BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240025-EI

Petition for rate increase
by Duke Energy Florida.
____________________________/

VOLUME 5
PAGES 879 - 1100

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 21, 2024

TIME: Commenced: 11:00 a.m.
Concluded: 1:30 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

(Whereupon, prefiled direct testimony of Daniel J. Lawton was inserted.)

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

DIRECT TESTIMONY

OF

DANIEL J. LAWTON

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Mary A. Wessling
Associate Public Counsel

Austin A. Watrous
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Suite 812
Tallahassee, FL 32399-1400
(850) 488-9330

*Attorneys for the Citizens
of the State of Florida*

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DIRECT TESTIMONY OF

DANIEL J. LAWTON

SECTION I: <u>INTRODUCTION/BACKGROUND/SUMMARY</u>

Q. 1 PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 12600 Hill Country Boulevard, Suite R-275, Austin, Texas 78738.

Q. 2 PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. My consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, financial analyses, revenue requirements/cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities, and in court proceedings. I have worked with numerous municipal utilities developing electric rate cost of service studies for reviewing and setting rates. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas utility rate proceedings and other litigation including appellate, and contract matters. I have included a brief description of my relevant educational background and professional work experience in Schedule (DJL-1).

Q. 3 HAVE YOU PREVIOUSLY FILED TESTIMONY IN RATE PROCEEDINGS

A. Yes. A list of cases where I have previously filed testimony is included in Schedule (DJL-1).

Q. 4 ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I have been retained to review the Duke Energy Florida, LLC ("Company," "DEF," "Duke") cost of capital request, and related financial issues, on behalf of the Florida Office of Public Counsel ("OPC").

Q. 5 WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

The purpose of my testimony in this proceeding is to address the Company's requested overall cost of capital for Duke's regulated electric operations. I will address and separately estimate the Company's: (i) requested overall rate of return to be earned on rate base investment; (ii) proposed capital structure; (iii) financial risk; (iv) business risk; (v) cost rates for equity capital; and (vi) long-term debt. As discussed below, the Company's filing includes three cost of service models including three cost of capital estimates based on what is described as a three-year Rate Plan covering the rate years 2025, 2026, and 2027. With the understanding that

OPC strongly opposes approval of the proposed three-year rate plan as addressed further by other OPC expert witnesses, my analysis addresses cost of capital in each of the three proposed rate years of the multi-year rate proposal.[1]

The Company's proposed capital costs are presented and discussed in the direct testimony of Duke cost of capital witness, Mr. Adrien McKenzie, and Duke financial witness Mr. Karl Newlin, and the results presented in the Company's filed MFR Section D "Cost of Capital Schedules." In addition, I address several issues related to the Company's financial integrity, investment requirements, cash flow issues, and impacts of the proposed multi-year rate plan related to return on invested capital.

Q. 6 WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. I have reviewed prior orders of the Florida Public Service Commission ("Commission"), the Company's direct testimony presented in this proceeding, Company responses to discovery requests in this proceeding, Value Line Investment Survey ("Value Line"), financial reports such as the 10-K filed with the SEC of the Company and other utility companies of comparable risk, and other relevant financial

[1] I have been made aware by counsel for the office that the OPC has taken various legal positions regarding the power or authority of the Commission to entertain the remote second and third fully projected test years. I am also aware that the OPC successfully challenged the authority of the Commission to determine a multi-year "rate plan" for a regulated utility in a litigated rate case that is not resolved via a settlement agreement in the form of a contract. My testimony, to the extent it opines on costs applicable to 2026 and 2027, does not concede the validity or legality of those years for those years. Furthermore, although I am an attorney, I do not offer any opinion on Florida law as it relates to any of the matters in this case. I solely address the risk considerations associated with a so-called multi-year plan in Questions 11-16 of my testimony.

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information available in the public domain. When relying on various sources, I have referenced such sources in my testimony and/or attached exhibits and included copies or summaries in my schedules and/or work papers.

Q. 7 PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS RELATED TO EQUITY RETURN IN THIS CASE.

A. My analysis of the Company's requested 11.15% cost of equity capital, or shareholder profit, in this proceeding is based on evaluating capital market data employing several commonly employed financial models. The models are described in the following pages as well as summarized in the attached Schedules (DJL-7), (DJL-8), (DJL-9), and (DJL-10). The results employing financial data from the adjusted[2] Company's proposed peer group of companies are shown in the following table:

[2] I excluded Allete Energy from my use of the Company's proposed peer group because the stock of Allete Energy is currently being purchased in an acquisition proposal. Given that Mr. McKenzie's analysis excludes all firms involved in merger or acquisition, Allete Energy should be removed.

Table 1

Cost of Equity Estimates Employing DUKE Comparable Risk Group [3]

MODEL	RANGE	MIDPOINT
DCF Model	8.68% - 8.85%	8.76%
Two-stage DCF	9.66% - 9.98%	9.82%
CAPM	9.42% - 9.68%	9.55%
ECAPM	9.59% - 9.78%	9.68%
Average of all Models	9.34% - 9.57%	9.45%
Minimum Maximum Midpoint		8.68% 9.98% 9.33%

A second analysis employing the same financial models but applied to an alternative 16-company peer group was analyzed and those results are shown in the following table:

[3] Each cost of equity capital estimate is discussed in the testimony and is presented in Schedules (DJL-7), (DJL-8), (DJL-9), and (DJL-10). Also note Allete Energy is removed from the analysis.

Table 2

Cost of Equity Estimates Employing Alternative 16-Company Comparable Risk Group[4]

MODEL	RANGE	MIDPOINT
DCF Model	9.08% - 9.23%	9.15%
Two-stage DCF	9.66% - 9.73%	9.70%
CAPM	9.52% - 9.59%	9.56%
ECAPM	9.66% - 9.71%	9.69%
Average of all Models	9.48% - 9.56%	9.52%
Minimum		9.08%
Maximum		9.73%
Midpoint		9.41%

The results of the two analyses shown in Tables 1 and 2 fall relatively close. Relying on the midpoint estimates from the DCF and two-stage DCF from each analysis (Table 1 and Table 2) provides the following midpoint results; 8.76%, 9.82%, 9.15%, and 9.70%. This DCF model range of results overlaps the CAPM and ECAPM results in each comparable risk group analysis. Moreover, the 8.76% to 9.82% range of midpoints covers most of the bond yield risk premium model range discussed below. Given the above, the indicated cost of capital range is 9.30% - 9.60% and I recommend a point estimate cost of capital of 9.45%. The point estimate of 9.45% is calculated by the reasonable range of 9.30 – 9.60 for both groups of comparable companies.

[4] Each cost of equity capital estimate is discussed in the testimony and is presented in Schedules (DJL-7), (DJL-8), (DJL-9), and (DJL-10).

Q. 8 WHAT IS YOUR OVERALL COST OF CAPITAL RECOMMENDATION FOR DUKE IN THIS CASE?

A. Based on my analyses (which are fully explained in the following pages), I make the following conclusions and recommendations for Duke's cost of capital in each of the three years of the proposed multi-year rate plan:

Table 3

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2025[5]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.61%	9.45%	4.311%
LONG-TERM DEBT	40.68%	4.49%	1.827%
SHORT-TERM DEBT	-0.20%	3.25%	-0.006%
CUSTOMER DEPOSITS ACTIVE	0.76%	2.61%	0.02%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	1.00%	8.01%	0.08%
DEFERRED INCOME TAXES	12.13%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.23%

[5] Capital structure and cost rates (except equity cost) per Company filing MFR D-1a, page 3 of 5. Equity cost of 9.45% per this testimony.

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Table 4

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2026[6]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.73%	9.45%	4.321%
LONG-TERM DEBT	40.58%	4.52%	1.834%
SHORT-TERM DEBT	-0.01%	3.20%	-0.000%
CUSTOMER DEPOSITS ACTIVE	0.71%	2.61%	0.019%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.93%	8.03%	0.075%
DEFERRED INCOME TAXES	12.04%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.25%

Table 5

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2027[7]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.83%	9.45%	4.331%
LONG-TERM DEBT	39.57%	4.63%	1.832%
SHORT-TERM DEBT	1.10%	3.20%	0.035%
CUSTOMER DEPOSITS ACTIVE	0.67%	2.61%	0.018%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.89%	8.13%	0.072%
DEFERRED INCOME TAXES	11.94%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.29%

[6] Capital structure and cost rates (except equity cost) per Company filing MFR D-1a, page 2of 5. Equity cost of 9.45% per this testimony.
[7] Capital structure and cost rates (except equity cost) per Company filing MFR D-1a, page 1of 5. Equity cost of 9.45% per this testimony.

As discussed below, these recommended return levels (9.45% equity return in each year of the proposed rate years) are reasonable. These proposed changes to the Company's rate request result in an overall cost of capital of 6.23% for rate year 2025, 6.25% for rate year 2026, and 6.29% for rate year 2027. These alternative capital costs are consistent with current market capital costs in the utility industry, consistent with recent regulatory authority decisions around the country, and consistent with just and reasonable rates for consumers.

My analyses of the Company's overall cost of capital request, which includes: (i) a multi-year rate plan[8] with three separate years of overall capital costs; (ii) substantially increased equity capital and long-term debt capital to fund investment over the three year rate plan; (iii) Mr. McKenzie's overstated recommended 11.15% equity return for Duke electric operations; and (iv) the overall weighted return request to be earned on rate base investment of 7.01% in 2025, 7.03% in 2026, and 7.07% in 2027 (see Company MFR Schedule D-1a) indicates that the Company's request is overstated, inconsistent with current and expected market capital costs, and inconsistent with just and reasonable rates for consumers.

[8] DEF refers to this as a "plan" but there is no commitment by the company to waive its legal rights to come in for rate relief, as suggested by DEF witness Marcia Olivier in her direct testimony at page 8 that their proposed rate increase will keep them out for three years "barring any unforeseen circumstances." I will use DEF's terminology for simplicity's sake, but I am not conceding that there is commitment to a plan in the form of an ironclad "stay-out."

Q. 9 PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. Based on my analyses (which are fully explained in the following pages), I make the following conclusions and recommendations:

(i) I recommend a return of 9.45% on shareholder equity for Duke, which is consistent with current market capital cost requirements for electric utility operations and is more than adequate for Duke to maintain its financial integrity and creditworthiness;

(ii) I recommend no changes to Duke's proposed capital structure, which consists of 53% equity on a financial basis for each year of the multi-year rate plan, which is consistent with current equity ratios of operating electric utility operations around the country;

(iii) I recommend no changes to Duke's long-term or short-term debt costs; and

(iv) I recommend an overall cost of capital applied to rate base investment of 6.23% for rate year 2025; 6.25% for rate year 2026; and 6.29% for rate year 2027.

SECTION II: OVERVIEW OF THE COMPANY RATE REQUEST AND ISSUE SUMMARY

Q. 10 PLEASE DESCRIBE THE COMPANY'S PROPOSED RATE REQUEST.

A. The Company is proposing a forecasted multi-year rate plan where the three rate years are calendar-years 2025, 2026, and 2027.[9] The Company's current rates are based on a multi-year rate plan, established through a Commission-approved negotiated settlement agreement, where the rate years are calendar years 2022, 2023, and 2024.[10] Under the proposed multi-year rate plan, the Company's case is based on three projected test periods for the calendar years 2025, 2026, and 2027. The total amount of projected level of capital investment (rate base) for each of the three years in the test period is $20,534,271,000 in 2025, $21,428,996,000 in 2026, and $22,198,157,000 in 2027.[11] The Company is requesting rate increases of $593 million in 2025, an additional $98 million in 2026, and an added increment of $129 million in 2027, which would total approximately $2.1 billion over the three years of the multi-year rate plan.

The Company's main cost driver is projected investment over the 2025 – 2027 rate plan. Specifically, the Company states that "DEF faces substantial capital needs over the next several years to add solar generation and energy storage capacity… ."[12] Duke witness Karl Newlin states that the capital requirement over the three-year rate plan are

[9] The term "rate year" is used to define the period proposed rates from this case will be in effect.
[10] See PSC-2021-0202-PS-EI ("2021 Settlement").
[11] See MFR A pages 1 – 3.
[12] Direct testimony Karl Newlin at page 22, lines 11 – 12.

$8.8 billion, with $8.1 billion for project requirements and $0.7 billion for debt refunding.[13]

Thus, based on Mr. Newlin's testimony, the requested increase is primarily driven by capital additions. I should note that Duke witness Marcia Olivier does address other cost drivers ranging from depreciation to demolition costs for this case.

Q. 11 DO YOU HAVE ANY COMMENTS ON MULTI-YEAR RATE PLANS?

A. Yes, I have several general comments. First, traditional ratemaking establishes rates based on a single, 12-month test year period where costs, revenues, and investment are evaluated on an historical, forecasted, hybrid (forecasted and historical) period and sometimes adjusted for known and measurable changes. Once rates are set, the utility is authorized to charge consumers these new rates until rates are changed or reset by the regulatory authority in some future case.

In a multi-year rate plan or a flexible price mechanism, the regulatory authority is asked to establish different rates for more than one future period. Thus, there may be multiple price increases over future periods without a formal rate proceeding to reset rates. For example, instead of filing a new traditional rate case when conditions change – a multi-year rate plan may forecast changing conditions in revenues, costs, and/ or investment and request adjusted new rates for the forecasted change in conditions.

[13] Direct testimony Karl Newlin at page 22, lines 12 – 19.

Q. 12 IN THIS CASE HAS DUKE FORECASTED CHANGING FUTURE CONDITIONS?

A. Yes. In this proceeding Duke has presented three future test years for 2025, 2026, and 2027 where revenues, costs, and investment are based on Company forecasts for each future year of the rate plan. The Duke multi-year rate plan results in three forecasted rate increases, or price changes, over the three year plan. These rate increases are $593 million in 2025, $98 million in 2026, and $128 million in 2027, totaling an $820 million increase over the life of the plan. Each rate increase is based on a forecast of revenues or sales, costs, and investment over the plan period. Thus, the multi-year rate plan is dependent on the quality and accuracy of these annual forecasts in terms of whether the rates proposed are just and reasonable.

Q. 13 HOW SHOULD THE DUKE PROPOSED RATE PLAN BE EVALUATED?

A. Any rate plan that is dependent on multiple future forecasts must have the assurance that these future forecasts are both objective and unbiased to assure consumer rates are both just and reasonable. To the extent that the underlying revenue and/or sales forecast is understated, the actual billing units, margins and revenues will be higher than estimated which will increase utility profits. To the extent forecasts of costs are overstated, excess revenues will fall to the bottom line profits of the utility. Lastly, to the extent investment rate base and project construction additions are overstated and/or

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delayed, again profits will increase. All forecasts for each year of the multi-year rate plan must be reasonable for a reasonable rate result.

Q. 14 DOES THE UTILITY BENEFIT FROM A MULTI-YEAR RATE PLAN?

A. Yes. First the utility benefits by having planned and locked-in rate increases to address forecasted revenue changes, cost changes, and or investment changes. This will prevent earnings erosion and maintenance of profits and cash flow metrics. Minimizing regulatory lag associated with the processing of a rate changes by having predetermined rate changes for different plan years enhances cash flow metrics, and quality of earnings are maintained through periodic cash increases. These periodic increases provide timely recovery of planned investment and avoid regulatory lag and earnings erosion.

Such planned increases limit and reduce to the utility risk and enhance a utility's financial health. One way to see these benefits is to review the Duke earnings for 2022 and 2023 where the Company was under the first two years of the prior multi-year rate plan. Duke earned an equity return of 10.47% in 2022 and 10.45% in 2023. Both these earned returns were well above the authorized midpoint return which formed the basis of the 2022 and 2023 rates. Duke was able to add investment and earn higher returns through the prior negotiated rate plan.

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Q. 15 ARE THE RISKS OF REGULATORY LAG AND EARNING EROSION SHIFTED TO CUSTOMERS IN A MULTI-YEAR RATE PLAN THAT IS NOT THE PRODUCT OF A NEGOTIATED SETTLEMENT?

A. Yes. In the scenario presented to the Commission here, the Company will have developed and would control the plan into the future. To the extent the revenue forecast is understated, expense forecast is overstated, or planned investment schedules are slowed, the Company will earn added profits. Any risks of regulatory lag and earnings erosion do not vanish – rather, customers will now have those risks in the form of paying higher rates for higher utility profits.

Q. 16 DO YOU MAKE A RECOMMENDATION ON THE PROPOSED MULTI-YEAR RATE PLAN?

A. No. Other OPC expert witnesses will address forecasts and rate plan issues. I just outline the evidence and facts supporting the lower utility risks associated with the proposed multi-year plan.

SECTION III: <u>REGULATORY ISSUES AND COST OF CAPITAL</u>

Q. 17 PLEASE EXPLAIN THE COST OF CAPITAL CONCEPT AS IT RELATES TO THE REGULATORY PROCESS.

A. The overall rate of return to be earned on rate base investment is an essential element in the regulatory and rate setting process and is typically a major part of overall revenue requirements. For example, in this case, the Company's requested overall return for rate year 2025 (the first year of the rate plan) is 7.01%. As is discussed below, and for illustrative purposes only, a 50-basis point reduction in the 11.15% rate of return on equity (to a 10.65% level) can have a large impact on overall revenue requirements. As shown in the table below, a 50 basis point reduction in equity return in the 2025 test year would result in an approximate $62.1 million per year reduction in annual revenue requirements including the impact of the federal income tax and other revenue gross-up factors for electric customers.[14]

TABLE 6

IMPACT OF 50-BASIS POINT REDUCTION IN EQUITY

RATE BASE 2025	**$20,534,271,000**
RATE OF RETURN @10.65% EQUITY	**6.78%**
REQUIRED INCOME	**$1,392,223,574**
CURRENT INCOME	**$996,671,000**
CALCULATED DEFICIENCY	**$395,552,574**
INCOME GROSS-UP MULTIPLIER	**1.3433**
RATE CHANGE	**$531,345,773**
DIFFERENCE FROM $593,446,000 REQUEST	**$62,100,227**

Thus, equity return can have a large impact on revenue requirements for consumers.

Q. 18 PLEASE EXPLAIN HOW THE VARIOUS COMPONENTS OF COST OF CAPITAL ARE DETERMINED.

A. The overall rate of return in the regulatory process is best explained in two parts. First,

[14] Tax Factor equal 1/(1-tax rate), which is (1/(1-.21)) equals 1.26582. This tax factor of 1.26582 times the requested shareholder profit level requested equals taxes and profits.

return to securities, such as long-term debt and short-term debt, both of which are included in the capital structure, are contractually set at issuance. The reasonableness of the cost of this contractual obligation between the utility and its investors is examined by regulatory agencies as part of the utility's overall revenue requirement.

The second part of a company's overall return requirement is the appropriate cost rate to assign the equity portion of capital costs. The return to equity should be established at a level that will permit the Company an opportunity to earn a fair rate of return. By fair rate of return, I mean a return to equity holders, which is sufficient to hold and attract capital, sufficient to maintain financial integrity, and a return to equity holders comparable to other investments of similar risks.

Two U.S. Supreme Court decisions are often cited as the legal standards for rate of return determination. The first is *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262. U.S. 679 (1923). The *Bluefield* case established the following general standards for a rate of return: The return should be sufficient for maintaining financial integrity and capital attraction and a public utility is entitled to a return equal to that of investments of comparable risks.

The second U.S. Supreme Court decision is the *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942). In the *Hope* decision, the Court affirmed its earlier *Bluefield* standards and found that methods for determining return are not the test of reasonableness; rather, the result and impact of the result are controlling.

The cost of capital is defined as the annual percentage that a utility must receive to maintain its financial integrity, to pay a return to security owners, and to ensure the continued attraction of capital at a reasonable cost and in an amount adequate to meet future needs. Mathematically, the cost of capital is the composite of the cost of several classes of capital used by the utility such as debt, preferred stock, and common stock, weighted on the basis of an appropriate capital structure.

The ratemaking process requires the regulator to determine the utility's cost of capital for debt, preferred stock, and equity costs. These calculations of costs, when combined with the proportions of each type of capital in the capital structure, result in a percentage figure that is then multiplied by the value of assets (investment) used and useful in the production of the utility service to ultimately arrive at a rate charged to customers. Rates should not be excessive (exceed actual costs) or burdensome to the customer and at the same time should be just and reasonable to the utility.

Q. 19 PLEASE EXPLAIN THE COST OF EQUITY CONCEPT.

A. The cost of equity, or return on equity capital, is the return expected by investors over some prospective time period. The cost of equity one seeks to estimate in this proceeding is the return investors expect prospectively when the rates from this case will be in effect.

The cost of common equity is not set by contract, and there are no hard and fast mathematical formulae with which to measure investor expectations with regard to equity requirements and perceptions of risk. As a result, any valid cost of equity recommendation must reflect investors' expectations of the risks facing a utility.

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Q. 20 WHAT PRINCIPAL METHODOLOGY DO YOU EMPLOY IN YOUR COST OF EQUITY CAPITAL ANALYSES?

A. I employ the Discounted Cash Flow ("DCF") methodology for estimating the cost of equity, keeping in mind the generally accepted premise that any utility's cost of equity capital is the risk-free return plus the premium required by investors for accepting the risk of investing in an equity instrument. It is my opinion that the best analytical technique for measuring a utility's cost of common equity is the DCF methodology. I also employ the two-stage DCF to reflect different growth rate assumptions. Other return on equity modeling techniques such as the Capital Asset Pricing Model ("CAPM"), Empirical Capital Asset Pricing Model ("ECAPM"), and bond yield equity risk premium model are often used to check the reasonableness of the DCF results. I have employed all of these modeling methods to arrive at my recommendations in this case.

Q. 21 PLEASE DESCRIBE THE RISKS YOU REFER TO ABOVE.

A. As I stated earlier in this testimony, equity investors require compensation above and beyond the risk-free return because of the increased risk factors investors face in the equity markets. Thus, investors require the risk-free return plus some risk premium above the risk-free return. The basic risks faced by investors that make up the equity risk premium include business risks, financial risks, regulatory risks, and liquidity risks.

SECTION IV: CURRENT CAPITAL MARKET CONDITIONS

Q. 22 PLEASE DESCRIBE CURRENT AND EXPECTED ECONOMIC CONDITIONS.

A. Current economic conditions reflect declining inflation under tighter monetary policy with higher federal funds rates and higher interest rates as a result of economic disruptions from the COVID-19 economic impacts of early 2020 period. The pandemic and shutdown led to substantial economic structural changes that are still having impacts today in terms of monetary policy by the Federal Reserve.

Starting in March 2021, the Consumer Price Index (CPI) began to climb above 2.5% and the CPI increase was steady to 8.6% for May 2022, and 9.1% for June 2022, before declining in July 2022 to 8.5%.[15] The June 2022 9.1% CPI is the largest 12-month increase since the 12-month period ending November 1981.[16]

The Federal Reserve's tighter monetary policy has had an impact on inflation as can be seen in the January through April 2024 reported inflation levels of 3.1% January 2024, 3.2% February 2024, 3.5% March 2024, and 3.4% for April 2024, all of which are substantially below the 2022 year and first six months of 2023.[17]

The Federal Reserve employs the Personal Consumption Expenditure (PCE) metric for measuring long-run inflation. During the November 2023 through April 2024

[15] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (June 10, 2022) and U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (July 13, 2022) and August 10, 2022.
[16] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (July 13, 2022).
[17] www.bls.gov/news.release/cpi May 15, 2024.

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period, the annual measure of the PCE price index was as follows:

Table 7[18]

PERSONAL CONSUMPTION EXPENDITURES PRICE INDEX

NOVEMBER 2023 THROUGH APRIL 2024

NOVEMBER 2023	**2.7%**
DECEMBER 2023	**2.6%**
JANUARY 2024	**2.5%**
FEBRUARY 2024	**2.5%**
MARCH 2024	**2.7%**
APRIL 2024	**2.7%**

Like the CPI measure discussed above, the PCE metric has declined substantially from the 2022 and 2023 levels.

Q. 23 WHAT HAS BEEN THE FEDERAL RESERVE RESPONSE TO INCREASING INFLATION?

A. When addressing inflation, the Federal Reserve and the Federal Open Market Committee (FOMC) look to the percent change in inflation as measured by the metric

[18] Personal Consumption Expenditures Expenditure Price Index, Bureau of Economic Analysis ("BEA") Release Date (May 31, 2024); also see www.bea.gov/news/2022/peronal-income-and-outlays-april-2024.

PCE as the primary measure of price changes when determining and implementing long-term monetary policy goals.[19] The FOMC, in its recent May 1, 2024 meeting, noted that "[i]nflation has eased over the past year but remains elevated."[20] The FOMC also stated that the target range of the federal funds rate would remain at 5.25% to 5.50%, and adjustments to the federal funds rate would consider the incoming data, the evolving outlook, and the balance sheet risks.[21] The FOMC concluded that the "Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent."[22]

In the March 20, 2024 "Summary of Economic Projections," the FOMC members provided forecasts for the federal funds rate as follows:

TABLE 8

CURRENT AND PROJECTED FEDERAL FUNDS RATE

Year	**Federal Funds Rate**[23]
Current May 2024 level	**5.25% - 5.50%**
2024	**4.6% - 5.1%**
2025	**3.4% - 4.1%**
2026	**2.6% - 3.4%**
Longer-run	**2.5% – 3.1%**

[19] *President's Message: CPI vs. PCE Inflation: Choosing a Standard Measure,* Federal Reserve Bank of St. Louis (July 1, 2013) at page 2, The Federal Reserve has employed the PCE inflation metric rather than the CPI measure since about 2000 in setting long-term monetary policy. After extensive analysis the Federal Reserve selected the PCE metric because: (i) the expenditure weights in the market basket measure change as consumers substitute goods and services; (ii) the PCE market basket includes more comprehensive coverage of goods and services; and (iii) historical PCE is subject to revision and correction beyond seasonality adjustments.
[20] Federal Reserve FOMC Statement May 1, 2024.
[21] Federal Reserve FOMC Statement May 1, 2024.
[22] Federal Reserve FOMC Statement May 1, 2024
[23] *Summary of Economic Projections*, Federal Open Market Committee, page 2 Table 1, Federal Funds Rate Median Projections (March 20, 2024).

The most recent FOMC projections in Table 8 indicate decreases in the federal funds rate through the remainder of 2024 from the May 2024 5.50% level to about 4.6% - 5.1% by year-end. These FOMC projections also indicate that the federal funds rate will decrease to 3.1% - 4.1% by the end of 2025 and further decrease to 2.6% - 3.4% by the end of 2026. Obviously, these are the current projections, which are all subject to change as the Federal Reserve delicately balances reducing inflation while maintaining employment and economic growth in the general economy.

Also, **i**n the March 20, 2024 "*Summary of Economic Projections,"* the FOMC members provided forecasts for the PCE that the inflation rate in the United States will average 2.4% over the entire year 2024, decline to 2.2% for the year 2025, and further decline to 2.0% in the year 2026.[24] When addressing inflation, the Federal Reserve and FOMC look to the percent change in inflation PCE as well as "core PCE" (which excludes fuel and food changes from the metric calculation) as the primary measure of price changes when determining and implementing long-term monetary policy goals.[25]

While the financial markets, and the economy in general, have experienced periods of uncertainty and turmoil since early 2020, government intervention has generally had a positive impact on financial markets and on the general economy. Recent 2023 – 2024 declining trends in inflation, whether measured by the CPI or PCE have caused the Federal

[24] *Summary of Economic Projections*, Federal Open Market Committee, page 1, Table 1, PCE Inflation Median Projections (March 20, 2024).
[25] *President's Message: CPI vs. PCE Inflation: Choosing a Standard Measure,* Federal Reserve Bank of St. Louis (July 1, 2013) at page 2, The Federal Reserve has employed the PCE inflation metric rather than the CPI measure since about 2000 in setting long-term monetary policy. After extensive analysis the Federal Reserve selected the PCE metric because: (i) the expenditure weights in the market basket measure change as consumers substitute goods and services; (ii) the PCE market basket includes more comprehensive coverage of goods and services; and (iii) historical PCE is subject to revision and correction beyond seasonality adjustments.

Reserve to cease increasing the federal funds rate and project lower federal funds rates in the immediate future. The end result is that cost of capital today includes expectations of declining interest rates.

Q. 24 DOES THE FACT THAT INTEREST RATES ARE EXPECTED TO BE DECREASING MEAN OTHER CAPITAL COSTS SUCH AS EQUITY ARE ALSO DECREASING?

A. Yes. Capital costs do move together – so if interest rates are rising (falling), the cost of other capital such as equity will increase (decrease), as well. The key difference is that equity and debt costs do not move in lock-step. In other words, debt costs may increase by 1.0%, but equity costs will change a smaller fraction of 1.0%.

For the period 1981 through 2023, the average of the absolute value change in 30-year U.S. Treasury bond yields is about 60 basis points.[26] For authorized electric utility equity returns over the same time period, the average absolute value rate of change is about 25 basis points or less than half the rate of change in U.S. Treasury yields.[27] Thus, while it may be correct to conclude debt costs will decrease over the short-term, if history is a guide, equity cost changes whether increasing or decreasing should be of substantially smaller magnitude.

[26] See Schedule (DJL-10) and Workpaper DJL-10.
[27] See Schedule (DJL-10) and Workpaper DJL-10.

Q. 25 DO THE RECENT FEDERAL RESERVE POLICY ACTIONS PROVIDE YOU ANY INSIGHT AS TO THE DIRECTION AND LEVEL OF LONGER-TERM INTEREST RATES?

A. Monetary policy objectives of the Federal Reserve are designed to stimulate economic growth and employment while targeting inflation at levels of about 2.0%. As discussed above, the FOMC May 1, 2024 press release addressed the FOMC's concerns with inflation. As stated earlier, following the March 20, 2024, FOMC projections, there is an expectation for Federal Funds rate decreases before year end 2024 and continuing declines in 2025, 2026, and beyond. The expectation of lower interest rates and declining cost of capital is most likely to occur over the three-year period included in the multi-year rate plan. Thus, if the Commission is to accept the three-year period included in the multi-year rate plan, fairness requires that the declining interest rates and declining cost of capital be recognized.

Q. 26 WHAT LEVEL OF INTEREST RATES DO YOU EMPLOY FOR YOUR COST OF CAPITAL ANALYSIS?

A. I generally employ the most current three-month average as the best approximation of interest rate levels. In my opinion, the most recent three months of activity adequately capture the market expectations and trends of interest rates while avoiding any limited influences those monthly or shorter durations may have on interest rates. Given the expectations for rate decreases to come in the Federal Funds rate by year end and into 2025-2027, I employed a 3.0% - 4.0% 30-year Treasury bond yield range to capture the impacts from the most recent statements in Federal Reserve policy.

Q. 27 WHAT CONCLUSIONS DO YOU DRAW FROM CURRENT ECONOMIC CONDITIONS IN PROVIDING GUIDANCE IN SETTING EQUITY CAPITAL COSTS IN THIS PROCEEDING?

A. As general matter, capital costs remain low in comparison to historical levels. Through 2023, the average authorized equity returns for electric at 9.59% have remained low as shown in Schedule (DJL-10). The bottom line is that the general economic data does not support substantially increasing capital costs. The current average authorized ROE for gas and electric is around 9.6% - Duke now seeks to substantially boost the profit level to 11.15%. Duke's cost of capital proposals are not reasonable and are inconsistent with market data.

SECTION V: <u>DUKE AND THE FLORIDA REGULATORY PROCESS</u>

Q. 28 DOES THE REGULATORY PROCESS IN FLORIDA AFFORD THE COMPANY RISK REDUCING OPPORTUNITIES?

A. The regulatory process in Florida provides ample opportunity to recover revenues, address regulatory lag concerns, and promote earned returns and margins over and above cost recoveries. The Florida FPSC's supportive regulatory environment includes regulatory mechanisms such as subsequent year adjustments to avoid regulatory lag, forward-looking test periods, negotiated multi-year rate plans, revenue recovery

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mechanisms such as fuel and capacity recovery mechanisms, environmental cost recovery clauses, storm hardening cost recovery, ability to petition for storm cost recovery outside a base rate proceeding[28], credit supportive storm cost treatment, and an overall credit supportive regulatory environment.[29] While Moody's points to risk of storms and the cost impacts on credit metrics, Moody's also points out that the Florida Legislature provides timely storm hardening cost recovery.[30]

All of these credit supportive regulatory mechanisms help offset the impacts of regulatory lag, enhance cash flow, and strengthen financial integrity.

Q. 29 HAVE OTHER REGULATORY AUTHORITIES WEIGHED IN WITH REGARD TO DUKE SUBSIDIARY COST OF CAPITAL?

A. Yes. The Parent Company Duke Energy has a number of vertically integrated electric operations operating in several states subject to rate regulation. The following table is a summary of regulatory authority decisions on capital structure and cost of equity for several DEF sister subsidiaries for the 2023 the early 2024 period.

[28] While perhaps not explicitly called out by Moody's, the storm cost recovery process allows for DEF to begin collections of storm costs on an accelerated, interim basis.
[29] See Moody's Investor Services Credit Opinion Duke Energy Florida pages 1 – 4, (May 22, 2023).
[30] See Moody's Investor Services Credit Opinion Duke Energy Florida page 1.

TABLE 9

RECENT DUKE SUBSIDIARY AUTHORIZED RETURNS AND EQUITY RATIO[31]

COMPANY	REGULATORY AUTHORITY	EQUITY RETURN	EQUITY RATIO	EFFECTIVE DATE
DUKE ENERGY CAROLINAS	NCUC	10.10%	53.00%	JAN. 2024
DUKE ENERGY CAROLINAS	PSCSC	9.94%	51.21%	MAY 2024
DUKE ENERGY KENTUCKY	KPSC	9.75%	52.145%	OCT. 2023
DUKE ENERGY PROGRESS	NCUC	9.80%	53.0%	OCT. 2023
DUKE ENERGY PROGRESS	PSCSC	9.60%	52.43%	APR. 2023
DUKE ENERGY OHIO	PUCO	9.50%	50.50%	JAN. 2023
AVERAGE		9.78%	52.04%	2023 - 2024

As shown in the table above, recent equity return for Duke electric utility operations range from 9.50% to 10.10% and average 9.78% for the 2023 and beginning of 2024 period. These results and facts do not support the Company's equity return range of 10.50% to 11.50% and 11.15%-point estimate. To accept the Company's proposal requires a belief that Duke in Florida is substantially riskier than all other Duke

[31] See MFR Schedule F Duke 2023 10K at page 18 of 384. The May 2024 PSCSC decision provided from PSCSC Docket No. 2023-388-F and 2023-403-E (Settlement).

operating subsidiaries, but there is no evidence to support such a conclusion. Actually, the evidence suggests given the supportive regulatory environment in

Florida, Duke Florida is less risky and requires a lower equity return than the other Duke electric subsidiary operations.

Expanding the analysis to consider all electric related utility decisions, one finds that the average authorized electric return is 9.46% for 2022 and 9.59% for 2023.[32] Again, to accept the Company's 11.15% equity return proposal requires a belief that Duke Florida is substantially riskier on average than all other electric utility operations, but there is no evidence to support such a conclusion. Actually, the evidence suggests that Duke Florida is less risky and requires a lower equity return than the average electric utility.

Q. 30 CAN YOU PROVIDE AN EXAMPLE OR EVIDENCE THAT DEF IS LESS RISKY?

A. Yes. Risk for shareholders is measured as the ability of a firm to earn a reasonable return on equity. In the case of a regulated utility, the reasonable return on equity is established by the regulatory authority. Below, I include a table of actual earned return by DEF relative to this Commission's authorized equity return for the years 2014 through 2023.

[32] See Schedule (DJL-10) Authorized Electric Equity Return 2022 and 2023.

TABLE 10

AUTHORIZED VERSUS EARNED EQUITY RETURNS

FOR DEF 2014- 2023[33]

YEAR	ROE BOTTOM RANGE	ROE MID-POINT	ROE TOP RANGE	ACHIEVED ROE	ACTUAL AUTHORIZED RETURN ELECTRIC UTILITY
2014	9.50%	10.50%	11.50%	9.36%	9.91%
2015	9.50%	10.50%	11.50%	10.06%	9.84%
2016	9.50%	10.50%	11.50%	9.82%	9.77%
2017	9.50%	10.50%	11.50%	9.80%	9.74%
2018	9.50%	10.50%	11.50%	9.13%	9.60%
2019	9.50%	10.50%	11.50%	10.83%	9.66%
2020	9.50%	10.50%	11.50%	10.86%	9.44%
2021	9.50%	10.50%	11.50%	9.48%	9.38%
2022	9.10%	10.10%	11.10%	10.47%	9.46%
2023	9.10%	10.10%	11.10%	10.45%	9.59%

As can be seen from the Table above, DEF has been able to achieve an actual equity return within the range of authorized annual equity return in seven of the recent ten years. In the years DEF did not achieve the authorized return, the Company was

[33] Data from earnings surveillance reports. Actual average authorized equity returns from Schedule (DJL-10).

marginally below the authorized equity return level; missing the range by 2 basis points in 2021, 14 basis points in 2014, and missing the rage by 37 basis points in 2018. All other years were within the ROE range and since 2019 above the midpoint of the range in 4 of 5 years. Also, Duke was able to achieve an equity return higher than the average authorized return for electric utilities from around the country in 8 of 10 years since 2014.These earned return results demonstrate that DEF has operated in a regulatory environment where the Company has consistently earned its authorized returns – even in what can be described as a turbulent economic environment given the COVID-19 impacts on the economy in recent years. This evidence does not support the Company's proposal that the DEF equity return should be set at 11.15%, well above current authorized equity return levels.

Q. 31 HAVE RATING AGENCIES WEIGHED IN WITH REGARD TO THE DEF REGULATORY MECHANISMS?

A. Yes. As discussed earlier, Moody's risk evaluation relies on the benefits and attributes of supportive Florida regulation coupled with the benefits of regulatory mechanisms, which are generally viewed as important attributes by credit rating agencies in evaluating risk and creditworthiness.

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Q. 32 EARLIER YOU MENTIONED REGULATORY LAG. HOW DOES THIS LAG IMPACT RATE SETTING AND REGULATORY RISK?

A. Regulatory lag is the period of time it takes to adjust tariffs in a rate case proceeding. Generally, it is the time between the utility rate request and the realization of a needed rate adjustment and the ultimate authorization of a rate change. For example, a utility requesting a rate increase of $1million based on a historical test year may claim earnings erosion due to the regulatory lag during the pendency of the rate process until the authorized increase is implemented.

The counter argument to these claims of regulatory lag and risk is that the utility controls the timing of its rate requests. Also, regulatory lag is built into the regulatory process to encourage the utility to control and monitor costs as a means of bolstering profits. Regulatory lag can work both ways – sometimes there is earnings erosion while other times there can be excess earnings.

Other contributions to regulatory lag are increasing costs, inflation, increasing capital investments, and lower growth and sales. The regulatory process in Florida provides the Company ample opportunity to earn its authorized return by mitigating regulatory lag and maintaining cash flows and liquidity in the rate process.

Q. 33 DO THE CREDIT RATING AGENCIES SUCH AS MOODY'S VIEW RATE MECHANISMS FAVORABLY?

A. Yes. Rating agencies are foremost concerned with a utility's ability to recover costs and earn an adequate return to cover expenses and debt obligations with a margin of

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safety on top of costs. For example, Moody's states a "… utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings."[34] In terms of rate mechanisms and the impacts of reducing risks, Moody's states the following:

> One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risks of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.[35]

Moody's concludes that the more clauses a utility has in place, the lower the risk for the utility.[36]

[34] "*Cost recovery Provisions Key To Investor- Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) at page 1.
[35] "*Cost recovery Provisions Key To Investor-Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) page at pages 1-2.
[36] "*Cost recovery Provisions Key To Investor-Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) at page 2.

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Q. 34 DOES THE COMPANY FACE ANY UNUSUAL BUSINESS OR FINANCIAL RISK?

A. DEF does propose a large construction program over the next several years for solar facilities and other assets which will increase the size of rate base as planned projects go into service.[37] As Moody's points out, the Company's 2023 – 2027 capital forecast totaling around $12 billion is approximately $2.6 billion higher than it spent over 2018 – 2022.[38] There is an expectation that cash flow metrics will be impacted over the construction period until all facilities are included in rates, then cash flow metrics will increase.[39] Despite the large construction program and expectation of impacts on cash metrics, Moody's continues to have a positive outlook for Duke. Moody's sees the multi-year rate plan as a key factor impacting Duke's future credit metrics favorably. Moreover, while the risk of severe storms is always high in Florida, Moody's sees these risks as mitigated by credit supportive regulatory treatment.[40]

Q. 35 IN YOUR OPINION, CAN A HIGH EQUITY RETURN WHEN COMBINED WITH COST RECOVERY MECHANISMS LEAD TO EXCESS PROFITS AND EXCESSIVE OR UNREASONABLE RATES?

A. Yes. I have described how the cost recovery mechanisms assure stable and consistent recovery no matter: (i) the weather; (ii) consumer usage preferences, conservation levels and demand; (iii) fuel cost increases; and in cases like a negotiated multi-year

[37] See Moody's Credit Opinion May 22, 2023 at page 4.
[38] Moody's Credit Opinion May 22, 2023 at page 4.
[39] Moody's Credit Opinion May 22, 2023 at page 4.
[40] Moody's Credit Opinion May 22, 2023 at page 4.

rate plan (iv) infrastructure capital additions through the rate plan or system hardening, or capital replacement due to storm damage through storm cost recovery mechanisms. Through such mechanisms, revenue recovery is stable and consistently assuring cash flow for corporate needs and profit levels. Risk as measured by volatility of return is addressed by these cost recovery mechanisms. Equity return levels are a function of risk levels so if risk is addressed in the mechanisms – a higher equity return authorization would overcompensate risk and result in unfair or unreasonable rates.

A better way to look at the DEF regulatory risk profile is to say that it makes my recommended ROE conservative. The 9.45% ROE recommendation and the 6.23% (2025 test year) overall rate of return recommendation represent DEF's costs of capital largely without regard to the Florida multi-year rate plan.

SECTION VI: <u>COMPARABLE GROUP ANALYSIS</u>

Q. 36 PLEASE EXPLAIN AND DESCRIBE THE STARTING POINT OF YOUR COST OF CAPITAL ANALYSIS FOR THIS CASE.

A. The first step for any cost of equity capital analysis is the selection of a comparable group of companies for which market data is available to conduct a market-based cost of capital analysis. I reviewed Mr. McKenzie's risk screening criteria for his comparable group analysis and selection. I agree with most of Mr. McKenzie's selection or screening criteria for the comparable group analysis in this case. I do find that Mr. McKenzie has excluded from his comparable group companies with issuer credit ratings more than 1-notch different (higher or lower) than DEF's issuer credit rating of A3 (Moody's) and BBB+ (S&P). In my opinion, the 1-notch issuer credit analysis is very limiting and does not improve the analysis.

I should also point out that one of Mr. McKenzie's selected comparable companies, Allete Energy, is currently involved in a merger acquisition with a buy-out provision from a Canadian pension fund, and no longer meets Mr. McKenzie's selection criteria. I have removed Allete Energy from the cost of capital analyses.

While I have used Mr. McKenzie's comparable group of 9 companies (originally 10-companies but Allete Energy is removed), I also employed a 16-company risk group of electric utilities for comparable analysis. This alternative risk group is based on firms designated by Value Line as an electric utility with the following criteria: (i) consistent cash dividend payments; (ii) investment grade level issuer rating from Standard & Poor's and/or Moody's; and (iii) not party to merger or acquisition.

The difference between this alternative group and the Company proposal is that Mr. McKenzie limits his group to a one-notch difference from Moody's A3 rating and S&P's BBB+ rating. The financial one-notch limitation is somewhat restrictive.

I also will employ an expanded 16-company comparable group for the electric utility group B.[41] The 9-company utility group A and the 16-company electric utility group B of companies are shown in the following Table 11.

[41] Direct Testimony DEF witness Adrien McKenzie, Exhibit AMM-3, page 1 of 1.

Table 11

COMPARABLE COMPANY GROUP

Company	Stock Ticker
UTILITY GROUP A	
AMEREN CORPORATION	AEE
CONSOLIDATED EDISON	ED
NEXTERA, INC.	NEE
OGE ENERGY CORPORATION	OGE
PINACLE WEST CAPITAL CORP	PNW
PORTLAND GENERAL ELECTRIC CO.	POR
PPL CORP.	PPL
WEC ENERGY GROUP	WEC
XCEL ENERGY INC.	XEL
ELECTRIC UTILITY GROUP B	
ALLIANT ENERGY CORP	LNT
AMEREN CORPORATION	AEE
AMERICAL ELECTRIC POWER	AEP
AVISTA CORPORATION	NWE
DUKE ENERGY CORPORATION	DUK
ENTERGY CORPORATION	ETR
EVERGY, INC.	EVRG
IDACORP, INC.	IDA
MGE ENERGY, INC.	MGEE
NEXTERA, INC.	NEE
NORTHWESTERN CORPORATION	NWE
OGE ENERGY CORPORATION	OGE

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PINACLE WEST CAPITAL CORP	**PNW**
PORTLAND GENERAL ELECTRIC CO.	**POR**
SOUTHERN COMPANY	**SO**
XCEL ENERGY	**XEL**

All of these companies are dividend-paying electric utilities with investment grade bond ratings. I have included a listing in Schedule (DJL- 4) of the electric utilities in the comparable group along with basic data for beta, historical, forecasted equity ratios, and a forecast of comparable earnings from the Value Line data base.

SECTION VII: <u>COST OF CAPITAL MODELS DCF ANALYSIS</u>

Q. 37 PLEASE EXPLAIN THE CONSTANT GROWTH DCF METHODOLOGY YOU HAVE EMPLOYED IN YOUR ANALYSIS.

A. The price that an investor is willing to pay for a share of common stock today is determined by the income stream the investor expects to receive from the investment. The return the investor expects to receive over the investment time horizon is composed of: (i) dividend payments; and (ii) the appreciated sale value of the investment. A proper analysis adds dividends to the gain on the final sale value, and discounts these expected future earnings to a present value.

To determine or estimate investor requirements using the DCF model, one computes a cost of capital requirement, or discount rate from the current market data and the expected dividend stream. The DCF model stated as a formula is as follows:

$$K = D/P + G$$

where:
K = required return on equity,
D = dividend rate,
P = stock price,
D/P = dividend yield, and
G = growth in dividends.

Q. 38 PLEASE EXPLAIN HOW YOU CALCULATED THE DIVIDEND YIELD FOR THE COMPARABLE COMPANIES.

A. The dividend yield is the ratio of the dividend rate to the stock price. When calculating the dividend yield, one must be cautious and not rely on spot stock prices. One must be equally cautious not to rely on long periods of time as the data becomes unrepresentative of market conditions. The objective is to use a period of time such that the resulting dividend yield is representative of the prospective period when rates will be in effect.

While there is no fixed period for selecting the denominator of the dividend yield (i.e., stock price), the key guideline is that the yield not be distorted due to fluctuations in stock market prices. On the other hand, dividends (the numerator of the yield calculation) are relatively stable as opposed to the stock prices, which are subject to daily and cyclical market fluctuations. The selection of a representative time period will dampen the effect of stock market changes.

The price and dividend data used for each of the proxy companies in the comparable group is contained in my Schedule (DJL-5).

I have examined monthly closing stock prices for the period November 2023 through April 2024, for a 12-week period ending in April 2024 along with 52 week high and low averages, to calculate a representative price for the dividend yield calculation. For this analysis, I have employed the recent 3-month average price (February 2024, through April 2024) in calculating the dividend yield.

To calculate dividends, I employ the current annualized dividend, increased for ½ the expected growth rate. Because utility companies tend to increase quarterly dividends at different times throughout the year, the assumption is that dividend increases will be evenly distributed over the calendar quarters for the comparable group companies. Given the above, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term estimates of growth to the current dividend yield. I have calculated the yield employing the current dividends for each comparable company as reported by Value Line and the recent three-month average price and the resulting dividend yields are shown in my Schedule (DJL-5).

Q. 39 EXPLAIN HOW YOU HAVE CALCULATED THE EXPECTED GROWTH RATE IN YOUR CONSTANT GROWTH DCF ANALYSIS FOR THE COMPANIES IN THE COMPARABLE GROUP.

A. Like the dividend yield, there exists no single or simple method to calculate growth rates. The calculation of investor growth expectations is the most difficult part of the DCF analysis. To estimate investor expectations of growth, I have examined historical growth, forecasted growth rates, and other financial data for each of the companies in the comparable group.

Implementation of the DCF model requires the exercise of considerable judgment with regard to estimating investor expectations of growth, and it is a difficult task, but such difficulties are not insurmountable. Many economic factors affect capital markets in general and individual stocks specifically. Such economic variables, which were discussed earlier, entail the current state of the economy, including the trade deficit, federal budget uncertainty, fiscal policy, inflation, and Federal Reserve Board policies on interest rates.

Investors generally have good information on the economic and financial variables outlined above. All of this information is available quickly, especially in recent decades with easy access to the internet.

Like the information available on the general economy, investors also have access to a wealth of information about particular types of securities, industries and specific company investments. This information is also factored into investor expectations and therefore the stock price individuals are willing to pay.

Common stock earnings growth rate forecasts and historical growth rate data may be found in the Value Line publication. These Value Line earnings estimates are five-year projections in annual earnings. Again, Value Line is widely available to the public, and is a good source of earnings projections. Other earnings estimates are forecasted by Zacks as well as First Call projections from Yahoo finance, which are widely available on the internet at Zacks.com and Yahoo Finance, respectively. Those

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earnings projections along with other stock-specific financial data provide a range of estimates of earnings and are readily available at no cost.

Another growth estimate is referred to as the sustainable growth or retention ratio growth estimate. To project future growth in earnings under the sustainable growth method, one multiplies the fraction of a firm's earnings expected to be retained (not paid out as dividends) by the expected return on book equity. As a formula:

Growth = ("b" x "r")

Where:
"b" =1- (dividends per share/earnings per share)
"r" =earnings per share / net book value share

All the data necessary to calculate the elements of the sustainable growth method are available on a forecasted basis in Value Line.

I have extended this sustainable growth formula to include the impact of external equity financing. The growth formula including external financing is:

$$g = br + sv$$

The terms "b" and "r" have been described above, "s" is the expected growth in shares to finance investment, and "v" is the profitability of those expected investments.

Q. 40 PLEASE EXPLAIN YOUR GROWTH RATE ANALYSIS.

A. I have included in my Schedule (DJL-6), a three-page schedule showing the growth rates I have reviewed in my analysis. The first set of growth rates examined is the five-year and ten-year historical growth rates in earnings per share, dividends per share, and book value per share as reported by Value Line. The second set of growth rates are the Value Line forecasted growth rates in dividends, book value and earnings per share for each company in the comparable group. The third set of growth rates examined is the Zacks forecasted growth rates in earnings. The fourth growth estimate considered, the First Call earnings growth estimate, is readily available to investors at Yahoo Finance.

In addition, I have examined the growth rates based on the forecasted internal growth, the so-called sustainable growth estimate discussed above.

The growth rates described above provide a range of estimates for each of the comparable companies. The resulting range of average and median forecasted growth rates for the electric utility comparable group is shown in Schedule (DJL-6).

Q. 41 DID YOU RELY ON THE HISTORICAL GROWTH RATES?

A. No. Historical growth rates are a starting place for the analysis, but investors consider additional information when formulating expectations. Moreover, whether the trends of the past ten or five years continue to hold for the future is often a suspect assumption. Instead, for the constant growth DCF I rely on the sustainable growth estimates as a better predictor of investor expectations. I do employ the Value Line, Zacks, and Yahoo finance earnings estimates and sustainable growth estimates in the two-stage growth model.

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Q. 42 PLEASE SUMMARIZE YOUR CONSTANT GROWTH DCF ANALYSIS.

A. The 9-company comparable group mean and median results fall in a range of 8.68% to 8.85% with about an 8.76% midpoint. These analyses can be found in my Schedule (DJL-7), SLIDE 1, column F, lines 1 - 12. The DCF results for the 16-company alternative electric utility comparable group mean and median results fall in a higher range of 9.08% to 9.23% with about a 9.15% midpoint. These analyses can also be found in my Schedule (DJL-7), SLIDE 2, column F.

Q. 43 HAVE YOU CALCULATED ADDITIONAL DCF ANALYSES FOR THE COMPARABLE GROUP COMPANIES?

A. Yes. I have calculated a two-stage non-constant growth DCF analysis for the companies in the comparable groups.

Q. 44 PLEASE DESCRIBE YOUR TWO-STAGE NON-CONSTANT GROWTH DCF.

A. This analysis calculates equity cost using a non-constant growth two-stage DCF Model. The constant growth DCF model can be adjusted to reflect multiple growth assumptions because the constant growth rate assumption is often not consistent with investor expectations. As an example, it is often the case where short-term growth estimates are not consistent with long-term sustainable growth projections. In those instances, where more than one growth rate estimate is appropriate, a multi-stage non-constant growth model can be employed to derive a cost of capital estimate. In other words, the constant growth model is adjusted to incorporate multiple growth rate periods, assuring a constant growth (long-term) rate is estimated for a longer period.

For the comparable group, the first growth stage (years 1-5) of the model, the Value Line forecasted growth in dividends is employed and an annual dividend is calculated. The second stage (years 6 and beyond) employs an earnings growth estimate based on the individual company in the comparable group of forecasted earnings per share Value Line, Zacks, and Yahoo Finance and the forecast sustainable growth estimate ("b*r" + "s*v"). The estimated cash flows are modeled over an extended period and return is calculated employing the Internal Rate of Return formula ("IRR").

Q. 45 WHAT ARE THE RESULTS OF THE TWO-STAGE NON-CONSTANT GROWTH DCF ANALYSIS?

A. The results of the two-stage non-constant growth DCF analysis for the 9-company utility group are shown in Schedule (DJL-8), Slide 1, column K, lines 1 -12. The 9-company utility company comparable group mean and median results indicate a cost of equity range of 9.66% to 9.98% with an 9.82% midpoint. The results of the two-stage non-constant growth DCF analysis for the 16-company alternative utility group are shown in Schedule (DJL-8), Slide 2, column K, lines 1 - 19. The alternative electric company comparable group mean and median results indicate a cost of equity range of 9.66% to 9.73% with a 9.70% midpoint.

SECTION VIII: BOND YIELD EQUITY RISK PREMIUM, CAPM, AND ECAPM COST OF EQUITY ESTIMATE

Q. 46 PLEASE DESCRIBE THE RISK PREMIUM ANALYSIS.

A. Debt instruments such as bonds (long-term debt) are less risky than common equity when both classes of capital are issued by the same entity. Bondholders have a prior contractual claim to the earnings of the corporation and returns on bonds are less variable and more predictable than stocks. The bottom line is that debt is less risky than equity. There are numerous return studies of capital market investments, all of which show lower returns with lower risks and higher returns with higher risk investments. These financial truisms provide a sound theoretical basis and foundation for the risk premium method for estimating equity costs. The risk premium approach is useful in that the analysis is based on current market interest rates.

The risk premium approach is not without its problems and drawbacks. In practice and application, there is considerable debate as to the historical time period to analyze and added debate concerning the calculation of the bond/equity return risk spread. Historical debt/equity risk spreads measured over many decades may not be relevant to current capital market requirements. Others argue that a long-term analysis is necessary, since the goal is to measure investors' long-term expectations.

Another version of the risk premium method is the capital asset pricing model ("CAPM").

Finally, I examine Empirical Capital Asset Pricing Model (ECAPM") estimates. The

ECAPM is quite similar to the CAPM described above with the difference being an adjustment for the beta estimate in the model. Firms with beta estimates below unity tend to have actual beta values that are higher. The ECAPM includes an adjustment to correct for any systematic measurement errors in beta.

<u>CAPITAL ASSET PRICING MODEL ANALYSIS</u>

Q. 47 PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RETURN ESTIMATE EMPLOYING THE CAPM.

A. I employed the basic CAPM formula denoted as follows:

$$R_f + \beta(R_m - R_f)$$

Where:

R_f = risk free rate;
β =beta;
R_m= market return; and
R_m - R_f= market risk premium or MRP

This is the typical model structure employed by most financial analysts in estimating equity returns.

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Q. 48 WHAT RISK FREE (R_f) VALUE DID YOU EMPLOY IN YOUR CAPM ESTIMATE?

A. I typically employ the most recent three-month average of the 30-Year U.S. Treasury Bond rates. This three-month average is:

Table 12[42]

30-Year U.S. Government Bond Yields

February 2024	4.38%
March 2024	4.36%
April 2024	4.61%
3-Month Average	4.45%

I have employed a 3.0% to 4.0% range 30-Year U.S. Treasury Bond yield which is consistent with the market expectations of declining future rates as the Federal Reserve is expected to lower federal funds rates over the foreseeable future of the proposed 2025 – 2027 test year periods proposed in this case. I should note that since January 2022, the average 30-year U.S. Treasury yield has been 3.7%. Over this January 2022-April 2024, period the federal funds rate has gone from zero to 4.5%. Now, given the projections of federal funds rates to reverse course, a 3.0% to 4.0% expectation for U.S. Treasury yields is reasonable.

Q. 49 WHAT VALUE DID YOU EMPLOY FOR BETA IN YOUR CAPM ANALYSIS?

A. I employed a Value Line beta estimate for each company in the comparable group as

[42] The monthly bond yields are presented in Schedule (DJL-3)

shown in my Schedule (DJL-4), column A into the CAPM Schedule (DJL-9) columns A and F.

Q. 50 WHAT VALUE HAVE YOU EMPLOYED FOR THE MARKET RISK PREMIUM ("MRP")?

A. To calculate the MRP, I first looked at the historical risk premiums for the period 1926-2022. The following summarizes the historical MRP for the 1926-2022 period:

Table 13

Market Risk Premium

Investment[43]	Arithmetic Mean Return
Large Company Stocks	12.03%
Long Term Government Bonds	5.0%
Historical MRP	7.03%

Thus, the historical MRP is 7.03% above the risk-free rate for long-term U.S. Treasury Bonds.

I also estimated a second MRP by measuring the difference between the forecasted equity return for the two groups of electric comparable companies as reported by Value Line for the period 2027 – 2029. As shown in Schedule (DJL-4) at Slide 1, column K, the 9-company comparable group forecasted average return is about 10.77% (The 15.19% outlier for WEC Energy is excluded from the calculation). Also shown in Schedule (DJL-4) the alternative electric comparable group forecasted return shown at

[43]Market Results for Stocks, Bonds, Bills, and Inflation, 1926-2022, Kroll 2023 Classic Yearbook.

column K, is about 10.77%% (The 15.96% return outlier for Southern Company is excluded from this calculation). Employing an assumed 30-year U.S. Treasury yield of 3.5% for the risk-free rate produces an MRP of 7.27 % (10.77 % - 3.5%).

A third MRP estimate is calculated by examining the historical market risk premiums produced by the difference in authorized returns and 30-year U.S. Treasury yields. These results are shown in Schedule (DJL-10) and for electric, the MRP is 5.45.

To calculate the MRP to use in this case, I have employed the long view 1926 - 2022 average historical MRP of 7.03%, the comparable group forward or forecast estimate of MRP of 7.27%, and the historical 1981-2023 regulated utility MRP estimate of about 5.50%. Giving equal weight to each of these estimates results in an MRP estimate as follows:

TABLE 14

FINAL MARKET RISK PREMIUM

KROLL HISTORICAL MRP	7.03%
FORECASTED COMPARABLE GROUP MRP	7.27 %
1981 – 2023 HISTORICAL UTILITY MRP	5.45 %
AVERAGE MRP	6.58 %

This average 6.58% MRP estimate is consistent with the expected ranges of MRP's of 5% - 8% found in a number of studies in the financial literature and is consistent with current financial markets expectations for MRPs.[44]

Q. 51 WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES FOR THE ELECTRIC COMPANY COMPARABLE GROUP?

A. The results of the CAPM analyses can be found in my Schedule (DJL-9) at column D for the electric comparable group. The range of results for the Duke proposed utility group indicate an equity return range of 9.42% to 9.68% with a 9.55% midpoint. The CAPM range of results for the alternative electric utility group indicate an equity return range of 9.52% to 9.59% with a 9.56% midpoint.

Q. 52 IN YOUR ANALYSES, HAVE YOU INCLUDED A CALCULATION OF THE EMPIRICAL CAPM OR ECAPM RETURN ESTIMATE FOR THIS CASE?

A. Yes. Like the CAPM analysis discussed above, the ECAPM estimate of equity return relies on basic financial portfolio theory. To correct for the potential of biased beta estimates, an adjustment is made so as not to understate the cost of equity. The basic formula for the ECAPM for beta conversion is as follows:

$$K=R_f + 0.25(R_m - R_f) + 0.75\beta(R_m - R_f)$$

[44]Morin, Roger; New Regulatory Finance, Public Utility Reports, Inc. (2006). See Chapter 5.

Q. 53 WHAT ARE THE RESULTS OF YOUR ECAPM ANALYSES FOR THE ELECTRIC COMPANY COMPARABLE GROUP?

A. The results of the ECAPM analyses can be found in my Schedule (DJL-9) at column H. The range of ECAPM results for the Duke proposed comparable group are 9.59% to 9.78% with a midpoint of 9.68%. The range of ECAPM results for the alternative 16-company electric comparable group are 9.66% to 9.71% with a midpoint of 9.69%.

Q. 54 DESCRIBE YOUR BOND YIELD EQUITY RISK PREMIUM ANALYSIS.

A. The bond yield equity risk premium analysis is presented in Schedule (DJL-10) and evaluates the risk/return differential between the authorized electric utility return on equity relative to 30-year U.S. Treasury bond yields for the period 1981-2023. The resulting risk premium is combined with the estimated 30-year U.S. Treasury yield of 3.0% to 4.0% to determine the range of risk premium estimates of equity costs.

The resulting risk premium range of results for the utility group is 9.68% to 10.27% with a 9.97% midpoint estimate. These risk premium results exceed all other model results and were not considered in the final analysis.

Q. 55 PLEASE SUMMARIZE YOUR COST OF EQUITY CAPITAL RESULTS AND RECOMMENDATION.

A. Table 14 below is a summary of the equity cost estimates for the comparable group

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companies employing the constant growth DCF, 2-Stage DCF, CAPM, and ECAPM models.

Table 15

Cost of Equity Estimates Employing DUKE Comparable Risk Group [45]

MODEL	RANGE	MIDPOINT
DCF Model	8.68% - 8.85%	8.76%
Two-stage DCF	9.66% - 9.98%	9.82%
CAPM	9.42% - 9.68%	9.55%
ECAPM	9.59% - 9.78%	9.68%
Average of all Models	9.34% - 9.57%	9.45%
Minimum		8.68%
Maximum		9.98%
Midpoint		9.33%

The second financial analysis employed the same financial models, but applied the models to an alternative 16-company peer group. Those results are shown in the following table:

[45] Each cost of equity capital estimate is discussed in the testimony and is presented in Schedules (DJL-7), (DJL-8), and (DJL-9).

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Table 16

Cost of Equity Estimates Employing Alternative 16-Company Comparable Risk Group[46]

MODEL	RANGE	MIDPOINT
DCF Model	9.08% - 9.23%	9.15%
Two-stage DCF	9.66% - 9.73%	9.70%
CAPM	9.52% - 9.59%	9.56%
ECAPM	9.66% - 9.71%	9.69%
Average all Models	9.48% - 9.56%	9.52%
Minimum		9.08%
Maximum		9.73%
Midpoint		9.40%

The results of the two analyses shown in Tables 15 and 16 are relatively close. I recommend a point estimate cost of capital of 9.45%.

SECTION IX: CAPITAL STRUCTURE

Q. 56 WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. Based on the direct testimony of Company witness Karl Newlin, the Company's filed capital structure for each year of the multi-year rate plan includes 45.61.% equity

[46] Each cost of equity capital estimate is discussed in the testimony and is presented in Schedules (DJL-7), (DJL-8), and (DJL-9).

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in 2025, 45.73% equity in 2026, and 45.83% equity in 2027 all on a regulatory-based capitalization.[47] I refer to regulatory capital structure because for ratemaking purposes, non-investor supplied funds representing deferred taxes and investment tax credits (ITC's) are included in capitalization for ratemaking purposes. The Duke capital structure assumes a 53% financial equity percentage (where financial basis assumes equity, long-term debt, and short-term debt).[48] In this case, the Company's capital structure is driven by the financial assumptions of 53.0% equity and 47.0% debt. Included in the Table below is a summary of each class of capital for each of the three years of the multi-year rate plan as proposed by Duke.

[47]Direct Testimony Karl Newlin at page 15, lines 10 – 16, also see MFR D-1a, pages 1, 2, and 3 of 5.
[48] Direct Testimony Karl Newlin at page 15, lines 14– 16.

TABLE 17

COMPANY PROPOSED CAPITAL STRUCTURE 2025 – 2027

CAPITAL	2025 TEST YEAR[49]	2026 TEST YEAR[50]	2027 TEST YEAR[51]
COMMON EQUITY	45.61%	45.73%	45.83%
LONG TERM DEBT	40.68%	40.58%	39.57%
SHORT TERM DEBT	-0.20%	-0.01%	1.10%
DEPOSITS ACTIVE	0.76%	0.71%	0.67%
DEPOSITS INACTIVE	0.01%	0.01%	0.01%
ITC'S	1.00%	0.93%	0.89%
DEFERRED TAX	12.13%	12.04%	11.94%
TOTAL	100.00%	100.00%	100.00%

As shown in the Table, the capital structure has slight variations each year, but does remain relatively constant. The largest percentage change is the increase in 2027 short-term debt reflecting financing capital additions in 2026 and 2027.

[49] MFR D-1a page 3 of 5.
[50] MFR D-1a page 2 of 5.
[51] MFR D-1a page 1 of 5.

Q. 57 DO YOU HAVE COMMENTS AND RECOMMENDATIONS ON THE COMPANY'S PROPOSED CAPITAL STRUCTURE RATIOS FOR DEBT AND EQUITY?

A. No. In this case the Company's capital structure is based on a 53% equity ratio on a financial basis. The current authorized equity ratio for Duke is based on the settlement of the last case and is consistent with the equity ratio proposed in this case.[52] Moreover, the testimony and evidence presented by Company witness McKenzie shows the comparable group average equity ratio of 53.8% on an operating company basis is consistent with the Duke proposed 53% for this case.[53] Further, the 16-Company comparable group equity ratio (on an operating company basis) about 52.3% well within range of the Duke proposed 53.0% for this case. Thus, Duke's proposed 53.0% equity ratio proposal is consistent with comparable electric utility current authorized levels of equity. Duke's financial risk as measured by the equity and debt ratio metrics is consistent with the comparable companies. For all of the above reasons, I recommend that the Commission employ the Duke proposed capital structure.

Q. 58 WHAT CAPITAL STRUCTURE AND COST RATES ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT IN THIS CASE?

A. Based on the analyses and results discussed above, I am recommending a capital structure employing Duke's proposed capital levels and cost rates except that the equity

[52] Docket No. 22-06014 Final Order at page 31.
[53] See Direct testimony Adrien McKenzie at Exhibit ANM-5, page 2 of 2.

return should be set at 9.45%. The capital structure and cost rates are set forth in the following three tables:

Table 18

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2025[54]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.61%	9.45%	4.311%
LONG-TERM DEBT	40.68%	4.49%	1.827%
SHORT-TERM DEBT	-0.20%	3.25%	-0.006%
CUSTOMER DEPOSITS ACTIVE	0.76%	2.61%	0.02%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	1.00%	8.01%	0.08%
DEFERRED INCOME TAXES	12.13%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.23%

Thus, the recommended overall cost of capital for the 2025 test year is 6.23% and includes a 9.45% equity cost.

If the Commission approves a three year or multi-year rate plan as proposed by Duke, which OPC does not support, then I have included a cost of capital for those periods as follows.

[54] Capital structure and cost rates (except equity cost) per Company filing MFR D-1a, page 3 of 5. Equity cost of 9.45% per this testimony.

Table 19

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2026 [55]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.73%	9.45%%	4.321%%
LONG-TERM DEBT	40.58%	4.52%	1.834%
SHORT-TERM DEBT	-0.01%	3.20%	-0.000%
CUSTOMER DEPOSITS ACTIVE	0.71%	2.61%	0.019%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.93%	8.03%	0.075%
DEFERRED INCOME TAXES	12.04%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.25%

The cost of capital for the 2026 period is 6.25% which includes a 9.45% cost of equity. Finally, the third year of the proposed rate plan cost of capital is as follows:

[55] Capital structure and cost rates (except long-term debt cost and equity cost) per Company filing MFR D-1a, page 2of 5. Equity cost of 9.45% per this testimony.

Table 20

Recommended Capital Structure and Cost Rates for

Duke Operations Rate Year 2027 [56]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	45.83%	9.45%	4.331%
LONG-TERM DEBT	39.57%	4.63%	1.832%
SHORT-TERM DEBT	1.10%	3.20%	0.035%
CUSTOMER DEPOSITS ACTIVE	0.67%	2.61%	0.018%
CUSTOMER DEPOSITS INACTIVE	0.01%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.89%	8.13%	0.072%
DEFERRED INCOME TAXES	11.94%	0.00%	0.00%
TOTAL CAPITAL	100.00%		6.29%

As can be seen from the above table, when the common equity cost rates reflect current market conditions and risks, the final recommended Company's overall cost of capital is substantially lower than the Duke request for each year for the rate plan. I have included the capital structure and cost rates in my Schedule (DJL-11).

[56] Capital structure and cost rates (except long-term debt cost and equity cost) per Company filing MFR D-1a, page 1of 5. Equity cost of 9.45% per this testimony.

SECTION X: <u>FINANCIAL INTEGRITY</u>

Q. 59 HAVE YOU REVIEWED CREDIT RESEARCH REPORTS FOR THE COMPANY REGARDING CREDIT QUALITY AND CORPORATE FINANCIAL METRICS?

A. Yes. As I discussed earlier, rating agencies view the Company's credit outlook as Stable and not threatened or under pressure of additional downgrade at this time. I have discussed these issues earlier with regard to a recent Moody's and the S&P Credit Reports.

Q. 60 WILL YOUR RECOMMENDED RETURN PROVIDE THE COMPANY SUFFICIENT CASH FLOW AND FINANCIAL METRICS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes. Based on the capital structure and cost rates above, my recommended overall cost of capital provides sufficient financial metrics for the Company. As stated earlier, these cost rates reflect recovery of all current debt costs and equity returns are consistent with current authorized equity returns.

Q. 61 WHAT FINANCIAL RATIOS OR FINANCIAL METRICS SHOULD THE COMMISSION CONSIDER WHEN EVALUATING COST OF EQUITY?

A. In my opinion, the Commission should consider the financial metrics that bond rating agencies consider in evaluating credit risk to a company. Key financial metrics involve cash flow coverage as a percentage of debt, and debt leverage ratio.

Q. 62 HOW ARE THESE FINANCIAL RATIOS CONSIDERED AND CALCULATED?

A. Ratings agencies such as Moody's Investor Services, Fitch Ratings, and Standard & Poor's develop rating guidelines that make explicit general ratings outcomes that are typical or expected given various financial and business risk combinations. A rating matrix or guideline is just that, a guideline, not a rule written in stone that guarantees a particular rating for a particular achieved financial metric level.

Funds or cash flow from a company's operations, in other words cash flow, are very critical to any rating/risk consideration. Interest and principal obligations of a company cannot be paid out of earnings if earnings are not cash. Thus, analyses of cash flow reveal debt-servicing ability.

Debt and capital structure considerations are indicative of leverage and flexibility to address financial changes. The 2008 liquidity crisis that hit all markets and industries is an example of the importance of financial flexibility. Stable and continuous cash flows provide financial flexibility. As discussed earlier, the array of cost recovery mechanisms available to Duke assure stable cash flows.

Given the recent ratings reports from both Moody's and Standard & Poor's, Duke is not in danger of losing current credit ratings, and my recommendations will not cause

Duke's financial integrity to diminish.

SECTION XI: <u>RESPONSIVE TESTIMONY TO COST OF CAPITAL WITNESS MR. ADRIEN MCKENZIE</u>

Q. 63 DO YOU HAVE ANY COMMENTS REGARDING THE DIRECT TESTIMONY AND RECOMMENDATIONS OF COMPANY WITNESS ADRIEN MCKENZIE?

A. Yes, I have a number of comments. First, as to Mr. McKenzie's recommended return on equity of 11.15% for Duke, such a return level is overstated and not supported by market data.[57] Mr. McKenzie's 11.15% recommendation appears to be based on his range of 10.50% to 11.50%. range from model results rather than current and/or expected market conditions, business or financial risk considerations, or other specific risk considerations. I discussed earlier in this testimony current market data and how such current market data supports a lower equity return. Further, Mr. McKenzie proposes the 11.15%% equity return in light of average authorized returns in the country that are about 9.60%.[58] There is no evidence that suggests Duke Florida operations are riskier than the average electric utility. Moreover, when you consider the risk reducing benefits of Florida rate mechanisms and the benefits of the negotiated multi-year rate plans of the past, along with the proposed multi-year rate plan (if

[57] Direct Testimony Mr. McKenzie at page 3, line 15.
[58] Direct Testimony Mr. McKenzie at page 3, line 15 and Schedule (DJL-10) which shows annual average authorized returns.

approved over OPC objection), Duke is less risky.

Q. 64 IS AN 11.15% EQUITY RETURN RECOMMENDATION REASONABLE IN THIS CASE?

A. No. There are several reasons why an 11.15% equity return is not reasonable in this case. First, Mr. McKenzie's own historical and current authorized equity return data in his Exhibit AMM-10, page 2, column (a) "Allowed ROE," demonstrates an 11.15% equity return is overstated. The last time that annual average authorized electric returns exceeded 11.15% was 2002 or almost 22 years ago.[59] Moreover, recent 2022 - 2023 authorized electric returns have been in the 9.6% range according to Mr. McKenzie.[60] Mr. McKenzie provides no reason to award Duke a bonus of 155 basis points (11.15% Mr. McKenzie recommendation – 9.6% average authorized equity return) or $192.2 million in annual revenues.[61] Certainly, the rating agencies do not view Duke as riskier than the average utility.

Second, Mr. McKenzie is correct that capital costs have increased along with inflation since 2021 and 2022, but even with changing interest rates and inflation, regulatory authorities around the country have not authorized average equity returns exceeding 9.66%.[62] As I noted earlier, there is currently an expectation of continued decreasing

[59] Direct Testimony Mr. McKenzie at Exhibit No. AMM-10 page 2 of 3 when the average authorized equity return was 11.21%.
[60] Direct Testimony Mr. McKenzie at Exhibit No. AMM-10, page 2 of 3 for 2022 and 2023.
[61] Based on the relationship of 50 basis points equaling $62.1 million in revenue requirements discussed in Question 17.
[62] Direct Testimony Mr. McKenzie at Exhibit No. AMM-10, page 2 of 3 for 2022 and 2023.

capital cost rates with decreasing inflation. Such expectations of declining inflation and interest rates do not support Mr. McKenzie's recommendation to radically increase the Duke equity returns.

Q. 65 DO YOU HAVE ANY COMMENTS REGARDING THE MR. MCKENZIE'S DCF ANALYSIS?

A. Yes, Mr. McKenzie's DCF analysis results for his 10-company comparable group are presented in his Exhibit AMM-6, Page 3 of 3. Only his 9.3% result employing the sustainable growth rate is consistent with current market returns authorized by regulatory authorities. The remaining results ranging from 10.2% to 10.6% are substantially in excess of expected returns authorized by regulatory authorities. While, these higher returns are the result of analyst earnings forecasts from Value Line, Zacks, and IBES, the end result appears overstated. I also employ these analyst forecasts in my two-stage DCF analysis, but one must be cautious as often these analyst forecasts are overstated and revised downward. This is especially true when economic conditions are expected to change course with market capital costs expected to decline given the current Federal reserve policies. Given the above, only Mr. McKenzie's 9.30% DCF estimate should be considered reasonable.

Q. 66 DO YOU HAVE ANY COMMENTS REGARDING MR. MCKENZIE'S CAPITAL ASSET PRICING MODEL ESTIMATES?

A. Yes, I have several comments. First, the CAPM results are presented in Mr.

McKenzie's Exhibit AMM-8, page 1 of 1, and show an 11.6% equity return estimate for Duke. Again, an 11.6% equity return is not consistent with declining capital costs or current authorized returns in the 9.6% range. Such an outlier as 11.6% should have alerted Mr. McKenzie that something is wrong when the model produces results about 200 basis points higher than the expected regulated utility return.

The second problem with the CAPM estimates is that Mr. McKenzie's estimate of risk premium of 7.3% is based on expected returns of the dividend paying stocks in the S&P 500.[63] As I discussed in the CAPM section of this testimony, a fair analysis of market risk premiums suggests a 6.6% risk premium. Third, Mr. McKenzie suggests a risk-free rate of 4.4% for the CAPM analysis.[64] While current U.S. Treasury yields are 4.4% and higher, as I described earlier, there is a market expectation and monetary policy projections of lower future interest rates. These facts have been ignored by Mr. McKenzie as demonstrated by his model projections of ROE's 200 basis points higher than current levels.

Q. 67 DO YOU HAVE ANY COMMENTS REGARDING THE MR. MCKENZIE'S EMPIRICAL CAPITAL ASSET PRICING MODEL?

A. Yes, First, the ECAPM results are presented in AMM-9 and indicate an 11.7% equity return. Like the CAPM results discussed above, the ECAPM model produces unreliable ROE estimates. The problems with the ECAPM are the same as the CAPM issues I

[63] Direct Testimony Mr. McKenzie at Exhibit No. AMM-8 page 1 columns (a – b).
[64] Direct Testimony Mr. McKenzie at Exhibit No. AMM-8, page 1 column c.

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pointed out above.

Q. 68 DID MR. MCKENZIE DEVELOP OTHER EQUITY RETURN MODELS FOR HIS ANALYSES?

A. Yes, Mr. McKenzie developed a risk premium analysis producing a 10.79% equity return estimate.[65] In addition, Mr. McKenzie developed an Expected Earnings analysis which produced an 11.1% equity return estimate.[66] Given current market returns and market expectations, both the risk premium 10.79% result and the Expected Earnimgs 11.1% estimate are excessive and can only be considered outliers. The Commission should not consider such results that do not reflect current and expected market requirements.

Q. 69 AFTER REVIEWING MR. MCKENZIE'S MODELS AND RESULTS HOW DID HE ARRIVE AT HIS 11.15% RECOMMENDATION IN THIS CASE?

A. Unfortunately, Mr. McKenzie never explains how he arrived at his 10.50% to 11.50% range or his 11.15% recommendation. I have summarized each of Mr. McKenzie's model results in the Table below which demonstrate how Mr. McKenzie arrived at his results in this case.

[65] Direct Testimony Mr. McKenzie at Exhibit No. AMM-10 page 1 of 3.
[66] Direct Testimony Mr. McKenzie at Exhibit No. AMM-11 page 1 of 1.

TABLE 21
SUMMARY OF MR. MCKENZIE ROE MODEL ESTIMATES

DCF MODEL[67]	9.30%	10.20%	10.40%	10.60%
CAPM[68]	11.60%			
ECAPM[69]	11.70%			
RISK PREMIUM[70]	10.79%			
EXPECTED [71][72]EARNINGS	11.1%			

It appears that the 10.50% bottom of Mr. McKenzie's range is based on the average the two highest DCF results of 10.40% and 10.60%, which provide 10.50%. Now, to calculate the 11.50% top end of the range, you average the three highest results CAPM 11.60%, ECAPM 11.70%, and Expected Earnings 11.10% which produces about 11.50%.

Now, to calculate the 11.15% point estimate, you only need to average the **highest result from each model** as follows: DCF 10.60%, CAPM 11.60%, ECAPM 11.70% Risk Premium 10.79%, and Expected Earnings 11.10% and the average is 11.16%, or about 11.15% selected by Mr. McKenzie. Mr. McKenzie's recommendation is based on averaging the highest results – this is no way to estimate a reasonable return or to set fair and just rates for consumers.

The bottom line is that Mr. McKenzie's estimated model results far exceed any authorized equity return around the country and ignore market expectations of declining

[67] Direct Testimony Mr. McKenzie at Exhibit No. AMM-6 page 3 of 3.
[68] Direct Testimony Mr. McKenzie at page 63 line 11.
[69] Direct Testimony Mr. McKenzie at page 66 line 12.
[70] Direct Testimony Mr. McKenzie at page 70 line 14.
[71] Direct Testimony Mr. McKenzie at page 73 line 6.
[72] Direct Testimony Mr. McKenzie at page 73 line 6.

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capital costs. Then Mr. McKenzie averages the highest of these overstated model results to arrive at his recommendation in this case.

Q. 70 DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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(Whereupon, prefiled direct testimony of Kevin J. Mara was inserted.)

C26-2178

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

DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Mary Wessling
Associate Public Counsel

Austin Watrous
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

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DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO: 20240025-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS?

A. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am the Executive Vice President of the firm GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering. I am a registered engineer in Florida and 22 additional states.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I received a degree of Bachelor of Science in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC.

In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Bedford, New Hampshire; Augusta, Maine; Orlando, Florida; Folsom, California, Redmond, Washington; and Madison, Wisconsin. GDS has over 180 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. I have submitted testimony before the following regulatory bodies:

- Vermont Department of Public Service
- Federal Energy Regulatory Commission ("FERC")

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- District of Columbia Public Service Commission
- Public Utility Commission of Texas
- Maryland Public Service Commission
- Corporation Commission of Oklahoma
- Public Service Commission of South Carolina
- Florida Public Service Commission

I have also submitted expert opinion reports before United States District Courts in California, South Carolina, and Alabama.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit KJM-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. GDS was retained by the Florida Office of Public Counsel ("OPC") to provide technical assistance regarding Duke Energy Florida's ("DEF" or "Company") petition for a rate increase. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. To address the projected capital spending for proposed transmission and distribution plant.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARATION OF YOUR TESTIMONY?

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to the Florida Public Service Commission ("PSC" or "Commission") Staff's discovery, and other discovery materials pertaining to the case and its impacts on the Company.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS BASED ON YOUR REVIEW OF THE COMPANY'S TRANSMISSION AND DISTRIBUTION INVESTMENT.

A. Based on the limited time I and the OPC had to evaluate a rate case filing utilizing three projected test years and a projected historical period (2024) and because of additional onerous circumstances, I recommend that the transmission and distribution-related capital costs be excluded from the 2026 and 2027 projected test years in this proceeding.

Q. WHAT DO YOU MEAN BY "ADDITIONAL ONEROUS CIRCUMSTANCES"?

A. In Docket NO. 20240026-EI, I filed testimony addressing a similar but more limited situation of a single projected test year and two subsequent year adjustments for 2026 and 2027. Inexplicably, the testimony schedule for the Tampa case was established to require my testimony to be filed on June 6, 2024, even though the hearing in that case is scheduled after the DEF case hearing. I asked the OPC to seek relief from this situation. They did but were ultimately unsuccessful in their efforts. The timing of the effort to prepare the Tampa Electric testimony at the time depositions were being conducted limited my ability to fully analyze the four projected years of the DEF filing. Nevertheless, I am able to make a high level recommendation about the 2026 and 2027 proposed transmission and distribution plant additions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address and make recommendations on specific issues that affect the capital requirements for transmission and distribution infrastructure in this proceeding effective for the 2025 test year and the requested fully projected 2026 and 2027 test years.

II. TRANSMISSION AND DISTRIBUTION PLANT ADDITIONS FOR PROPOSED 2026 AND 2027 PROJECTED TEST YEARS

Q. WHAT CAPITAL COSTS ARE INCLUDED IN THE PROJECTED TEST YEARS FOR THE TRANSMISSION SYSTEM?

A. The capital costs included in the 2025 test year and the 2026 and 2027 projected test years are shown in Table 1 below:[1]

Table 1: Transmission Actuals and Budgets

Dollars in $ 1,000,000

Investment Category	2023 Actuals[2]	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Grid Servicing/Support	$ 1.0	$ 12.5	$ 1.4	$ 1.5	$ 1.5
Growth	$ 376.5	$ 324.9	$ 272.9	$ 320.7	$ 311.7
Physical Security	$ 0.6	$ 33.1	$ 57.6	$ 9.0	$ 8.6
Regulatory	$ 59.2	$ 50.1	$ 4.3	$ 4.4	$ 4.0
Reliability	$ 73.0	$ 157.9	$ 167.6	$ 80.6	$ 81.6
Total	**$ 510.3**	**$ 578.5**	**$ 503.8**	**$ 416.2**	**$ 407.3**

The total projected cost for the 2026 and 2027 projected test years combined is $823.5 Million.

[1] Response to OPC's First Set of Interrogatories, No. 55.
[2] I am aware that the 2023 balances were part of the budget at the time the Minimum Filing Requirement ("MFR") schedule were prepared in this case. Despite the uncertainty about finality of the 2023 balance and inclusion of true actuals in the MFRs, I am treating these dollars as actual in reliance on OPC's First Set of Interrogatories, No. 55.

Q. IN YOUR OPINION, SHOULD THE CAPITAL COSTS FOR THE 2026 AND 2027 PROJECTED TEST YEARS BE INCLUDED IN THIS PROCEEDING?

A. No. Based on my expertise and the limited amount of time to conduct an in-depth analysis, I recommend that the costs for the 2026 and 2027 projected test years should be excluded from this proceeding. When budgeting, construction costs become more difficult and more uncertain to predict as the projections extended further into the future. For 2024 and 2025, these short term costs are relatively certain and have been used for singular future test years in Florida in prior proceedings. However, broad budgets and forecast elements and assumptions related to growth and reliability are inherently uncertain to predict in the future and should not be relied upon for rate making purposes.

Q. ARE THESE TRANSMISSION COSTS NOT A PART OF A FIXED BUDGET?

A. No. The transmission upgrades and modifications stem from the Confidential September 2023 Transmission Addition Plan.[3] This document specifically states:

> It should be noted that this document represents a plan and not a commitment to build. Furthermore, note that the Planned Dates listed for each project are the Requested In-Service Dates (ISD), and are subject to change due to challenges based on weather events, capital allocations, operational clearances, permitting, and routing, etc.[4]

From this statement it is clear the transmission budgets are not fixed. These budgets are subject to change both in terms of commitment to build and the in-service date which are vital for projected test years.

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[3] Response to OPC's First Set of Interrogatories, No. 55.

[4] Response to OPC's First Set of Interrogatories, No. 55, Confidential 2023 TAP, page 4.

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Q. HOW FLUID ARE THE COMPANY'S TEST YEAR PLANT ADDITION NUMBERS REGARDING THE COMPLETION OF TRANSMISSION PROJECTS WITHIN THE BUDGETS' YEARS?

A. The completion of the transmission projects varies significantly especially when trying to project a specific future year for completion. The confidential 2023 Transmission Addition Plan[5] ("TAP") has 23 transmission projects scheduled to be completed in 2026 and 2027 which is 3 to 4 years into the future at the time the case was prepared. For comparison, I considered the 2021 TAP[6] which had 22 projects projected to be completed between 2023 and 2026 which coincides with 2 to 4 years into the future. When these projects from the 2021 TAP are compared to the 2023 TAP, only 8 had the same completion date, 10 were delayed by one or more years, 6 projects in the 2023 TAP were not included in the 2021 TAP, and 3 projects from 2021 were simply canceled or deleted.

Q. BASED ON YOUR COMPARISON OF THE 2021 TAP TO THE 2023 TAP, WHAT IS YOUR CONCLUSION?

A. The transmission projects and completion dates are ever-changing. Even when considering the transmission plans are only two years apart, only 36% of the 2021 projects to be installed 2 to 4 years in the future were completed or projected to be completed in the same year. Delays or cancellations occurred. In addition, new projects appeared. This means that the distant projected test years cannot be expected to accurately contain a fixed set of projects. The evidence of the fluid nature of the transmission plans shows that there is too much uncertainty in the projects to be completed 3 to 4 years into the future to rely on future budgets for estimating rate base capital expenditure.

[5] Response to OPC's First Set of Interrogatories, No. 55, Confidential 2023 TAP.
[6] Response to OPC's First Set of Interrogatories, No. 55, Confidential 2021 TAP.

Q. WHAT CAPITAL COSTS ARE INCLUDED IN THE PROJECTED TEST YEARS FOR THE DISTRIBUTION SYSTEM?

A. The capital costs for the distribution system included in the 2025 projected test year and for the 2026 and 2027 projected test years are shown in Table 2 below:[7]

Table 2: Distribution System Actuals and Budgets

Dollars in $ 1,000,000

Distribution Program	2023 Actual[8]	2024 Forecasted	2025 Forecasted	2026 Forecasted	2027 Forecasted
Expansion	$ 199.0	$ 109.6	$ 191.2	$ 196.0	$ 200.9
Restore	$ 33.9	$ 25.7	$ 26.3	$ 27.0	$ 27.7
Maintenance	$ 240.2	$ 269.9	$ 184.0	$ 135.4	$ 143.0
Major Projects	$ 102.0	$ 167.6	$ 170.4	$ 212.1	$ 204.0
Total	**$ 575.1**	**$ 572.8**	**$ 571.9**	**$ 570.5**	**$ 575.6**

The total distribution cost for the 2026 and 2027 projected test years combined is $1.146 billion.

Q. IN YOUR OPINION, SHOULD THE DISTRIBUTION CAPITAL COSTS FOR 2026 AND 2027 PROJECTED TEST YEARS BE INCLUDED IN THIS PROCEEDING?

A. No. Based on my expertise and the limited amount of time to conduct an in-depth analysis, I recommend that the distribution costs for the 2026 and 2027 projected test years should be excluded for this proceeding. The reason for advocating the exclusion of the future distant projected test years is that the costs that far into the future cannot be known with any degree of certainty. The number of new customers, growth in system demand, and the amount of restoration cannot be accurately projected. Some high level assumptions can be made for budgeting purposes, but that level of detail is insufficient for the purpose of rate

[7] Response to OPC Interrogatory No. 55.
[8] See discussion in footnote 2.

making. For instance, I have observed that the increase in the budgets for 2026 and 2027 for expansion and restoration is simply a 2.5% increase of the prior year. An inflationary increase is not sufficient when considering the investment for expansion of new services and actual plant additions. These amounts can vary from year to year, as is clearly shown in the difference between the years 2023 and 2024 in Table 2 above.

Q. HOW HAVE SUPPLY CHAIN AND INFLATIONARY COSTS IMPACTED DISTRIBUTION PROJECTS?

A. In recent years, the electric power industry has struggled with a combination of supply chain shortages and inflationary pressures on material. For example, transformers have been in short supply with lead times up to 2 years and price increases of 4 to 9 times in the past three years.[9] Also, other equipment such as some types of pad-mounted switchgear have a lead time of over 52 weeks and random material such as anchors, and lightning arresters have also been in short supply. DEF has already acknowledged the negative impact that supply chain issues can have on the Company's ability to execute its plans.[10] Another example is based on the Handy-Whitman Index which is an inflation index that provides a cost index for every year for different types of FERC's Uniform System of Accounts compared to a base year. For distribution components in the South Atlantic market, the index shows significant fluctuations in costs since 2021 and the first quarter of 2023.[11] There has been settling of prices for many of the components and currently the Department of Energy is working on national standards on distribution transformers in an effort to reduce supply chain constraints.[12] The volatility of these prices does not make it

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[9] NREL, *Major Drivers of Long-Term Distribution Transformer Demand*, February 2024.
[10] Response to OPC's Sixth Set of Interrogatories, No. 118; Vanessa Goff Deposition taken May 20, 2024, page 40, Lines 4-6l; Vanessa Goff Late-Filed Deposition Exhibit No. 4.
[11] Handy-Whitman index for January 2023, South Atlantic Region.
[12] DOE and Industry Team Up to Keep the Lights on for America, February 22, 2024, https://www.energy.gov/oe/articles/doe-and-industry-team-keep-lights-america

possible to predict costs 3 to 4 years into the future which is what the 2026 and 2027 projected test years represent. This reflects a significant amount of uncertainty regarding the projections provided by DEF.

Q. IN YOUR OPINION, SHOULD THE TRANSMISSION AND DISTRIBUTION RELATED CAPITAL COSTS FOR THE PROJECTED 2026 AND 2027 TEST YEARS BE INCLUDED IN THIS PROCEEDING?

A. No. The distribution costs for 2026 and 2027 should be excluded for this proceeding.

Q. IN YOUR OPINION, SHOULD THE TRANSMISSION AND DISTRIBUTION RELATED CAPITAL COSTS FOR THE PROJECTED 2025 TEST YEAR BE INCLUDED IN THIS PROCEEDING?

A. I have not formed an opinion about 2025. My silence on this year should not be deemed an endorsement of the projected transmission and distribution additions that DEF proposed in the early part of 2023 for inclusion in 2025.

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. I reserve the right to revise my recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the

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issues and effects of those issues on the Company's petition. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

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(Whereupon, prefiled direct testimony of Helmuth W. Schultz, III, was inserted.)

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 PER DESIGNATION OF THE COMPANY

DIRECT TESTIMONY
OF
HELMUTH W. SCHULTZ, III.
ON BEHALF
OF
THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Mary A. Wessling
Associate Public Counsel

Austin A. Watrous
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Suite 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

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DIRECT TESTIMONY

OF

Helmuth W. Schultz, III

On Behalf of the Office of Public Counsel
Before the
Florida Public Service Commission
Docket No. 20240025-EI

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz, III. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, ("Larkin") Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan, 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, P.L.L.C.

A. Larkin performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including water and sewer, gas, electric and telephone utilities.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DESCRIBES YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. I have attached Exhibit HWS - 1, which is a summary of my background, experience and qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION AS AN EXPERT WITNESS?

A. Yes. I have provided testimony before the Florida Public Service Commission ("Commission" or "FPSC") as an expert witness in the area of regulatory accounting and storm recovery costs in numerous cases as listed in Exhibit HWS - 1.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin was retained by the Florida Office of Public Counsel ("OPC") to review the request for Duke Energy Florida, LLC (the "Company" or "DEF") for a three-year cumulative base revenue increase of $2.105 billion to be collected from customers over that period. The initial total base revenue increase of $593.446 million based on a projected 2025 test year, a base revenue increase of $691.346 million based on a projected 2026 test year (an incremental increase of $97.9 million) and a base revenue increase of $819.945 million based on a projected 2027 test year (an incremental increase of $128.599 million)

Q. ARE YOU INCORPORATING ANY RECOMMENDATIONS OF OTHER OPC WITNESSES?

A. Yes. William Dunkel makes recommendations regarding requested depreciation and the dismantlement study, Daniel Lawton makes recommendations regarding capital structure, and Return on Equity, David Dismukes makes recommendations regarding the sales forecasts and multiple test years, Kevin Mara is addressing proposed transmission and distribution plant additions, James Dauphinais will address the economics of certain proposed resource additions and regulatory considerations related to the reserve margin, and I am incorporating their recommendations into my testimony as they affect revenue requirements.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE COMPANY'S REQUEST.

A. The petition for Docket No. 20240025-EI is described by DEF as a proposal for setting rates based on three projected test years that would run from 2025 through at least the last billing cycle of December 2027, consisting of: (a) an increase in base rates and charges sufficient to generate a total base rate revenue increase of $593.446 million based on a projected 2025 test year; (b) a 11.5% mid-point return on equity ("ROE") and an equity ratio ranging from 45.61% to 45.73% to 45.83%, respectively on a regulatory-based capitalization; (c) the continuation of the Storm Damage Reserve provision approved as part of DEF's 2021 Settlement Agreement.

Q. IS THE OPC SUBMITTING SCHEDULES WITH RECOMMENDATIONS BASED ON THE THREE YEARS REQUESTED?

A. Yes. Attached as Exhibit HWS-2 are the recommendations based on an analysis of the three years requested. In addition to the legal objections related to the legality of the second and third projected years that I have been informed about, and as explained in the testimony of David Dismukes, the OPC takes the position that any base rate increase must be limited to the revenue requirement substantiated and proven by DEF using the projected 2025 test year. I am providing the adjustments to the Company filing for those years, but I do not support any rate increase for those periods.

Q. PLEASE SUMMARIZE WHAT THE COMPANY HAS INCLUDED IN ITS REQUEST TO THE FLORIDA PUBLIC SERVICE COMMISSION?

A. The April 2, 2024, petition filed by DEF seeks a base rates revenue increase of $593 million in 2025, an incremental increase of $98 million in 2026, and an incremental increase of $129 million in 2027 for a total increase of $820 million by 2027.

Q. HAS THE COMPANY IDENTIFIED CORRECTIONS TO THEIR FILING?

A. Yes, but at the time I was finalizing my analysis and testimony, DEF had not provided a formal updated filing so my recommendations are based on the initial filing.[1]

[1] I am aware that late in the afternoon of June 6, 2024, five calendar days before Intervenor Testimony was due and after denying in depositions that material corrections would be made until closer to hearing (if at all), the Company filed a Notice of Identified Adjustments. The information in this notice may have an effect on my analysis and recommendations. However, at the stage my testimony was in at that time of receipt of this notice, it was impossible

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III. ORGANIZATION OF TESTIMONY

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. In Section IV, without conceding the appropriateness of the 2026 and 2027 test years for establishing rates, I present the overall financial summary for the base rate change, showing the revenue requirement increase (decrease) for the test years ended December 31, 2025, December 31, 2026, and December 31, 2027, on behalf of OPC and the customers of DEF. In section V, I discuss Citizens' proposed adjustments to rate base. In section VI, I discuss Citizens' adjustments to operating income. In Section VII, I discuss the capital structure. Exhibit HWS-2 presents the schedules and calculations in support of the respective test years ended December 31 revenue requirement. Exhibit HWS-3 is a compilation of discovery responses referenced in my testimony. Exhibit HWS-4 is a 1986 Staff Memorandum that I reference in my testimony.

IV. OVERALL FINANCIAL SUMMARY

Q. WHAT IS THE DECEMBER 31, 2025, BASE RATE REVENUE REQUIREMENT DEFICIENCY OR EXCESS FOR DEF?

A. As shown on Exhibit HWS-2, Schedule A, Page 1 of 3, based on the information provided by DEF as of the date of development of my testimony, the OPC's appropriate adjustments in this case result in a revenue sufficiency of at least $27.990 million for DEF for the

to reconcile the notice with the filing and extensive discovery. I will review the Notice of Identified Adjustments, and, if warranted, file supplemental testimony incorporating the impact.

December 31, 2025. This eliminates the proposed base rate revenue increase of $593.446 million requested by DEF in its filing. Exhibit HWS-2, Schedule A, Page 2 of 3, is shown on a contingent basis and under protest given the OPC position about the legality of the second projected test year being entertained by the Commission and reflects the OPC's appropriate adjustments in this case resulting in a revenue sufficiency of $11.377 million in 2026, which is $702.723 million less than the $691.346 million requested by DEF. Finally, Exhibit HWS-2, Schedule A, Page 3 of 3, is shown on a contingent basis and under protest given the OPC position about the legality of the third projected test year being entertained by the Commission and reflects the OPC's appropriate adjustments in this case that limit the allowable revenue increase for DEF for the December 31, 2027, test year to no more than $89.434 million. This is $730.511 million less than the proposed base rate revenue increase of $819.945 million requested by DEF in its filing and significantly less than the $2.105 billion, three-year cumulative revenue collection proposed by DEF.

Q. DO YOU MAKE ADJUSTMENTS TO THE 2026 AND 2027 PROJECTED TESTS YEAR THAT COULD YIELD A POSITIVE REVENUE REQUIREMENT ABOVE CURRENT REVENUES?

A. Yes.

Q. DOES THAT MEAN THAT YOU ARE ACKNOWLEDGING THAT DEF HAS LAID THE PROPER FOUNDATION TO DEMONSTRATE ENTITLEMENT TO RATE RELIEF IN THE FORM OF REVENUE INCREASES FOR THAT YEAR?

A. No. To the contrary, my adjustments are to the numbers the Company filed. The purpose of my testimony is not to provide evidence regarding the second and third projected test years. OPC expert David Dismukes will testify to the forecasting and adequacy of 2026 and 2027 to support rate relief at this time. It is my understanding that the two occasions when the Commission allowed the use of a second projected test year (for FPL in 1984 and 1985 and Duke in 1993 and 1994), the second (and subsequent years) resulted in projected overearnings.[2] In my 40-plus years of testifying as an expert before regulators around the country, my experience has been that utilities have a tendency to over-project costs and under-project revenues and savings. My revenue adjustment, based on historical evidence, and David Dismukes' evidence relating to under-forecasting of revenues for the next three years, is concrete evidence of this very phenomenon. The failed experiment in the 1983 and 1992 cases using only a second test year bolsters this evidence and should cause Florida regulators to have grave concerns about setting rates using a second and third projected test year. Additionally, OPC Witness James Dauphinais indicates that DEF has accelerated generation assets into the three projected test year periods despite having an excessive

[2] In 1983, in Docket No. 830465-EI Florida Power & Light (FPL) petitioned for a two-step rate increase using 1984 and 1985 projected test years. The request was approved with the caveat that major assumptions would be reviewed for correctness the later part of 1984. That review by Staff revealed projected overearnings that were resolved, leaving the rate increase in place with an agreement to refund revenues based on earnings above the top of the 16.6% ROE range for 1985. Order No. 14005, issued January 16, 1985 in Docket No. 830465-EI. See February 20, 1986, Staff Memorandum attached as Exhibit HWS-4. On the second occasion, Duke predecessor Florida Power Corp., sought a two-step-rate increase using 1993 and 1994 projected test years. The Commission agreed but less than half way through the second year the Staff opened an overearnings investigation that was resolved through stipulation. Order No. 19940852-FOF-EI, issued July13, 1994 in Docket Nos. 940621-EI and 9308667-EI.

reserve margin. While I am not offering an opinion on the integrated resource planning aspects of this case, my experience tells me that this is just another piece of evidence that shows DEF has overstated revenue requirements in this case.

Q. WILL THE COMMISSION BE ABLE TO PROTECT THE CUSTOMERS THROUGH THE EARNINGS SURVEILLANCE PROGRAM?

A. No. In the first place, DEF's point person for this rate case, Marcia Olivier, did not agree to such a mechanism. When she was asked in a deposition about truing up at the mid-point of the ROE for the outer years in this case, she said the company was not requesting a true-up mechanism.[3] She did not take the opportunity to even indicate that the Company was willing to consider one. She also acknowledged that (pursuant to the company's filed case) 100 basis points on equity was worth approximately $125 million to $130 million between 2025 and 2027.[4] Even if the Commission aggressively monitored earnings and put money subject to refund and promptly investigated overearnings caused by excessively gloomy projections, the customers would lose the first $125 million to $130 million (on an annual basis) of revenue collected above the rate setting midpoint. Consequently, I do not believe that Commission has the ability to fully protect customers in the case of setting rates so far in advance with little-to-no information about revenue and cost-savings windfalls.

[3] Deposition of Marcia Olivier, May 23, 2024, Volume I, pp. 71-72.
[4] Deposition of Marcia Olivier, May 23, 2024, Volume I, p. 75.

Q. SO WHAT ARE YOU SAYING?

A. I am saying that I have no confidence in the accuracy of the information that DEF has projected for the projected test years – especially the second and third years -- and I do not believe that customers can be protected if the Commission sets rates for 2026 and 2027 and gets it wrong. Accordingly, it should not be construed that my adjustments that may ultimately yield a positive revenue requirement for 2026 or 2027 means that the Company has demonstrated the need for rate relief in that year.

Q. PLEASE DISCUSS THE EXHIBIT YOU PREPARED IN SUPPORT OF YOUR TESTIMONY AS IT PERTAINS TO THE DECEMBER 31ST TEST YEARS FOR 2025, 2026 AND 2027.

A. Exhibit HWS-2, consists of Schedules A, A-1, B, B-1 through B-4, C, C-1 through C-16, and D.

Q. WHAT IS SHOWN ON SCHEDULE A?

A. Schedule A presents the revenue (sufficiency) deficiency on a contingent basis and under protest given the OPC position about the legality of the second and third projected test years being entertained by the Commission for the respective years ending December 31, 2025, December 31, 2026, and December 31, 2027, giving effect to all of the adjustments being recommended by Citizen's witnesses. Schedule A-1 reflects the calculated revenue multiplier.

Q. WHAT IS SHOWN ON SCHEDULE B?

A. Schedule B presents OPC's adjusted rate base and, on a contingent basis and under protest given the OPC position about the legality of the second projected test year being entertained by the Commission, identifies the adjustments, including those of various OPC witnesses, impacting rate base that I am recommending in this case. Schedules B-1 through B-4 provide supporting calculations for these adjustments.

Q. WHAT IS SHOWN ON SCHEDULE C?

A. OPC's adjusted net operating income, on a contingent basis and under protest given the OPC position about the legality of the second projected test year being entertained by the Commission, is shown on Schedule C. The adjustments to net operating income, including those of various OPC witnesses, are listed on Schedule C-1. Schedules C-2 through C-16 provide supporting calculations for these adjustments.

Q. WHAT IS SHOWN ON SCHEDULE D?

A. Schedule D presents, on a contingent basis and under protest given the OPC position about the legality of the second projected test year being entertained by the Commission, OPC's

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recommended capital structure and overall rate of return as recommended by OPC witness Daniel Lawton.

Q. WOULD YOU PLEASE DISCUSS EACH OF YOUR SPONSORED ADJUSTMENTS TO DEF'S FILING?

A. Yes, I will address each adjustment I am sponsoring below.

V. RATE BASE

PLANT HELD FOR FUTURE USE

Q. WHAT IS THE ISSUE WITH PLANT HELD FOR FUTURE USE?

A. The Company is requesting that base rates include $94.468 million for the Levy County Land in Plant Held For Future Use as part of rate base in total and on a jurisdictional basis in all three years of the request. Also included is $16.727 million for Levy Land (CSX Acquisition) as part of Transmission Plant Held for Future Use. The jurisdictional amount varies by year with a $7.267 million jurisdictional adjustment made in the year ended December 31, 2025. The Company has not shown that the non-transmission portion of this land will be used in the near future.

Q. WHAT IS THE PURPOSE OF INCLUDING PLANT HELD FOR FUTURE USE RATE BASE?

A. Plant Held For Future Use is included in rate base when it is probable that the land will be used for regulated purposes in the near future. The key is when the property will knowingly be used for regulated purposes.

Q. WHY DO YOU BELIEVE THE LEVY LAND SHOULD BE EXCLUDED FROM RATE BASE?

A. As noted on Company Schedule B-1 for the years ended December 31, 2023, and December 31, 2024, the Company excluded the Levy Land. The exclusion is because the land was not considered to be ready for use in regulated operation. There is no evidence that it is probable that the land will be used for a regulated project in the foreseeable near future.

Q. WOULD YOU AGREE THAT IT IS TRUE THAT EVIDENCE OF, AND BASIS FOR, THE LAND'S EXCLUSION FROM RATE BASE (PLANT HELD FOR FUTURE USE) IS CONTAINED IN A 2017 SETTLEMNT?

A. Yes. Although I am not pointing to the settlement as justification for excluding the land, I am noting that the 2017 settlement provides guidance as follows:[5]

[5] Order No. PSC-201700451-AS-EU, issued November 20, 2017 in Docket No. 20170009-EI, at 24-25. (Emphasis added.) I have also been advised by the OPC that the language cited in the italicized passage from this order may

<u>Levy Nuclear Project ("LNP"):</u>

> 10. By no later than January 1, 2019, DEF shall remove the Levy Land from rate base and earnings surveillance report results. Levy Land is defined as the land reflected in DEF's 2016 FERC Form 1, page 214, lines 6 and 8, specifically the Lybasse parcel (1,845 acres) in the amount of $27,667,950 (system) and the Rayonier/Lybasse parcel (3,105 and 94 acres, respectively) in the amount of $66,404,373(system), for a total of $94,072,323(system). Upon this initial removal of the Levy Land from rate base, DEF shall write off its actual post-2013 costs, in the amount of $36,621,816.70 (system) as estimated on July 31, 2017, related to the LNP Combined Operating License ("COL"), including AFUDC. DEF agrees not to seek future recovery from retail customers of any of the LNP's COL-related costs, including carrying charges. ***DEF retains the right to maintain ownership of the Levy Land and to file a petition with the Commission in conjunction with its next general base rate case, or any other relevant proceeding during the Term of this 2017 Second Revised and Restated Settlement Agreement pursuant to Paragraph 15, for potential re-inclusion of any portion of such land into rate base, subject to approval by the Commission in DEF's next base rate proceeding or other relevant proceeding contemplated under this 2017 Second Revised and Restated Settlement Agreement.*** Parties reserve the right to object to inclusion of such land costs in rate base or rates. If DEF sells the Levy Land, DEF's shareholders will be permitted to retain any gain or loss on sale. Any Levy Land restored to rate base by Commission approval shall be thereafter subject to the Commission's policy on gains or losses on sales.

This passage is a starting point for the period when the land was excluded. Even though the land had been historically ready for use, as evidenced by its inclusion in clause rate base related to the Nuclear Cost Recovery Clause as a part of the Levy Nuclear Project, it is not clear that it has ever been included in base rates. It is reasonable for an outside observer to assume that since the land has been excluded from base rates since 2019 that it was not probable the land would be used for regulated operations. Based on information provided in this docket, that is still the case. The Company was asked whether

provide that the window for including the Levy land in rate base expired at the conclusion of the 2017 Settlement agreement. To the extent this is the case, my testimony on this issue would be surplus.

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a specific date can be provided where the land will be utilized and what facility would be constructed at Levy. The response was "At this time, DEF does not have a more specific project plan."[6] Clearly a plan does not exist, so the $94.468 million of cost for Production Plant should be excluded in each year of the request. There is no facility identified in the April 29, 2024, Ten-Year Site Plan proposed for location on that Levy site for the next ten years.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE TRANSMISSION PORTION OF LEVY?

A. No. It is my understanding that some of the transmission plans related to this land may be providing some benefit to customers.

DISMANTELMENT STUDY

Q. ARE THERE ANY CONCERNS WITH THE REQUEST FOR DISMANTELMENT COSTS BEING PART OF RATE BASE?

A. Yes, there are concerns. Rate base is impacted when dismantlement costs are amortized to expense. The Company has requested an increase in the amortization of dismantlement costs as discussed by Company witness Kopp. Exhibit No. JTK – 2 identifies the current amortization as $20,597,000. This same amount is reflected in MFR Schedule B-9 for each of the years 2024-2027. As the amortization is recorded, it increases accumulated

[6] DEF response to OPC's Seventh Set of Interrogatories, No. 189.

depreciation. As will be discussed later, OPC witness William Dunkel is recommending an adjustment to the amortization requested by DEF. The adjustment will reduce the amount expensed and the amount credited to accumulated depreciation.

Q. WHAT ARE YOU RECOMMENDING TO THE COMMISSION?

A. As shown on HWS Exhibit -2, Schedule C-13 accumulated depreciation should be reduced $12,158,000 in 2025, $36,473,000 in 2026, and $60,789,000 in 2027.

CAPITAL ADDITIONS

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S REQUEST FOR CAPITAL ADDITIONS?

A. The Company has included in their request an overly optimistic amount of plant additions during the projected prior year, 2024, and in each of the forecasted test years included in DEF's request. This lends further support to the inappropriateness of the projected distant, outer test years. As shown on Exhibit HWS - 2, Schedule B-2, Page 1 of 2, actual total plant additions ranged from a low of $1,674,484,000 in 2020 to high of $2,139,142,000 in 2023 over the five years 2019 to 2023. The five-year average for plant additions is $1,942,499,000. The projected capital additions for 2024 is $2,805,182,000; for 2025 is $3,170,242,000; for 2026 is $2,225,367,000; and for 2027 is $2,230,503,000. The differences from year-to-year are attributable in part to an approximate 80% increase in projected solar generation additions, an approximate increase of 124% in projected transmission plant additions and an approximate increase of 148% in projected distribution plant additions. Another factor that contributes to the concern with the Company's optimism is that capital expenditures are not reflecting the same level of growth.

Q. ARE NOT CAPITAL EXPENDITURES AND PLANT ADDITIONS THE SAME?

A. No. Plant additions represent the additions to the plant account once construction is completed. Whereas capital expenditures reflect charges to Construction Work In Progress ("CWIP").

Q. DID YOU MAKE ANY COMPARISON OF THE PROJECTED AND ACTUAL CAPITAL EXPENDITURES?

A. Yes. The Company was requested in OPC's First Set of Interrogatories, No. 1 to provide the budgeted capital expenditures for 2018 through 2027, and actual capital expenditures for 2018 to 2023. As shown on Exhibit HWS - 2, Schedule B-3, the information indicated that historically, the actual expenditures exceeded budgeted expenditures. It is also noteworthy that actual expenditures in each of the five years 2019-2023 exceeded plant additions. The anomaly is that the forecasted additions to plant in 2024 and 2025 exceed the "budgeted"[7] expenditures for the same periods. Then in 2026 and 2027, the "budgeted" expenditures exceed the forecasted additions to plant. The distant, outer years' 2026 and

[7] DEF's forecasting witness Michael O'Hara acknowledged that at the time the MFRs were prepared, the only official budget year was 2023. Michael O'Hara Deposition, May 31, 2024 at pp. 39-40. He acknowledged that the current 2024 budget was not incorporated into the MFRs. Michael O'Hara Deposition, May 31, 2024 at p. 41.

2027 additions, while higher than historical additions, are significantly less than 2024 and 2025. If the forecasted plant additions and forecasted capital expenditures were treated consistently, the changes to CWIP would be commensurate. However, that is not the case.

Q. COULD YOU EXPLAIN THE SIGNIFICANCE OF THESE DIFFERENCES AND PROVIDE AN EXAMPLE THAT WOULD SHOW WHY, IN ADDITION TO REJECTING THE DISTANT, OUTER YEAR PROJECTED TEST YEARS ENTIRELY, THE COMMISSION SHOULD REJECT THE LEVEL OF ADDITIONS IN THE FORECASTED YEARS?

A. Yes. As discussed earlier, capital expenditures flow through CWIP and when plant is completed, CWIP is credited and the plant additions are transferred to plant accounts. A high-level example of the additions and deductions to CWIP shows that an inconsistency exists over the forecasted period. The CWIP balance on December 31, 2023, was $998 million. The projected expenditures for 2024 added to CWIP are $2,545 million and the forecasted plant additions removed from CWIP and transferred to plant are $2,805 million. The expected result should be a projected CWIP balance of $708 million on December 31, 2024; instead Company Schedule B-1 shows a projected CWIP balance of $951 million on December 31, 2024. The CWIP balance did decrease but not commensurate with what would be expected based on the high-level analysis. A $243 million difference is significant.

Q. ARE THERE OTHER CONCERNS WITH THE COMPANY'S PROJECTED CAPITAL ADDITIONS?

A. Yes. There are concerns whether the Company can monitor its projects commensurate with the volume of projected additions. The Company was asked in OPC's First Request for Production of Documents, No. 14 to provide variance reports for historical periods. The response included a variety of reports, some of which purported to include capital but because the responses were for multi-state Duke operations and significantly redacted, the specifics for DEF could not be determined. It should be a serious concern for the Commission in its consideration of the fidelity of four projected test years (2024-2027), if specific variances to capital cannot be identified and explained.

A second concern is with the actual development of projected costs. The Company was requested in OPC's Third Request for Production of Documents, No. 32 to provide a copy of a high-level summary of the software used to generate plant costs. No such responsive document was provided. Instead, only a written summary was provided. Three significant facts were noted. The first was that CWIP data is developed separately and manually input into the model. No specifics were provided as to the CWIP data that was input. Second, the response states: "Documentation (invoices/quotes) are not required as support for entries into the system but are generally maintained at the functional level to develop estimates." A policy of not requiring support for cost information is highly concerning especially when the Company uses the term "generally maintained" as part of its explanation. Finally, the explanation makes no mention of a justification of the project with a cost/benefit analysis.

This leads to another significant concern. In my experience, when plant additions are proposed for management approval and allocation of capital, some cost/benefit analysis is required. The response to OPC's First Set of Production of Documents, Request No. 21 stated that "DEF has not performed any cost/benefit analyses of DEF's three proposed test years." The Company was requested in OPC's First Set Interrogatories, No. 34 to identify cost savings programs or initiatives from 2018-2024. The response stated that DEF projects incorporate cost savings that reduce O&M costs. When asked to provide cost savings for the period 2025-2028, a feedback loop was triggered. The response to OPC's First Set of Interrogatories, No. 35 referred to the response to OPC's First Set of Interrogatories, No. 34. This infinite circularity would hardly pass muster in a single historical test year or single projected test year case; it should have less than zero credibility in one with second and third outer years.

Another request seeking identification of cost savings was included in OPC's First Set of Interrogatories, No. 36. This request was for a schedule showing historic and projected cost savings. A key statement in DEF's response stated, "Below please find details on forecasted savings as ***allocated*** to Duke Energy Florida by business function through 2028 for the various initiatives." (Emphasis added.) This statement suggests as noted earlier that DEF cannot identify specific cost savings generated or existing from Florida-specific DEF projects. The response states later that DEF does not separately track cost savings and that "DEF ***believes*** there are cost savings associated with the efficiencies gained but has not set up a tracking mechanism to quantify the benefits." (Emphasis added.) It is easy to believe that projects provide a benefit but knowing that benefits actually result should be a prerequisite. It defies credulity that DEF and Duke Energy management blindly authorize hundreds of millions of dollars in project capital expenditures in total ignorance of the actual benefits to be gained from the projects. Instead, this failure to track cost savings associated with efficiencies is at best poor management and at worst reeks of management seeking to hide the savings from constructive regulators to induce them to keep the hidden savings to the benefit of shareholders while saddling customers with the costs to achieve those benefits.

Q. WHY IS THE DETERMINATION OF COSTS AND BENEFITS AND/OR COST SAVINGS SIGNIFICANT?

A. For a company that serves 2 million customer accounts and which intends to invest in capital projects amounting to hundreds of millions and even billions of dollars, a cost/benefit analysis should be required and some form of identification of specific cost savings should be identifiable in order to justify the project(s). For example, as part of satisfying the burden of proof for including projected plant additions in base rates, Vermont regulators require companies to include a cost/benefit analysis to justify the capital project. Absent this type of analysis, projects could be undertaken that increase costs without any real benefit and/or justification. Such an analysis deficiency is deemed imprudent by Vermont regulators. DEF's and Duke Energy's failure to provide any of this information in this case should likewise go unrewarded.

Q. WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE PROJECTED PLANT REQUEST FOR THE YEARS 2025, 2026 AND 2027?

A. Separate and apart from the OPC's legal objections and the contingent nature of the OPC's participation under protest in that portion of a case that allows even consideration of the second and third outer years, the amounts projected for 2025, 2026 and 2027 should be reduced. I recommend each year be reduced by the excess plant projected in 2024 and by the subsequent flow-through of excesses from the respective base rate years. As shown on Exhibit HWS - 2, Schedule B-2, Page 1 of 2, I am recommending that total plant be reduced $1,181,590,000 in 2025; $1,740,253,000 in 2026; and $1,829,046,000 in 2027. After factoring in a prorate of SPP plant additions, base rate plant should be reduced $966,636,000 in 2025; $1,402,028,000 in 2026; and $1,465,114,000 in 2027. My recommendation factors in the testimony on solar plant additions by OPC resource planning expert James Dauphinais. I have factored in the prudence and questionable prudence of solar dollars but does not indicate that I am conceding that these solar additions should be, or will be, built on the schedule. OPC witness James Dauphinais primarily focuses on whether the projects are or are not cost-effective. I understand that there may be discovery responses pending and analyses that may be supplemented by OPC engineering experts Kevin Mara and James Dauphinais. My analysis is subject to amendment on this issue. To be clear, it is my testimony that given the historical trends discussed above regarding DEF's projected and actual capital expenditures, the likelihood that all of the projected capital additions will be in-service by the end of 2027 is highly doubtful, regardless of how prudent and cost-effective they may or may not be.

Q. WOULD YOU EXPLAIN WHY YOU CHOSE TO MAKE YOUR ADJUSTMENT AND HOW YOU DETERMINED THE ADJUSTMENT?

A. Yes. The historical trend for plant additions as shown on Exhibit HWS - 2, Schedule B-2, Page 1 of 2 fluctuated from year-to-year; both increasing and decreasing. There is no trend of continual increases. Factoring into my analysis the trend and the Company's proposal for additions, I elected to focus on the 2023 actual expenditures as a comparative for the additions. This is significant since the plant additions in 2023 of $2,139,142,000 exceeds both the five-year average of $1,942,499,000 and the four-year average of $1,981,686,000. In evaluating the 2024-2027 proposed additions, I considered the fact that the 2023 actual plant additions of $2,139,142,000 were $480,950,000 below the forecasted 2023 plant additions of $2,620,092,000. Essentially, the use of the 2023 actuals as a comparative is conservative and allows DEF more than $150 million of plant costs than would be recommended using the historical average. The adjustment begins with 2024 where the forecasted plant additions are $2,805,182,000, which are $666,040,000 more than the 2023 actual of $2,139,142,000. This difference flows through to each of the respective years 2025-2027. The 2025 forecasted plant additions of $3,170,242,000 exceed the 2023 actuals by $1,031,100,000. Since plant is added throughout the year, the adjustment to 2025 is the 2024 adjustment of $666,040,000 plus $515,550,000 or 50% of the 2025 total plant adjustment, resulting in my recommended adjustment of $1,181,590,000, as shown on line 32, Column C of Exhibit HWS - 2, Schedule B-2, Page 1 of 2.

Even though it is relatively absurd to assume that distant, outer projected test years can be accurately projected, I am providing my analysis of the numbers presented by DEF. The 2026 adjustment of $1,740,253,000, as shown on line 32, Column D of Exhibit HWS - 2, Schedule B-2, Page 1 of 2, is based on the 2024 adjustment, the full year cost adjustment for 2025, and 50% of the difference between the 2026 plant additions of $2,225,367,000 and the 2023 actual additions of $2,139,142,000. The 2027 adjustment of $1,829,046,000, as shown on line 32, Column E of Exhibit HWS - 2, Schedule B-2, Page 1 of 2, is based on the 2024 adjustment, the full year cost adjustments for 2025 and 2026, plus 50% of the difference between the 2027 plant additions of $2,230,503,000 and the 2023 actual additions of $2,139,142,000. Each of the annual adjustments are then reduced to account for a prorate of the forecasted SPP Plant additions that are recovered as part of the SPP clause. This calculation is shown on Exhibit HWS - 2, Schedule B-2, Page 2 of 2. The recommended adjustments, which do not represent a determination by me or the OPC that there is sufficient fidelity to the DEF self-serving projection process are conservative given the concerns identified earlier.

Q. PLEASE EXPLAIN HOW YOU FACTORED IN THE TESTIMONY OF OPC EXPERTS KEVIN MARA AND JAMES DAUPHINIAIS.

A. Both of the witnesses discuss specific plant and make specific recommendations. My recommendation is based on DEF's excessive forecasts that based on historical additions to plant are overly optimistic. The specific recommendations are considered to be included in my overall recommendation so that the adjustment captures costs that are specific and takes into consideration the Company's historical performance and their inability to meet the optimistic expectations. As discussed earlier, the historical five-year average for plant additions for 2019-2023 was $1,942,499,000 and more recently the 2023 actual additions of $2,139,142,000 were 81.6% of the $2,620,062,000 forecast.

Q. WHAT IF THE COMMISSION CHOOSES TO IGNORE THE HISTORICAL RESULTS AND REJECTS YOUR RECOMMENDATION?

A. Ignoring history will in my opinion burden customers with a cost increase that is not justified. To the extent the Commission rejects my recommendation, then the specific recommendations by OPC engineering expert Kevin Mara and resource planning expert James Dauphinais should be evaluated independently for inclusion or exclusion from the test years.

ACCUMULATED DEPRECIATION

Q. IS THERE AN IMPACT ON ACCUMULATED DEPRECIATION ASSOCIATED WITH THE REDUCTION TO PLANT?

A. Yes, As shown on HWS Exhibit – 2, Schedule B-4, the mathematical calculation of projected accumulated depreciation is performed to reduce it $25,543,000 in 2025, $64,792,000 in 2026 and $112,300,000 in 2027.

CASH WORKING CAPITAL

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S REQUEST FOR CASH WORKING CAPITAL?

A. The Company's test year request includes the deferred rate case expense and, as will be discussed later, I am recommending excluding rate case expense under the unique circumstances of this case. As shown on Exhibit HWS – 2, Schedule C-7, my recommendation results in a reduction of $2,392,000 in 2025, $1,625,000 in 2026 and $751,000 in 2027 to cash working capital.

VI. NET OPERATING INCOME

REVENUE

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO REVENUE?

A. Yes. On May 6th, 2024, 34 days after the filing, the Company provided a response to the Commission Staff's First Set of Interrogatories, No.2 that admitted that a more recent load forecast than the one underlying the filing, had been made in support of the Ten-Year Site Plan. This update indicated that projected sales in the filing are understated. The interrogatory response admitted that an increase in revenue of $53,157,000 was required for 2025. The response further showed the company view of how the revised load forecast would impact the two distant outer years. Not surprisingly the company's projection of the change to the distant years was relatively minimal. I have reflected this adjustment on Exhibit HWS- 2, Schedule C-2. Additionally, Exhibit HWS- 2, Schedule C-2, reflects adjustments to revenue as recommended by Citizens' witness David Dismukes, based on his review of DEF's forecast. The total adjustment recommended by David Dismukes is $94,000,000 in 2025; $110,000,000 in 2026; and $136,000,000 in 2027. The recommendation is inclusive of DEF's admitted understatement of revenue discussed just above.

PAYROLL

Q. HAVE YOU REVIEWED THE PAYROLL COST INCLUDED IN THE COMPANY'S BASE RATE REQUEST?

A. Yes, I have. The Company's request for 2025, 2026, and 2027 includes $240,354,521; $245,782,341; and $251,210,159 respectively, projected to be charged to O&M expense. For capital projects for 2025, 2026 and 2027, the Company proposed to charge an identical amount of $209,457,176 each year. The capital charges are exactly the same as is forecasted for 2024. With all the fluctuations in capital payroll from 2018-2023, it is not plausible that the actual amounts in each of the four future years will be exactly the same. The amounts do not even include any costs charged to recovery clauses. The DEF revenue request, according to Schedule C-35, assumes an average employee complement of 3,874. The history of payroll expensed and capitalized excluding other payroll and recovery clause payroll, along with the changes in the employee complement is detailed on Exhibit HWS - 2, Schedule C-3.

Q. ARE THERE ANY CONCERNS WITH THE COMPANY'S REQUEST?

A. Yes, there are multiple concerns. The request, according to Schedule C-35, assumes an employee complement of 3,874 each year 2023 through 2027. According to the response to OPC's First Set of Interrogatories, No. 21, there was an average of 2,957 employees and an average of 5 part time employees in 2023. Through March of 2024 the actual averages remained the same. The trends and averages are reflected on Exhibit HWS - 2, Schedule C-3, Page 2 of 2. The first concern is that the Company has indicated no changes in employees yet there is supposedly a plan to add 28 solar tech positions from 2025 to 2027 and in response to OPC's Seventh Set of Interrogatories, No. 165, DEF stated that there is a possible need to make 180 apprentice hires from 2025 to 2027. According to the response to OPC's First Set of Interrogatories, No. 12, the Company does not develop a budget for payroll based on a projected employee complement. Additionally, there is no information provided that demonstrates what offsets or efficiency measures will reduce the indicated projected increases.

A second concern is that despite a significant forecasted increase in capital project spending, the Company states in response to OPC's First Set of Interrogatories, No. 34 that they are incorporating cost savings and/or efficiencies by utilizing internal crews on capital projects. Despite this, the forecasted percentage of capitalized payroll is decreasing. This trend is inconsistent with the discovery response.

A third concern is that despite capital project spending varying from one year to the next DEF has assumed that the dollar amount to be capitalized is ***exactly the same*** in each year 2024 through 2027. This assumption defies reality. Based on more than 45 years of experience in reviewing rate requests, this suggests to me that the Company's planning and estimating of distant years' future project costs is not based on an objective, verifiable methodology such as trends and/or analysis that justify project costs or the payroll costs in DEF's request. This is a serious concern.

Q. WHY DOES SCHEDULE C-35 HAVE A HIGHER AVERAGE NUMBER OF EMPLOYEES THAN WHAT YOU HAVE REFLECTED ON PAGE 2 OF EXHIBIT HWS - 2, SCHEDULE C-3?

A. Based on the response to OPC's Twelfth Set of Interrogatories, No. 327, it is suggested that the differences are affiliate employees. The request was for a separation of the labor dollars for affiliates and the respective number of affiliate employees generating those labor dollars. The PDF version of the response did not show any employee detail but the Excel version of the response indicates an estimated number of affiliate employees.

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE BUDGETING PROCESS IN RELATION TO THE CONCERN WITH THE COMPANY'S REQUEST TO ADD POSITIONS?

A. The Company testimony does not detail any specifics as to what new positions are required and why they are required. The responses to OPC's First Set of Interrogatories, No. 12, OPC's First Set of Interrogatories, No. 13, and OPC's First Set of Interrogatories, No. 21 state the Company does not budget headcount. This is troubling for two reasons. First, absent a budget headcount, the budgeting for payroll dollars exhibits a lack of control and allows for budgeting haphazardly for the different departments. It should be noted that this difference between departments is explained to some extent in the response to OPC's First Set of Interrogatories, No. 18 where the Company states:

> During the budgeting process, each department is responsible for budgeting for their current and anticipated headcount, including an assumption to reduce their total labor dollars to account for attrition credits (i.e., vacancy factor). This assumption is not standard across

> groups as each group has varying degrees of 'normal' turnover experienced throughout the year. The budget system does have an identifier (in resource type) to be able to identify this credit, but it is not used consistently. A group like Customer Call Centers experience so much turnover, that the methodology that works best for them is to budget an average number of heads and salary with no specific attrition credit. Meanwhile, a group like the State President organization is typically more stable and may budget specific people/salaries and vacancies, if applicable, with a lower attrition credit.

So, while multiple responses represent that the Company does not budget by headcount, this response suggests that they do. If the Company does not budget headcount, then the 3,874 shown on Schedule C-35 is not supported.

As to the number of positions included in the filing, Schedule C-35 says that for each year 2023 through 2027 the projected average number of employees is 3,874. Yet the response to OPC's First Set of Interrogatories, No. 13 states the filing includes the addition of new solar plant employees. The response claims that 12 are going to be added in 2025, 8 will be added in 2026 and another 8 in 2027. If the proposed employee additions are reflected in O&M expense as the response states, then either Schedule C-35 is wrong when it reflects the projected average employee count or in each of the respective years an exact an offsetting number of employees are expected to leave the employ of the Company. A further concern with the additional employees is the response to OPC's First Request for Production of Documents, No. 4 states that DEF has no documents justifying its need for the additional positions.

Q. WOULD YOU EXPLAIN WHY PAYROLL CAPITALIZATION IS AN ISSUE?

A. Yes. Historically the capitalization percentage for payroll has fluctuated but has increased from 35.34% in 2018 to 45.43% in 2023. This is significant when rates are being set because the other factor to consider is the amount of payroll being expensed. The percentage of payroll expensed in 2018 was 53.32% and in 2023 it was 46.18%. The increase in capitalized payroll is consistent with the increases in capital expenditures and the amount of plant going into service over the same time frame. The concern for the projected periods is that even with a significant increase plant forecasted to go into service and an increase in forecasted capital expenditures, the Company has reduced the percentage of payroll being capitalized and has in turn increased the percentage of payroll being expensed. This assumption by the Company is not consistent with the historical trend or with what would be a commonsense expectation. If one were to assume the forecasted level of plant additions, all of which are projected to be higher than 2023, were reasonable for the years 2024-2027, then it would be expected that the percentage of payroll capitalized would have a commensurate increase. The Company has instead forecasted a declining percentage of payroll being capitalized and fixed level of dollars every year. There is no justification for a reduction to the percentage of payroll being capitalized or assumed to be fixed at the same level over a four-year period.

Q. WHAT WOULD BE THE CONSEQUENCES OF ACCEPTING THE COMPANY'S REQUEST AS FILED?

A. Customers would pay twice for payroll dollars incurred by ignoring the historical results that as capital project costs increase and the percentage of payroll being capitalized has correspondingly increased. If rates are set using the Company requested amounts, customers would pay the O&M portion in current rates unless an adjustment to properly capitalize payroll dollars. When actual payroll is incurred during the period rates are in effect and properly recorded, the higher actual cost would be capitalized, and when rates are reset those same dollars will be included in the plant costs a second time as part of the Company's subsequent request. The revenue requirement ratio of the impact of expense to capital is approximately 9:1, meaning that if rates are set based on an unreasonably low amount of capitalized payroll and then actual results reflect increased capitalization of the same payroll dollars, shareholders receive a commensurate windfall and customers overpay in rates.

Q. IS THERE ANY OTHER EVIDENCE THAT THE FORECASTED PERCENTAGES ARE OVERSTATED FOR O&M EXPENSE AND UNDERSTATED FOR CAPITAL?

A. Yes. As shown on Exhibit HWS - 2, Schedule C-3, Page 1, Line 7, the 2023 forecast for O&M was 49.46% and for capital was 43.47%. On line 6, the actual O&M was 46.18% and the capital was 45.43%. The Company forecast in 2023 overstated O&M payroll and understated capital payroll. Despite the increase in forecasted plant, the Company reflects a declining percentage of payroll being capitalized and an increased percentage charged to O&M. History and common sense refute the Company's assumptions. The Commission should recognize this and protect customers from overpaying.

Q. WHAT DO YOU RECOMMEND FOR PAYROLL EXPENSE IN THE RESPECTIVE TEST YEARS 2025-2027?

A. Based on the 2023 O&M percentage of total payroll, the 2025 payroll expense request of $240,354,521 should be reduced by $16,807,770 to $223,546,751. My adjustment is reflected on Exhibit HWS - 2, Schedule C-3. The adjustment simply multiplies the requested total payroll times 46.18%, the 2023 actual percentage of O&M payroll expense, excluding incentive compensation.

Without conceding the propriety of even determining revenue requirements for the outer, distant years, applying the same 46.18% factor to the total requested payroll for 2026 and 2027 reduces the company's projection of payroll expense by $19,235,428 and $21,663,086, respectively.

Q. WOULD YOUR RECOMMENDED REDUCTION TO PLANT BE INCONSISTENT WITH YOUR RECOMMENDATION TO REFLECT A HIGHER CAPITALIZTION RATE?

A. No. My recommendation to adjust plant is based on the 2023 actual capital additions. Here I am recommending the use of the actual 2023 capitalization rate, so the adjustments are consistent.

Q. WHAT IS YOUR RECOMMENDATION FOR THE POSITIONS BEING ADDED?

A. I am recommending that the O&M expense be reduced $1,109,148 in 2025. Without conceding the propriety of even determining revenue requirements for the outer, distant years, O&M expense should be reduced $1,848,580 in 2026 and $2,588,012 in 2027. As indicated earlier, the Company has not provided any justification for the additions.

INCENTIVE COMPENSATION

Q. HAVE YOU ANALYZED DEF'S REQUEST FOR INCENTIVE COMPENSATION FOR THE RESPECTIVE TEST YEARS?

A. Yes, I have. In response to OPC's First Set of Interrogatories, No. 15, the Company indicated that the 2023 test year included $37,771,548 of Short-Term Incentive Compensation, of which $17,432,224 or 46.15% was expensed. The Long-Term Incentive Compensation totaled $15,008,732, of which $12,770,871 was expensed. In response to OPC's First Set of Interrogatories, No. 16, the Company forecasted Short Term Incentive

Compensation expense of $25,100,218 in 2025, $25,732,973 in 2026, and $26,365,728 in 2027. Each of the years reflect a higher O&M expense than the 2023 actual amount. The Long-Term Incentive Compensation expense forecasted are $13,739,006 in 2025, $14,122,579 in 2026 and $14,506,152 in 2027.

According to MFR Schedule C-2 the Company did not exclude the Long-Term Incentive adjustment in the forecasted years consistent with the Commission adjustments reflected in MFR Schedule C-2 for the years 2023 and 2024.

Q. IS THERE A CONCERN WITH THE COMPANY'S INCLUSION OF ALL THE INCENTIVE COMPENSATION PLAN COSTS IN THE REQUESTED TEST YEARS?

A. Yes. In the past the Commission has excluded a portion of, or all of, the projected incentive compensation expense. In fact, in Docket No. 20210015-EI, Florida Power & Light Company excluded portions of executive and non-executive incentive compensation that FPL stated were excluded by the 2010 Rate Order (Order No. PSC-2010-10153-FOF-EI). The decision in the FPL Rate Order first excluded executive and non-executive incentive compensation from an above target ratio to the target ratio. The order further excluded 100% of what was defined as target executive compensation and 50% of what was identified as target non-executive compensation.

Q. IS THERE ANOTHER EXAMPLE WHERE THE COMMISSION EXCLUDED INCENTIVE COMPENSATION?

A. Yes. In the last full rate case for this company, Docket Nos. 20090079-EI, 20090144-EJ, 20090l45-El, in Order No. PSC-2010-0131-FOF-El, the Commission disallowed all of the Company's requested incentive compensation stating that "PEF should pay the entire cost of incentive compensation, as its customers do not receive a significant benefit from it."[8] It is especially noteworthy that the decision was based on the lack of customers receiving a "significant benefit," instead of by application of that standard of the lack of "any benefit."

Q. PLEASE IDENTIFY ANY ISSUES YOU HAVE WITH THE INCENTIVE COMPENSATION COSTS, PLANS OR THE ASSUMPTION THAT COSTS ARE APPROPRIATE.

A. The first issue is that while the amount of short-term incentive compensation declined each year from $83.2 million in 2021 to $51.311 million in 2022 to $37.772 million in 2023, in conjunction with the evidenced effort in this case to reverse 15 years of Commission directed non-inclusion, the Company now is projecting inclusion of the materially increased amounts of incentive compensation to $47.408 million in 2025 to $48.405 million in 2026 to $48.863 million in 2027. That equates to a 25.5% increase over the 2023 amount, which represents a revenue requirement for which there is no justification offered.

[8] Order No. PSC-2010-0131-FOF-EI, Docket Nos. 20090079-EJ, 090144-El, 090145-EI, issued March 5, 2010, at 115.

Second, adding to the concern over forecasted amounts, is the fact that the Company proposes to increase the portion of incentive compensation charged to O&M expense (and conversely decrease the amount capitalized) despite the increase of requested plant additions. This is similar to and consistent with the troubling phenomenon that I noted above relating to capitalized payroll. In 2023, the Company expensed 46.2% of short-term incentive compensation, when it had been forecasted to be 52.04%, and in the respective forecasted years 2024-2027 the percentage expense continuously increased from 52.3% up to 54.2%. These facts set the table for the disturbing potential scenario of projected levels of expensing to be reversed ***after*** rates are set and corresponding actual dollar amounts to be capitalized in the actual periods, allowing for shareholder windfalls.

Third, according to the response to OPC's First Set of Interrogatories, No. 29, from 2018 through 2023, every one of the DEF employees and DEB employees eligible for incentive compensation received an incentive compensation payment. This suggests that there is not really an incentive created for employees to perform above the day-to-day operational requirements. This is inconsistent with the very foundation underlying the very existence of incentive compensation plans: that the plan is designed to put compensation at risk and create an incentive to achieve goals that will require employees to improve operations. It is questionable that a true set of goals exists when more than 10,000 employees who were eligible for short term incentive compensation performed at such a high-level warranting payment and not one employee performed at less than award level requirements.

Fourth, the Company's argument that incentive compensation is required to attract and retain employees in the utility industry is not supported. Fifth, some employees eligible for short-term incentive also receive additional incentive compensation as part of the long-term plans. Finally, the term incentive compensation is a misnomer that has evolved over time to collect revenues from customers to pay extra compensation at the discretion of the Company.

Q. WHAT DO YOU MEAN THE TERM INCENTIVE COMPENSATION IS A MISNOMER FOR DISCRETIONARY PAY?

A. In utility regulation years ago, the issues raised with compensation revolved around the prudence of the annual forecasted increases or the level of pay of certain highly compensated employees. Subsequent to that time period, ratemaking challenges evolved to address the payment of bonuses. This, in turn, created an issue because the term bonus suggested the payment was discretionary and/or a means to pay a select group of employees added compensation. In somewhat more recent years, the issue transitioned to challenges to the payment of incentive compensation to top level employees. Again, there was a concern with the payment being discretionary and/or means to pay a select group of employees added compensation. In very recent years the phenomenon of incentive compensation being available to most, if not all of the employees of a company is increasingly predominant. This is the background that brings us to the circumstances of this case.

C27-2235

Q. WHY IS THE PAYMENT TO SOME EMPLOYEES UNDER BOTH THE SHORT-TERM PLAN AND THE LONG-TERM PLAN A CONCERN?

A. Initially, this relates to the merits of the plan alone; but the issue extends to whether it is appropriate to allow payment to a select group of employees by means of two plans. This is even more concerning when it comes to determining what is a reasonable amount of compensation. In the response to OPC's Seventh Set of Interrogatories, No. 147 it was indicated that employees who participated in both plans received $2,106,724 in the short-term plan.

Q. THE COMPANY CLAIMS THE INCENTIVE COMPENSATION IS PART OF A COMPENSATION PACKAGE THAT IS REQUIRED TO ATTRACT AND RETAIN A COMPETENT WORKFORCE. WHY DO YOU STATE THE CLAIM IS NOT SUPPORTED?

A. The Company claims that their position is supported by compensation surveys and that the compensation paid to its employees falls within a range that is reasonable. The problem lies with the circular, self-promotional nature of the structure of the surveys throughout the industry. In evaluating compensation included in the base rates of a utility, one cannot rely on studies that are not on an apples-to-apples comparison basis. Additionally, the studies referred to do not have comparable goals that truly incent employees to perform at a level over and above that upon which the employee's base compensation is determined. In response to OPC's First Request for Production of Documents, No. 9, the Company stated, "Duke Energy does not have studies in its possession that compare incentive compensation allowed in rates for its various jurisdictions." In response to OPC's Seventh Set of Interrogatories, No. 194 the Company stated it is does not consider whether the allowance or disallowance of incentive compensation occurred in other jurisdictions.

This ostrich-head-in-the-sand approach is invalid for ratemaking. Duke Energy certainly has access to the underlying information (i.e. regulators orders) for its operating utilities in Ohio, Indiana, Kentucky, North Carolina and South Carolina jurisdictions. DEF's decision to avoid doing an analysis negatively impacts its obligation to carry the burden of proof on recovery of these costs. The fact that numerous jurisdictions have excluded some or all of incentive compensation is highly relevant and for various reasons cannot be ignored when determining what is reasonable. In some cases, the costs are split in the regulators' decision, based on the conclusion that both shareholders and customers benefit, while in some cases the regulator excluded all the cost after determining that the goals are not sufficient, or the benefit is clearly for shareholder or a combination thereof. Finally, the response to OPC's Fifth Set of Interrogatories, Nos. 95 through 102, contains no market data to support the claim the Company's compensation is within the market median during the forecast years.

Q. IS THERE ANY INDICATION THAT SOME ADDED PERFORMANCE IS REQUIRED BY EMPLOYEES IN ORDER TO RECEIVE THE INCENTIVE PAYMENTS?

A. No. In my 40-plus years of analyzing bonus and incentive compensation costs and plans, the performance metrics are key and the absence of a requirement for improvement is a common problem. The bottom line is that from 2018 to 2023, not one employee under the DEF incentive compensation plan was excluded from the incentive payment because of poor performance. Essentially it is a given that the payment will be made, indicating that this is really nothing more than supplemental pay. For DEF, the goals have changed but they have not been changed to create a true incentive for performance. The short-term goal for the primary metric and trigger mechanism is Earnings Per Share ("EPS") and that is by itself clearly a problematic metric. The Company provided the scorecards for 2020 through 2022 in response to OPC's First Set of Interrogatories, No. 25. The EPS goal was $5.05, and the adjusted achieved EPS was $5.12. The minimum EPS goal for payment in 2021was $5.00. The goal was reduced from that in 2020 despite having been being achieved for the prior year. The adjusted EPS achieved in 2021 was $5.24. In 2022 the minimum for payout was set at $5.25. This represents a penny increase over the 2021 achievement. The adjusted EPS achieved in 2022 was $5.41. According to the response to OPC's Eleventh Set of Interrogatories, No. 306, the minimum payout for 2023 was set at achieving $5.45 a mere 4 cent increase. The achievement for 2023 was $5.56. The [redacted] according to OPC's First Request for Production of Documents, No. 8, qualifies employees for a payout upon the company achieving a minimum EPS of [redacted] The Company's 2023 fourth quarter Earnings Review and Business Update indicated a 2024 ADJUSTED EPS GUIDANCE RANGE of $5.85 - $6.10. Apparently, it is okay, for purposes of designing incentive compensation, to have an incentive target below the true EPS goal.

In similar fashion, another financial goal that fails to encourage improvement is found in the metric of controlling the level of O&M expense incurred. The 2021 allowed minimum requirement was increased 11.8% from the actual 2020 achievement of $4,830 million to

$5,400 million. The objective here should be to limit the minimum goal to the last achievement holding the line on expenses, but instead it allowed for increased spending. The 2022 allowed minimum O&M spending target of $5,365 million was 3.8% higher than the actual 2021 achievement of $5.166 billion. The 2022 achievement was $5,239 million. Appropriately, the Company set a minimum in 2023 of $4,790 million. That creates an incentive to reduce costs. The achievement for 2023 was $4,536 million. But in [redacted] the Company again eliminated the incentive nature of the goal by setting the minimum at [redacted], a level that allowed for payment despite increased spending. Clearly the incentive for improvement in spending control is inadequate.

Q. WHY DID YOU FOCUS ON EPS AS BEING THE PRIMARY METRIC?

A. EPS is primary since this metric is focused on providing a benefit to shareholders and it is the primary determinant in whether a payout will be made. In response to OPC's Eleventh Set of Interrogatories, No. 308 the Company stated that "The resulting STI payout level for all measures will depend on where the EPS achievement falls between the minimum EPS goal level and the circuit breaker. *If the minimum EPS goal level is not met, no STI payout for any metric will occur.*" (Emphasis added.) This clearly explains why setting the EPS goal at a level below previously achieved levels does not provide an incentive for improvement. This key point can be easily missed when evaluating what triggers the payment because companies refer to all the goals and try and persuade commissions that the other goals equally matter. The EPS determines if payment will occur and how much will be paid. The other goals are designed for the then-determined distribution (i.e., the resulting amount to be paid out). This fact also is direct evidence that payments focus on shareholders. DEF's incentive compensation is not designed to incent but is essentially guaranteed.

Q. ARE GOALS THE SAME FOR THE LONG-TERM INCENTIVE COMPENSATION PLANS?

A. No. According to the response to the response to OPC's First Request for Production of Documents, No. 8 the performance goals are set at 40% for EPS, 20% incident case and at 40% on total shareholder return. The EPS is figured on a cumulative basis for a three-year period. At a minimum the long-term plan is 80% shareholder oriented. The goals referenced are about the distribution and whether there is an award is dependent on earnings. But another element of this plan that must be considered is the fact that the compensation is paid in shares of stock. This means DEF may be asking customers to pay for an increase in equity upon which they will have to pay a return for years to come.

Q. HAS THE COMPANY JUSTIFIED THE INCLUSION OF 100% OF INCENTIVE COMPENSATION IN THE CURRENT FILING?

A. Absolutely not. The Company's attempt is no different than other utilities by claiming incentive compensation is part of a compensation package required to attract and retain competent employees, but they have not supported this claim. Typically, when an issue is raised the companies respond by saying that if we do not pay this, we will lose employees, or we will have to increase base pay. In all the years I have analyzed this issue, I have not seen a company follow through on this threat, even after a disallowance occurs when rates were being set.

Q. PLEASE EXPLAIN WHY THE SMALL INCREASE IN GOALS IN SOME OF THE YEARS CONSIDERED IS AN INDICATION THAT THE ASSOCIATED METRICS ARE NOT REASONABLE.

A. The 2022 the minimum for payout was set at $5.25, a one cent increase over the 2021 achievement. That reflects a .7% increase. As stated earlier, the level of EPS growth required for a payout of incentive compensation is significantly less than expectations for Duke Energy EPS growth expectations.

Q. YOU INDICATED THAT EPS WAS BENEFICIAL TO SHAREHOLDERS. DOES THE COMPANY DISPUTE THE BENEFIT TO SHAREHOLDERS?

A. No. Company witness Shannon Caldwell identifies EPS and Operations & Maintenance expense are financial goals. These categories are shareholder goals. Company witness Caldwell also states that EPS is a primary goal.[9]

In response to OPC's Seventh Set of Interrogatories, No. 148 the Company stated the following:

> The Committee believes that tying a portion of the STI payments to adjusted EPS aligns pay outcomes of Duke Energy's employees with the interests of shareholders and other stakeholders, including customers. When approving financial goals, the Committee reviews

[9] Prefiled Direct Testimony of Shannon Calwell at 18, lines 8-15.

> Duke Energy's financial plan, as well as the current economic and regulatory environment, expectations for investment opportunities and customer satisfaction. The adjusted EPS goal is calibrated with our publicly announced guidance range and considers industry comparisons and growth expectations to establish the threshold, target, and maximum performance levels.
>
> Broadly speaking, alignment amongst shareholders and customers is inherent in the design of Duke Energy's incentive compensation programs. There is not a divergence of interests between customers and shareholders – both shareholders and customers benefit from a financially sound and efficiently operated utility that provides safe and reliable service to customers. Our shareholders are interested not only in a financially sound company, but also customer reliability and affordability. Further, both shareholders and customers benefit from a competitive compensation package that allows Duke Energy to attract and retain a competent workforce.

There is no dispute that shareholders are beneficiaries of the payment of incentive compensation. When considering whether the payment of incentive compensation is required, it must be determined who really benefits from the plan if a benefit exists. Since EPS is the key factor and shareholders are the main beneficiary of EPS, shareholders should, at a minimum, share in the cost of the plan or absorb all the cost if there is a certainty of payment instead of a true incentive to increase earnings.

Q. ARE THERE ANY CONCERNS WITH THE INCENTIVE COMPENSATION PLANS THEMSELVES?

A. Yes. The forecast years 2025-2027 do not have goals even set at this time. As discussed earlier, the goals over the years do not provide a real incentive for improvement and since goals do not exist for the forecast years, the related costs of achieving these unknown goals are not known and measurable. The only way the payout can be assumed is if the Company continues to treat incentive compensation as a guaranteed payment to all employees. The plans cannot be incentive plans if goals do not exist for improvement in the future and the improved performance is not reflected in either cost savings or a mitigation of cost increases. The lack of goals for the projected outer years may also pose another threat to consumers. To the extent that efficiencies are not disclosed to the regulators, up-front assignment of 100% of incentive costs to customers years in advance as proposed by DEF and then establishment of unknown goals in the future to unlock those efficiencies would have a "double-whammy" effect. Customers would pay for the incentive payments and the efficiencies unlocked would only benefit the shareholders.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR INCENTIVE COMPENSATION BASED ON THE INFORMATION CURRENTLY AVAILABLE?

A. Yes. Consistent with past decisions I am recommending reductions to projected long-term plan expense of $13,379,000; $14,123,000; and $14,506,000 for the years 2025, 2026 and 2027, respectively. Projected short-term plan expense should be reduced $25,100,000 in 2025; $25,733,000 in 2026; and $26,366,000 in 2027. The adjustment is reflected on Exhibit HWS - 2, Schedule C-4.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. I excluded 100% of the projected long-term expense and 100% of projected short-term expense from my recommendation because the goals do not generate an incentive for improvement, the costs are discretionary dependent on the achievement of a shareholder goal of EPS, and there are no known and measurable goals for the forecast years.

Q. WHAT IF THE COMMSSION CONCLUDES THAT BASED ON PAST PRECEDENT, SOME INCENTIVE EXISTS FOR ALLOWING SOME COSTS?

A. If the Commission is inclined to ignore the fact that the cost cannot be known and measurable, it should consider the most recent performance and past decisions. That would mean 100% of long-term costs should be excluded and at least 50% of the short-term be excluded, in recognition that shareholders are the primary beneficiary of any improvements in operations that produce savings and performance over and above that which is expected as part of the employee's employment commitment. Another consideration the Commission should factor into their decision is the fact that beyond the benefit to shareholders for any supposed extra performance, if performance is below expectations, shareholders are held harmless because the delta of the lower payment than the amount of incentive compensation included in base rates will flow through to shareholders. Allowing any incentive in base rates is a win-win for shareholders. Past precedent coupled with the projected nature of the DEF filing requires the exclusion of 100% of short-term incentive compensation costs.

EMPLOYEE BENEFIT EXPENSE

Q. ARE THERE ANY CONCERNS THAT YOU HAVE WITH EMPLOYEE BENEFITS FORECASTED FOR THE YEARS 2025-2027?

A. Yes. The filing on MFR Schedule C-6 reflects Pensions & Benefits charged to or projected to be charged to account 926 for the years 2019-2027. The amounts for years 2019-2023 reflect actual and budgeted numbers. Actual expense ranged from a low of $859,000 in 2023 to a high of $42,059,000 in 2019. The average for the five years is $21,504,000. As shown on Exhibit HWS - 2, Schedule C-5, four of the five years, actual expense was below the budgeted amounts. The current year's budget for 2024 is $14,974,000. The forecasted expense for 2025-2027 as reflected in account 926 are $26,318,000; $42,124,000; and $59,614,000, respectively are included in the MFRs. The increases are significant and are questionable in that they lack support or rigor in their projection. In addition, the Company was requested to provide detailed breakdown of the actual and budgeted costs as reflected on MFR Schedule C-6 and in the response to OPC's Seventh Set of Interrogatories, No.146, the summary that was provided had different amounts for the 2022 and 2023 actuals.

Q. WERE YOU ABLE TO IDENTIFY WHAT CONTRIBUTED TO THE SIGNIFICANT INCREASE IN EXPENSE?

A. Yes, to some extent. In response to OPC's Twelfth Set of Interrogatories, Nos. 325 and 326, the Company was requested to reconcile the benefit cost in account 926 with the benefit costs in MFR Schedule C-35. This discovery identified the differences and provided a breakdown of costs so the driving factors to the increased costs could be identified. The actual five-year average for the credit for Pension Non-Service Costs was $35,469,617. The budgeted credit in 2024 is $46,892,561. The 2025 forecasted credit is $38,724,470, but then the projected credit in 2026 and 2027 is only $25,771,720 and 16,326,901, respectively. Increased costs in the forecast years are reflected in Employee Savings Active and Medical Active accounts as might be expected but the reduced credit is the primary driver of this balance. That reduced credit is concerning. However, when I reviewed historical costs, the increases in Employee Savings Active and Medical Active costs when compared to forecasted costs concerned me. I found the change in cost concerning, despite the expectation of some increase. Perhaps equally alarming was observing that ***allocated*** costs in the forecast years did not change.

Q. PLEASE EXPLAIN WHY THE MEDICAL ACTIVE AND EMPLOYEE SAVINGS ACTIVE COSTS ARE CONCERNING?

A. The Employee Savings Active actuals in 2022 and 2023 were $22,467,261 and $21,907,753, respectively. Based on the response to OPC's Seventh Set of Interrogatories No. 146 the budget exceeded actual by more than $6 million. Additionally, as shown on HWS Exhibit - 2 Schedule C-5, page 2 of 2, line 6 the 2019-2023 five-year average is $20,951,284 which indicates that this cost remains level and that in each of the years actual was below budget. However, the forecasted 2024 Employee Savings Active cost is $30,984,000, an increase of 41.4%. The test year projected costs then increase approximately 7% annually. Clearly the 2024 increase by all appearances is significantly excessive and serves as an inflated base for increases in the 2025-2027 test years.

The increases in Medical Active cost are similarly concerning since the forecasted 2024 increase is 19% and the respective test years projections are then increased 6.5%. The response to OPC's Seventh Set of Interrogatories, No. 146, the 2019-2023 five-year average is $34,795,032. Costs fluctuated up and down over the period and again the actual was below budget in each year. The 2024-2027 forecast does not reflect this rollercoaster effect. The Company simply assumed that after the significant 2024 forecasted increase, that constant increases would occur each year. This assumption is contradictory to the historical trend and is not supported within the filing. The budget-to-actual comparisons and the five-year averages are summarized on Exhibit HWS - 2, Schedule C-5, Page 2 of 2.

Q. WHY IS THERE A CONCERN THAT ALLOCATED COSTS DID NOT CHANGE IN THE FORECASTED TEST YEARS?

A. The concern is that DEF is requesting an increase in rates from customers, but they use a plug number for costs apparently because the amounts are not known and measurable. This is similar to the problematic assumption discussed above where the number of employees in the forecast is assumed to go unchanged and is not known when budgeting the payroll costs. The fact that costs and numbers are not known and measurable should be a grave concern to the Commission when assessing the reasonableness of the multiple test years.

C27-2247

Q. DID YOU IDENTIFY ANY OTHER CONCERNS IN REVIEWING THE DETAIL IN THE RESPONSE TO OPC'S TWELFTH SET OF INTERROGTORIES, NO. 325 AND 326?

A. Yes. The level of O&M expense in account 926 for employee benefits as shown on MFR C-4 are only a small portion of what is charged to O&M and similar to payroll the percentage allocated to O&M is increased (resulting in undercapitalization) in the forecast years when compared to the historical periods.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO EMPLOYEE BENEFITS?

A. Yes. As shown on Exhibit HWS - 2, Schedule C-5, Page 1 of 2, I am recommending a reduction to the projected expenses in the amount of $4.694 million to employee benefit expense in 2025, $5.920 million in 2026, and $7.248 million in 2027. The adjustment is a basic flowthrough of my recommended payroll adjustment based on the percentage of benefit expense to payroll expense as reflected in the filing. This adjustment is conservative based on the DEF's budgeting issues. The adjustment is based on the O&M employee benefits expense as reflected in the response to OPC's Twelfth Set of Interrogatories No, 326 excluding the payroll tax portion.

CONTRACTOR COSTS

Q. IS THERE A CONCERN WITH CONTRACTOR COSTS INCLUDED IN THE FILING?

A. Yes. The Company was requested to provide details on the Distribution contractors as discussed in Brian Lloyd's testimony. The supplemental response to OPC's Seventh Set of Interrogatories, No. 164 states: "For the years 2025-2027, contractor costs for Capital & O&M cannot be determined because the projections are not produced at that level of detail." This is concerning since the O&M dollars for 2022 and 2023 were $33,808,856 and $19,318,633, respectively. The amounts are significant and the forecasted cost for 2025-2027 are assumed to have some level of contractor costs included. It is not appropriate to assume future costs exist for ratemaking purposes when you cannot identify the level of costs and you have no justification for those costs. The O&M actual costs fluctuated every year 2019-2023. The actual average distribution O&M contractor costs for 2022 and 2023 is $26,563,745. The 2024 forecasted base rate expense is $31,025,167. Following similar Company assumptions that the projected 2025-2027 amounts are the same as the projected 2024 numbers (i.e. employee count, affiliate costs) it is assumed that in each of the years 2025-2027, the minimum included by DEF in its request for distribution contractor O&M expense is $31,025,167. Based on DEF's lack of detail in the forecasted dollars I am recommending a $4,461,423 reduction to projected distribution contractor O&M expense. This is the difference between the historical two-year average of $26,563,745 and the 2024 projected cost of $31,025,167.

Q. WHY DID YOU USE A TWO-YEAR AVERAGE INSTEAD OF YOUR TYPICAL USE OF A LONGER AVERAGE?

A. The distribution costs for 2019-2021 reflected costs now shifted to the SPP Clause. However, if I were to factor in the 2019-2021 costs to make an apples-to-apples comparison, I would have to offset those costs by SPP costs. Using the average SPP costs for 2022 and 2023 as an offset to the 2019-2021 average costs would result in approximately the same adjustment.

Q. IS THE LACK OF DETAIL FOR THE TEST YEARS 2025-2027 COMMON?

A. As discussed in various sections of my testimony, DEF has reflected the exact same amounts in each of the test years for various types of costs because information was not available in planning. That deficiency or weakness on DEF's part should not be the regulator's problem. Some other examples are the responses to OPC's Thirteenth Set of Interrogatories, Nos. 336 and 337 where the Company stated that forecasted contractor cost information is not available for 2025-2027 for distribution maintenance and transmission maintenance. Essentially DEF's forecasted cost recovery request to the Commission and customers is "do not worry what costs we are asking you to pay, just trust us and pay them."

SERP

Q. HAS THE COMPANY REQUESTED RECOVERY OF SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN?

A. Yes. Based on the response to OPC's First Set of Interrogatories, No. 32 the Company is including $2,949,042 for recovery of Supplemental Executive Retirement Plan ("SERP") costs in base rates.

Q. WHAT IS SERP?

A. SERPs are non-qualified deferred compensation plans offered to a company's key employees, typically high-ranking officials such as CEOs, CFOs, and other C-suite executives. Unlike qualified retirement plans (such as 401(k)s), SERP contributions are not tax-deductible when made by the employer. However, employers generally will receive a tax deduction for SERP contributions when the benefits become taxable to the executive. While the company does not get an immediate tax benefit for contributing to a SERP, it can deduct the contributions later when the executive receives the benefits. This treatment is because it is a special way of compensating select employees.

Q. WOULD YOU AGREE THAT EXCLUSION OF SERP IS A NORMAL COMMISSION ADJUSTMENT MADE WHEN A COMPANY FILES ITS REQUEST?

A. Yes. In fact, the Company was reflecting the exclusion from the cost of service for the years 2023 and 2024 on Company Schedule C-2. The testimony of Marcia Olivier states that Long-Term Incentive Plan costs and SERP costs were excluded in the 2017 settlement, but that DEF now believes they are legitimate expenses, and the direct testimony of Shannon Caldwell will further explain the costs. In review of Shannon Caldwell's testimony, I could not locate any discussion on SERP.

Q. ARE YOU AWARE OF ANY DETAIL OF THE PLAN FOR DEF?

A. Yes. The response to OPC's First Set of Interrogatories, No. 32 states the plan is closed to new employees hired after December 31, 2013, and eligibility is limited to "Employees who are members of a select group of management or highly compensated employees" that qualify under ERISA may participate in the Plan. The plan currently provides benefits to 134 active employees with ECBP balances (Duke Energy Florida: 3; Duke Energy Business Services: 71; All others: 60). The purpose of the plan is to provide additional retirement benefits to all highly compensated employees whose benefits under the Retirement Plan were restricted by IRS limitations. With this plan, the limitations apply to all Company employees who are not a select group.

Q. IS THE COST A LEGITIMATE EXPENSE FOR INCLUSION IN BASE RATES?

A. No. The costs for SERP are over and above the allowable normal retirement plan contributions provided for all employees. This is an added cost that is consider excessive compensation and should not be the responsibility of customers. If shareholders believe the costs are appropriate, then they should be responsible for the costs.

Q. WHAT ARE YOU RECOMMENDING FOR TREATMENT OF SERP COSTS?

A. I am recommending that O&M expense be reduced $2,949,042 in each of the years 2025-2027.

DIRECTORS & OFFICERS LIABILITY INSURANCE

Q. IS THE COMPANY REQUESTING DIRECTORS & OFFICERS LIABILITY INSURANCE?

A. Yes. The responses to OPC's First Set of Interrogatories, No. 4 and OPC's First Set of Interrogatories, No. 51 identified different Directors & Officers Liability Insurance ("D&O") expense for the forecast years 2025-2027. The response to OPC's Eleventh Set of Interrogatories, No. 295 stated that the response to OPC's First Set of Interrogatories, No. 51 is the accurate information for what is included in the Company's request. The amount requested is $2,998,000 in each of the respective years. The history of this cost is summarized on Exhibit HWS - 2, Schedule C-6.

C27-2253

Q. WHAT IS THE PURPOSE OF D&O INSURANCE?

A. D&O insurance is designed to protect directors and officers from decisions they make that are determined to be bad decisions or decisions of a questionable nature. In my experience the only claims made necessitating this coverage are made by shareholders.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO D&O INSURANCE EXPENSE?

A. I am recommending that the entire cost of $2,998,000 be excluded from rates since this cost provides no benefit to customers.

Q. ARE YOU AWARE OF THIS BEING ADDRESSED IN PREVIOUS RATE CASES IN FLORIDA?

A. Yes. I addressed this issue in Docket No. 20090079-EI. In the Progress Energy Florida ("PEF") case, the Commission allowed PEF to place one half the cost of DOL insurance in that single test year's expenses while noting that other jurisdictions have made an adjustment for DOL insurance and that the Commission had disallowed DOL insurance in wastewater cases.[10]

[10] Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket Nos. 20090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc. at p. 99.

Q. IF THE COMMISSION DISALLOWED HALF THE COST IN THE PEF DOCKET, WHY ARE YOU RECOMMENDING A TOTAL DISALLOWANCE IN THIS CASE?

A. I am recommending to the Commission that there be a complete disallowance or -- at the very least -- an equal sharing because the cost associated with DOL insurance benefits shareholders first and foremost. As explained earlier, the benefit of DOL insurance is the protection shareholders receive from directors' and officers' imprudent decision making. The benefit of this insurance clearly inures primarily to shareholders; some of whom generally are the parties initiating any suit against the directors and officers.

RATE CASE EXPENSE

Q. WHAT HAS THE COMPANY INCLUDED IN RATE CASE EXPENSE FOR THIS RATE CASE?

A. According to Company MFR Schedule C-2 the DEF is requesting $874,000 of amortization for each of the years 2025-2027.

Q. ARE THERE CONCERNS WITH THE AMOUNT REQUESTED?

A. Yes. According to MFR Schedule C-10, the requested test year costs of $2,623,000 are to be amortized over three years. The cost consists of $2,159,099 of outside consultants' costs and $463,873 of costs identified as various. The detail on the cost is of major concern. For example, there is $305,000 included for the test year dismantlement study and $97,106 for a depreciation study as outside consulting costs. Added to that are various Depreciation/Dismantlement Study costs of $51,395. The legal costs requested are $1,600,247 or 61% of the request. Clearly the requested costs are excessive, and they completely lack in support and justification.

Q. WHAT ARE YOU RECOMMENDING?

A. I am recommending the entire cost of the case be excluded reducing the annual expense by $874,000. The cash working capital would then be reduced $2,392,000 in 2025, $1,625,000 in 2026 and $751,000 in 2027.

Q. WHY SHOULD ALL THE COSTS BE EXCLUDED FROM RECOVERY?

A. The purpose of the filing is to increase rates so shareholders can earn a reasonable return. Clearly the primary beneficiary of this rate case is shareholders, and they should be responsible for the cost. Additionally, the results of my analysis demonstrate that DEF is not entitled to any rate increase for the years 2025 and 2026. Furthermore, no rate increases for the second and third years should be allowed for a variety of reasons including remoteness. These two elements of the case as filed further indicate that customers should not pay for the litigation costs of an unnecessary, inappropriate filing.

C27-2256

UNCOLLECTIBLE EXPENSE

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO DEF'S UNCOLLECTIBLE FACTOR?

A. Yes. The Company has proposed a different uncollectible rate in each of the years 2025-2027. The projected rates applied adjusted to projected gross revenues are .282% in 2025, .309% in 2026, and .338% in 2027. It is impossible for the Company to know what the rate will be in the respective years. On Exhibit HWS - 2, Schedule C-8, I have reflected the actual net bad debt factor by year from 2018-2023. The Company recognized the years 2022 and 2023 are an anomaly and have reflected a lower rate. The years 2018-2021 show a relatively consistent uncollectible rate. The 2002 and 2023 rate is reflective of significant difference attributable to the COVID impact on collections. On line 8 of my schedule, I have calculated the four-year average for 2018-2021 of .258% that reflects a more normal rate. Applying the .258% to the as filed, adjusted projected gross revenue results in a reduction of $1.294 million in 2025, $2.786 million in 2026, and $4.320 million in 2027. With the recommended level of revenue in the years 2025-2027, a second adjustment increasing expense of $243,000 in 2025, $284,000 in 2026, and $351,000 in 2027 should be made.

PAYROLL TAX EXPENSE

Q. WILL YOUR RECOMMENDED ADJUSTMENT TO PAYROLL IMPACT PAYROLL TAX EXPENSE?

A. Yes. On Exhibit HWS - 2, Schedule C-5, I have calculated a reduction to projected payroll tax expenses of $3,986,000 in 2025, $4,185,000 in 2026, and $4,376,000 in 2027. The adjustment is a simple flowthrough of my recommended payroll adjustment and incentive compensation adjustment. I determined the effective payroll tax expense rate in each of the respective years 2025-2027 by dividing the test year payroll tax expense on line 2 by the total of O&M payroll costs expensed on line 1 in the respective test years. I then applied the effective rate to the total recommended adjustment to payroll expense as shown on line 6.

GAIN ON DISPOSITION

Q. IS THERE AN ISSUE WITH WHAT THE COMPANY HAS REFLECTED AS A GAIN FROM DISPOSITION?

A. Yes. The gain from disposition reflected on MFR Schedule C-1 is $1,323,000 for 2025, $1,137,000 for 2026 and $982,000 for 2027. The Company has understated its projection in the respective years 2025-2027 based on historical actuals. As shown on Exhibit HWS - 2, Schedule C-9, the three-year average gain on dispositions was $3,407,000. The Company forecasted $1,339,000 for 2023 yet the actual was $3,012,000 so it is evident the forecasted amounts are understated.

C27-2258

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A. The recommended adjustments are $2,084,000 in 2025, $2,270,000 in 2026, and $2,425,000 in 2027.

DEPRECIATION EXPENSE

Q. WOULD YOU EXPLAIN HOW YOU REFLECTED MR. DUNKEL'S REVISIONS TO DEPRECIATION RATES?

A. Yes. OPC witness William Dunkel provided me his revised depreciation rates for the different types of historical and projected production plant and energy storage balances. On HWS Exhibit - 2, Schedule C-9, Page 5 of 5, I summarized the production information to base production, intermediate, peaking and solar. For each category an overall average rate was calculated. The average rates were then applied to the 13-month average for the respective production categories as reflected in DEF's MFR Schedule B-7 and for energy storage. The respective calculations are reflected on HWS Exhibit - 2, Pages 2, 3, and 4 of 5. The calculated result reduces projected depreciation expense $74,016,00 in 2025, $72,511,000 in 2026, and $70,358,0000 in 2027 on a jurisdictional basis.

Q. WHY DOES YOUR ADJUSTMENT TO DEPRECIATION DECREASE EVEN THOUGH THE PLANT AVERAGE INCREASED?

A. It is not clear to me how the amount identified by DEF on MFR Schedule C-4 changed with respect to the change in plant. In doing the calculation of Citizens' recommended depreciation expense, it is a simple plant average multiplied by the respective category rate. The same does not hold true with the Company's expense. As an example, the December 31, 2027, the projected 13-month average plant of $7,168,983,000 for Base Production multiplied by the proposed Company rate of 4.51% for Base Production equals $323,321,000. According to DEF MFR Schedule C-4 the depreciation is $325,973,000. Even separately applying the different plant balances within the Base Production category does not calculate to the expense reflected on MFR Schedule C-4.

Q. SHOULD THIS PHENOMENON INFLUENCE WHETHER THE ADJUSTMENT IS MADE?

A. No. The calculation using the OPC's recommended rates produces a result based on the Company's requested additions as shown in MFR Schedule B-7. The adjustment to the amount reflected by DEF in the filing results in the OPC's recommended expense.

Q. HOW DOES THE ADJUSTMENT IMPACT RATE BASE?

A. On HWS Exhibit -2, Schedule C-10, Page 1 of 5, the respective adjustments to accumulated depreciation are reflected on line 7. Projected accumulated depreciation is reduced $37,008,000 in 2025, $110,272,000 in 2026, and $181,707,000 in 2027, on a jurisdictional basis. The adjustment to 2025 is based on 50% of the depreciation expense to reflect an average. The 2026 adjustment includes $74,016,000 from 2025 and 50% of the $72,511,000 expense adjustment for 2026. The 2027 adjustment is the $74,016,000 from 2025 plus the $72,511,000 expense adjustment for 2026 plus 50% of the $70,358,000 2027 expense adjustment. These percentages are consistent with the forecasted plant adjustment I recommended above.

Q. ARE THERE OTHER ADJUSTMENTS TO DEPRECIATION EXPENSE BEYOND THE PLANT ADJUSTMENTS DISCUSSED EARLIER?

A. Yes. Based on the testimony and analysis of Mr. Dunkel, I have recalculated the depreciation expense by applying an overall composite depreciation rate to my recommended annual plant adjustment. As shown on Exhibit HWS - 2, Schedule C-11, projected depreciation expense should be reduced $32,034,000 in 2025, $46,463,000 in 2026, and $48,554,000 in 2027. The change to accumulated depreciation is reflected on Exhibit HWS - 2, Schedule B-2, Page 2 of 2. Projected accumulated depreciation is reduced $25,543,000 in 2025, $64,792,000 in 2026, and $112,300,000 in 2027.

PROPERTY TAXES

Q. IS THERE AN ISSUE WITH THE FORECASTED PROPERTY TAXES AS REFLECTED IN THE FILING?

A. Yes. Property taxes in 2023 were $146.905 million and the forecasted 2024 amount increased $41.770 million to $188.675 million. The response to OPC's First Set of Interrogatories, No. 47 indicates that the average tax rate declined from 2018 to 2022, then increased from 1.481% in 2022 to 1.521% in 2023. Beginning with 2024, the projected average tax rate increases by 4.799% to a rate of 1.594%. For each of the forecasted test years 2025-2027, the projected rate exceeds 1.606%. Similarly, the taxable value forecasted in 2024 is 19.765% higher than the 2023 taxable value compared to a cumulative five-year increase from 2018 through 2023 of 19.169%. A one-year increase that exceeds the increase over a 5-year period is clearly excessive and unreasonable. The 2024 increase in taxable value of 19.765% exceeds the 9.279% increase in Net Plant in Service based on MFR Schedule B-1. The Company's forecasted taxable values and average tax rates are contrary to historical levels and are not justified.

Q. WHAT ARE YOU RECOMMENDING FOR PROPERTY TAX EXEPNSE?

A. Two adjustments are required. First as shown on Exhibit HWS - 2, Schedule C-12, Line 6, is an adjustment to reflect our recommended adjustment to plant. This reduced projected property taxes $5,731,000 in 2025, $12,052,000 in 2026, and $8,679,000 in 2027. The proposed adjustment is based on the ratio of the forecasted tax increase to forecasted plant as shown on line 4 applied to Citizens recommended plant adjustment as shown on line 5. The second adjustment is to reflect the property tax rate based on the 2023 average tax rate. This adjustment applies the difference between: (1) the Company's estimated tax rate identified in the response to OPC's First Set of Interrogatories, No. 49 and (2) the 2023 DEF average tax rate of 1.521% applied to DEF's estimated taxable value provided in the response to OPC's First Set of Interrogatories, No. 50. The respective reduction to the projected amounts as shown on Line 10 are $10,525,000 in 2025, $18,705,000 in 2026, and $12,884,000 in 2027 are appropriate after making a prorate of the plant adjustment to avoid any duplication. This is considered conservative since the adjustment starts with DEF's forecasted taxable value that appears to be excessive because 2025-2027 are developed from off the extraordinary 2024 increase. The 2024 forecasted taxable value of

$11,735,821,413 is $1,936,810,074 higher than the 2023 taxable value of $9,799,011,339. That single year increase is 23% higher than the five-year increase of $1,576,252,067 from 2018-2023.

Q. HOW IS IT THAT YOUR COMBINED RECOMMENDED ADJUSTMENT IS GREATER THAN DEF'S INCREASES IN 2026 AND 2027?

A. If the adjustment were only based on the use of the lower tax rate, that alone would be less than the Company's forecasted increase. Since the adjustment also includes a reduction to plant, that accounts for the added reduction. The projected increases by the Company for the years 2025-2027 are derived after the extraordinary increase in 2024. The taxable values utilized by DEF for 2025-2027 followed the extraordinary increase in 2024. The 2023 property taxes were $146,905,000. Applying the 2023 tax rates of 1.521% to the Company's estimated taxable value as shown on Line 11 of Exhibit HWS - 2, Schedule C-12, the recommended taxes would be $193,712,000 in 2025, $208,509,000 in 2026, and $230,839,000 in 2026.

DISMANTLEMENT EXPENSE

Q. WOULD YOU EXPLAIN YOUR ADJUSTMENT TO DISMANTLEMENT EXPENSE?

A. Yes. OPC witness William Dunkel analyzed the Company's request for increasing its amortization expense for dismantlement. Mr. Dunkel is recommending that the projected increase in amortization of $34,108,049 as reflected in Company Exhibit No. JTK-2 be reduced to $9,792,515. As shown on Exhibit HWS-2, Schedule C-13, I have reflected that adjustment. In addition, I have identified an added reduction of $698,000 in 2025, $3,822,000 in 2026, and $5,744,000 in 2027 to DEF's projected amounts. The total adjustment is $25,013,000 in 2025, $28,137,000 in 2026, and $30,059,000 in 2027 is reflected on Line 17 of Exhibit HWS - 2, Schedule C-13.

Q. WHY ARE YOU PROPOSING AN ADDITIONAL ADJUSTMENT?

A. The Company's study indicates an adjustment of $13,510,000 to the $20,597,000 currently reflected in the 2024-2027 forecasted amount. In reviewing the filing, MFR Schedule C-2 shows an amortization adjustment for the dismantlement study of $14,208,000 in 2025, $17,332,000 in 2026, and $19,254,000 in 2027. The amounts are higher than the $13,210,000 requested by DEF so the difference is considered unsupported and should be excluded.

INFLATION ADJUSTMENT

Q. WHY ARE YOU RECOMMENDING AN INFLATION ADJUSMENT?

A. The response to OPC's Twelfth Set of Interrogatories No. 320 stated that "at the direction of senior management" a 3% inflation was added to base recoverable costs. The inflation adder reflected in the response in each respective year is more than 3% presumedly because the base recoverable, while not fixed, is the cumulative increase beginning with 2024. The increase between 2025 and 2026 is $14 million. Similarly, the increase between 2026 and 2027 is also $14 million. In evaluating the adder amount it is assumed that in 2024 the adder is $14 million. The issue is that the Federal Planning Bureau is forecasting a 2% CPI-U inflation factor for 2025. With all the existing uncertainty with forecasted costs and lack of specifics an excessive inflation adder only heightens the concern with the request.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A. As shown on Exhibit HWS-2, Schedule C-14 I am recommending that projected O&M expense be reduced $4,365,000 in 2025, $4,478,000 in 2026 and $4,594,000 in 2027. The adjustments are determined by multiplying the annual increase in the adder amount by a negative 33.33% (the reduction from 3% to 2%) and then prorating the result by the ratio of the O&M expense amount from MFR Schedule C-1 to what DEF identified as the as filed amount in the response to OPC's Twelfth Set of Interrogatories No. 320. The prorating was done because I could not reconcile what MFR Schedule C-1 identified as Other Operation and Maintenance Expense and the as-filed amount in the response.

C27-2265

INCOME TAXES

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO INCOME TAX EXPENSE?

A. On Exhibit HWS - 2, Schedule C-15 I have increased projected income tax expense $81,184,000 associated with the $320,315,000 increase in projected operating income in 2025. Projected income taxes increased $94,325,000 in 2026 and $101,039,000 in 2027. Additionally, I am recommending an annual reduction of $11,284,000 ($10,383,000 jurisdictional) to income tax expense to reflect the impact of Rule 25-14.004 Effect of Parent Debt on Federal Corporate Income Tax.

Q. HAS THE COMPANY REFLECTED THE EFFECT OF PARENT DEBT ON FEDERAL CORPORATE INCOME TAX COMPONENT OF THE REVENUE REQUIREMENT?

A. No, DEF has not reflected the Parent Debt Adjustment ("PDA") in its rate filing. According to DEF witness Newlin, the Commission's current Rule 25-20 14.004, F.A.C. requirement to address whether or not a parent debt adjustment should be computed to adjust the Company's revenue requirement should not be followed because he feels that the rule is obsolete and because the rule does not reflect the way regulated utilities like DEF now calculate income tax. The witness explains that the existing rule imputes the tax effect of parent interest that may never be deductible by the subsidiary for tax purposes because prior to making the parent debt tax adjustment, the utility is making an interest reconciliation adjustment to recognize the interest that is inherent in the utility's FPSC-

C27-2266

adjusted capital structure. These opinions do not reflect an understanding of the way the rule operates. I would note that it does not appear that the Company filed for a waiver of the rule, so the witness's feelings about the rule do not seem to be relevant.

Q. PLEASE EXPLAIN WHY THE ADJUSTMENT IS APPROPRIATE.

A. This adjustment is standard adjustment in a Florida rate filing. Rule 25-14.004 requires the Company to reflect the income tax expense of the parent debt that is presumed to be invested in the equity of the subsidiary where the parent-subsidiary relationship exists, and the parties join in the filing of a consolidated return. The adjustment is necessary since the Company is not a stand-alone company and customers are required to pay a return on the investment by the parent company in DEF. Under the Company's assumption, there is no equity investment by the parent company.

In fact, the PDA information on MFR Schedule C-24 suggests that the parent's equity has declined from a positive of $13,838,085,000 as of December 31, 2023, to a negative equity of $3,523,977,000 as of December 31, 2027. I find it very interesting how this change could occur. The presentation essentially assumes that beginning in 2024, the parent company's investment in its subsidiaries is exceeded by the subsidiaries retained earnings. DEF has reflected Parent Debt Adjustments of $10,801,000 ($9,984,00 jurisdictional) in 2023 and $11,284,000 ($10,383,000 jurisdictional) in 2024 to income tax expense. The weighted cost of parent debt is shown on MFR Schedule C-24, but the schedule does not provide the calculation of the adjustment itself. An attempt to recalculate the parent debt amounts reflected on MFR Schedule C-2 was not successful. In reviewing the excel version of MFR

Schedule C-2, I found the formula for calculating the debt amount referenced documents that I could not locate.

Q. WHAT ARE YOUR CONCERNS WITH WHAT DEF HAS INCLUDED IN THE FILING WITH RESPECT TO THE PARENT DEBT CALCULATION AND INFORMATION SUPPLIED?

A. As discussed earlier, there is no documentation supporting how the parent equity went from a positive to a negative. The actual calculations could not be reviewed at the time of my testimony finalization to determine the reasonableness of the amounts shown in 2023 and 2024.

Q. DO YOU AGREE THAT DEF HAS REBUTTED THE PRESUMPTION THAT THE DEBT OF THE PARENT (DUKE ENERGY) IS INVESTED IN THE EQUITY OF DEF?

A. No. As stated earlier DEF suggests that it has rebutted the presumption by making an unsupported claim that its capital structure is reflective of its stand-alone position and that parent investment is not financing the Company. This assertion does not meet the test of the rule which states in subsection (3) that:

> It shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.

This also is rebutted by the Company witness Karl Newlin when he refers to the benefits of Duke Energy's Master Credit Facility and how that results in DEF being able to borrow at a lower rate than would otherwise be available to DEF as a stand-alone issuer.[11] Mr. Newlin also states that DEF benefits from operational efficiencies from the shared corporate services.[12] Clearly this would not be available to DEF absent the investment in DEF by Duke Energy.

The company's bare claim fails this test. The original investment in DEF was made by Duke Energy and despite the changes to equity through earnings, added investments, and the payment of dividends, Duke Energy remains the equity holder of the Company. Any transactions between the parent and subsidiary for the period Duke Energy invested in DEF and the test year, does not eliminate the fact that the initial investment of Duke Energy in DEF contains a portion of the debt that is embedded in Duke Energy's capital structure.

Q. COMPANY WITNESS KARL NEWLIN STATES AT PAGE 24 THAT THE COMMISSION RULE DOES NOT RECOGNIZE RETAINED EARNINGS OF ITS SUBSIDIARIES. DO YOU AGREE WITH THAT CLAIM?

A. No. This assertion ignores the rule which states in subsection (3) that:

> The capital structure of the parent used to make the adjustment shall include at least long term debt, short term debt, common stock, cost free capital and investment tax credits, excluding retained earnings of the subsidiaries.

[11] Direct testimony of Karl Newlin at page 21.
[12] Id. at page 22.

Clearly, the rule requires excluding retained earnings of the subsidiaries in making the calculation for the adjustment.

Q. HAVE YOU DETERMINED AN ADJUSTMENT FOR THE PARENT DEBT?

A. Yes. As discussed above, I am recommending a reduction to projected income tax expense of $11,284,000 ($10,383,000 jurisdictional) to each of the years 2025-2026 based on the 2024 adjustment made by DEF on MFR Schedule C-2 to income tax expense.

Q. WHY ARE YOU USING THE 2024 ADJUSTMENT FOR THE YEARS 2025-2027?

A. The information to verify and/or make the calculation could not be located in the filing. The use of the 2024 amount as a surrogate is similar to DEF's practice for a number of forecasted costs in the filing for the test years 2025-2027. The only difference is DEF has information available to make the adjustments, but I do not have similar access. This adjustment is subject to revision as information becomes available in the case.

VII. CAPITAL STRUCTURE

Q. DO YOU HAVE ANY ADJUSTMENTS TO DEF'S PROPOSED CAPITAL STRUCTURE?

A. Since OPC witness Lawton accepted the proposed capital structure for purposes of his analysis, I do not reflect any adjustments to the capital structure. The capital structure as reflected in Exhibit HWS – 2, Schedule D has been adjusted for the reconciliation of rate base to capital structure factoring in Citizens' recommended adjustments. Below, I reflect the proper interest synchronization adjustment necessitated by the reconciliation of projected rate base and projected capital structure.

INTEREST SYNCHRONIZATION

Q. PLEASE EXPLAIN THE INTEREST SYNCHRONIZATION ADJUSTMENT.

A. Because rate base changes occur, the amount of estimated interest for tax purposes changes. That change, along with changes in the interest rate for financing rate base, impacts income taxes. As shown on Exhibit HWS - 2, Schedule C-16, my recommended reduction to rate base results adjusts OPC witness Daniel Lawton's capital structure increasing the interest deduction. Factoring in the Company adjustment for interest synchronization, the result is an increase to income tax expense of $13,012,000 in 2025, $14,831,000 in 2026, and $15,020,000 in 2027.

Q. Does this conclude your direct testimony?

A. Yes, it does at this time. Because of the limited time allowed to review a filing that the Company has significantly more time to assemble, there may be a need to supplement. As noted earlier the Company's filing of a Notice of Identified Adjustments may have an effect on my analysis and recommendations. The timing of this notice made it impossible to reconcile the notice with the filing and extensive discovery. I will review the Notice of

Identified Adjustments, and, if warranted, file supplemental testimony incorporating the impact.

C27-2272

June 26, 2024

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

Re: Docket No. 20240025 - EI

Dear Mr. Teitzman,

Please find enclosed for filing in the above referenced docket three pages of revised testimony and one revised exhibit of the Direct Testimony and Exhibits of Helmuth W. Schultz, III, filed by OPC on June 11, 2024. None of the revised pages of testimony or the revised exhibit contain information previously redacted as confidential by DEF on June 21, 2024.

To summarize, the revisions to Mr. Schultz's testimony and exhibit include:

1) Testimony:
   a. Page 5, Line 21;
   b. Page 6, Lines 5-6, and 11; and
   c. Page 73, Lines 14-15.

2) Exhibits
   a. Various numbers throughout Exhibit HWS-2.

The revisions to the testimony are underlined but not highlighted in order avoid confusion about whether the revisions were confidential. As for the revisions to Exhibit HWS-2, since the revisions impacted (in a small way) several of the values in some schedules, OPC thought it best to provide a complete copy of revised HWS-2, rather than just the individually revised schedules. The revised schedules within HWS-2 are highlighted where any revisions have been made in order to clearly identify which numbers have been revised; however, nothing in either the original or revised HWS-2 was previously redacted as confidential by DEF. The word "Revised" was also added to the top of each revised page of testimony and all of the pages of Exhibit HWS-2 for clarity.

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

Sincerely,

Walter Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No. 93590

III. ORGANIZATION OF TESTIMONY

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. In Section IV, without conceding the appropriateness of the 2026 and 2027 test years for establishing rates, I present the overall financial summary for the base rate change, showing the revenue requirement increase (decrease) for the test years ended December 31, 2025, December 31, 2026, and December 31, 2027, on behalf of OPC and the customers of DEF. In section V, I discuss Citizens' proposed adjustments to rate base. In section VI, I discuss Citizens' adjustments to operating income. In Section VII, I discuss the capital structure. Exhibit HWS-2 presents the schedules and calculations in support of the respective test years ended December 31 revenue requirement. Exhibit HWS-3 is a compilation of discovery responses referenced in my testimony. Exhibit HWS-4 is a 1986 Staff Memorandum that I reference in my testimony.

IV. OVERALL FINANCIAL SUMMARY

Q. WHAT IS THE DECEMBER 31, 2025, BASE RATE REVENUE REQUIREMENT DEFICIENCY OR EXCESS FOR DEF?

A. As shown on Exhibit HWS-2, Schedule A, Page 1 of 3, based on the information provided by DEF as of the date of development of my testimony, the OPC's appropriate adjustments in this case result in a revenue sufficiency of at least $26,745 million for DEF for the

to reconcile the notice with the filing and extensive discovery. I will review the Notice of Identified Adjustments, and, if warranted, file supplemental testimony incorporating the impact.

C27-2272c

December 31, 2025. This eliminates the proposed base rate revenue increase of $593.446 million requested by DEF in its filing. Exhibit HWS-2, Schedule A, Page 2 of 3, is shown on a contingent basis and under protest given the OPC position about the legality of the second projected test year being entertained by the Commission and reflects the OPC's appropriate adjustments in this case resulting in a revenue sufficiency of <u>$13.314</u> million in 2026, which is <u>$704.660</u> million less than the $691.346 million requested by DEF. Finally, Exhibit HWS-2, Schedule A, Page 3 of 3, is shown on a contingent basis and under protest given the OPC position about the legality of the third projected test year being entertained by the Commission and reflects the OPC's appropriate adjustments in this case that limit the allowable revenue increase for DEF for the December 31, 2027, test year to no more than <u>$87.472</u> million. This is <u>$732.473</u> million less than the proposed base rate revenue increase of $819.945 million requested by DEF in its filing and significantly less than the $2.105 billion, three-year cumulative revenue collection proposed by DEF.

Q. **DO YOU MAKE ADJUSTMENTS TO THE 2026 AND 2027 PROJECTED TESTS YEAR THAT COULD YIELD A POSITIVE REVENUE REQUIREMENT ABOVE CURRENT REVENUES?**

A. Yes.

C27-2272d

reflected in Exhibit HWS – 2, Schedule D has been adjusted for the reconciliation of rate base to capital structure factoring in Citizens' recommended adjustments. Below, I reflect the proper interest synchronization adjustment necessitated by the reconciliation of projected rate base and projected capital structure.

INTEREST SYNCHRONIZATION

Q. PLEASE EXPLAIN THE INTEREST SYNCHRONIZATION ADJUSTMENT.

A. Because rate base changes occur, the amount of estimated interest for tax purposes changes. That change, along with changes in the interest rate for financing rate base, impacts income taxes. As shown on Exhibit HWS - 2, Schedule C-16, my recommended reduction to rate base results adjusts OPC witness Daniel Lawton's capital structure increasing the interest deduction. Factoring in the Company adjustment for interest synchronization, the result is an increase to income tax expense of <u>$12,787,000</u> in 2025, <u>$14,801,000</u> in 2026, and <u>$14,991,000</u> in 2027.

Q. Does this conclude your direct testimony?

A. Yes, it does at this time. Because of the limited time allowed to review a filing that the Company has significantly more time to assemble, there may be a need to supplement. As noted earlier the Company's filing of a Notice of Identified Adjustments may have an effect on my analysis and recommendations. The timing of this notice made it impossible to reconcile the notice with the filing and extensive discovery. I will review the Notice of

C27-2272e

(Whereupon, prefiled direct testimony of David Fialkov was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	))))	DOCKET NO. 20240025-EI

TESTIMONY OF DAVID FIALKOV

ON BEHALF OF AMERICANS FOR AFFORDABLE CLEAN ENERGY, INC.,

CIRCLE K STORES, INC., RACETRAC, INC., AND WAWA, INC.

JUNE 11, 2024

DIRECT TESTIMONY OF DAVID FIALKOV

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David Fialkov, 1330 Braddock Place, Suite 501, Alexandria, VA 22314

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Americans for Affordable Clean Energy, Inc. ("AACE"), Circle K Stores, Inc. ("Circle K"), RaceTrac Inc. ("RaceTrac"), and Wawa, Inc. ("Wawa") (collectively, the "Fuel Retailers").

Q. What issues are you addressing in this proceeding?

A. I am addressing AACE's associational standing in this rate case and the individual ratepayer standing of Circle K, RaceTrac, and Wawa. Additionally, I am addressing the proposed Electric Vehicle Make Ready Infrastructure Program and whether the rates, terms, and conditions that Duke Energy proposes to charge third party EV charging fuel retailers are such that they can be reasonable and economically offer third party EV charging to the public.

Q. What are AACE's interests in this proceeding?

A. **AACE.** AACE is an established nonprofit association of fuel retailers that includes Circle K, RaceTrac, and Wawa, each of which is also intervening in this matter with AACE. AACE's intervention in this matter is on behalf of its five fuel retailer members in Florida, all of whom are Duke Energy customers, representing more than 1,500 refueling locations across the state. AACE members include owners and operators of convenience stores, public travel facilities, and truck stops that provide fuel and other goods, services, and amenities at refueling stations throughout Florida and across the United States, primarily consisting of retail consumer goods, vehicle repair and service products, food, and fuel. In addition, AACE members are among Florida's most sophisticated and forward-thinking fuel retailers. Currently, AACE members provide fuel for all shapes, forms and types of vehicles found on the nation's roads today. Electric service is instrumental to the ability of the AACE members operating in the Duke Energy service area to offer any and all of their fuel and other services to Floridians and the larger traveling public. In addition, electric vehicle ("EV") charging for AACE members is just another type of transportation fuel, and the EV charging is totally dependent upon receiving reliable and affordable electric service. Thus, the rates, terms and conditions governing the provision of electricity to AACE members in the Duke Energy service territory will substantially and materially impact their ability to provide vehicle fueling services generally and especially EV charging services. Collectively, AACE's members in Duke Energy's Territory consume significant quantities of electricity and require reasonably price and reliable supply of electricity to power their businesses.

Q. What are Circle K's interests in this proceeding?

A. Circle K's success in the convenience retailing industry spans more than 60 years, beginning in Texas and growing across the U.S. and internationally. Today, Circle K is the global brand of Alimentation Couche-Tard, Inc. ("Couche-Tard"). Couche-Tard is a global leader in convenience and mobility, operating in 29 countries and territories, with more than 16,700 stores, of which approximately 13,100 offer road transportation fuel. It is one of the largest independent convenience store operators in the United States and it is a leader in the convenience store industry and road transportation fuel retail in Canada, Scandinavia, the Baltics, as well as in Ireland. It also has an important presence in Poland and Hong Kong Special Administrative Region of People's Republic of China and has recently expanded to Belgium, Germany, Luxembourg, and the Netherlands. More than 150,000 people are employed throughout its network. Circle K is a leading destination for EV charging in Europe, with nearly 2,500 chargers at more than 500 locations. In addition, the company expects to have 200 locations across North America offering EV fast charging services by the end of 2024. Currently, there are approximately 820 Circle K locations in Florida, of which, 150 are located within Duke Energy's service area. Circle K's use of electricity makes Circle K a large retail customer of Duke Energy, paying Duke Energy substantial amounts for electric service each year. Circle K's continued operation and further expansion of EV refueling stations within Duke Energy's service area is dependent, in part, upon the outcome of this docket. While Circle K offers EV charging in other areas and looks to expand its EV charging services, Circle K has not yet deployed EV charging in the Duke Energy service area.

Q. What are RaceTrac's interests in this proceeding?

A. RaceTrac is a family-owned business that has been serving guests since 1934. Together with its franchise-brand RaceWay, RaceTrac operates over 800 convenience stores and employs over 10,000 team members across its footprint. The company has been proudly serving Floridians for almost half a century. Currently, there are 295 stores (249 company-owned RaceTrac stores and 46 franchise-operated RaceWay stores) in Florida, which are supported by over 4,200 team members. Since 2017, RaceTrac has invested about $92 million each year in the state and plans to invest approximately $100 million in 2024. RaceTrac has refueling stations located at the most convenient real estate for travelers, including many locations along alternative fuel corridors. Of its refueling stations, 78 are located within Duke Energy's service area. Additionally, RaceTrac has one Store Support Center in Duke Energy's Service area, making RaceTrac a large retail customer of Duke Energy, paying Duke Energy substantial amounts for electric service each year. RaceTrac offers EV charging in other areas outside of Duke Energy's service area and looks to expand its EV charging services in the Duke Energy service area.

Q. What are Wawa's interests in this proceeding?

Wawa is a privately held, family-owned company that began as an iron foundry in 1803. As of 2023, Wawa was number 20 on Forbes' list of America's largest private companies. Wawa operates more than 1,040 stores and employs over 46,000 team members across its footprint. Approximately 865 of these locations include motor vehicle refueling stations. The company has been proudly serving Floridians since 2012. Currently, there are 280 stores in Florida, which are supported by over 10,000 team members, and Wawa is continuing to actively expand in Florida. Of its Florida locations, Wawa has 79 locations within Duke Energy's service territory, 17 of which have EV charging stations, making Wawa a large retail customer of Duke Energy, paying Duke Energy substantial amounts for electric service each year. Wawa anticipates adding 39 EV refueling stations within Duke Energy's service territory over the next 10 years.

Q. Are there any other witnesses testifying on behalf of the Fuel Retailers?

A. No

Q. Are you sponsoring any exhibits with your testimony?

A. No.

(Whereupon, prefiled direct testimony of Lindsey R. Stegall was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC	)	Docket No. 20240025-EI
	)	
	)	Submitted for filing: June 11, 2024
	)	

DIRECT TESTIMONY OF

LINDSEY R. STEGALL

ON BEHALF OF EVGO SERVICES, LLC

JUNE 11, 2024

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EXHIBITS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, title and business address.

A. My name is Lindsey R. Stegall. I am a Senior Manager of Market Development and Public Policy at EVgo Services, LLC ("EVgo"). My business address is 11835 W. Olympic Blvd. Suite 900E Los Angeles, CA 90064.

Q. Have you prepared a statement of your experience and qualifications?

A. Yes. My qualifications are included as Exhibit LRS-1 to this testimony.

Q. On whose behalf are you testifying in this proceeding?

A. I am appearing on behalf of EVgo. EVgo is a leader in charging solutions, building and operating the infrastructure and tools needed to expedite the mass adoption of electric vehicles (EVs) for individual drivers, rideshare and commercial fleets, and businesses. EVgo is one of the nation's largest public fast charging providers, featuring over 1,000 fast charging locations across more than 35 states, including stations built through EVgo eXtend™, its white label service offering. EVgo is accelerating transportation electrification ("TE") through partnerships with automakers, fleet and rideshare operators, retail hosts such as grocery stores, shopping centers, and gas stations, policy leaders, and other organizations.

Under its owner-operator business model, EVgo develops, finances, owns, and operates its fast-charging network. EVgo works with site host partners across the country to deploy EV charging solutions at retail locations that are already part of customers' daily routines. EVgo installs the public direct current fast chargers ("DCFC") at no cost to the site host partner. EVgo also maintains the customer relationship with the EV driver, providing a call center that is available to customers 24/7, and is responsible for operations and maintenance of its EV charging network. Today, nearly 40% of EVgo's fast charging stalls are powered by a 350kW charger—

almost double the percentage a year ago—to best serve vehicle models with the most advanced battery technology and high peak charging speeds.

Q. What is EVgo's interest in this proceeding?

A. EVgo is an electric commercial retail customer of Duke Energy Florida, LLC ("DEF" or "the Company"), taking service under the Company's General Service Rates. EVgo currently owns and operates 25 fast-charging stalls in the Company's service territory with plans for expansion across the state.

In this proceeding, DEF proposes to replace its existing Commercial and Industrial Rebates Program ("C&I Rebates Program") with a new Electric Vehicle Make Ready Credit Program ("MRC Program"). DEF also proposes to recover the costs of its proposed MRC Programs from its ratepayers (which include EVgo). Company witness Duff explains DEF's proposed MRC Program and associated costs and revenues in detail, while Company witness Olivier describes the incorporation of the MRC Program into DEF's cost of service.

If the Commission approves DEF's proposed MRC Program, EVgo will pay for the costs of the program through rates and will also be eligible to participate in the program. Further, the success of DEF's proposed TE programs will impact the rates paid by DEF ratepayers in the future. Increased electrification leads to a higher electric load, which distributes system costs across a larger customer base, thereby exerting downward pressure on rates. Therefore, the outcome of this proceeding will directly affect EVgo.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission, the utility, and stakeholders with the unique perspective of an established owner-operator of EV charging infrastructure with experience in more than 35 states, including Florida, to ensure the Company's proposed MRC Program will achieve its desired objectives and benefit DEF's customers. In order to achieve those aims, the program must prudently invest ratepayer money and be designed to effectively drive deployment of EV charging infrastructure in the Company's service territory.

EVgo supports the non-residential component of DEF's proposed MRC Program in concept and applauds the Company for proposing an improvement over its existing C&I Rebates Program. However, I recommend certain modest modifications to the program that are necessary to ensure it achieves its objectives and maximizes benefits for DEF's ratepayers.

Q. Please summarize your recommendations to the Commission in this proceeding.

A. EVgo recommends the Commission approve the MRC Program with the following modest modifications:

1. Increase the make ready credit maximum for public DCFC greater than 50 kW to $50,000 per stall.
2. Adjust the MRC Program budget for DCFC greater than 50 kW to reflect EVgo's proposed make ready credit maximum level while continuing to accommodate DEF's forecasted participation levels (a total of 164 DCFC installs greater than 50 kW between 2025 and 2027). This could be accomplished by re-allocating the $22.8 million non-residential budget among the seven different sectors, as opposed to increasing DEF's overall MRC Program budget.

Adopting these recommendations will ensure the MRC Program achieves higher participation rates than the existing C&I rebate program,[1] unlocking greater benefits for DEF ratepayers, while keeping the overall budget constant.

II. BACKGROUND

C29-3038

Q. What is DCFC infrastructure and how does it drive greater EV adoption?

A. Public or commercial DCFC charges a vehicle's battery using direct current at high power, which allows for fast charging in minutes instead of hours. DCFC is well-suited for quick charge needs in and around cities, towns, and suburbs and along high-traffic travel corridors. DCFC stations are located at or near places where drivers live, drive, and shop, including retail locations, restaurants, grocery stores, and other locations where an EV driver will be for 15-45 minutes. By contrast, Level 2 charging typically provides a full charge in 4 to 8 hours and is sought in longer duration, long dwell-time locations such as at workplaces, homes, amusement parks, or other destinations where drivers may spend several hours.

EVgo has found that public DCFC helps drive EV adoption, and therefore increases charging and electric load by serving a variety of drivers' needs. DCFC builds the range confidence of EV drivers, especially on trips between cities or across the country. As the Florida Department of Transportation ("FDOT") notes in its Electric Vehicle Infrastructure Master Plan ("EVMP") released in 2021, range anxiety during longer trips is still a perceived barrier to EV adoption.[2] Public DCFC also plays an important role in dense, urban, and suburban areas where not every home has a driveway, attached garage, or in many cases, any dedicated parking. In fact, according to the International Council on Clean Transportation, apartment-dwelling EV drivers living in multifamily housing rely on public charging for 50-80% of their charging[3] as they typically do not have access to dedicated parking or home charging. Similarly, research from UCLA's Luskin Center shows that 43% of multifamily housing residents rely on DCFC stations for their primary means of charging.[4] Although Florida provides homeowners with the right to install charging stations in their residences,[5] renters, including those living in multifamily housing, still lack this "right to charge," further exacerbating these drivers' need to access public fast charging. Thus, siting DCFC in community locations near multifamily housing and existing amenities drives EV adoption by providing charging options to drivers that do not own a single-family home.

Q. What definitions are useful to understand when discussing EV charging infrastructure?

A. I aim to clarify EVgo's definitions of certain terms that will appear in my testimony. First, a DCFC *location* is a site with one or more EV chargers serving one or more stalls. A *stall* is a parking space where one vehicle can charge at a time. An EV *charger* is a device that provides electricity to recharge the batteries of EVs. An EV charger may have one or more connectors and the ability to serve one or more stalls. A *connector* includes the cable and plug that connects the charger to the EV. Two stalls may be supported by one EV charger with two connectors that can "power share," providing electricity to two vehicles simultaneously.[6] *Port* is another term that is frequently used but is not consistently defined.

Q. What public interest benefits of TE has the state of Florida recognized?

A. Florida's EVMP explains that TE provides opportunities to transform mobility by providing environmentally friendly and cost effective travel options while promoting energy independence.[7] It notes that electric mobility provides several benefits to both transportation and energy sectors including, but not limited to, reduced greenhouse gas ("GHG") emissions leading to positive environmental impacts; increased energy diversity and independence; zero tailpipe emissions leading to improved air quality, reduction in noise pollution and improved vehicle efficiency; and lower cost of vehicle ownership for households due to lower fuel and maintenance costs.[8]

Q. How does electric vehicle charging benefit utility ratepayers?

A. Electric vehicle charging increases electric load and thereby spreads system costs over a greater volume of customers, causing downward pressure on future rates. DEF witness Duff aptly illustrates this impact in his testimony, where he explains—in the context of the Company's proposed MRC Program— "the ongoing increase in energy consumption will continue to add revenue to the system . . . [t]he resulting downward pressure on rates is a benefit to all customers."[9]

These ratepayer benefits are not just theoretical. A 2020 study by Synapse Economics found that the benefits from TE outweighed the costs for the two utilities in the U.S. with the most EVs—Pacific Gas & Electric ("PG&E") and Southern California Edison ("SCE"). Synapse observed that over eight years, "EV drivers in PG&E's and SCE's service territories contributed **$806 million more in revenues than associated costs**, driving rates down for all customers."[10]

The economic benefits of TE for ratepayers are widely recognized by utilities and public service commissions across the country and several studies have been conducted across the country to quantify these benefits.

Q. Have the ratepayer benefits of TE been quantified for the state of Florida?

A. Yes. In 2019, Duke Energy worked with M.J. Bradley & Associates ("MJB&A") to conduct six state-level analyses "intended to provide input to state policy discussions about actions required to promote further adoption of electric vehicles, as well as to inform internal Duke planning efforts."[11] The study focused on Florida estimated the costs and benefits of increased adoption of plug-in electric vehicles ("PEVs") in the state, including the financial benefits that would accrue to all electric utility customers in Florida due to greater utilization of the electric grid during low load hours and resulting increased utility revenues from PEV charging. The study found that if Florida PEV adoption follows the moderate trajectory assumed by the Energy

Information Administration, $2.2 billion will accrue to electric utility customers in the form of reduced electric bills from TE by 2050.[12] If PEV sales in Florida are high enough to get the state onto a more aggressive trajectory (for example through supportive policies and programs), the study estimates that benefits for utility customers could exceed $21.7 billion for utility customers by 2050.[13] While this study is a few years old, it still illustrates the potential magnitude of ratepayer benefits from increasing TE in the state.

III. MAKE READY CREDIT PROGRAM

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I address the Company's proposal to replace its existing C&I Rebate Program with a new MRC Program. As I stated above, EVgo supports the Company's proposal in concept, but recommends certain modest modifications to the program. Below, I will explain my support for the program concept and my recommended modifications. As EVgo is focused primarily on high power charging, I will focus on the portion of the proposal related to public DCFC greater than 50 kW.

Q. Please describe the Company's C&I Rebates Program.

A. The Company piloted the C&I Rebates Program in January 2022 after the Commission's Order approving the 2021 Settlement Agreement. The program provides a rebate to C&I customers that install EV charging stations behind a separate meter. For public DCFC, DEF offers up to $4,195 per charger capable of charging at a dedicated capacity of 50 kW and above.[14]

Q. Has the C&I Rebates Program been successful?

A. DEF states that the program has not been as successful as expected. While the Company originally projected that the program's first two years of operation would distribute approximately $8.6 million in customer incentives for 1,420 chargers, to date, only 26 EV chargers have been installed through the program with 79 EV charger installations pending.[15]

Q. Why does the Company believe the program has been unsuccessful?

A. One of the reasons the Company states for the minimal participation by its C&I customers is the former requirement that chargers be placed on rate GST-1.[16] The Company also found that some customers did not provide certain requested information required to complete the application process.[17] Importantly, the Company further noted that "participating customer feedback… indicated that participation was negatively impacted because EV charger installation costs were viewed as too high, despite available incentives."[18]

Q. What does the Company propose with regard to the C&I Rebates Program in this proceeding?

A. The Company proposes to deploy the MRC Program as a replacement for the C&I Rebates Program from 2025 through 2027. The proposed MRC Program would provide an incentive, in the form of a credit on a customer's bill or a payment to a contractor, to defray a portion of the EV "make ready" expenses related to the installation of the infrastructure needed to bring safe electrical service to EV charging hardware. This program would be available to nonresidential DEF customers that install at their premises the wiring and circuitry required for a Level 2 or higher-powered EVSE(s). The Company will not own the make ready infrastructure associated with the MRC Program.

Q. What are make-ready expenses?

A. Make-ready expenses refer to the costs of service panels, junction boxes, conduit, wiring and other components necessary to make a particular location able to accommodate EVSE.

Q. How will the program determine make ready credits for public DCFC greater than 50 kW?

A. DEF notes that for charging installations with more than 50 kW aggregate load, the calculation to determine the maximum credit will be performed on a case-by-case basis using information from the Customer Usage Profile form. The incentive range that would be offered for different power levels is not clear to me based on filings in this proceeding, but Exhibit TJD-1 shows that, for loads greater than 50 kW, the budget allocates up to $20,000 per install for DCFC.[19]

Q. What is the proposed budget and estimated participation level for public DCFC greater than 50 kW?

A. According to Exhibit TJD-1, the budget appears to be designed to support 164 installs between 2025 and 2027 at a total budget of $3,275,354.

Q. How does DEF define "install" with regard to the MRC Program?

A. This term does not appear to be defined, but I interpret *install* to be the equivalent of what I have described as an EV *charger*—a device that provides electricity to EVs which may have one or more connectors and the ability to serve one or more stalls.[20]

Q. What is EVgo's position on the proposed MRC Program?

A. EVgo applauds DEF for proposing a program aimed at supporting deployment of EV charging by defraying make ready costs. Make ready programs have been implemented across the nation and, when well-designed and funded at levels that align with the installed costs of DCFC, have been successful at deploying infrastructure and driving ratepayer benefits. In particular, EVgo appreciates that the MRC Program is agnostic to the EV charging ownership model deployed at a given site,[21] and that the Company has taken steps to improve the offering, such as increasing the incentive amount per install for public DCFC (relative to the existing C&I Rebates Program) in response to customer feedback.

However, while EVgo supports the general concept of DEF's proposed MRC Program, I am concerned the Company's proposed maximum credit per install for public DCFC greater than 50 kW is misaligned with the costs of installing DCFC[22] and will therefore not meaningfully support DCFC deployment. Despite the Company's clear intention to support deployment of public charging through this improved program design, like the C&I Rebate Program, the MRC Program will likely underperform unless DEF modifies its credit levels. If the program is unsuccessful, DEF ratepayers would be denied the benefits that result from increased charging deployment and accelerated TE.

Q. Please elaborate.

A. Regarding the previous C&I Rebates Program, DEF found that "[t]he magnitude of program incentive amounts for several segments are believed to be insufficient to drive meaningful participation."[23] Unfortunately, the proposed MRC Program does not fully address this issue. In a 2023 study, the National Renewable Energy Laboratory assessed the costs of charging infrastructure to estimate the cumulative capital investment required to deploy a charging network that would accommodate the EVs on the road in 2030. For DCFC, the study estimated the hardware cost for a 150 kW charger ranged from \$66,400 to \$102,200 per port,[24] while the hardware cost for a 350+ kW charger ranged from \$116,400 to \$167,400 per port.[25] Additionally, the study estimated the installation costs for a 150 kW charger ranged from \$45,800 to \$94,000 per port, while the installation costs for a 350+ kW charger ranged from \$63,700 to \$117,900 per port.[26] Consequently, each port could cost between \$112,200 and \$285,300, with costs likely in the higher range due to common requirements such as prevailing wage, Americans with Disabilities Act accessibility, and Build America, Buy America. Table 1 illustrates these costs alongside DEF's proposed make ready credit for DCFC greater than 50 kW.

Table 1.

	150 kW charger	**350+ kW charger**
Hardware Cost	Between $66,400 and $102,200 per port	Between $116,400 and $167,400 per port
Installation Costs	Between $45,800 and $94,000 per port	Between $63,700 and $117,900 per port
Total Costs	Between $112,200 and $196,200 per port (and therefore potentially higher per charger)	Between $180,100 and $285,300 per port (and therefore potentially higher per charger)
DEF Proposed MRC Credit	$20,000 per EV charger	$20,000 per EV charger

Given the magnitude of these costs, I am concerned the Company's proposed $20,000 maximum make ready credit (for EV chargers greater than 50 kW)—which is less than 10% of total DCFC costs—will not spur meaningful participation, creating the risk that the MRC program will end up just as undersubscribed as the existing C&I Rebates Program.

Q. What are the potential consequences of an unsuccessful MRC program?

A. As I have explained previously, an unsuccessful program that deploys fewer DCFCs will result in reduced benefits for ratepayers over the long term. It will also reduce the broader public interest benefits recognized by Florida's EVMP. Further, a utility program requires ratepayer funding to administer. If DEF's program is not optimally designed and fails to meet its objectives, these annual program costs will be squandered without delivering the expected benefits. This would represent an inefficient use of ratepayer funds, which is contrary to fundamental principles of public utility regulation and the Commission's goals.[27]

Q. Are there other utility make ready programs across the country that efficiently and effectively support DCFC deployment and serve as good examples?

A. Yes. Utility programs across the country have recognized the costs of DCFC hardware and installation and have set their level of utility investment in make ready infrastructure accordingly. For example:

- Rocky Mountain Power in Utah's Electric Vehicle Infrastructure Program[28] provides rebates of $45,000 per single-connector charger and $63,000 per multi-connector charger, covering up to 75% of total charger and installation costs. The program also provides incentives for electrical infrastructure and installation costs up to $50,000 per port for chargers over 125 kW. The program provides a maximum incentive of $500,000 per site.
- Tucson Electric Power's make ready program offers utility investment of up to $40,000 per DCFC connector, covering up to 75% of project costs.[29] The utility has allocated $16.4 million for commercial rebates.
- Xcel Energy in Colorado's EV Supply Infrastructure Program provided make ready infrastructure for 186 privately developed public DCFC with a total budget of $9.63 million between 2021 and 2023.[30] Xcel also has a pending make-ready program proposal that, if approved, would offer a $45,000 make-ready rebate per DCFC connector. If a DCFC location is in a disproportionately impacted community, the program would offer up to

$130,000 per connector in make-ready and charger rebates (depending on power levels).[31]

Q. What do you recommend regarding the proposed make ready program?

A. EVgo recommends the Commission approve the MRC Program with the following modifications:

1. Increase the make ready credit maximum for public DCFC greater than 50 kW to $50,000 per stall.
2. Adjust the MRC Program budget for DCFC greater than 50 kW to reflect EVgo's proposed make ready credit maximum level while continuing to accommodate DEF's forecasted participation level. This could be accomplished by re-allocating the $22.8 million non-residential budget among the seven different sectors, as opposed to increasing DEF's overall MRC Program budget.

Q. Why do you propose a make ready credit of $50,000 per stall?

A. This level of investment considers the costs of public DCFC and will meaningfully drive program participation, improving the program's efficiency and maximizing the benefits to ratepayers. This level of investment is also consistent with other utility programs across the country that have been successful. I suggest a per stall credit instead of a per install or per charger credit because aligning the credit with stall count more accurately reflects the functionality of the deployment. For instance, a four-stall site can serve four EV drivers regardless of the number of chargers, whereas a two-charger site could serve two to four drivers, depending on the number of connectors and stalls associated with the two chargers.

Q. How will the modified MRC Program lead to increased EV adoption?

A. As identified in Florida's EVMP, one key critical barrier to EV adoption is the lack of charging stations.[32] Adopting my recommended program modifications will help address this barrier by ensuring the program achieves DEF's intended program participation levels and increases the deployment of public DCFC. The greater availability of public charging stations will accelerate EV adoption by increasing consumers' range confidence and improve charging accessibility for drivers living in multifamily housing.

Q. How will the modified MRC Program benefit DEF's ratepayers?

A. As I explained previously, the greater incremental loads created by increased EV adoption and EV charging growth will reduce electric rates over time by spreading system costs across a greater number of customers. Again, Company Witness Duff explains this phenomenon in his Direct Testimony, stating the MRC Program will benefit all customers because "the ongoing increase in energy consumption will continue to add revenue to the system […] without adding cost to the system. The resulting downward pressure on rates is a benefit to all customers."[33] Moreover, MJB&A evaluated the costs and benefits of increased penetration of PEVs in eight states and found that "[e]lectric vehicle charging increases utility revenues as we shift from gasoline use to greater reliance on the electric system. Higher revenues support investment and maintenance of the electric system, benefiting all utility customers, regardless of the vehicle they drive."[34] As I explain previously, MJB&A estimated that $2.2 billion will accrue to electric utility customers in Florida in the form of reduced electric bills from TE by 2050 given a moderate EV adoption trajectory. If policies and programs supporting TE are adopted, such as the modified MRC Program I recommend, electrification will accelerate and could result in benefits exceeding $21.7 billion for utility customers by 2050, according to MJB&A. Again, real world data supports this theory, as a 2020 study by Synapse Economics observed that over eight years two California utilities saw $806 million more in revenues from EV drivers than associated costs, which drove rates down for all customers.[35]

IV. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. EVgo recommends the Commission approve the MRC Program with the following modifications:

1. Increase the make ready credit maximum for public DCFC greater than 50 kW to $50,000 per stall.
2. Adjust the MRC Program budget for DCFC greater than 50 kW to reflect EVgo's proposed make ready credit maximum level while continuing to accommodate DEF's forecasted participation level. This could be accomplished by re-allocating the $22.8 million non-residential budget among the seven different sectors, as opposed to increasing DEF's overall MRC Program budget.

Adopting these recommendations will ensure the MRC Program is a prudent and efficient ratepayer investment that drives increased participation compared to the existing C&I rebate program, maximizing the benefits for DEF ratepayers as well as the broad public interest benefits recognized by the state.

Q. Does this conclude your direct testimony?

A. Yes.

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[1] Duff Direct Testimony at 10:23-11:4.
[2] *See* Florida Department of Transportation, *EV Infrastructure Master Plan* at 7 (July 2021), available at: https://fdotwww.blob.core.windows.net/sitefinity/docs/default-source/emergingtechnologies/evprogram/fdotevmp.pdf?sfvrsn=b5888a_2.
[3] Nicholas, M. et al., International Council on Clean Transportation, *Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets* at 9 (January 2019), available at:

https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf.
[4] DeShazo and Di Filippo, UCLA Luskin Center for Innovation, *Evaluating Multi-Unit Resident Charging Behavior at Direct Current Fast Chargers* at 3, 13 (February 2021), available at: https://innovation.luskin.ucla.edu/wp-content/uploads/2021/03/Evaluating-Multi-Unit-Resident-Charging-Behavior-at-Direct-Charging-Behavior-at-Direct-Current-Fast-ChargersCurrent-Fast-Chargers.pdf.
[5] FLA. STAT. Ch. 718 § 113 (2021).
[6] *See* EVgo Blog, *Simultaneous Charging: Less Equipment, More Happy Customers* (Mar. 8, 2023), available at: https://evgo.com/blog/simultaneous-charging-less-equipment-more-happy-customers/.
[7] Florida Department of Transportation, EV Infrastructure Master Plan at 4.
[8] *Id.* at 5.
[9] Duff Direct Testimony at 20:23:21:3.
[10] *See* Frost, J. et al., Synapse Energy Economics, *Electric Vehicles Are Driving Rates Down* (June 2020), available at: https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf (emphasis added).
[11] *See* M.J. Bradley & Associates, *Electric Vehicle Cost-Benefit Analysis*, *Plug-In Electric Vehicle Cost Benefit Analysis: Florida* at 19 (January 2019), available at: https://www.erm.com/globalassets/documents/mjba-archive/reports/2019/flpevcbanalysis07jan19.pdf.
[12] *Id.* at ii.
[13] *Id.* at iii.
[14] *See* https://www.duke-energy.com/business/products/ev-complete/charger-rebate.
[15] Duff Direct Testimony at 10:23-11:4.
[16] The Company has since changed that requirement.
[17] The Company plans to develop an online checklist to guide customers before and during the application process to address this.
[18] Duff Direct Testimony at 11:9-11.
[19] Exhibit TJD-1.
[20] EVgo has issued interrogatories in an attempt to clarify DEF's proposal. As of the filing of this testimony, those interrogatories remain pending.
[21] Duff Direct Testimony at 22:2-7.
[22] *See* Levy, J. et al., EVgo, *The Costs of EV Fast Charging Infrastructure and Economic Benefits to Rapid Scale-Up* (May 18, 2020), available at: https://site-assets.evgo.com/f/78437/x/f28386ed92/2020-05-18_evgo-whitepaper_dcfc-cost-and-policy.pdf.
[23] Duff Direct Testimony at 11:21-12:2.
[24] In this case "port" refers to a unit that provides power to charge only one vehicle at a time and therefore is equivalent to my defined term "stall."
[25] Eric Wood et al., rep., *The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure* (National Renewable Energy Laboratory, June 2023), https://www.nrel.gov/docs/fy23osti/85654.pdf, at 33.
[26] *Id.*
[27] *See* Florida Public Service Commission, *Mission Statement and Goals of the Florida Public Service Commission*, available at: https://www.psc.state.fl.us/about (accessed June 10, 2024) (stating a goal of economic regulation is to "[e]ncourage efficiency and innovation among regulated utilities.")
[28] *See* Rocky Mountain Power, *Utah Rebates for Business EV Chargers and Make-Ready Projects*, available at: https://www.rockymountainpower.net/savings-energy-choices/electric-vehicles/utah-commercial-incentives.html (last accessed on June 11, 2024).
[29] *See* Tucson Electric Power, *Program details*, available at: https://tepev.clearesult.com/program-details (last accessed on June 11, 2024).
[30] *See* Xcel Energy, *Transportation Electrification Plan, Public Service Company of Colorado, 2021-2023*, available at: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=926521&p_session_id= (last accessed on June 11, 2024).
[31] Colorado Public Utilities Commission, Proceeding No. 23A-0242E, Decision No. C24-022.
[32] Florida Department of Transportation, EV Infrastructure Master Plan at 7.

[33] Duff Direct Testimony at 20-21.

[34] *See* M.J. Bradley & Associates, *Electric Vehicle Cost-Benefit Analyses*, available at: https://mjbradley.com/sites/default/files/NE%20PEV%208%20state%20Summary%2009nov17.pdf (last accessed on June 11, 2024).

(Whereupon, prefiled direct testimony of Jonathan Ly was inserted.)

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**

DIRECT TESTIMONY AND EXHIBITS OF JONATHAN LY

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

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LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
DEF	Duke Energy Florida
EIA	Energy Information Administration
FIPUG	Florida Industrial Power Users Group
kW	Kilowatt
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
Proposed Solar Projects	14 Solar Projects Proposed by DEF
PTC	Production Tax Credit

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DIRECT TESTIMONY OF JONATHAN LY

<u>Introduction and Qualifications</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly, 1314 Welch Street, Unit A, Houston, TX 77006.

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

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley and a Master's degree in Energy and Earth Resources from the University of Texas at Austin. Since joining J. Pollock, Incorporated in 2018, I have participated in numerous regulatory proceedings regarding the ratemaking process, resource planning, certificates of convenience and necessity, and assessments of planned new resources in Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Duke Energy Florida (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 the outcome of this proceeding.

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Q WHAT ISSUES DO YOU ADDRESS?

A I am addressing the cost-effectiveness of the 14 solar projects proposed by DEF for which it is seeking cost recovery in this base rate proceeding (hereinafter referred to as the Proposed Solar Projects). In addition, I also discuss the need for customer protections to balance the risk associated with these proposed solar resources between DEF and its customers.

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

A Yes. My colleague, Mr. Pollock, will address TECO's class cost-of-service study, class revenue allocation, and rate design.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JL-1** through **JL-3.**

Q DOES THE FACT THAT YOU ARE LIMITING YOUR TESTIMONY TO THE AFOREMENTIONED ISSUES MEAN THAT YOU ARE ENDORSING DEC'S OTHER PROPOSALS IN THIS CASE?

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

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A My findings and recommendations are as follows:

- The purported cost-effectiveness of the Proposed Solar Projects for which DEF is seeking cost recovery in this base rate proceeding are not supported by robust analysis. Further, DEF has not provided sensitivity analyses supporting the benefits of these projects under a range of capital and fuel cost assumptions.

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- The net present value (NPV) benefits DEF claims would be achieved by the Proposed Solar Projects are based upon inflated natural gas prices. If future fuel prices are lower than DEF projects, these benefits could be diminished or even negated, thereby imposing an incremental cost on DEF's customers.
- Given the significant uncertainties surrounding the cost-effectiveness analysis, if the Commission approves the Proposed Solar Projects, it should also impose conditions to balance the risks of these resources between DEF and its customers.
- The Commission should implement a cost cap on the Proposed Solar Projects and establish a minimum capacity factor guarantee based upon DEF's projections.
- The Commission should also ensure that each of the Proposed Solar Projects entering rate base qualify for the production tax credits in an amount no less than projected by DEF, which should also be included as an offset to these projects' base revenue requirements when rate recovery is authorized.

Proposed Solar Projects

Q FOR WHAT PROJECTS IS DEF SEEKING COST RECOVERY IN THIS PROCEEDING?

A DEF is seeking cost recovery for fourteen solar projects. The characteristics of the fourteen Proposed Solar Projects are summarized in Table 1.

Table 1
Summary of Proposed Solar Projects

Project	Nameplate Capacity (MW)	Installed Cost ($/kW)	Annual Capacity Factor	In-Service Date
Bailey Mill Solar Center	74.9	$1,522	27%	March 2026
Half Moon Solar Senter	74.9	$1,522	27%	March 2026
Rattler Solar Center	74.9	$1,522	27%	March 2026
Sundance Solar Center	74.9	$1,522	27%	June 2025
Unnamed 2025 Solar Facility 1	74.9	$1,522	27%	June 2025
Unnamed 2025 Solar Facility 2	74.9	$1,522	27%	December 2025
Unnamed 2026 Solar Facility 1	74.9	$1,529	27%	2026

Table 1 Summary of Proposed Solar Projects				
Project	**Nameplate Capacity (MW)**	**Installed Cost ($/kW)**	**Annual Capacity Factor**	**In-Service Date**
Unnamed 2026 Solar Facility 2	74.9	$1,529	27%	2026
Unnamed 2026 Solar Facility 3	74.9	$1,529	27%	2026
Unnamed 2026 Solar Facility 4	74.9	$1,529	27%	2026
Unnamed 2027 Solar Facility 1	74.9	$1,523	27%	2027
Unnamed 2027 Solar Facility 2	74.9	$1,523	27%	2027
Unnamed 2027 Solar Facility 3	74.9	$1,523	27%	2027
Unnamed 2027 Solar Facility 4	74.9	$1,523	27%	2027
Source: Direct Testimony of Vanessa Goff at 5–6 and 10–11; Exhibit BG-2; DEF Response to LULAC POD 2, 2024 Rate Case Solar Study CPVRR Results.				

DEF's estimated total cost to construct the proposed Solar Projects is $1.598 billion, which translates into a capital cost of $1,524 per kilowatt (kW).[1] The capital cost includes all interconnection and upgrade costs.[2]

Q DOES DEF ASSERT THAT THE PROPOSED SOLAR PROJECTS WILL BENEFIT CUSTOMERS?

A Yes. DEF estimates that the NPV benefits of the Proposed Solar Projects are $550 million or approximately 34% of the projected capital costs.[3]

Q DO YOU HAVE ANY CONCERNS WITH THE PROPOSED SOLAR PROJECTS?

A Yes. First, the Proposed Solar Projects represent a $1.598 billion addition to rate base. The corresponding benefits are only a small fraction of the projected upfront

[1] Direct Testimony of Vanessa Goff at 4, 10–11.

[2] *Id.* at 10.

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

capital costs. Any material changes in the assumed capital costs, fuel savings, operating performance, and/or the magnitude of the applicable production tax credits (PTCs) could result in the costs exceeding the benefits. Thus, unless the Commission finds DEF's cost-effectiveness analysis to be sufficiently robust (that is, the benefits exceed the costs under a wide range of assumptions), the Proposed Solar Projects should not be approved.

Second, absent the PTCs, which apply during the first ten years of commercial operation, the Proposed Solar Projects would not be cost-effective. Thus, as a policy matter, the Commission should guarantee, at a minimum, that the PTCs flow through to customers based on projected performance – even if DEF is unable to monetize them. This PTC guarantee is discussed in more detail later.

Cost-Effectiveness Analysis

Q WHAT IS A COST-EFFECTIVENESS ANALYSIS?

A A cost-effectiveness analysis estimates the impact of a new generating project (or projects) by comparing system-wide costs and benefits both with and without the new project (or projects) over its (their) expected life (or lives). The analysis is typically conducted using a production cost simulation model. For example, DEF uses the EnCompass Expansion Planning and Production Cost model.[4] The costs associated with a new project are the incremental capital cost (both generation and transmission) and operating costs over the expected life. The benefits attributable to a new project are the capital, fuel, and non-fuel operating costs that a utility would avoid incurring with the addition of the new project. If the Commission finds that a project is not likely

[4] *Id*. at 17.

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to be cost effective, it can protect ratepayers by declining to approve the project, thus saving customers from the capital, fuel, and non-fuel operating costs that would have been spent on the cost-ineffective project.

Because these new generating resources have expected lives of 30 years, a cost-effectiveness analysis must, by necessity, rely on assumptions about future load growth, inflation, commodity costs, financing costs, labor and materials costs, and operating performance. Given the wide range of required assumptions, it is customary to conduct a base case and several sensitivity studies to determine a range of possible outcomes.

Q HAS DEF CONDUCTED A COST-EFFECTIVENESS ANALYSIS OF THE PROPOSED SOLAR PROJECTS?

A Yes. The results of DEF's cost-effectiveness analysis are summarized in **Exhibit JL-1**.

Q WHAT DO THE RESULTS OF DEF'S COST-EFFECTIVENESS SHOW?

A The Proposed Solar Projects are only beneficial for customers because of the PTCs. In other words, absent taxpayer subsidies, the Proposed Solar Projects would not be cost-effective. Even considering the impact of these PTCs, the margin of benefit for the Proposed Solar Projects is only 34% of the projected incremental capital costs. These benefits are largely attributable to the forecast fuel savings associated with the Proposed Solar Projects. However, if these fuel savings were to diminish or otherwise fail to materialize, the cost-effectiveness of these facilities would be jeopardized.

Q DID DEF PRESENT ANY SENSITIVITY ANALYSES TO ASSESS THE COST AND BENEFITS FROM THE PROPOSED SOLAR PROJECTS IF EITHER FUTURE CAPITAL COSTS WERE HIGHER OR COMMODITY COSTS WERE LOWER THAN PROJECTED?

A No. DEF does not appear to have evaluated the Proposed Solar Projects using sensitivity cases which assume a wide range of possible future scenarios (*i.e.*, varying levels of capital costs for the solar projects or fuel prices aside from its base case assumptions). Therefore, the cost-effectiveness analysis is not supported by robust studies — as such, the results are not competent, substantial evidence in support of these projects.

Q DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE PROJECTED FUEL COST SAVINGS?

A Yes. The projected fuel cost savings assume that Henry Hub natural gas prices forecasted by DEF will escalate by 2.2% on average per year. Furthermore, these assumptions are significantly higher than Henry Hub natural gas futures prices from the New York Mercantile Exchange (NYMEX) and projections produced by the Energy Information Administration (EIA), as shown in **Exhibit JL-2** and summarized in Table 2 below.

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Table 2 Levelized Natural Gas Price Forecast 2024 Through 2036 ($/MMBtu)	
Description	**Levelized Cost***
DEF	$4.99
EIA Reference	$4.08
NYMEX Futures (30-Day Avg)	$3.97
NYMEX Futures (90-Day Avg)	$3.78
EIA High Oil & Gas Supply	$3.47

Sources: DEF Response to FIPUG ROG 4-51; EIA 2023 Annual Energy Outlook (Table 13); S&P Global Market Intelligence.
* 6.83% Discount Rate.

Additionally, DEF assumes that the Proposed Solar Projects will generate energy at an average annual capacity factor of 27% over the first 10 operating years of each of these facilities' lives, during which each facility would be eligible for PTCs. Meanwhile, the projected fuel savings are based on an average annual capacity factor of 27% over their expected lives. If these facilities fail to operate at such levels, the PTCs and system fuel savings associated with these plants would be diminished.

Q PLEASE DISCUSS THE EIA'S REFERENCE GAS FORECAST THAT IS INCLUDED IN TABLE 2.

A EIA's Reference natural gas price forecasts reflect the agency's base case assumptions. Although the levelized amounts included in Table 2 show that the EIA Reference forecast is similar to the NYMEX Futures prices, the EIA has consistently overstated natural gas prices under its Reference forecast. This is documented in **Exhibit JL-3**, which compares the EIA's Reference natural gas price forecasts

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published in its Annual Energy Outlooks for the years 2017 – 2023 to actual spot gas prices over the time span. Further, the EIA has generally lowered its Reference gas forecast in successive editions of its Annual Energy Outlook. Consequently, little weight should be given to EIA's inflated Reference forecast. Because DEF's natural gas forecasts are even higher, they should also be disregarded.

Q WHAT IS THE EIA'S HIGH OIL AND GAS SUPPLY SCENARIO

A EIA describes its High Oil and Gas Supply scenario as follows:

> In the High Oil and Gas Supply case, we assume the estimated ultimate recovery per well to be 50% higher than in the Reference case for:
>
> • Tight oil, tight gas, and shale gas in the Lower 48 States
>
> • Undiscovered resources in Alaska
>
> • Offshore Lower 48 states
>
> Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. The Liquid Fuels Market Module (LFMM) assumes crude oil pipeline and export capacity increases in the projection period to accommodate higher levels of domestic oil production.[5]

Q HAVE EIA'S HIGH OIL AND GAS SUPPLY FORECASTS PERFORMED BETTER THAN EIA'S REFERENCE FORECASTS?

A Yes. EIA's High Oil and Gas Supply scenario has consistently projected lower natural gas prices than its Reference forecasts. Therefore, although it is not perfect, this scenario has provided a more accurate forecast. As shown in **Exhibit JL-2**, NYMEX futures prices converge with the EIA's High Oil and Gas Supply forecast in the early to mid-2030s.

[5] U.S. Energy Information Administration, *Annual Energy Outlook: 2023 Case Descriptions* at 6 (Mar. 2023).

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Q WHAT ARE NYMEX FUTURE PRICES?

A NYMEX natural gas futures prices (depicted by the orange lines in **Exhibit JL-2**) are based on average closing prices of futures contracts traded through 2036 at the Henry Hub. The Henry Hub is a natural gas pipeline in Louisiana that serves as the official delivery location for futures contracts on NYMEX. The 30-day average reflects the period from April 10 to May 21, 2024, and the 90-day average reflects the period from January 12 to May 21, 2024.

Q DO NYMEX FUTURES CONTRACT PRICES PROVIDE VALUABLE INFORMATION ABOUT FUTURE LONG-TERM ENERGY MARKET FUNDAMENTALS?

A Yes. Futures contracts are highly liquid in the near term, and futures prices are highly visible because they are widely disseminated by the various financial and commodity exchanges. Thus, futures contract prices are an important source of price discovery for sellers and producers, and they are an essential tool for making future production and consumption decisions. Further, they represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations. The NYMEX futures prices are based on an actual market.

Q PLEASE SUMMARIZE YOUR ASSESSMENT OF DEF'S NATURAL GAS PROJECTION.

A DEF's natural gas forecasts are significantly higher than forecasts developed by the EIA and futures prices for natural gas reflecting actual market expectations. Therefore, the Commission should be skeptical and cautious of accepting DEF's purported fuel savings attributable to the Proposed Solar Projects, and consequently, the overall cost-effectiveness of these projects.

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Q HOW SHOULD THE COMMISSION ASSESS THE COST-EFFECTIVENESS ANALYSIS OF THE PROPOSED SOLAR PROJECTS?

A The Commission and its staff should rigorously review whether customers will actually benefit from the Proposed Solar Projects. Even under DEF's analysis, the Proposed Solar Projects are not cost-effective without the PTCs. When subjected to more scrutiny, it is clear that the projected benefits may not outweigh the projected costs, particularly if:

- Future commodity costs are lower than DEF has projected;
- Projected Solar Project costs are more expensive than projected; and
- Projected Solar Projects fail to produce energy at a 27% annual capacity factor over the first 10 years.

Therefore, if the Commission approves the Proposed Solar Projects, any rate base treatment should be contingent on providing specific and meaningful consumer protections.

Consumer Protections

Q RECOGNIZING YOUR CONCERNS ABOUT THE LACK OF SENSITIVITY ANALYSES IN DEF'S COST-EFFECTIVENESS ANALYSIS, SHOULD THE COMMISSION IMPOSE CONDITIONS TO ESTABLISH A MORE BALANCED RISK APPORTIONMENT BETWEEN DEF AND ITS CUSTOMERS?

A Yes. There are several measures that should be implemented to provide a more balanced risk apportionment, including:

- Imposing a cap on the construction costs;
- Establishing a performance standard for the Proposed Solar Projects; and

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- Providing a guarantee that the Proposed Solar Projects are fully eligible to receive PTCs and that all PTCs (grossed up for taxes) will be flowed through to DEF's customers in an amount no less than DEF has projected.

Q WHAT COST CAP FOR THE SOLAR FACILITIES DO YOU RECOMMEND?

A I recommend a cost cap of $1,524 per kW, which is DEF's projected cost of the Proposed Solar Projects. This amount represents the total estimated costs of the Proposed Solar Projects of $1.598 billion divided by the total nameplate capacity of 1,048.6 MW.

Q SHOULD ANY OTHER ALLOWANCES BE REFLECTED IN THE CONSTRUCTION COST CAPS?

A No. The projected installed cost already includes contingency allowances of 4%.[6]

Q WHAT PERFORMANCE STANDARDS WOULD HELP REBALANCE THE RISKS ASSOCIATED WITH THE PROPOSED SOLAR PLANTS?

A As previously discussed, the amount of energy generated from the Proposed Solar Projects is critical to determining the amount of PTCs that DEF will receive and whether, and to what extent, DEF and its customers realize any fuel cost savings. The most logical performance standard would be to require that the Proposed Solar Projects achieve a minimum annual capacity factor. In the event that the minimum annual capacity factor standard is not met, ratepayers should be held harmless for the difference between DEF's projected minimum annual capacity factor and the actual minimum annual capacity factor. In other words, the Commission should evaluate the difference between the actual energy output of the Proposed Solar Projects against

[6] Direct Testimony of Vanessa Goff at 11-12.

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the energy that would be generated at a defined minimum annual capacity factor. If the actual amount of energy falls below the guaranteed level, the shortfall amount should be multiplied by the value of the grossed-up PTCs to determine the value of PTCs that should be provided to customers to be made whole. Similarly, the shortfall amount should also be multiplied by avoided energy costs for each of the Proposed Solar Projects to determine the amount of fuel savings that should be credited to customers through the fuel clause cost recovery proceeding.

Q WHAT MINIMUM ANNUAL CAPACITY FACTOR WOULD BE REASONABLE?

A Given that DEF's projections assume a 27% average annual net capacity factor for each of the Proposed Solar Projects' operating lives, it would be reasonable to hold DEF to those projections.

Q HOW CAN THE COMMISSION ENSURE THAT DEF'S CUSTOMERS BENEFIT FROM THE PRODUCTION TAX CREDITS?

A First, as a prerequisite for recovering any of the investment, the Proposed Solar Projects must qualify for the PTCs. Any portion of the investment that does not qualify should either be disallowed or not included in rate base. Alternatively, customers should be held harmless should DEF's projected PTCs upon which DEF is asking the Commission to approve the 14 new solar projects fail to materialize, either in whole or in part. This means that DEF should compensate customers for the value of the lost PTCs for any portion of the Proposed Solar Projects that do not fully qualify.

Second, to ensure that customers receive the full benefits of the PTCs, the Commission should require that all PTCs (grossed up for income taxes) be included as offsets to DEF's base revenue requirements associated with each Proposed Solar Project that is placed into commercial operation and for which cost recovery is authorized.

Q WOULD IMPLEMENTING THESE PROTECTIONS ELIMINATE ALL RISKS TO DEF'S CUSTOMERS?

A No. As previously stated, the amount of any fuel savings will also depend on future natural gas prices. If natural gas prices are well below DEF's projections, the projected production cost savings may not fully materialize even if the Proposed Solar Projects are built within budget, operate at the projected capacity factors and are fully eligible for PTCs.

In summary, DEF's customers will continue to face significant risks of higher rates as a result of the Proposed Solar Projects, even if the recommended protections are implemented. However, the Commission should more appropriately apportion the risks of DEF's 14 Proposed Solar Projects between customers and DEF than would be the case in the absence of any ratepayer protections.

Conclusion

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

A Given the significant uncertainty surrounding the cost-effectiveness of the Proposed Solar Projects, the Commission should make the following findings:

- Implement a cost cap of $1,524 per kW for the Proposed Solar Projects.
- Establish a minimum annual capacity factor for the Proposed Solar Projects of 27%. In the event this minimum annual capacity factor is not met, DEF's customers should be held harmless for the capacity shortfall.
- Ensure that each portion of the Proposed Solar Projects that enters rate base fully qualifies for the PTCs projected by DEF.
- Require that all PTCs (grossed up for income taxes) be included as offsets to the base revenue requirements associated with the Proposed Solar Projects.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A
Qualifications of Jonathan Ly

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly. My business mailing address is 1314 Welch Street, Unit A, Houston, TX 77006.

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

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I received a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley in 2013 and a Master's degree in Energy and Earth Resources from the University of Texas at Austin in 2017. In addition, I have completed a course in utility accounting and finance.

I joined J. Pollock, Incorporated in 2018 as an energy analyst assisting consultants in the preparation of financial and economic studies of investor-owned, cooperative, and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, integrated resource planning, and certificates of convenience and necessity. I began working as a regulatory consultant affiliated with J. Pollock, Incorporated in 2021 expanding upon my responsibilities and assignments in matters I had previously worked on as an energy analyst. I have been involved in various projects in multiple states including Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming.

Q **PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

A J. Pollock, Inc. 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.

C30-3075

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jonathan Ly

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
240202	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Solar Projects; Cost-Effectiveness Analysis; Consumer Protections	6/6/2024
240101	DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Association, Inc.	E-7. SUB 1304	Direct	NC	Fuel and Fuel-Related Cost Factors	5/23/2024
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Rebuttal	MI	Uncollectible Expense Allocation; Economic Breakeven Points	5/17/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Stipulation Support	NM	Stipulation Support regarding Long-Term Purchased Power Agreement and Ratemaking Treatment	5/10/2024
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Direct	MI	Class Cost-of-Service Study; Revenue Allocation; Rate Design	4/22/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Direct	NM	Long-Term Purchased Power Agreement; Ratemaking Requests	4/1/2024
210301	LCRA TRANSMISSION SERVICES CORPORATION	Texas Industrial Energy Consumers	55867	Direct	TX	Wholesale Transmsision Rate	3/18/2024
231203	MINNESOTA POWER	Large Power Intervenors	E-015/GR-23-155	Direct	MN	Advanced Metering Infrastructure; Class Revenue Allocation; Rider for Voluntary Renewable Energy	3/18/2024
240102	NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	23-G-0627	Direct	NY	Class Revenue Allocation; Rate Design	3/1/2024
220604	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00252-UT	Direct	NM	Certificate of Convenience and Necessity	12/1/2023
230301	EL PASO ELECTRIC COMPANY	Texas Industrial Energy Consumers	54929	Direct	TX	Certificate of Convenience and Necessity	10/24/2023
220504	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revised Class Cost-of-Service Study; Class Revenue Allocation; Energy Assistance Program	8/4/2023
230502	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Surrebuttal	AR	Additional Sum associated with Power Purchase Agreements	7/20/2023
230502	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Direct	AR	Additional Sum associated with Power Purchase Agreements	6/8/2023
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Rebuttal	MI	Uncollectible Expense Allocator	5/8/2023
221201	CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Direct	MI	Class Cost-of-Service Study, Allocation of Other Distribution Plant; Average & Peak Versus Average & Excess Methods	4/17/2023
220503	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Surrebuttal	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	8/1/2022
220503	ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Direct	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	6/22/2022

C30-3076

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 JONATHAN LY

STATE OF TEXAS)
) SS
COUNTY OF HARRIS)

Jonathan Ly, being first duly sworn, on his oath states:

1. My name is Jonathan Ly. I am a regulatory consultant affiliated with J. Pollock, Incorporated which is located at 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. J. Pollock, Inc. has 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.

Jonathan Ly

Subscribed and sworn to before me this 11th day of June 2024.

JANET SANTA MARIA
Notary Public, State of Texas
Comm. Expires 05-06-2028
Notary ID 132466829

Janet Santa Maria Notary Public

Commission #: 132466829

My Commission expires on 05-06-2028.

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(Transcript continues in sequence in Volume 6.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 4th day of September, 2024.

Debbie R. Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028