300	8/18/2023	9.80
14	Vermont	Green Mountain Power Corp.	C-23-1852-TF	8/23/2023	9.58
15	Arizona	Tucson Electric Power Co.	D-E-01933A-22-0107	8/25/2023	9.55
16	Alaska	Alaska Electric Light Power	D-U-22-078	8/31/2023	11.45
17	Idaho	Avista Corp.	C-AVU-E-23-01	8/31/2023	9.40
18	Colorado	Public Service Co. of CO	D-22AL-0530E	9/6/2023	9.30
19	Montana	MDU Resources Group	D-2022-11-099	9/21/2023	9.65
20	Kentucky	Duke Energy Kentucky Inc.	C-2022-00372	10/12/2023	9.75
21	New Mexico	Southwestern Public Svc Co.	C-22-00286-UT	10/19/2023	9.50
22	Montana	NorthWestern Energy Group	D-2022-7-78 (elec)	10/25/2023	9.65
23	Oklahoma	Public Service Co. of OK	Ca-PUD2022-000093	11/3/2023	9.30
24	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-125 (Elec)	11/3/2023	9.70
25	Wisconsin	Northern States Power Co.	D-4220-UR-126 (Elec)	11/9/2023	9.80
26	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-124 (Elec)	11/9/2023	9.80
30	Wyoming	PacifiCorp	D-20000-633-ER-23	11/28/2023	9.35
31	Michigan	DTE Electric Co.	C-U-21297	12/1/2023	9.90
33	Arkansas	The Empire District Electric C	D-22-085-U	12/7/2023	9.70
34	California	PacifiCorp	A-22-05-006	12/14/2023	10.00
35	North Carolina	Duke Energy Carolinas LLC	D-E-7 Sub 1276	12/15/2023	10.10
36	Oregon	Portland General Electric Co.	D-UE-416	12/18/2023	9.50
37	California	Pacific Gas and Electric Co.	Advice 4813-G/7046-E	12/22/2023	10.70
38	California	San Diego Gas & Electric Co.	Advice Letter 4300-E / 3239-G	12/22/2023	10.65
39	California	Southern California Edison Co.	Advice Letter 5120-E (U 338-E)	12/22/2023	10.75
40	Nevada	Nevada Power Co.	D-23-06007	12/26/2023	9.52
41	Idaho	Idaho Power Co.	C-IPC-E-23-11	12/28/2023	9.60

Authorized Return On Equity For Vertically Integrated Electric Utilities
In Rate Cases Decided in 2023 and 2024

Line	*State*	*Company*	*Docket*	*Date Decided*	*Return on Equity (%)*
42	New Mexico	Public Service Co. of NM	C-22-00270-UT	1/3/2024	9.26
43	Kentucky	Kentucky Power Co.	C-2023-00159	1/19/2024	9.75
44	Arizona	UNS Electric Inc.	D-E-04204A-22-0251	1/30/2024	9.75
45	Virginia	Virginia Electric & Power Co.	C-PUR-2023-00101	2/28/2024	9.70
46	Michigan	Consumers Energy Co.	C-U-21389	3/1/2024	9.90
47	Arizona	Arizona Public Service Co.	D-E-01345A-22-0144	3/5/2024	9.55
50	West Virginia	Monongahela Power Co.	C-23-0460-E-42T	3/26/2024	9.80
51	Indiana	AES Indiana	Ca-45911	4/17/2024	9.90
52	Indiana	Indiana Michigan Power Co.	Ca-45933	5/8/2024	9.85
53	**Average for 2023**				**9.80**
54	**Average for 2024**				**9.72**
55	**Average for 2023 through May 2024**				**9.78**

Docket No. 20240025-EI
Monthly System Peaks
Exhibit JP-2, Page 1 of 1

Duke Energy Florida
Monthly Peak Demands as a
Percent of the Annual System Peak Demand
<u>for the Years 2020 through 2025</u>



Duke Energy Florida

Derivation of the Energy and 4CP Demand Allocations
Test Year Ending December 31, 2025

Line	RATE CLASS		MWh SALES @ METER LEVEL	ENERGY DELIVERY EFFICIENC Y FACTOR	SOURCE LEVEL MWh	kWH ENERGY ALLOCATOR to Total	AVG 4 CP @ METER LEVEL Annual Hrs	DEMAND DELIVERY EFFICIENCY FACTOR	AVG 4 CP MW @ SOURCE LEVEL	AVG 4 CP DEMAND %
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RS-1	Secondary	20,887,162	0.947848	22,036,411		5,009.2	0.935585	5,354.1	
2	Total Residential Service (RS)		20,887,162		22,036,411	52.890%	5,009.2		5,354.1	63.537%
3	GS-1	Transmission	3,193	0.986991	3,235		0.6	0.980071	0.6	
4	GS-1	Primary	27,007	0.975070	27,697		5.4	0.962361	5.6	
5	GS-1	Sec Del/Prim Mtr	-	0.975070	-		-	0.962361	-	
6	GS-1	Secondary	2,167,209	0.947848	2,286,452		429.5	0.935585	459.1	
7	Total General Service Non-Demand (GS-1)		2,197,408		2,317,384	5.562%	435.5		465.3	5.522%
8	GS-2	Secondary	208,404	0.947848	219,870		23.8	0.935585	25.4	
9	Total General Service		208,404		219,870	0.528%	23.8		25.4	0.301%
10	GSD	Transmission	483,697	0.986991	490,073		76.8	0.980071	78.4	
11	GSD	Transmission Del / Primary Met	-	0.975070	-		-	0.962361	-	
12	GSD	Primary	1,754,074	0.975070	1,798,921		278.5	0.962361	289.4	
13	GSD	Primary Del / Secondary Met	4,266	0.975070	4,375		0.7	0.962361	0.7	
14	GSD	Secondary Del / Primary Met	-	0.975070	-		-	0.962361	-	
15	GSD	Secondary	10,914,992	0.947848	11,515,554		1,733.0	0.935585	1,852.3	
16	SS-1	Transmission	5,683	0.986991	5,758		0.8	0.980071	0.8	
17	SS-1	Transmission Del / Primary Met	2,884	0.975070	2,957		0.4	0.962361	0.4	
18	SS-1	Primary	56,107	0.975070	57,541		7.6	0.962361	7.9	
19	Total Firm Service		13,221,702		13,875,179	33.302%	2,097.8		2,229.9	26.462%
20	CS	Transmission	-	0.986991	-		-	0.980071	-	
21	CS	Primary	65,945	0.975070	67,631		15.8	0.962361	16.4	
22	CS	Secondary	(0)	0.947848	(0)		-	0.935585	-	
23	SS-3	Transmission	-	0.986991	-		-	0.980071	-	
24	SS-3	Primary	140,426	0.975070	144,017		14.7	0.962361	15.3	
25	Total Curtailable Service		206,371		211,647	0.508%	30.5		31.7	0.376%
26	IS	Transmission	966,401	0.986991	979,139		113.5	0.980071	115.8	
27	IS	Transmission Del / Primary Met	221,646	0.975070	227,313		26.0	0.962361	27.0	
28	IS	Primary	975,797	0.975070	1,000,745		114.6	0.962361	119.1	
29	IS	Primary Del / Transmission Met	-	0.986991	-		-	0.980071	-	
30	IS	Primary Del / Secondary Met	-	0.947848	-		-	0.935585	-	
31	IS	Secondary	368,766	0.947848	389,056		43.3	0.935585	46.3	
32	IS	Secondary Del / Primary Met	-	0.975070	-		-	0.962361	-	
33	SS-2	Transmission	2,272	0.986991	2,302		0.3	0.980071	0.3	
34	SS-2	Transmission Del / Primary Met	42,748	0.975070	43,841		6.0	0.962361	6.2	
35	SS-2	Primary	9,697	0.975070	9,944		1.4	0.962361	1.5	
36	Total Interruptible Service		2,587,326		2,652,340	6.366%	305.1		316.2	3.752%
37	LS	Secondary	333,500	0.947848	351,849		3.8	0.935585	4.1	
38	Total Lighting Service		333,500		351,849	0.844%	3.8		4.1	0.049%
39	Total Retail		39,641,872		41,664,681	100.000%	7,905.7		8,426.7	100.000%

Docket No. 20240025-EI
Class Cost-of-Service Study
Exhibit JP-4, Page 1 of 1

DUKE ENERGY FLORIDA
FIPUG's Revised Class Cost-of-Service Study at Present Rates
4CP Method With MDS
Test Year Ending December 31, 2025
(Dollar Amounts in Thousands)

Line No.	Description	Total Retail Adjusted	Residential	Gen Service Non Demand	Gen Service 100% L.F.	Gen Service Demand	Gen Service Curtailable	Gen Service Interruptible	Lighting Energy	Lighting Facilities	EV Solution
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(9)
	Rate Base										
1	Electric Plant in Service	$26,060,890	$17,334,902	$1,467,561	$97,789	$5,308,104	$73,848	$691,436	$217,725	$845,326	$24,200
2	Accum. Depreciation & Amort.	(7,310,021)	(4,828,704)	(409,003)	(27,279)	(1,499,653)	(20,575)	(202,927)	(55,873)	(262,391)	(3,616)
3	Net Plant in Service	18,750,869	12,506,198	1,058,558	70,510	3,808,451	53,272	488,509	161,851	582,935	20,585
4	Construction Work in Progress	1,090,298	700,757	61,337	3,191	278,578	3,920	37,172	2,526	2,817	(0)
5	Plant Held for Future Use	115,262	73,367	6,383	353	30,269	432	4,268	124	64	2
6	Working Capital	578,401	395,190	33,641	2,669	110,654	1,547	15,628	7,428	11,084	560
7	Total Rate Base	20,534,831	13,675,512	1,159,919	76,725	4,227,952	59,171	545,577	171,929	596,900	21,146
	Revenue										
8	Class Revenue	2,917,976	1,877,991	196,143	9,006	645,989	8,124	74,717	11,191	88,800	6,015
9	Revenue Credits	51,809	41,951	3,238	287	4,732	41	437	1,107	16	1
10	Total Revenue	2,969,785	1,919,943	199,381	9,293	650,721	8,165	75,154	12,298	88,816	6,016
	Operating Expense										
11	Operations & Maintenance	568,048	376,772	32,791	2,831	114,128	1,624	17,808	7,900	14,003	191
12	Depreciation	1,080,827	711,727	60,723	4,058	220,749	3,053	28,981	8,787	40,352	2,396
13	Tax Other Than Income Tax	195,889	130,710	11,082	758	39,717	556	5,187	1,781	5,892	206
14	Gain/Loss on Disposition	(1,323)	(883)	(75)	(5)	(269)	(4)	(34)	(11)	(41)	(1)
15	Operating Expense before Tax	1,843,440	1,218,327	104,521	7,642	374,325	5,230	51,942	18,457	60,206	2,791
16	Income Tax Expense	107,245	68,034	14,035	(346)	25,110	88	(1,260)	(3,047)	3,929	703
17	Total Operating Expense	1,950,685	1,286,360	118,557	7,295	399,435	5,318	50,681	15,409	64,135	3,494
18	**Net Operating Income**	$1,019,100	$633,582	$80,824	$1,998	$251,286	$2,847	$24,472	($3,112)	$24,681	$2,521
19	**Rate of Return**	4.96%	4.63%	6.97%	2.60%	5.94%	4.81%	4.49%	-1.81%	4.13%	11.92%
20	**Releative Rate of Return**	100%	93%	140%	52%	120%	97%	90%	-36%	83%	240%

Docket No. 20240025-EI
Class Revenue Allocation
Exhibit JP-5
Page 1 of 1

Duke Energy Florida

FIPUG-Recommended Class Revenue Allocation
Based on FIPUG's Revised 4CP/MDS Class Cost-of-Service Study
Test Year Ending December 31, 2025
(Dollar Amounts in Thousands)

		Present COS Present Revenues		Base Revenue at Present	Base Revenue at Proposed	Base Revenue Increase		Proposed COS Proposed Revenues	
Line	Rate Class	ROR (%)	Index	Rates	Rates	Amount	Percent	ROR (%)	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RS	4.63%	0.93	$1,875,200	$2,222,345	$449,785	24.0%	7.07%	1.01
2	GS-1	6.97%	1.40	$196,080	$197,740	$1,813	0.9%	7.07%	1.01
3	GS-2	2.60%	0.52	$9,075	$11,848	$2,621	28.9%	5.21%	0.74
4	GSD, SS-1	5.94%	1.20	$647,895	$842,851	$64,705	10.0%	7.07%	1.01
5	GS, CS, SS-2, SS-3	4.81%	0.97	$8,096	$14,579	$1,792	22.1%	7.07%	1.01
6	IS-2	4.49%	0.90	$75,463	$94,551	$19,022	25.2%	7.07%	1.01
7	LS Energy	-1.81%	-0.36	$11,351	$14,819			0.00%	0.00
8	LS Facilities	4.13%	0.83	$88,800	$108,687	$23,632	26.6%	7.07%	1.01
9	EV Solution	11.92%	2.40	$6,015	$4,574			11.92%	1.70
10	Total Retail	4.96%	1.00	$ 2,917,975	$ 3,511,994	$ 563,370	19.3%	7.01%	1.00

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	**DOCKET NO. 20240025-EI** **Filed: June 11, 2024**

AFFIDAVIT OF JEFFRY POLLOCK

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

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

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

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20240025-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 11th day of June 2024.

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

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2027.

CERTIFICATE OF SERVICE

I **HEREBY CERTIFY** that a true and correct copy of the foregoing Direct Testimony and Exhibits of Jeffry Pollock has been furnished by electronic mail this 11th day of June 2024 to counsel for Duke Energy Florida, LLC, (DEF) who, after conducting a review for confidential information, have represented to counsel for FIPUG that DEF will serve the following with Jeff Pollock's testimony unredacted to parties with a non-disclosure agreement in place and redacted to those parties without a non-disclosure agreement in place:

Jennifer Crawford,
Major Thompson,
Shaw Stiller,
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
JCrawfor@psc.state.fl.us
MThompso@psc.state.fl.us
SStiller@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Walt Trierweiler,
Charles J. Rehwinkel,
Mary Wessling,
Austin Watrous,
Office of Public Counsel
111 W. Madison St., Rm 812
Tallahassee, FL 32399
rehwinkel.charles@leg.state.fl.us
trierweiler.walt@leg.state.fl.us
watrous.austin@leg.state.fl.us
wessling.mary@leg.state.fl.us

James W. Brew,
Laura Wynn Baker,
Sarah B. Newman,
Stone Mattheis Xenopoulos & Brew, PC
PCS Phosphate-White Springs
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
jbrew@smxblaw.com
lwb@smxblaw.com
sbn@smxblaw.com

Bradley Marshall
Jordan Luebkemann
Hema Lochan
Earthjustice
LULAC & FL Rising
111 S. Martin Luther King Jr. Blvd.
Tallahassee, Florida 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org
hlochan@earthjustice.org
flcaseupdates@earthjustice.org

William C. Garner
Law Office of William C. Garner, PLLC
SACE
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

Tony Mendoza
Patrick Woolsey
Sierra Club
2101 Webster Street Suite 1300
Oakland, CA 94612
tony.mendoza@sierraclub.org
patrick.woolsey@sierraclub.org

Nikhil Vijaykar
Keyes & Fox LLP
EVgo Services, LLC
580 California St., 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

Lindsey Stegall
EVgo Services, LLC
11835 W. Olympic Blvd., Ste. 900E
Los Angeles, CA 90064
Lindsey.Stegall@evgo.com

Sari Amiel
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
sari.amiel@sierraclub.org

Peter J. Mattheis
Michael K. Lavanga
Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew, PC
NUCOR
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

Frederick L. Aschauer, Jr.
Allan J. Charles
Lori Killinger
Lewis, Longman & Walker P.A.
AACE / Circle K / RaceTrac / Wawa
106 East College Avenue, Suite 1500 Tallahassee, Florida 32301
fascbauer@llw-law.com
acharles@llw-law.com
lkillinger@llw-law.com

Dianne M. Triplett,
Matthew R. Bernier,
Stephanie A. Cuello,
Robert Pickels
Duke Energy Florida, LLC
299 First Avenue North
St. Petersburg, FL 33701
dianne.triplett@duke-energy.com
matt.bernier@duke-energy.com
stephanie.cuello@duke-energy.com
robert.pickels@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Robert Scheffel Wright
John T. LaVia, III
Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper, P.A.
Florida Retail Federation
1300 Thomaswood Drive
Tallahassee, Florida 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

/s/ Jon C. Moyle, Jr.
Jon C. Moyle, Jr.