BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240001-EI

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
__________________________________/

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PROCEEDINGS: HEARING

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

DATE: Tuesday, November 5, 2023

TIME: Commenced: 10:00 a.m.
Concluded: 11:54 a.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
TALLAHASSEE, FLORIDA
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APPEARANCES:

MARIA JOSE MONCADA, WILLIAM P. COX and DAVID LEE, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420; appearing on behalf of Florida Power & Light Company (FPL).

MATTHEW R. BERNIER and STEPHANIE A. CUELLO, ESQUIRES, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, LLC (DEF).

MALCOLM N. MEANS, J. JEFFREY WAHLEN and VIRGINIA PONDER, ESQUIRES, Ausley Law Firm, Post Office Box 391, Tallahassee, Florida 32302; appearing on behalf of Tampa Electric Company (TECO).

BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301; appearing on behalf of Florida Public Utilities Company (FPUC).

APPEARANCES CONTINUED:

WALT TRIERWEILER, PUBLIC COUNSEL; CHARLES J. REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA CHRISTENSEN, MARY A. WESSLING OCTAVIO SIMOES-PONCE and AUSTIN WATROUS, ESQUIRES, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400; appearing on behalf of the Citizens of the State of Florida (OPC).

JON C. MOYLE, JR. and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, FL 32301; appearing on behalf of Florida Industrial Users Group (FIPUG).

ROBERT SHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry and Harper, P.A., 1300 Thomaswood Drive, Tallahassee Beach, Florida 32308; appearing on behalf of Florida Retail Federation (FRF).

JAMES W. BREW, LAURA W. BAKER and SARAH B. NEWMAN, ESQUIRES, Stone Law Firm, 1025 Thomas Jefferson Street NW, Suite 800 West Washington, DC 20007; appearing on behalf of Florida White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate - White Springs (PCS).

APPEARANCES CONTINUED:

PETER J. MATTHEIS, MICHAEL K. LAVANGA and JOSEPH R. BRISCAR, ESQUIRES, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, D.C. 20007; appearing on behalf of Nucor Steel Florida, Inc., (NUCOR).

SUZANNE BROWNLESS and RYAN SANDY, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

KEITH C. HETRICK, GENERAL COUNSEL; OCTAVIO CIBULA, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

P R O C E E D I N G S

CHAIRMAN LA ROSA: Let's move to the 07 -- excuse me, the 01 docket. I will give staff a few seconds to move around a little bit and get comfortable.

MS. BROWNLESS: Thank you.

CHAIRMAN LA ROSA: I will assume by having your card out there, that means you are officially ready.

MS. BROWNLESS: Yes.

CHAIRMAN LA ROSA: All right. Ms. Brownless, ready when you are. Yep, I am sorry, let's go ahead and start with preliminary matters.

MS. BROWNLESS: Yes, sir.

There are proposed Type 2 stipulations for all issues except Issues 2K through 2N, FPL's issues associated with replacement power for the St. Lucie Nuclear Units 1 and 2.

The issues for which there are proposed Type 2 stipulations can be voted on today.

The procedural issues associated with FPL's Issues 2K through 2N should also be voted on today.

Nucor and PCS Phosphate have been excused from today's hearing.

CHAIRMAN LA ROSA: Excellent. Let's move, then, to the prefiled testimony.

MS. BROWNLESS: All parties have agreed to excuse all listed witnesses and the prefiled testimonies of all witnesses have been stipulated to by all parties.

We would ask that the prefiled testimony of all witnesses listed on page five of the Prehearing Order be moved into the record at this time.

CHAIRMAN LA ROSA: All right. Then the listed prefiled testimony is moved into the record without any objection.

(Whereupon, prefiled direct testimony of Gary P. Dean was inserted.)

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DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20240001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2023 - December 2023

DIRECT TESTIMONY OF
Gary P. Dean

April 3, 2024

Q. Please state your name and business address.

A. My name is Gary P. Dean. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company"), as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for DEF. These responsibilities include completion of regulatory financial reports and analysis of local, state, and federal regulations and their impacts on DEF. In this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated Projection, and Projection Filings in the Fuel Adjustment, Capacity Cost Recovery, and Environmental Cost Recovery Clauses.

Q. Please describe your educational background and professional experience.

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A. I received a Master of Business Administration from Rutgers University and a Bachelor of Science degree in Commerce and Engineering, majoring in Finance, from Drexel University. I joined DEF on April 27, 2020, as the Rates and Regulatory Strategy Manager. Prior to working at DEF, I was the Senior Manager, Optimization for Chesapeake Utilities Corporation ("CUC"). In this role, I was responsible for all pricing related to the company's natural gas retail business. Prior to working at CUC, I was the General Manager, Electric Operations for South Jersey Energy Company ("SJEC"). In that capacity I held P&L and strategic development responsibility for the company's electric retail book. Prior to working at SJEC I had various positions associated with rates and regulatory affairs. In these positions I was responsible for all rate and regulatory matters, including tariff and rate design, financial modeling, and analysis, and ensuring accurate rates for billing.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2023 through December 2023, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. (GPD-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. (GPD-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. (GPD-3T), Schedules A1 through A3, A6, and A12 for December 2023, year-to-date; Exhibit No. (GPD-4T), DEF's capital structure and cost rates; and Exhibit No. (GPD-5T), DEF's Annual Clean Energy Impact Program report. Schedules A1 through A9, and A12 for the year ended December 31, 2023, were originally filed with the Commission on January 19, 2024.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, provisions of the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission, and any accounting rules and orders established by this Commission. The Company relies on the information included in this testimony and exhibits in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-2023-0343-FOF-EI, the total estimated 2023 period ending fuel under-recovery is $554.9 million. The actual under-recovery for 2023 is $574.1 million, resulting in a final fuel adjustment true-up under-recovery amount of $19.2 million. Exhibit No. (GPD-1T).

Per Order No. PSC-2023-0343-FOF-EI, the estimated 2023 capacity cost recovery true-up amount was an under-recovery of $10,551,826. The actual capacity true-up amount for 2023 is an under-recovery of $18,983,615, resulting in a final capacity true-up under-recovery amount of $8,431,789 million. Exhibit No. (GPD-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2023 for fuel cost recovery?

A. The actual ending balance as of December 31, 2023, for true-up purposes is an under-recovery of $574,091,902, as shown on Exhibit No. (GPD-1T).

Q. How does this amount compare to DEF's 2023 ending balance included in the Company's September 5, 2023 Projection Filing?

A. The actual true-up amount for the January 2023 - December 2023 period is an under-recovery of $574,091,902, which is $19,202,150 greater than the year end estimated under-recovery balance of $554,889,752 included in

DEF's Projection filing approved by Order No. PSC-2023-0343-FOF-EI, as shown on Exhibit No. (GPD-1T).

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company monthly, which included an update to reflect the True-Up WACC as prescribed in Order No. PSC-2020-0165-PAA-EU.

Q. What factors contributed to the increase of $19,202,150 in the period-ending jurisdictional net under-recovery shown on your Exhibit No. (GPD-1T)?

A. The $19.2 million is driven primarily by increased generation and purchase power costs of $14.9 million and $29.0 million, respectively, offset by $22.9 million in higher sales.

Q. Please explain the components shown on Exhibit No. (GPD-1T), sheet 6 of 6, which helps to explain the $41.3 million unfavorable system variance from the actual-estimate projected cost of fuel and net purchased power transactions.

A. Exhibit No. (GPD-1T), sheet 6 of 6 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the <u>amount</u> (mWh's) of energy required; (2) changes in the

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<u>heat rate</u> of generated energy (BTU's per kWh); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $41.3 million unfavorable system variance is mainly attributable to higher light oil and coal generation and firm and economy purchases.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. (GPD-3T) in the footnote to line 6b on page 1 of 2, Schedule A2. Consistent with Order No. PSC-2018-0240-PAA-EQ, DEF included an adjustment of approximately $12.3 million system ($12.2 million retail) for amortization of the Florida Power Development, LLC, qualifying facility regulatory asset.

Q. Did DEF make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes. DEF included a $3.5 million reduction to coal inventory attributable to semi-annual aerial surveys conducted on May 10and November 6, 2023, in accordance with Order No. PSC-1997-0359-FOF-EI, Docket No. 19970001-EI. This adjustment represents 1.8% of the total coal consumed at the Crystal River facility in 2023.

Q. Did DEF exceed the economy sales threshold in 2023?

A. No. DEF did not exceed the gain on economy sales threshold of $3.2 million in 2023. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2023 was $3.1 million. Consistent with Order No. PSC-2001-2371-FOF-EI, shareholders will not retain any of the gain.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2023 hearings been updated to incorporate actual data for all of year 2023?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2021 through 2023, as follows:

Year	Actual Gain
2021	$ 2,855,389
2022	$ 5,458,082
2023	$3,105,955
Three-Year Average	$ 3,806,475

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2023, for capacity cost recovery?

A. The actual ending balance as of December 31, 2023, for true-up purposes is an under-recovery of $18,983,615, as shown on Exhibit No. (GPD-2T).

Q. How does this amount compare to the estimated 2023 ending balance included in the Company's Actual/Estimated Filing?

A. When the estimated 2023 under-recovery of $10,551,826 is compared to the $18,983,615 actual under-recovery, the final capacity true-up for the twelve-month period ended December 2023 is an under-recovery of $8,431,789, as shown on Exhibit No. (GPD-2T).

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission.

Q. What factors contributed to the actual period-end capacity under-recovery of $8.4 million?

A. Exhibit No. (GPD-2T), sheet 1 of 3, compares actual results to the original projection for the period. The $8.4 million under-recovery is primarily due to lower capacity revenue in conjunction with higher capacity costs.

OTHER MATTERS

Q. What capital structure and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2023 through December 2023?

A. DEF used the capital structure and cost rates consistent with the language in Order Nos. PSC-2020-0165-PAA-EU and PSC-2022-0357-FOF-EI. The capital structure and cost rates relied on to calculate the revenue requirement rate of return for the period January 2023 through December 2023 are shown on Exhibit No. (GPD-4T).

Q. Did DEF include its Clean Energy Impact annual program report as prescribed by Order No. PSC-2023-0191-TRF-EI, dated June 29, 2023?

A. Yes. As Ordered by the Commission, DEF has provided the annual report as Exhibit No. (GPD-5T).

Q. Does this conclude your direct true-up testimony?

A. Yes.

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DUKE ENERGY FLORIDA, LLC
DOCKET NO. 20240001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2024 through December 2024

DIRECT TESTIMONY OF
GARY P. DEAN

July 26, 2024

Q. Please state your name and business address.
A. My name is Gary P. Dean. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20240001-EI?
A. Yes. I provided direct testimony on April 3, 2024.

Q: Has your job description, education, background, and professional experience changed since that time?
A. No.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present for Commission approval the actual/estimated fuel and capacity cost recovery true-up amounts of Duke

Energy Florida, LLC ("DEF" or the "Company"), for the period of January 2024 through December 2024.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (GPD-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2024 actual/estimated fuel and purchased power true-up balance, and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2024 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2024 and estimated data from July through December 2024.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2024 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an $8,537,789 over-recovery. The calculation begins with the actual under-recovered balance of $232,659,640 taken from Schedule E1-B, page 1 of 2, line 13, through the month of June 2024. This balance plus the estimated July through

December 2024 monthly true-up calculations comprise the estimated $8,537,789 over-recovered balance at year-end. The projected December 2024 true-up balance includes interest which is estimated from July through December 2024 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.444% per month.

Q. In Order No. PSC-2024-0171-PCO-EI, the Commission approved a midcourse correction that required DEF to return its net projected $233,496,431 reduction in fuel costs for the 2024 period beginning June 2024, and further adjusted the 2024 fuel factor based on DEF's forecasted sales data for the June 2024 – May 2025 period. Please explain how the Company's currently projected true-up balance compares to the projected true-up balance approved by the Commission from DEF's midcourse.

A. As shown on Schedule E1-B, page 2 of 2, DEF is projecting a 2024 over-recovered true-up balance of $8,537,789. This is an $88,752,391 reduction from the approved projected 2024 remaining midcourse over-recovery of $97,290,180 (calculated as follows: 2024 midcourse net projected over-recovery of $233,496,431 divided by 12 months times 5 months in 2025). The reduction is primarily due to higher fuel costs.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2024 compare with the same period forecast used

in the Company's 2024 Mid-Course Correction Filing approved in Order No. PSC-2024-0171-PCO-EI?

A. Light oil decreased $0.45/mmbtu (1%). Coal and natural gas increased $0.05/mmbtu (1%) and $0.34/mmbtu (8%), respectively.

Q. Have any adjustments been made to estimated fuel costs for the period January 2024 through December 2024?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $11.8 million (grossed up to approximately $11.8 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2024 through December 2024. There was a coal inventory adjustment of approximately $2.9 million attributable to the semi-annual aerial survey conducted on May 6, 20243, in accordance with Order No. PSC-1997-0359-FOF-EI in Docket No. 1997001-EI. There was also an approximate $1.0 million in adjustments for net metering settlements. These adjustments are included on Schedule E1-B, line A5, columns Jan. Actual through Dec. Estimated.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2024?

A. Yes. DEF estimates the total gain on non-separated sales during 2024 will be $5,021,345 which exceeds the three-year rolling average of $3,806,475. Consistent with Order No. PSC-2000-1744-PAA-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2024, this is estimated to be $242,974.

CAPACITY COST RECOVERY

Q. What is DEF's 2024 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is a $6,798,946 under-recovery. The estimated true-up calculation begins with the actual under-recovered balance of $48,346,321 as of June 2024. This balance plus the estimated July through December 2024 monthly true-up calculations comprise the estimated $6,798,946 under-recovered balance at year-end. The projected December 2024 true-up balance includes interest which is estimated from July through December 2024 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.444% per month.

Q. What are the primary drivers of the estimated year-end 2024 capacity under-recovery?

A. The $6.8 million under-recovery is primarily attributable to increased forecasted revenues of approximately $3.8M, reduced by the $8.4 million Capacity Cost Recovery Clause 2023 net under-recovery filed on April 3, 2023 in the instant docket.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20240001-EI

Fuel and Capacity Cost Recovery Factors
January 2025 through December 2025

DIRECT TESTIMONY OF
GARY P. DEAN

September 5, 2024

Q. Please state your name and business address.

A. My name is Gary P. Dean. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20240001-EI?

A. Yes, I provided direct testimony on April 3, 2024, and July 26, 2024.

Q. Has your job description, education, background and/or professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

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A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Duke Energy Florida, LLC ("DEF" or the "Company") for the period of January 2025 through December 2025.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.(GPD-3), consisting of Parts 1, 2 and 3. Part 1 contains DEF's fuel cost forecast assumptions. Part 2 contains fuel cost recovery ("FCR") schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have also included a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required by Order No. PSC-2020-0165-PAA-EU. Part 3 contains capacity cost recovery ("CCR") schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.918 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.7623 ¢/kWh (adjusted for jurisdictional losses), an estimated prior period over-recovery true-up of (0.0209) ¢/kWh, a GPIF cost of 0.0039 ¢/kWh, a Clean Energy Connection

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("CEC") Program bill credit of 0.1738 ¢/kWh, and a Clean Energy Impact credit of (0.0006) ¢/kWh. Using this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated and 1% and 2% metering reduction factors are applied to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the CCR factors.

Schedule E1-D, lines 11-12 show the Company's proposed tiered rates of 3.630 ¢/kWh for the first 1,000 kWh and 4.700 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2 of my exhibit.

Schedule E1-E develops the Time of Use ("TOU") multipliers of 1.137 On-Peak, 0.995 Off-Peak and 0.909 Discount, consistent with DEF's 2024 Settlement Agreement approved by the Commission in Docket No. 20240025. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. In Order No. PSC-2024-0171-PCO-EI, the Commission approved a midcourse correction that required DEF to reduce its 2024 fuel cost factors effective June

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2024, based on projected sales from June 2024 through May 2025 to develop the revised fuel factors. Please explain how the Company's requested 2025 fuel cost recovery accounts for the impacts of this Order.

A. As shown on Schedules E1-A and E1-B DEF is projecting a fuel true-up balance over-recovery of $8,537,789, which denotes that it will reduce the 2025 projected fuel costs, as shown on Schedule E1-D. Since DEF's projected true-up balance is only $8,537,789, DEF has reflected a full 12-month recovery in 2025, in the normal process for handling actual/estimated true-up balances, rather than a January through May 2025 recovery.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The 2025 projected levelized residential fuel factor of 3.925 ¢/kWh is a decrease of 0.745 ¢/kWh or 16.0% from the 2024 revised levelized residential fuel factor of 4.670 ¢/kWh from DEF's mid-course filing approved in Order No. PSC-2024-0171-PCO-EI.

Q. Please explain the decrease in the 2025 fuel factor compared with the 2024 fuel factor.

A. The primary driver of the decrease in the 2025 fuel factor is a decrease in the prior period true-up of approximately $427M partially offset by an increase in year-over-year jurisdictional fuel and purchased power expense of approximately $288M.

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Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2025?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ, DEF included a retail adjustment of $11.26M for the January through December 2025 amortization of the Florida Power Development, LLC, qualifying facility regulatory asset.

Per Order No. PSC-2021-0059-S-EI, DEF has included $70.9M of costs associated with the 2025 projected bill credits for the DEF CEC Program as shown on Exhibit GPD-3, Schedule E1, line 25. As approved by this Order, bill credits are recovered through DEF's fuel and purchased power cost recovery clause.

Per Order No. PSC-2023-0191-TRF-EI, a credit of $248.3K is included for Clean Energy Impact ("CEI") as shown on Exhibit GPD-3, Schedule E1, line 26. As approved by this Order, net program revenues from REC sales are credited to the fuel clause to offset other fuel expenses.

Q. Does the 2025 Projection Filing comply with the 2024 Settlement Agreement that was approved by the Commission on August 21, 2024, in Docket No. 20240025?

A. Yes. All matters in the 2024 Settlement Agreement have been incorporated into the filing.

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Q. Will DEF continue the tiered rate structure for residential customers?

A. Yes, DEF will continue to use inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company will use a two-tiered fuel charge whereby the charge for a residential customer's monthly usage in excess of 1,000 kWh (second tier) is priced 1.07 cents per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000-kWh price change breakpoint is reasonable in that approximately 72% of all residential energy is consumed in the first tier and 28% in the second tier. The Company believes the 1.07 cent higher per unit price, targeted at the second tier of the residential class energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company's base rates per the 2021 Settlement Agreement.

Q. How was the inverted fuel rate calculated?

A. Exhibit GPD-3, Inverted Fuel Rates, shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.925 ¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

C2-205

Q. Is DEF's current sharing mechanism impacted by its 2024 Settlement Agreement in Docket No. 20240025?

A. Yes. On August 21, 2024, the Commission approved DEF's 2024 Settlement Agreement. Effective January 2025, this settlement provides for DEF to implement an Asset Optimization Mechanism ("AOM"), and as a result the current sharing mechanism will not be applicable after 2024. As stated in my Actual-Estimated testimony filed on July 26, 2024, in this Docket, DEF estimates that its total gains on short-term wholesale power sales during 2024 will be $5,021,345, which will exceed the three-year rolling average of $3,806,475, and therefore DEF estimates that it will retain $242,974 under the current mechanism. Under the new program, gains on short-term wholesale power sales, short-term wholesale power purchase savings, and gains on all forms of asset optimization will be shared between customers and shareholders. On an annual basis, DEF customers will receive 100% of the gains up to a threshold of $4.9 million ("Customer Savings Threshold"). Incremental gains above the Customer Savings Threshold will be shared between DEF and customers as follows: DEF will retain 60% and customers will receive 40% of incremental gains between $4.9 million and $9.8 million; and DEF will retain 50% and customers will receive 50% of all incremental gains in excess of $9.8 million.

Q. Please explain the entry on Schedule E1, line 11, "Fuel Cost of Stratified Sales."

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A. DEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI and Reedy Creek for fixed amounts of base, intermediate, peaking, solar and plant-specific capacity. DEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-1997-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model along with purchased power information, generating unit operating characteristics, maintenance schedules, incremental delivered fuel prices and other pertinent data. The model then computes

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system fuel consumption and fuel and purchased power costs. This information is the basis for the calculation of the Company's fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. System sales are forecasted by the DEF Load Forecasting and Fundamentals Department using inputs including a sales-weighted 30-year average of weather conditions at the St. Petersburg, Orlando and Tallahassee weather stations, population projections and State of Florida economic assumptions from Moody’s Analytics. The Energy Information Agency (EIA) surveys of class energy consumption for the South Atlantic Region are incorporated as well.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts are based on a combination of third-party forecasts and forward contracts currently in place. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day. Consistent with past practices, DEF will continue to monitor fuel prices and update the Projection Filing prior to the November Hearing if changes in fuel prices warrant such an update.

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Q. Is the 2023 GPIF reward discussed in the March 15, 2024, direct testimony of Adam Bingham included in the proposed 2025 rates?

A. Yes. The GPIF reward of $1,603,057 is included on Schedule E1, line 24.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit (GPD-3) Part 3.

A. The following schedules are included in my exhibit:

Schedule E12-A – Calculation of Projected Capacity Costs – Year 2025

Schedule E12-A, page 1, includes estimated 2025 calendar year system capacity payments to Qualifying Facilities ("QF") and other power suppliers. The retail portion of the capacity payments is calculated using separation factors consistent with the 2024 Settlement Agreement approved by the Commission on August 21, 2024, in Docket No. 20240025.

The recovery of estimated Dry Casket Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included Schedule E12-A, page 1, line 35. The calculation of Total Recoverable Capacity & ISFSI costs are shown on line 36.

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Schedule E12-A, page 2, provides the dates and MWs associated with the QF and purchase power contracts.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2024

Schedule E12-B calculates the estimated true-up capacity under-recovered balance for the calendar year 2024 of $6,798,946. This schedule was also included in Exhibit GPD-2 to my direct testimony filed on July 26, 2024. The balance on Schedule E12-B is carried forward to Schedule E12-A, page 1, line 33 to be recovered from customers from January through December 2025.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the 12CP and 25% average demand allocators for each rate class. Schedule E12-D also includes the uniform percentage calculation and allocation of the ISFSI revenue requirement to the rate classes.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E calculates the CCR factors for capacity costs for each rate class based on the 12CP and 25% annual average demand allocators and ISFSI costs from Schedule E12-D. The factors for the Residential, General Service Non-Demand, General Service (GS-2) and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. The factor for ISFSI in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor, respectively. The factors allocate capacity costs to rate classes in the same way as would be allocated if recovered in base rates. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI. Pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilowatt (kW) rather than a kilowatt-hour (kWh) basis. These changes are reflected on Schedule E12-E in columns 11 through 13.

Q. Has DEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from DEF's most recent load research conducted for the period January through December 2022 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on April 28, 2023.

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Q. What is the 2025 projected average retail CCR factor?

A. The 2025 average retail CCR factor is 0.358 ¢/kWh, made up of capacity of 0.330 ¢/kWh and ISFSI costs of 0.028 ¢/kWh.

Q. Please explain the change in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The total projected average retail CCR rate of 0.358 ¢/kWh is 0.469 ¢/kWh, or 57%, less than the current 2024 factor of 0.827 ¢/kWh. This decrease is primarily due to four contracts terminating by the end of 2024 as reflected on Schedule E12-A.

Q. Does this conclude your testimony?

A. Yes

(Whereupon, prefiled direct testimony of Adam R. Bingham was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20240001-EI

GPIF Schedules for
January through December 2023

DIRECT TESTIMONY OF ADAM ROSS BINGHAM

March 15, 2024

Q. Please state your name and business address.

A. My name is Adam Bingham. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Florida, LLC ("DEF") as a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization.

Q. Describe your responsibilities as a Lead Fuels and Fleet Analyst.

A. As a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization, I analyze and model energy portfolios for DEF. My responsibilities include planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned Bachelor of Science and Master of Science degrees in Nuclear Engineering from Texas A&M University in 2007 and 2009, respectively. After graduation, I began working for Duke Energy in the Nuclear Fuels Engineering department located in Charlotte, NC, as an Engineer I in the Safety Analysis group. As a Safety Analysis engineer, my responsibilities included performing steady-state and transient computational analysis for a variety of nuclear reactor designs to support fuel reload activities and ensure plant changes comply with design and licensing basis requirements. In 2012, I acquired my Professional Engineer license for the state of North Carolina, which I actively hold today, and in 2013, I was promoted to Senior Engineer. In 2017, I moved to Nuclear Design within the Nuclear Fuels Engineering department as a Senior Engineer, where I performed quantitative analyses to support reload activities that design the fuel loading requirements for each nuclear plant. Additionally, I took on the role of fleet lead for developing and implementing new core monitoring software for all Westinghouse-designed nuclear power plants operated by Duke Energy and its subsidiaries. In 2019, I joined the Fuels and System Optimization department as a Senior Analyst in the Fuels and Fleet Analytics group. Within this role, I performed production cost modeling and system optimization analyses for DEF's portfolio of generating units, power purchases and sales. As part of this transition, I also became the coordinator of DEF's Generating Incentive Factor (GPIF) program. In 2022, I was promoted to the position of Lead Fuels & Fleet Analyst.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2023. This calculation was based on a comparison of the actual performance of DEF's Eight (8) GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. (ARB-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 26-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a reward of $1,603,057. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward/(penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 16 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability primarily concern the differences between target and actual planned outage hours and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF) and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

In addition, the Bartow CC unit had data excluded during the period in which its steam turbine was in a planned outage. The Bartow CC unit has the capability to be operated in simple cycle mode while the steam turbine is in an outage. When operating in simple cycle mode, the unit's heat rate will deviate significantly from its normal range. DEF's heat rate target setting process for the Bartow CC unit excludes historical data from periods when the unit operated in simple cycle mode. From mid-October until mid-December 2023 the steam turbine was in a planned outage; during this period, the Bartow CC unit was operated in simple cycle. To be consistent with the target setting process, simple cycle mode heat rate data was excluded from actuals for the purposes of calculating the heat rate for the Bartow CC in year 2023 during those times when the unit was being operated in simple cycle mode as the result of a planned outage.

Q. Have you provided the as-worked planned outage schedules for DEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 25 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 26 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA FOR FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH DECEMBER 2023

FPSC DOCKET NO. 20240001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2025

DIRECT TESTIMONY OF ADAM ROSS BINGHAM

September 5, 2024

Q. Please state your name and business address.

A. My name is Adam Bingham. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Florida, LLC ("DEF") as a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization.

Q. What are your responsibilities in that position?

A. As a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization, I analyze and model energy portfolios for DEF. My responsibilities include planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

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Q. Please describe your educational background and professional experience.

A. I earned Bachelor of Science and Master of Science degrees in Nuclear Engineering from Texas A&M University in 2007 and 2009, respectively. After graduation, I began working for Duke Energy in the Nuclear Fuels Engineering department located in Charlotte, NC, as an Engineer I in the Safety Analysis group. As a Safety Analysis engineer, my responsibilities included performing steady-state and transient computational analysis for a variety of nuclear reactor designs to support fuel reload activities and ensure plant changes comply with design and licensing basis requirements. In 2012, I acquired my Professional Engineer license for the state of North Carolina, which I actively hold today, and in 2013, I was promoted to Senior Engineer. In 2017, I moved to Nuclear Design within the Nuclear Fuels Engineering department as a Senior Engineer, where I performed quantitative analyses to support reload activities that design the fuel loading requirements for each nuclear plant. Additionally, I took on the role of fleet lead for developing and implementing new core monitoring software for all Westinghouse-designed nuclear power plants operated by Duke Energy and its subsidiaries. In 2019, I joined the Fuels and System Optimization department as a Senior Analyst in the Fuels and Fleet Analytics group. Within this role, I performed production cost modeling and system optimization analyses for DEF's portfolio of generating units, power purchases and sales. As part of this transition, I also became the coordinator of DEF's Generating Incentive Factor (GPIF) program. In 2022, I was promoted to the position of Lead Fuels & Fleet Analyst.

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2023, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2025. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated and reported in your March 15, 2024 testimony for the period January through December 2023?

A. DEF's calculated GPIF incentive amount for this period was a reward of $1,603,057. Please refer to my testimony filed March 15, 2024 for the details of how this incentive amount was calculated.

Q. Have there been any adjustments to the incentive amount filed in March?

A. No.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. (ARB-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2025 projection period, the GPIF program includes the following units: Bartow Unit 4, Citrus CC Unit 1, Citrus CC Unit 2, Crystal River Unit 5, Hines Units 1, 2, 3 and 4, and Osprey Unit 1. Combined, these units account for 81% of the estimated total system net generation for the period.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. (ARB-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate ("EUOR"). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> ("EUOF"). Because factors are additive (unlike rates), the EUOF and planned outage factor ("POF") when added to the equivalent availability factor ("EAF") will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%. The supporting tables and graphs for the target and range rates are contained in pages 49-94 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in historical performance?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. (ARB-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 30-48 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

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Q. What is the Company's estimated maximum incentive amount for 2025?

A. The estimated maximum incentive for the Company is $16,021,013. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. (ARB-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of James "Jim" McClay was inserted.)

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC. FOR

FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2024

FPSC DOCKET NO. 20240001-EI

DIRECT TESTIMONY OF James McClay

July 26, 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is James McClay. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas ("DEC"), an affiliate company of Duke Energy Florida, LLC ("DEF," "Petitioner" or "Company") as Managing Director of Natural Gas Trading. In that capacity, I manage the organization responsible for the natural gas trading, optimization, and scheduling functions for the regulated gas-fired generation assets in the Carolinas, Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC"), Duke Energy Florida, Duke Energy Indiana and Duke Energy Kentucky (collectively, the "Utilities"), as well as the organization responsible for power trading for Duke Energy Indiana and Duke Energy Kentucky. Additionally, I oversee the execution of the Utilities' financial hedging programs, fuel oil procurement, and emissions trading.

Q. Please describe your education background and professional experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I've been employed in various managerial roles at Progress Energy and Duke Energy overseeing Power, Natural Gas and Oil trading, hedging procurement. Prior to my tenure with Duke Energy, I was employed for approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and broker/ dealers.

Q. What is the purpose of your testimony?

A. DEF does not currently propose to hedge if the Commission approves the settlement agreement filed in Docket 20240025. If the Commission does not approve the settlement, this is the plan DEF proposes to follow. DEF also understands the Commission's request for utilities to evaluate options to mitigate fuel cost volatility. DEF believes the hedging program outlined in its 2025 Risk Management Plan would accomplish that goal, should the Commission determine it is appropriate for DEF to restart the program. Therefore, the purpose of this testimony is to outline DEF's hedging objectives and activities for 2025 if it were ordered to begin hedging.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibit:

- Exhibit No.___ (JM-1P) – 2025 Risk Management Plan (*Confidential*).

Q. What are the objectives of DEF's hedging activities?

A. The objectives of DEF's hedging program are to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers.

REDACTED

Q. Describe the hedging activities that the Company will execute for 2025.

A. DEF is not proposing to implement the outlined hedging activities. While DEF believes that hedging is a reasonable and prudent approach to mitigate price volatility, it understands that key consumer groups oppose hedging. However, if the Commission decides that DEF should hedge, DEF is providing its 2025 Risk Management Plan to demonstrate how it would hedge if so ordered. If the 2025 Risk Management Plan is implemented, DEF would hedge a percentage of its projected natural gas burns utilizing approved financial agreements. With respect to hedging activity, natural gas represents the largest component of DEF's overall hedging activity given it is the largest fuel cost component. DEF's target hedging percentage ranges would be between [redacted] to [redacted] percent of its forecasted calendar annual burns. Hedging in the ranges provided would allow DEF to monitor actual fuel burns, updated fuel forecasts, and make any adjustments as needed throughout the year. If hedging were to start in 2025 the Risk Management Plan outlines the activities DEF would implement to start its hedging program in 2025 without existing hedges in place and as the hedging program begins to mature it would take DEF all of 2025, 2026 and into the first half of 2027 to execute the layered hedging strategy and reach the minimum levels outlined in the Risk Management Plan.

Q. What were the results of DEF's hedging activities for January through July 2024?

A. As approved by the Commission, DEF is currently under a moratorium on hedging and has not executed any financial hedges for any periods since October 21, 2016, and therefore does not have any hedges in place for 2024.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Amin Mohomed was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF AMIN MOHOMED

DOCKET NO. 20240001-EI

APRIL 3, 2024

Q. Please state your name, business address, employer and position.

A. My name is Amin Mohomed. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "Company") as Assistant Controller.

Q. Please summarize your educational background and professional experience.

A. I graduated from Minnesota State University, Mankato in 2008 with a Bachelor of Science Degree in Accounting and Economics and earned a Master of Business Administration degree from the same university in 2010. From 2010 to 2017, I was employed by Wilary Winn, LLC, a consulting firm based in St. Paul, Minnesota providing valuation and accounting advisory services to the banking sector. From 2017 to 2019, I worked for FPL in the Accounting Policy & Research group. In 2019, I joined the Financial Accounting Standards Board as a member of its research staff, focusing on analyzing technical accounting issues and providing recommendations that addressed the needs of financial statement users. I returned to FPL in 2021 as the Sr. Manager of Accounting Policy & Research, and in 2023, I assumed my current role of Assistant Controller responsible for overseeing FPL's general accounting functions, including cost recovery clauses. I am a Certified Public Accountant ("CPA") licensed in the State of Minnesota and a member of the American Institute of CPAs.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause true-up amounts for the period January 2023 through December 2023.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. Exhibit AM-1 contains the FCR-related schedules and Exhibit AM-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2023 through December 2023 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

A. Unless otherwise indicated, the data are taken from the accounting books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

Q. Please summarize FPL's final 2023 FCR and CCR net true-up amounts.

A. The 2023 Final net true-up for the FCR is an over-recovery of $37,290,272 (Exhibit AM-1, page 1), inclusive of interest. Commencing May 1, 2024, the $37,290,272 net over-recovery will be flowed back to customers through updated FCR Factors approved as part of FPL's Mid-Course Correction filed on March 13, 2024.

The 2023 Final net true-up for the CCR Clause is an over-recovery, including interest, of $7,342,001 (Exhibit AM-2, page 1). FPL is requesting Commission approval to include this 2023 CCR Clause true-up over-recovery in the calculation of the CCR factors for the period January 2025 through December 2025.

Finally, FPL is requesting Commission approval to include $46,103,632 in the calculation of the FCR factors for the period January 2025 through December 2025, which represents FPL's share of the 2023 Asset Optimization gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

2023 FCR FINAL TRUE-UP CALCULATION

Q. Please explain the calculation of the 2023 FCR true-up amount.

A. The calculation of the FCR actual true-up by month for January 2023 through December 2023 is shown on pages 2 and 3 of Exhibit AM-1. The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Though it is not included as part of the 2023 FCR true-up calculation, have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2023?

A. Yes. Exhibit AM-1, page 3 (line 50) compares the actual end of-period true-up under-recovery, including interest, of $956,463,844 (column 3) to the actual/estimated end-of-period under-recovery of $993,754,116 (column 4) resulting in a net over-recovery of $37,290,271 (column 5). Exhibit AM-1, page 3, shows an increase in jurisdictional fuel costs of $50,255,233 (line 42) offset by the $88,505,324 increase in revenues (line 38), less interest of $959,830 (line 44) resulting in $37,290,271 (Line 50).

Q. Please summarize the variance schedule on page 4 of Exhibit AM-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.99 billion for 2023 (Exhibit AM-1, page 3, line 42, column 4). The actual jurisdictional fuel costs and net power transactions for the 2023 period are $3.04 billion (Exhibit AM-1, page 3, line 42, column 3). The resulting jurisdictional fuel costs and net power transactions are $50 million, or 1.7%, higher than previously projected (Exhibit AM-1, page 3, line 42, column 5). Jurisdictional fuel revenues for 2022 are $89 million, or 2.7%, higher than previously projected (Exhibit AM-1, page 3, line 38, column 5).

Page 3 of Exhibit AM-1 also presents the variance on a total system basis. Total system fuel costs and net power transactions were previously estimated to be about $3.13 billion for 2023 (Exhibit AM-1, page 3, line 23, column 4). The actual system fuel costs and net power transactions for the 2023 period are about $3.19 billion (Exhibit AM-1, page 3, line 23, column 3). The resulting fuel costs and net power transactions are $57 million, or 1.8%, higher than previously projected (Exhibit AM-1, page 3, line 22, column 5).

Q. Please explain the variance for total system fuel costs and net power transactions on page 4 of Exhibit AM-1.

A. Below are the primary reasons for the $57 million (total system) variance of total fuel costs and net power transactions.

<u>Fuel Cost of System Net Generation: $77 million increase (Exhibit AM-1, page 3, line 2, column 5)</u>

The table below on pages 5 and 6 provides the detail of this variance.

Fuel Variance	2023 Final True-Up	2023 Actual/Estimated	Difference
<u>Heavy Oil</u>			
Total Dollar	$228,682	$90	$228,592
Units (MMBtu)	19,278	6	19,272
$ per Unit	11.8623	14.2519	(2.3896)
Variance Due to Consumption			$274,659
Variance Due to Cost			($46,067)
Total Variance			$228,592
<u>Light Oil</u>			
Total Dollar	$18,104,031	$9,840,941	$8,263,090
Units (MMBtu)	992,275	547,986	444,288
$ per Unit	18.245	17.9584	0.2866
Variance Due to Consumption			$7,978,688
Variance Due to Cost			$284,401
Total Variance			$8,263,090

Fuel Variance	**2023 Final True-Up**	**2023 Actual/Estimated**	**Difference**
Coal			
Total Dollar	$30,179,175	$11,190,024	$18,989,151
Units (MMBtu)	8,056,233	3,383,502	4,672,731
$ per Unit	3.7461	3.3072	0.4388
Variance Due to Consumption			$15,453,802
Variance Due to Cost			$3,535,349
Total Variance			$18,989,151
Gas			
Total Dollar	$3,101,638,120	$3,055,487,382	$46,150,737
Units (MMBtu)	735,450,508	698,524,014	36,926,494
$ per Unit	4.2173	4.3742	(0.1569)
Variance Due to Consumption			$161,524,062
Variance Due to Cost			($115,373,325)
Total Variance			$46,150,737
Nuclear			
Total Dollar	$147,315,435	$143,739,823	$3,575,613
Units (MMBtu)	309,815,284	305,753,808	4,061,476
$ per Unit	0.4755	0.4701	0.0054
Variance Due to Consumption			$1,909,366
Variance Due to Cost			$1,666,247
Total Variance			$3,575,613
Total			
Total Dollar	$3,297,465,443	$3,220,258,260	$77,207,183
Units (MMBtu)	1,054,333,578	1,008,209,316	46,124,261
$ per Unit	3.1275	3.194	(0.0665)
Variance Due to Consumption			$187,140,578
Variance Due to Cost			($109,933,395)
Total Variance			$77,207,183

<u>Fuel Cost of Stratified Sales: $6.7 million decrease (Exhibit AM-1, Page 3, line 4, column 5)</u>

The decrease is attributable to the combination of lower than projected volumes for stratified sales and lower than projected fuel costs, especially natural gas, for stratified sales. This resulted in a decrease of $6.7 million in the period.

<u>Fuel Cost of Power Sold: $16.6 million increase (Exhibit AM-1, page 3, line 5, column 5)</u>

The increase for the Fuel Cost of Power Sold was primarily attributable to higher than projected economy power sales. FPL sold about 690,000 MWh more of economy power, resulting in a volume cost increase of about $17.2 million. This increase was partially offset by lower than projected unit fuel costs associated with economy power sales. The average unit fuel cost attributable to economy power sales was $0.31/MWh lower than projected, resulting in a cost decrease of about $1.2 million. The remaining increase was attributable to higher than projected St. Lucie Plant Reliability Exchange sales and higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

<u>Gains from Off-System Sales: $3.9 million increase (Exhibit AM-1, page 3, line 6, column 5)</u>

The increase for Gains from Off-System Sales was attributable to higher than projected economy power sales which was partially offset by lower than projected margins on economy power sales. FPL sold nearly 690,000 MWh more of economy power, resulting in a volume increase of $13.8 million. Margins on economy power sales averaged $2.71/MWh lower than projected, resulting in a revenue decrease of $9.8 million. The combination of higher economy power sales and lower margins on economy power sales resulted in a total increase in Gains from Off-System Sales of $3.9 million.

<u>Energy Payments to Qualifying Facilities: $0.6 million decrease (Exhibit AM-1, page 3, line 8, column 5)</u>

The decrease in Energy Payments to Qualifying Facilities was attributable to lower than projected purchases and lower than projected costs from Qualifying Facilities. In total, FPL purchased about 3,800 MWh less than projected, resulting in a volume decrease of about $148,000. The average unit fuel cost for these purchases was $0.86/MWh lower than projected, resulting in a cost decrease of about $449,000. The combination of lower purchases and lower fuel costs for Qualifying Facilities resulted in a total cost decrease of about $597,000.

<u>Energy Cost of Economy Purchases: $2.9 million increase (Exhibit AM-1, page 3, line 9, column 5)</u>

The increase was primarily attributable to higher than projected costs for economy power purchases. The unit costs for economy power purchases were $19.36/MWh higher than expected for the period.

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<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.2 million increase (Exhibit AM-1, page 3, line 13, column 5)</u>

The increase was attributable to higher than projected economy power sales.

<u>Variable Power Plant O&M Avoided Due to Economy Purchases: $2,073 decrease (Exhibit AM-1, page 3, line 14, column 5)</u>

The decrease was attributable to lower than projected economy power purchases.

<u>Optimization Credits: $9.2 million increase (Exhibit AM-1, page 3, line 15, column 5)</u>

The increase of about $9.2 million was attributable to higher than projected gains from natural gas optimization activities and the sale of renewable energy credits.

Q. What is the variance in retail FCR revenues?

A. As shown on Exhibit AM-1, page 3, line 38, actual 2023 jurisdictional FCR revenues were approximately $89 million higher than estimated. This is primarily due to 2,146,746,623 kWh higher than estimated jurisdictional sales (page 3, line 26, column 5).

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $46,103,632 as its share of the 2023 Asset Optimization gains. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2023 Asset Optimization gains through the 2025 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized amount of the gain in the calculation of the 2025 FCR factors and will reflect recovery of one-twelfth of the approved amount in each month's Schedule A2 for the period January 2025 through December 2025 as a reduction to jurisdictional fuel revenues applicable to each period.

2023 CCR FINAL TRUE-UP CALCULATION

Q. Please explain the calculation of FPL's 2023 CCR net true-up amount.

A. Exhibit AM-2, page 1 provides the calculation of the CCR net true-up for the period January 2023 through December 2023, an over-recovery of $7,342,001, which FPL is requesting to be included in the calculation of the CCR factors for the January 2025 through December 2025 period.

The actual end-of-period over-recovery for the period January 2023 through December 2023 of $10,621,656, shown on line 3 less the actual/estimated end-of-period over-recovery for the same period of $3,279,655 shown on line 7 that was approved by the Commission in Order No. PSC-2023-0343-FOF-EI, results in the net true-up over-recovery for the period January 2023 through December 2023 of $7,342,001 shown on line 9.

Q. Have you provided a schedule showing the calculation of the 2023 CCR actual true-up by month?

A. Yes. Exhibit AM-2, pages 2 through 4, shows the calculation of the CCR true-up for the period January 2023 through December 2023 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR Clause?

A. Yes. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2023?

A. Yes. Exhibit AM-2 pages 5 and 6 show the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2023 through December 2023.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit AM-2, page 5, line 13, column 5, the variance related to total system capacity costs is a decrease of $4.6 million or 1.8%. Below are the primary reasons for the decrease.

<u>Transmission of Electricity by Others: $1.7 million decrease (Exhibit AM-2, page 5, line 3, column 5)</u>

The decrease is primarily due to lower than projected purchases of transmission service to move energy associated with purchased power agreements into FPL's service area. The remaining amount of the decrease is due to lower than projected purchases of third-party transmission service used to facilitate economy power sales during the period.

Transmission Revenues from Capacity Sales: $1.4 million increase (Exhibit AM-2, page 5, line 4, column 5)

The increase is primarily attributable to higher than projected economy power sales which resulted in higher than projected transmission revenues from economy power sales.

Q. Please describe the variance in 2023 CCR revenues.

A. As shown on page 6, line 23, column 5, actual 2023 CCR revenues are $4.4 million lower than projected in the actual/estimated true-up filing.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit AM-2 as pages 16 and 17. Page 16 shows the actual capacity payments for FPL's Power Purchase Agreements for the period January 2023 through December 2023. Page 17 provides the short-term capacity payments for the period January 2023 through December 2023.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the CCR Clause?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2023 through December 2023 are included on page 18 of Exhibit AM-2.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF AMIN MOHOMED

DOCKET NO. 20240001-EI

JULY 26, 2024

Q. Please state your name, business address, employer and position.

A. My name is Amin Mohomed. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "Company") as Assistant Controller.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Florida Public Service Commission ("Commission") review and approval the calculation of FPL's actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2024 through December 2024.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibits AM-3 and AM-4. Exhibit AM-3 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2024 through December 2024. FCR Schedules A1 through A9 provide actual data for the period January 2024 through

June 2024. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit AM-3 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2024 through December 2024.

Exhibit AM-4 contains the CCR schedules, which provide the calculation of FPL's actual/estimated true-up amount and actual/estimated variances for the period January 2024 through December 2024.

Q. What is the source of the actual data that you present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the accounting books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with Generally Accepted Accounting Principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR actual/estimated true-up calculation compares actual data for January 2024 through June 2024 and revised estimates for July 2024 through December 2024 to the data reflected in FPL's 2024 FCR midcourse correction approved by Order No. PSC-2024-0091-PCO-EI on April 10, 2024.

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The CCR actual/estimated true-up calculation compares actuals for January 2024 through June 2024 and revised estimates for July 2024 through December 2024 to the data reflected in FPL's original projection for the period January 2024 through December 2024, which was filed on September 5, 2023, and approved by Order No. PSC-2023-0343-FOF-EI, issued on November 16, 2023.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2024, which reflects the interest rate from the last business day in June 2024.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2024 actual/estimated true-up by month?

A. Yes. Exhibit AM-3, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2024 through December 2024.

Q. Please explain the calculation of the 2024 FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Exhibit AM-3, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2024 end-of-period net true-up amount is an under-recovery, including interest, of $19.03 million, (Exhibit AM-3, page 1, line 50, column 15).

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the midcourse correction amounts for 2024?

A. Yes. Exhibit AM-3, page 2 provides a variance calculation that compares the 2024 actual/estimated period data by component to the same components from the March 2024 midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit AM-3.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $2.73 billion for 2024 (Exhibit AM-3, page 2, line 42, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.83 billion for that period (Exhibit AM-3, page 2, line 42, column 3). The resulting estimated under-recovery is due to higher-than-projected fuel costs offset by higher-than-projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $100.68 million, or 3.7%, higher than the midcourse correction estimates

(Exhibit AM-3, page 2, line 42, column 5), jurisdictional fuel revenues applicable to the period are projected to be $530.24 million, or 15.8%, lower than the midcourse correction estimates (Exhibit AM-3, page 2, line 38) and the interest expense is projected to be $12.59 million, or 156.6%, higher (Exhibit AM-3, page 2, line 44, column 5). The net impact due to the increase in jurisdictional fuel costs and the decrease in jurisdictional fuel revenues applicable to the period result in an over-recovery, including interest, of $680.80 million (Exhibit AM-3, page 2, line 50, column 5). The midcourse correction refunded this period is projected to be $661.77 million (Exhibit AM-3, page 2, line 50, column 4). Therefore, the Actual Estimated true-up is an $19.03 million under-recovery to be included in the 2025 projections (Exhibit AM-3, page 2, line 50, column 3).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $100.68 million increase in jurisdictional total fuel costs.

1 Fuel Cost of System Net Generation: $91.79 million increase (Exhibit AM-3, page 2,

2 line 2, column 5).

3 The table below provides the detail of this variance.

Fuel Variance	2024 Actual/Estimated	2024 Mid-Course Projections	Difference
Heavy Oil			
Total Dollar	$0	$0	$0
Units (MMBtu)	0	0	0
$ per Unit	0.0000	0.0000	0.0000
Variance Due to Consumption			$0
Variance Due to Cost			$0
Total Variance			$0
Light Oil			
Total Dollar	$13,839,692	$2,418,100	$11,421,592
Units (MMBtu)	704,833	129,041	$575,792
$ per Unit	19.6354	18.7389	0.8965
Variance Due to Consumption			$10,789,725
Variance Due to Cost			$631,867
Total Variance			$11,421,592
Coal			
Total Dollar	$17,770,574	$12,908,225	$4,862,349
Units (MMBtu)	5,103,453	3,568,037	1,535,416
$ per Unit	3.4821	3.6177	(0.1357)
Variance Due to Consumption			$5,554,734
Variance Due to Cost			($692,385)
Total Variance			$4,862,349
Gas			
Total Dollar	$2,895,109,962	$2,815,302,464	$79,807,498
Units (MMBtu)	703,079,884	675,617,081	$27,462,803
$ per Unit	4.1178	4.1670	(0.0493)
Variance Due to Consumption			$114,437,748
Variance Due to Cost			($34,630,249)
Total Variance			$79,807,498

Fuel Variance	2024 Actual/Estimated	2024 Mid-Course Projections	Difference
Nuclear			
Total Dollar	$144,365,476	$149,118,802	($4,753,326)
Units (MMBtu)	299,286,190	295,645,874	3,640,317
$ per Unit	0.4824	0.5044	(0.0220)
Variance Due to Consumption			$1,836,115
Variance Due to Cost			($6,589,441)
Total Variance			($4,753,326)
Total			
Total Dollar	$3,071,085,703	$2,979,747,591	$91,791,711
Units (MMBtu)	1,008,174,361	974,960,033	33,214,328
$ per Unit	3.0462	3.0563	(0.0101)
Variance Due to Consumption			$132,618,320
Variance Due to Cost			($42,897,698)
Other Adjustment	$453,599		$453,599
Total Variance	$3,071,539,302	$2,979,747,591	$91,791,711

Fuel Cost of Stratified Sales: $2.34 million decrease (Exhibit AM-3, page 2, line 4, column 5)

The decrease in Fuel Cost of Stratified Sales is primarily attributable to lower-than-projected unit fuel costs for these sales.

Fuel Cost of Power Sold: $5.82 million decrease (Exhibit AM-3, page 2, line 5, column 5)

The decrease for the Fuel Cost of Power Sold is primarily attributable to lower-than-projected fuel costs on economy power sales. The 2024 average unit fuel cost on economy power sales is now projected to be $3.40/MWh lower than originally projected, resulting in a decrease of approximately $10.10 million. This decrease is partially offset by higher-than-projected economy power sales. FPL now projects to sell approximately 163,000 MWh more of economy power, through 2024, resulting in an increase of $4.25 million. The combination of lower estimated fuel costs associated with economy power sales and projected higher volumes of economy power sales results in a net decrease of approximately $5.85 million. The remainder of the variance is due to higher MWh sales and lower-than-projected fuel costs under the St. Lucie Reliability Exchange.

<u>Gains from Off-System Sales: $3.61 million increase (Exhibit AM-3, page 2, line 6, column 5)</u>

The increase in Gains from Off-System Sales is primarily attributable to higher-than-projected economy power sales. FPL now projects to sell approximately 163,000 MWh more of economy power, resulting in an increase of approximately $2.65 million. Additionally, FPL now projects that margins on economy power sales will be $0.32/MWh higher, resulting in an increase of approximately $0.96 million. The combination of higher volume and margins on economy power sales results in a total increase for Gains from Off-System Sales of $3.61 million.

<u>Fuel Cost of Purchased Power: $14.66 million increase (Exhibit AM-3, page 2, line 7, column 5)</u>

The increase for the Fuel Cost of Purchased Power is primarily attributable to the fuel costs associated with the Santa Rosa Purchased Power Agreement. In April 2024, FPL entered into an agreement with Southern Company to purchase power from the Santa Rosa power plant, located in FPL's Northwest region, this purchase will provide economic and reliability benefits for FPL customers. The agreement between FPL and Southern Company began in June 2024 and runs through April 2025. This increase is partially offset by lower-than-projected fuel costs associated with purchases from the Solid Waste Authority and the St. Lucie Reliability Exchange, FPL projects that the unit costs will be $2.25/MWh and $2.55/MWh, respectively, lower than originally projected.

<u>Energy Payments to Qualifying Facilities: $2.69 million decrease (Exhibit AM-3, page 2, line 8, column 5)</u>

The decrease in Energy Payments to Qualifying Facilities is primarily attributable to lower-than-projected fuel costs and purchases from As-Available Co-Gen facilities.

<u>Energy Cost of Economy Purchases: $3.11 million decrease (Exhibit AM-3, page 2, line 9, column 5)</u>

The decrease for the Energy Cost of Economy Purchases is primarily attributable to lower-than-projected economy power purchases. FPL now projects to purchase approximately 99,000 MWh less of economy power than originally projected, reducing Energy Costs of Economy Purchases by approximately $4.51 million. This decrease is partially offset by $1.40 million increase in the unit cost of economy purchases which FPL now projects to be $9.51/MWh higher than originally projected. The combination of lower volume of economy purchases and higher unit costs for economy power purchases results in a net decrease of $3.11 million.

Incremental Personnel, Software, and Hardware Costs: $0.29 million increase (Exhibit AM-3, page 2, line 12, column 5)

The increase is primarily attributable to incremental personnel costs needed to support future activities associated with renewable energy credits Asset Optimization.

Variable Power Plant O&M Costs Avoided due to Economy Purchases: $.05 million decrease (Exhibit AM-3, page 2, line 14, column 5)

The decrease is attributable to lower than originally projected economy power purchases.

Optimization Credits: $0.60 million decrease (Exhibit AM-3, page 2, line 15, column 5)

The decrease for Optimization Credits is attributable to slightly lower-than-projected gains associated with asset optimization activities during the first half of the year.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2024 actual/estimated true-up by month?

A. Yes. Exhibit AM-4, page 3 provides the calculation of the CCR actual/estimated true-up by month for the period January 2024 through December 2024.

Q. Please explain the calculation of the CCR 2024 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit AM-4, page 3 shows the actual/estimated capacity costs and applicable revenues (January 2024 through June 2024 reflects actual data, while the data for July 2024 through December 2024 is based on updated estimates) compared to the original projection filing for the January 2024 through December 2024 period. Jurisdictional total capacity costs are estimated to be $7.94 million higher than the original projection filing (Exhibit AM-4, page 5, line 23, column 3), jurisdictional CCR revenues are projected to be $1.02 million higher than FPL's original projection filing (Exhibit AM-4, page 5, line 28, column 3), partially offset by $0.52 million interest owed to customers (Exhibit AM-4, page 5, line 31, column 3). The Actual Estimated true-up under-recovery is $6.40 million to be included in 2025 projections (Exhibit AM-4, page 5, lines 30 plus 31, column 3).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit AM-4, page 5, line 1, column 3, total system capacity costs are estimated to be $8.26 million or 3.7% higher-than-projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is a 3.7% increase from the original projection (page 5, line 23, column 4). Below are the primary reasons for the estimated $8.26 million increase in total system capacity costs.

Transmission of Electricity by Others - $0.34 million increase (Exhibit AM-4, page 4, line 3, column 3)

Approximately $0.18 million of the variance is due to transmission service purchased to move energy associated with economy power purchased into FPL's service area. The balance of the variance, $0.16 million, is due to higher-than-projected purchases of third-party transmission service used to facilitate higher-than-projected economy power sales during the first half of the year.

Incremental Plant Security Costs - O&M - $1.52 million decrease (Exhibit AM-4, page 4, line 6, column 3)

The decrease is primarily attributable to a reduction in scheduled trainings and a decrease in incremental plant security activity.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF AMIN MOHOMED

DOCKET NO. 20240001-EI

SEPTEMBER 5, 2024

Q. Please state your name, business address, employer and position.

A. My name is Amin Mohomed. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "Company") as Assistant Controller.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- The Fuel Cost Recovery ("FCR") Clause factors for the following periods: (i) January 2025 which do not include an incremental adjustment to reflect the ongoing fuel savings associated with the 12 solar energy centers expected to enter commercial operation by January 31, 2025 (the "2025 Project" or "Project") ; and, (ii) February 2025 through December 2025, which include an incremental adjustment to reflect the ongoing fuel savings associated with the 2025 Project. These factors are referred to collectively as the "2025 FCR factors."

- The 2025 FCR factors based on the traditional factor calculation method, which spreads the fuel savings associated with the 2025 Project over the entire calendar year, for informational purposes;
- The calculation of the jurisdictional amount of FPL's portion of the 2023 asset optimization gains to be recovered through the 2025 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2025 through December 2025 with and without the revenue requirement reduction to reflect incremental Inflation Reduction Act ("IRA") savings for January 2025 through December 2025.
- FPL's proposed cogeneration as-available energy ("COG-1") tariff sheets, which reflect updated variable operation and maintenance expense and loss factors for the company; and
- The computation of the incremental jurisdictional annualized base revenue requirement associated with the Solar Base Rate Adjustments ("SoBRA") related to the 12 universal photovoltaic solar energy centers expected to be placed in service in 2025, which is based on the first 12-months of operations of the 2025 Project. FPL is authorized to seek recovery of a SoBRA pursuant to the Company's 2021 Rate Settlement Agreement approved by the Commission in Order No. PSC-2021-0446-S-EI, as amended by PSC-2021-0446A-S-EI and supplemented in Order No. PSC-2024-0078-FOF-EI, Docket No. 20210015-EI ("2021 Rate Settlement" or "Settlement"). In addition, I will explain FPL's compliance with the calculation of the revenue requirement set forth in the Settlement, the

appropriate regulatory treatment for production tax credits ("PTC") associated with the 2025 Project, and the calculation of prorated depreciation-related accumulated deferred income taxes ("ADIT") which is required by Internal Revenue Code ("IRC") Treasury Regulation §1.167(1)-1(h)(6).

Q. Have you prepared or caused to be prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes. They are as follows:

Exhibit AM-5

- Schedules E1, E1-E, the RS-1 Inverted Rate Calculation, E2, and E10 provide the calculation of the FCR factors for January 2025, which exclude the fuel savings of the 2025 Project;
- Schedules E1-A, E1-C, E1-D, Asset Optimization Gains, and H1, which pertain to the entire 2025 calendar year;
- Pages 10 through 14, which provide the 2025 Projected Energy Losses by Rate Class;
- Pages 171 through 174, which provide updated COG-1 tariff sheets.

Exhibit AM-6

- Schedules E1, E1-E, the RS-1 Inverted Rate Calculation, E2, and E10 for the period February 2025 through December 2025, which include the incremental ongoing fuel savings for the 2025 Project.

Exhibit AM-7

- Schedules E1, E1-E, RS-1 Inverted Rate Calculation, E2, and E10 that provide the calculation of FCR factors for the period January 2025 through December 2025 based on the traditional factor calculation methodology, which spreads fuel savings for the 2025 Project over the entire calendar year for informational purposes.

Exhibit AM-8

- Pages 1 through 4 provide the calculation of 2025 CCR factors, excluding the IRA revenue requirement reduction;
- Pages 5 through 10 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 11 provides the calculation of amortization and return on the regulatory asset related to the Indiantown Transaction;
- Page 12 provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments included for recovery through the CCR clause for the period January 2025 through December 2025;
- Page 15 provides the calculation of the portion of the CCR factors related to the IRA revenue requirement reduction;
- Page 16 combines the results from page 4 and page 15 to provide the total 2025 CCR factors including the IRA revenue requirement reduction;
- Pages 17 through 29 provide the calculations of stratified separation factors.

Exhibit AM-9

- 2025 SoBRA Revenue Requirement Calculation.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2025 FCR factors shown on Schedule E1?

A. The 2025 FCR factors include the following adjustments: (i) an estimated net true-up, (ii) a consolidated Generating Performance Incentive Factor ("GPIF"), (iii) the jurisdictional amount associated with FPL's share of the 2023 asset optimization gains and (iv) the cost associated with the projected 2025 Subscription Credit for the FPL SolarTogether Program.

The total net true-up amount to be included in the 2025 FCR factors is a $19,030,441 under-recovery. This amount is reflected on line 37 of Schedule E1. The $19,030,441 under-recovery, divided by the projected retail sales of 126,505,752 MWh for January 2025 through December 2025, results in a charge of 0.0150 cents per kWh.

The testimony of FPL witness Rote filed on March 15, 2024 with an errata filed on September 4, 2024, presents a GPIF reward of $11,145,919 for the period ending December 2023. This amount is reflected on line 39 of Schedule E1. This $11,145,919 reward, divided by the projected retail sales of 126,505,752 MWh for January 2025 through December 2025, results in a charge of 0.0088 cents per kWh.

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FPL is including $43,950,552 for the jurisdictional amount associated with its share of 2023 asset optimization gains in the calculation of its 2025 FCR factors, as shown on line 40 of Schedule E1. FPL's activities under the asset optimization program in 2023 delivered $123,207,265 in total gains. Of these total gains, FPL is allowed to retain $46,103,632 (system amount) pursuant to Order No. PSC-13-0023-S-EI dated January 14, 2013, approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI dated, December 15, 2016, and approved as an ongoing program, with further modifications, by Order No. PSC-2021-0446-S-EI, dated December 2, 2021. The system amount of total gains of $46,103,632 has been allocated to the retail jurisdiction based on its load ratio share of system sales for 2023. The resulting jurisdictional amount to be recovered is $43,950,552 which is calculated and shown on page 4 of Exhibit AM-5. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount in each month's Schedule A2 for the period January 2025 through December 2025 as a reduction to jurisdictional fuel revenues applicable to each period. This $43,950,552, divided by the projected retail sales of 126,505,752 MWh for January 2025 through December 2025, results in a charge of 0.0347 cents per kWh.

FPL has included $245,377,980 associated with the projected 2025 Subscription Credit for the FPL SolarTogether Program, as shown on line 41 of Schedule E1. The subscription credit is based on the program's solar power plants' forecasted generation and the Subscription Credit rate as reflected in the SolarTogether tariff.

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This $245,377,980 divided by the projected retail sales of 126,505,752 MWh for January 2025 through December 2025, results in a charge of 0.1940 cents per kWh.

Schedule E2 provides the monthly FCR factors as well as the levelized FCR factor for 2025. Schedule E-1E provides the calculation of the January 2025 FCR factors by rate group for each period.

Q. Please explain the fuel cost of stratified sales amount reflected on line 4 of Schedule E1.

A. FPL has included a projected credit of $64,834,124 associated with stratified wholesale power sales contracts in effect in 2025. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel cost of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-97-0262-FOF-EI.

Q. Have you prepared a summary of the requested FCR costs for the projected period of January 2025 through December 2025?

A. Yes. Schedule E1 of Exhibit AM-7 provide this summary. Total recoverable jurisdictional fuel costs inclusive of adjustments for the period January 2025 through December 2025 are $3,431,589,874 (page 1, line 43). The jurisdictional fuel costs inclusive of fuel savings associated with the project are $3,112,084,981 (page 1, line 36) and are adjusted by the amounts previously discussed above. The adjustments include the total net true-up under-recovery amount of $19,030,441 (page 1, line 37); a GPIF reward of $11,145,919 for the period ending December 2023 (page 1, line 39); the jurisdictional amount associated with FPL's share of 2023 asset optimization gains of $43,950,552 (page 1, line 40); and the projected 2025 Subscription Credit for the FPL SolarTogether Program of $245,377,980 (page 1, line 41).

Calculation of 2025 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2025 through December 2025 to reflect the impact of the fuel savings associated with the 2025 Project.

A. Pursuant to the Settlement Agreement reached in FPL's base rate case approved by the Commission in Order No. PSC-2021-0446-S-EI, Docket No. 20210015-EI, FPL is authorized to recover through the SoBRA mechanism, the revenue requirements based on the first 12 months of operations of the 2025 Project. The SoBRA associated with the 2025 Project is expected to be implemented on February 1, 2025. FPL proposes that the corresponding fuel savings associated with the 2025 Project be reflected in the 2025 FCR factors beginning February 1, 2025, which is concurrent with the expected SoBRA in-service date, to align costs with the fuel savings benefits. This treatment is consistent with past practice approved by the Commission.

Q. How would a delay in the commercial operation date of the 2025 Project impact the 2025 FCR factors?

A. At this time, FPL does not anticipate a delay in the commercial operation date of the 2025 Project. Should FPL become aware of a delay, FPL will promptly provide notification to the Commission of such delay and provide an updated in-service date. FPL will not implement the 2025 SoBRA and related fuel savings until those units go into service.

Q. What are the projected 2025 fuel savings associated with the 2025 Project?

A. As explained in the testimony of FPL witness Cashman, the projected 2025 total system fuel savings associated with the 2025 Project are $47,915,404.

Q. Please explain the calculation of 2025 FCR factors reflecting the fuel savings associated with the 2025 Project.

A. FPL first calculates the FCR factors for January 2025 that excludes the fuel savings associated with the 2025 Project. These FCR factors assume the 2025 Project is not yet operating and therefore exclude the associated fuel savings. This adjustment is reflected on line 3 of Schedule E1 in Exhibit AM-5. The levelized FCR factor for January 2025 is 2.748 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $24.46 during this period.

Next, FPL calculates the FCR factors for February 2025 through December 2025 that include the fuel savings associated with the 2025 Project scheduled to go in service by February 1, 2025. This adjustment is shown on line 42 of Schedule E1 in Exhibit AM-6. The levelized FCR factor for February 2025 through December

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2025 including this adjustment is 2.710 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $24.08 for this period, reflecting a decrease of 36 cents.

Schedule E2 provides the monthly fuel factors as well as the levelized FCR factor for 2025. Schedule E-1E provides the calculation of the 2025 FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2025?

A. Yes. Although FPL requests approval of separate FCR factors for two periods, reflecting the impact of the 2025 Project upon commercial operation, FPL provides for informational purposes the calculation of a twelve-month levelized fuel factor for 2025. Exhibit AM-7 includes Schedules E1, E1-E, RS-1 Inverted Rate Calculation, E2, and E10, which calculate a twelve-month levelized fuel factor of 2.713 cents per kWh by including the fuel savings for the 2025 Project throughout the twelve months of 2025.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested CCR costs for the projected period of January 2025 through December 2025?

A. Yes. Pages 1 and 2 of Exhibit AM-8 provide this summary. Total recoverable capacity costs for the period January 2025 through December 2025 are $120,797,068 (page 2, line 32). This includes $121,736,404 of 2025 projected jurisdictional capacity costs (page 2, line 27) and the net true-up over-recovery for 2023 and 2024 of $939,336 (page 2, line 30 plus line 31). This $120,797,068 amount excludes the IRA revenue requirement reduction.

Q. Have you also provided a calculation of the 2025 CCR factors by rate class that include a revenue requirement reduction to reflect incremental IRA savings for January 2025 through December 2025?

A. Yes. As proposed by FPL in Docket No. 20220165-EI, FPL has included on pages 15 and 16 of Exhibit AM-8 a calculation of the 2025 CCR factors that include a revenue requirement reduction related to incremental IRA savings of $3,911,284. The total amount to be recovered through the CCR factors inclusive of the IRA reduction is $116,885,784. This approach is consistent with the Commission's approval of FPL's 2024 CCR factor calculation in Order No. PSC-2023-0343-FOF-EI (Order page 20; page 18 of Attachment A), issued November 16, 2023.

Q. What adjustments are included in the calculation of the combined 2025 CCR factors included in Exhibit AM-8?

A. The total net true-up to be included in the 2025 CCR factors is an over-recovery of $939,336, as shown on page 2, line 30 plus line 31. This over-recovery is comprised of FPL's 2023 final net true-up over-recovery of $7,342,001, which was filed on April 3, 2024, and FPL's 2024 actual/estimated true-up under-recovery of $6,402,666 filed on July 26, 2024.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Exhibit AM-8 provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. Has FPL calculated the Weighted Average Cost of Capital ("WACC") in accordance with Commission Order No. PSC-2020-0165-PAA-EU ("WACC Order")?

A. Yes. The resulting after-tax WACC to be applied to the 2025 projected CCR capital investments is 6.97%, which is based on FPL's 2025 forecast and currently approved midpoint ROE of 10.80%. The calculation of the WACC for 2025 is provided on page 12 of Exhibit AM-8.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of the capacity costs?

A. Yes. The separation factors used in the calculation are consistent with the FPL Ten Year Power Plant Site Plan 2024-2033 filed April 1, 2024. FPL has separated the production-related capacity costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of capacity costs between the retail and wholesale jurisdictions. The calculations of the stratified separation factors are provided in Exhibit AM-8 pages 17-29.

2025 SoBRA REVENUE REQUIREMENT

Q. What is the revenue requirement for the 2025 SoBRA?

A. As reflected on page 1 of Exhibit AM-9, the amount of FPL's requested base revenue increase for the first 12 months of operations of the 2025 Project is $61.087 million.

Q. Please briefly describe the basis for the 2025 SoBRA revenue requirement calculation.

A. Pursuant to paragraph 12(a) of the 2021 Rate Settlement, FPL is authorized to recover the incremental jurisdictional revenue requirement based on the first 12 months of operations of the 2025 Project. The cost of the components, engineering and construction for the 2025 Project are subject to a $1,250 per kW_{AC} Cost Cap less the cost (on a per kW_{AC} basis) of any land component allocated to the Project that was included in FPL's projected rate base as Plant Held for Future Use in FPL's most recent rate case test year. If approved, the 2025 SoBRA is expected to be implemented on February 1, 2025.

Q. Are there any accounting changes impacting the calculation of this year's SoBRA revenue requirement calculation compared to prior SoBRA calculations?

A. Yes. On June 29, 2023, the Federal Energy Regulatory Commission ("FERC") issued Order 898, Accounting and Reporting Treatment of Certain Renewable Energy Assets in Docket No. RM21-11-000, which among other items, amended the Uniform System of Accounts for public utilities by creating new electric plant and associated operating and maintenance ("O&M") accounts for wind, solar, and

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other renewable generating assets, with an effective implementation date of January 1, 2025. Since the Project will go in service in 2025, FPL has reflected the new solar generation FERC accounts required by Order 898 in its 2025 SoBRA revenue requirement calculation, which are shown on pages 2 and 4 of Exhibit AM-9.

Q. Please explain how FPL adhered to the Adjusted Cap in its 2025 SoBRA revenue requirement calculation.

A. The Adjusted Cap ($\$/kW_{AC}$) for each solar energy center in the 2025 Project, as calculated and presented by FPL witness Fagan in her testimony, was multiplied by each site's corresponding nameplate capacity of 74.5 MW to determine the total amount of adjusted capital costs to be included in the 2025 SoBRA revenue requirement calculation. The adjusted amount of capital costs is $1.036 billion, reflected as the total amount of plant in service on Exhibit AM-9, Page 2, Line 12, Column 2. In order to develop the revenue requirement, this plant in service amount must then be allocated by function.

Q. Please describe how FPL allocated the $1.036 billion plant in service to the proper functions.

A. FPL allocated the $1.036 billion to three categories – (i) Solar Production, (ii) Transmission, and (iii) Transmission Generator Step-up Transformer ("GSU") and Generation Leads – based on the following steps:

1. Based on the total construction costs for each site reflected on Exhibit KF-6 from FPL witness Fagan's testimony, including Ms. Fagan's errata, the Company categorized the capital components into the following: Solar Production, Transmission, Transmission GSU and Generation Leads, and

allowance for funds used during construction ("AFUDC");

2. FPL calculated the percentage of the total cost represented by each function in step 1;
3. FPL multiplied the percentages in step 2 to the adjusted capital costs for each site;
4. FPL split the AFUDC identified in step 3 into Solar Production, Transmission, and Transmission GSU and Generation Leads based on projected capital spend (by month) for each site;
5. FPL utilized the cost information calculated in steps 3 and 4 to determine the total amount of capital costs for Solar Production, Transmission, and Transmission GSU and Generation Leads. This total is used to calculate jurisdictional plant in service, accumulated depreciation, and depreciation expense.

Q. What AFUDC rate was utilized to estimate the amount of AFUDC included in the total amount of construction costs reflected on Exhibit KF-6 to FPL witness Fagan's testimony?

A. The estimated amount of AFUDC reflected on Exhibit KF-6 in FPL witness Fagan's testimony for each site was calculated using an AFUDC rate of 6.37%, which was approved by the Commission in Order No. PSC-2023-0142-PAA-EI, Docket No. 20230031-EI. On July 1, 2024, the Commission approved FPL's request to increase its AFUDC rate from 6.37% to 6.76%, effective January 1, 2024, in Order No. PSC-2024-0223-PAA-EI, Docket No. 20240057-EI. Because FPL adheres to the Adjusted Cap, application of the increased AFUDC rate does not impact the 2025 SoBRA revenue requirement. Therefore, the application of the increased rate is not reflected in FPL's 2025 SoBRA revenue requirement calculation.

Q. Please describe the inputs utilized to compute the revenue requirement for the 2025 SoBRA.

A. In addition to the capital cost calculation described above, the revenue requirement computations for the 2025 SoBRA are based on the following inputs:

- Depreciation rates: To compute depreciation expense and related accumulated depreciation, FPL utilized the depreciation rates approved by the Commission in the 2021 Rate Settlement for solar generation and transmission plant.
- Operating expenses: These are based on the Company's estimated operating expenses for the first 12 months of operations.
- Incremental cost of capital: As reflected in paragraph 12(h) of FPL's 2021 Rate Settlement, the Company is required to use a 10.8% return on common equity and an incremental capital structure that is adjusted to reflect the inclusion of applicable tax credits on a normalized basis. Therefore, ADIT are not included in the incremental capital structure, and instead, as described below, ADIT are included as a component of rate base. Additionally, as a result of the IRA and consistent with the 2024 SoBRA approved by this Commission, owners of solar projects with construction beginning before 2025 can elect to claim PTCs in lieu of investment tax credits ("ITC"). FPL has elected to claim PTCs on the 2025 Project, as that results in the higher economic tax credit. Therefore, no ITCs are included in its incremental cost of capital. FPL's incremental cost of

capital for the 2025 Project includes long-term debt and equity based on the same ratios and cost rates reflected in FPL's 2025 Capacity Cost Recovery Clause Projection filing in this docket.

- Accumulated deferred income taxes: As mentioned above, ADIT are included as a component of rate base. The ADIT for the 2025 Project primarily reflects the timing difference between book and tax depreciation over the life of the assets as well as the impact associated with the utilization of PTCs for the year ended December 31, 2025. In addition, FPL is required to comply with IRC Treasury Regulation §1.167(1)-1(h)(6) and utilize a proration formula to compute the depreciation-related ADIT balance to be included for ratemaking purposes when a forecasted test period is utilized to set rates. This treatment is consistent with the treatment applied in FPL's previously-approved SoBRAs revenue requirement calculations. The calculation of ADIT for the 2025 Project, based on the adjusted capital costs, is reflected on Page 5 of Exhibit AM-9.

Q. Please describe the PTCs associated with the revenue requirement calculation for the 2025 SoBRA.

A. In accordance with Section 45 of the IRC, the Company forecasts it will claim a PTC of approximately $60.1 million associated with the 2025 Project, thereby reducing total income tax expense. The PTC is calculated by multiplying projected net generation of approximately 2,001,724 MWh associated with the first calendar year of operation for the 2025 Project times a PTC rate of $30.00/MWh. The calculated PTC rate is based on the 2024 published Internal Revenue Service annual rate adjusted for an Inflation Adjustment Factor and Prevailing Wage Requirements.

Q. Did FPL calculate its 2025 SoBRA revenue requirement consistent with the calculations presented previously for SoBRAs and approved by this Commission?

A. Yes. The 2025 SoBRA revenue requirement is calculated in the same manner as the 2024 SoBRA calculation approved by the Commission in Order No. PSC-2023-0343-FOF-EI, except for the application of new FERC solar accounts required by FERC Order 898.

Additionally, with the exception of applying the Adjusted Cap and electing to receive the PTC instead of the ITC as described above, the 2025 SoBRA revenue requirements are calculated consistent with prior SoBRA filings, which were approved by the Commission in Order Nos. PSC-2018-0028-FOF-EI, PSC-2018-0610-FOF-EI and PSC-2019-0484-FOF-EI.

Q. How will FPL reflect capital and operating costs associated with the 2025 Project in its monthly earnings surveillance reports?

A. As authorized in paragraph 12(j) of FPL's 2021 Rate Settlement, FPL will include the total amount of actual capital and operating costs associated with the 2025 Project in its monthly earnings surveillance reports.

EFFECTIVE DATES

Q. What are the effective dates that FPL is requesting for the new FCR factors, and CCR factors for 2025?

A. FPL is requesting effective dates as follows:

- The FCR factors which do not include an incremental adjustment to reflect the ongoing fuel savings associated with the 2025 Project become effective January 1, 2025;
- The FCR factors which include the incremental SoBRA savings associated with the 2025 Project become effective after the 2025 Project has entered commercial operations which is expected to be February 1, 2025; and
- The CCR factors, including the incremental IRA revenue requirement reduction, for the period January 2025 through December 2025 become effective January 1, 2025.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Michael V. Cashman was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL V. CASHMAN

DOCKET NO. 20240001-EI

SEPTEMBER 5, 2024

Q. Please state your name, business address, employer and position.

A. My name is Michael V. Cashman. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408. I am employed by Florida Power & Light Company ("FPL") as Executive Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I earned a bachelor's degree in Mechanical Engineering and a master's degree in Business Administration from the University of Michigan. I joined the NextEra Energy family of companies in 1998, progressing professionally within the Market Analysis organization from Market Intelligence Analyst to Senior Director before being tapped to lead NextEra Energy Marketing's Asset Trading and Optimization organization. In 2022, responsibilities for Independent System Operator ("ISO") asset operations were consolidated with asset trading and optimization under me acting as the Executive Director of Asset Operations and Trading. In this role my team was responsible for managing the operations and optimization of 36 GW of generation located in eight U.S. and Canadian

Regional Transmission Organizations ("RTOs") as well as the management of annual commodity price exposure for approximately 250 Bcf of natural gas and 10 million barrels of oil and natural gas liquids production. I joined FPL's Energy Marketing and Trading organization in July of 2024 as the Executive Director of Wholesale Operations and Trading where I oversee power trading, coal and fuel oil operations as well as FPL's natural gas scheduling team.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits or schedules in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- Exhibit MVC-1 - 2025 Projected Dispatch Costs and Availability
- Exhibit MVC-2 - 2025 Risk Management Plan

I am co-sponsoring the following schedules included in the Exhibits of FPL witness Mohomed:

- Schedules E2 through E9 and H1 included in Exhibit AM-5;
- Schedule E2 included in Exhibits AM-6 and AM-7; and
- Schedule E12 included in Exhibit AM-8.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of natural gas, light fuel oil, and coal; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. Additionally, my testimony addresses the Incremental Optimization Costs included in FPL's 2025 Projection Filing.

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2025 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light fuel oil prices, FPL utilizes Over-The-Counter ("OTC") forward market prices. For coal, FPL utilizes actual coal purchases, current market quotes, and information from S&P Global to develop its short- and long-term coal price forecasts. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and light fuel oil represent expected future prices at a given point in time. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and light fuel oil in the short-term is incorporated into the curves at all times. FPL utilized forward curve prices from the close of business on August 1, 2024 for calculating its projected fuel costs included in the 2025 Fuel Cost Recovery ("FCR") factors. This forecast methodology and the resulting fuel forecast were utilized to develop cost projections for FPL during the January 2025 through December 2025 time period.

Q. Has FPL previously used these same forecasting methodologies?

A. Yes. For natural gas and light fuel oil, FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices, respectively, in 2004 for its 2005 projections and has used this methodology consistently since that time. For coal price forecasting, FPL implemented the methodology described above beginning in March 2022.

Q. What are the factors that typically can affect FPL's natural gas prices during the January through December 2025 period?

A. In general, the key factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

Henry Hub natural gas spot prices averaged $2.24 per MMBtu for the first half of 2024, compared with an annual average of $2.53 per MMBtu in 2023. In its August 2024 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts that Henry Hub natural gas spot prices will average $2.30 per MMBtu for 2024 and $3.30 per MMBtu in 2025.

The EIA forecasts that demand for natural gas will decline by 1% in 2025, dropping from roughly 90 billion cubic feet per day ("BCF/day") in 2024 to 89.1 BCF/day in 2025 due to normalizing weather and the increase in electricity generated from solar.

The EIA forecasts dry natural gas production to average 103 BCF/day during 2024 and increase to 105 BCF/day in 2025. Domestic natural gas inventories ended July 2024 at 16% above the five-year average and 8% above the same period last year. The EIA forecasts natural gas inventories to end the 2024 injection season (end of October) between 3.9 and 4.0 trillion cubic feet, or 6% above the five-year average.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2025 period.

A. FPL utilizes the Florida Gas Transmission Company, LLC ("FGT"), Gulfstream Natural Gas System, LLC ("Gulfstream"), Sabal Trail Transmission, LLC ("Sabal Trail"), Florida Southeast Connection, LLC ("FSC"), and Gulf South Pipeline Company, LLC ("Gulf South") pipelines to deliver natural gas to its generation facilities. FPL's total firm transportation capacity on FGT ranges from 1,387,000 to 1,511,000 MMBtu/day. It also has 695,000 MMBtu/day of firm transport on Gulfstream, 600,000 MMBtu/day of firm transport on Sabal Trail/FSC, and 30,000 MMBtu/day of firm transport on Gulf South.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to onshore gas supply. FPL has 325,000 MMBtu/day of firm transport on the Southeast Supply Header, LLC ("SESH") pipeline, 121,500 MMBtu/day of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, 200,000 MMBtu/day (January through March and November through December) and 345,000 MMBtu/day (April through October) of firm transport on the Gulf South pipeline, 80,000 MMBtu/day of firm transport on the Gulf South and Destin Pipeline Company, LLC ("Destin") pipelines combined, 75,000 MMBtu/day of firm transport on the Midcontinent

Express Pipeline LLC ("MEP") and Destin pipelines combined, 50,000 MMBtu/day (January through March) and 100,000 MMBtu/day (April through December) on the FGT and Trunkline Gas Company, LLC ("Trunkline") pipelines combined, and 100,000 MMBtu/day (January through March) and 125,000 MMBtu/day (April through December) on the Trunkline pipeline. FPL's firm transportation rights on these pipelines provide access for up to 1,171,500 MMBtu/day of onshore natural gas supply during the summer season, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 BCF of firm natural gas storage capacity in Bay Gas Storage ("Bay Gas"), located in southwest Alabama, 2.0 BCF (January through March) and 1.0 BCF (April through December) of firm natural gas storage capacity in Southern Pines Energy Center ("Southern Pines"), located in southeast Mississippi. Beginning April 1, 2025, FPL will hold an additional 2.0 BCF of firm natural gas storage capacity in Petal Gas Storage, located in southern Mississippi.

While the acquisition of upstream transportation capacity has helped mitigate a substantial portion of risk associated with offshore natural gas supply, natural gas storage capacity also remains an important part of FPL's gas portfolio from an operational perspective, by helping FPL balance consumption "swings" due to weather, solar generation variability, and overall unit availability. Storage

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capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

FPL continually evaluates its natural gas storage portfolio and will make adjustments as required to maintain reliability, provide the necessary flexibility to respond to demand changes, and to diversify its overall portfolio.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2025 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 1 of Exhibit MVC-1.

Q. Please describe FPL's utilization of light fuel oil.

A. FPL primarily utilizes light fuel oil (or ultra-low sulfur diesel) as a back-up fuel in its natural gas-fired generation units. FPL's light fuel oil system is comprised of approximately 1.6 million barrels of storage that provides an average of 83 hours of full load operation across the fleet of dual-fired units. FPL's light fuel oil system offers substantial flexibility through varying tank sizes, resupply options, and through varying locations and proximity to supply sources.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2025 period.

A. FPL's projection for the system average dispatch cost of light fuel oil, by month, is provided on page 1 of Exhibit MVC-1.

Q. What is the basis for FPL's projections of the dispatch cost of coal for Plant Scherer?

A. FPL's projected dispatch cost is based on FPL's price projection for coal delivered to the plant.

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2025 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by month, is shown on page 1 of Exhibit MVC-1.

Q. Do the fuel costs reflected on Schedule E3 for light oil and coal differ from the dispatch costs shown on page 1 of Exhibit MVC-1?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. The dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Exhibit AM-5.

A. The projected Average Net Heat Rates were calculated by the GenTrader model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to

GenTrader for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes or upgrades to plant equipment.

Q. Are you providing the outage factors projected for the period January through December 2025?

A. Yes. This data is shown on page 2 of Exhibit MVC-1.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2025.

Q. Please describe the significant planned outages for the January through December 2025 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from September 20, 2025 until October 30, 2025, or 40 days during the period. Turkey Point Unit 4 is scheduled to be out of service from March 1, 2025 until April 4, 2025, or 34 days during the period.

Q. Please identify any changes to FPL's generation capacity projected to take place during the January through December 2025 period.

A. As shown in FPL's 2024 Ten Year Power Plant Site Plan (Schedule 8, page 167), FPL projects a net increase in its 2025 summer firm capacity of 485 MW. This increase is attributable to the addition of 563 MW of solar generation and 18 MW of combined cycle upgrades. The additions are off-set by solar degradation (9 MW) and the retirement of gas-fired generation (87 MW).

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2025?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Exhibit AM-5 of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases FERC-mandated wholesale energy from Qualifying Facilities. Additionally, FPL engages in structured Power Purchase Agreements ("PPA") and shorter term, opportunistic economy power sales and purchases. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the FCR Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction.

Q. Please describe the method used to forecast wholesale (off-system) economy power purchases and sales.

A. Wholesale (off-system) economy power purchases and sales are projected based upon estimated generation costs, generation availability, fuel availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) economy power sales?

A. FPL has projected 2,985,500 MWh of wholesale (off-system) economy power sales for the period of January through December 2025. The projected fuel cost related to these sales is $69,424,269. The projected transaction revenue from these sales is $103,238,745. After taking into account the transmission costs and capacity revenues, the projected gain is $29,001,741.

Q. In what document are the fuel costs for wholesale (off-system) economy power sales transactions reported?

A. Schedule E6 of Exhibit AM-5 provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) economy power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) economy power purchases for the January to December 2025 period?

A. The costs of these economy purchases are shown on Schedule E9 of Exhibit AM-5. For the period, FPL projects it will purchase a total of 148,080 MWh at a cost of $6,524,090. If FPL generated this energy, FPL estimates that it would cost $10,585,771. Therefore, these economy purchases are projected to result in savings of $4,061,681.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of Palm Beach County ("SWA") and under two wind energy purchase agreements ("Kingfisher I" and "Kingfisher II") with Morgan Stanley Capital Group. FPL has also entered into two PPAs, one with Mercuria Energy America ("Mercuria PPA") for 225 MW of capacity and energy from the Lindsay Hill Combined Cycle Plant and the second with Southern Company for output from Santa Rosa Energy Center Combined Cycle Plant ("Santa Rosa PPA") for 230 MW of capacity and energy, in order to supplement FPL's winter reserves, while providing fuel savings. The Mercuria PPA runs from January 1, 2025 through February 28, 2025 and the Santa Rosa PPA runs from January 1, 2025 through April 30, 2025. In addition, FPL contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission and Florida Municipal Power Agency. Lastly, FPL purchases energy and capacity from Qualifying Facilities and "as-available" energy from a number of cogeneration and small power production facilities under existing tariffs and contracts, including solar energy purchases under agreements with three solar facilities located in Northwest Florida.

Q. Please provide the projected energy costs to be recovered through the FCR Clause for the power purchases referred to above during the January through December 2025 period.

A. Energy purchases under the SWA agreements are projected to be 808,740 MWh for the period at an energy cost of $32,060,321. FPL projects to purchase 1,031,280 MWh at an energy cost of $54,321,448 from Kingfisher I and Kingfisher II combined. Additionally, FPL projects to purchase 15,050 MWh at an energy cost of $1,343,898 and 367,899 MWh at an energy cost of $12,625,805 under the Mercuria PPA and Santa Rosa PPA, respectively. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 633,896 MWh at an energy cost of $2,870,619. These projections are shown on Schedule E7 of Exhibit AM-5.

In addition, as shown on Schedule E8 of Exhibit AM-5, FPL projects that purchases from Qualifying Facilities for the period will provide 569,112 MWh at a cost of $25,972,806.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy at FPL's avoided energy cost, FPL used its fuel price forecasts as inputs to the GenTrader model to project the avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that are not based on FPL's avoided energy cost (firm capacity and energy and "as-available" energy), the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 561,423 MWh of energy at a cost of $2,890,328. These projections are shown on Schedule E6 of Exhibit AM-5.

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2023, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. Pursuant to Paragraph 27 of the 2021 Rate Settlement, FPL's fuel hedging program was under a moratorium. Therefore, FPL had no hedging activity to report for 2023.

Q. Has FPL filed a comprehensive risk management plan for 2025, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. On July 26, 2024, FPL filed its comprehensive risk management plan for 2025. I adopt the filed plan as my Exhibit MVC-2.

THE ASSET OPTIMIZATION PROGRAM

Q. Has FPL included in its 2025 FCR factors projections of the savings that it will achieve under the Asset Optimization Program?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E2) for 2025.

Q. Has FPL included in its 2025 FCR factors projections of the Incremental Optimization Costs that it will incur under the Asset Optimization Program?

A. Yes. FPL has included in its 2025 FCR factors, Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and (ii) variable power plant O&M ("VOM") costs associated with wholesale economy sales and purchases.

Q. Have you made any changes in incremental personnel dedicated to the Asset Optimization Program?

A. FPL intends to dedicate an additional two personnel to the Program to optimize renewable energy credits.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software, and hardware expenses.

A. FPL projects to incur incremental expenses of $861,401 in 2025 for the salaries and expenses related to the four and a half (4.5) employees that will support the

Asset Optimization Program.

Q. Please describe the costs that are included in FPL's projections for VOM expenses.

A. FPL has included for recovery in its 2025 FCR factors VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Exhibit AM-5, FPL projects to sell 2,985,500 MWh and purchase 148,080 MWh of economy power. The 2021 Rate Settlement prescribes a VOM rate of $0.48/MWh. Applying that rate, FPL projects to incur VOM expenses of $1,433,040 associated with its economy sales and to avoid $71,078 with its economy purchases. FPL has included for recovery the net of these two figures, $1,361,962 (Schedule E2, sum of line nos. 14 and 15), in its 2025 FCR factors.

<u>CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE COMMERCIAL OPERATION OF NEW SOLAR GENERATION</u>

Q. Please describe the solar generation that FPL will put into commercial operation during 2025 pursuant to the 2021 Rate Settlement.

A. The solar generation to be constructed pursuant to the 2021 Rate Settlement will consist of twelve solar energy centers located at twelve sites. The twelve solar energy centers are sized to generate a total of 894 MW (nameplate capacity) and are scheduled to go into service by January 31, 2025. These twelve sites consist of Holopaw, Speckled Perch, Big Water, Fawn Solar, Hog Bay, Green Pasture, Thomas Creek, Fox Trail, Long Creek, Swallowtail,

C5-449

Tenmile, and Redlands.

Q. Will the operation of the new solar generation during 2025 result in fuel savings for FPL's customers?

A. Yes. For the February through December 2025 period, the operation of the twelve solar energy centers is projected to result in fuel savings for FPL's customers of $47,915,404.

Q. How did FPL calculate the projected fuel savings associated with the operation of the new solar energy centers?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of the twelve new solar energy centers. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the new solar generation fuel savings. In order to calculate the fuel savings, FPL ran two separate production cost simulations, one without the twelve new solar energy centers and one with the twelve new solar energy centers. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were lower in the case that included the twelve new solar energy centers.

Q. Does this conclude your testimony?

A. Yes, it does.

C5-450

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DANIEL DeBOER

DOCKET NO. 20240001-EI

SEPTEMBER 5, 2024

Q. Please state your name and address.

A. My name is Daniel DeBoer. My work business address is 15430 Endeavor Drive, Jupiter, Florida 33478.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL or the Company") as Vice President, Nuclear.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy to be produced by our nuclear units measured in Million British Thermal Units or ("MMBtu") for 2025. Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs included in the proposed fuel cost recovery factors for the period January 2025 through December 2025. I am also supporting FPL's projected 2025 incremental plant security and Fukushima-related costs. Additionally, my testimony discusses unplanned outages that occurred at the St. Lucie nuclear power plants over the period from June through July 2024.

Q. Aside from planned maintenance outages, does FPL project that its nuclear units will achieve 100% availability?

A. No, it does not. No nuclear plant in the industry projects 100% availability. Nuclear plants are complex industrial facilities that consist of dozens of interdependent systems, hundreds of major components, tens of thousands of sub-components, tens of thousands of tubes, miles of piping and many redundant safety features. FPL continuously improves the physical plant, procedures, and processes to improve reliability and maintain nuclear safety. However, even when prudent actions are taken, FPL's nuclear units – like all nuclear units in the industry – experience equipment failures and unplanned outages. My testimony describes outages that warrant further explanation for the Florida Public Service Commission.

Nuclear Fuel Costs

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at its nuclear units and current operating schedules for the period January 2025 through December 2025.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2025 through December 2025.

A. FPL projects the nuclear units will burn 301,570,988 MMBtu of energy at a cost of $0.4740 per MMBtu for the period January 2025 through December 2025. Projections by nuclear unit and by month are listed in Schedule E-4 of Exhibit AM-5, which is attached to FPL witness Mohomed's testimony.

Nuclear Plant Incremental Security Costs

Q. What is FPL's projection of incremental security costs at its nuclear power plants for the period January 2025 through December 2025?

A. FPL projects that it will incur $36.0 million in incremental nuclear power plant security costs in 2025. The costs consist of $5.1 million of capital expenditures and $30.9 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in maintaining a security force as a result of implementing the NRC's fitness-for-duty rule under 10 CFR Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintenance of the physical upgrades resulting from implementing the NRC's physical security rule under 10 CFR Part 73; and impacts of implementing the NRC's cyber security rule under 10 CFR Part 73. It also includes force-on-force modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force, as required by NRC inspection procedures.

Fukushima-Related Costs

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2025 through December 2025?

A. FPL's current projection of Fukushima-related costs for 2025 is approximately $944 thousand in O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. The projection includes FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

<u>2024 Unplanned Outage or Downpower Events</u>

Q. Please describe the unplanned outages or downpower at FPL's nuclear plants in 2024 for which FPL wishes to provide further information.

A. On June 4, 2024, St. Lucie Unit 2 was manually tripped due to a lowering of condenser vacuum. On June 18, 2024, St. Lucie Unit 2 experienced a tube leak in the condenser waterbox. This resulted in elevated steam generator sodium and chloride concentrations, requiring a forced unit shutdown to address the issue. Additionally, on July 28, 2024, St. Lucie Unit 1 experienced an automatic reactor trip when a main steam isolation valve ("MSIV") closed unexpectedly. FPL's responses to the unplanned outage events were prudent and efficient, and the units were returned to service safely. More details are described below.

<u>June 4, 2024 St. Lucie Unit 2</u>

Q. Please describe the circumstances related to the June 4 event.

A. On June 4, 2024, elevated levels of sodium were detected from one of the St. Lucie condenser hotwells on Unit 2. Operations reduced power to 92% to secure the associated circulating water pump ("CWP") on the "A" side. After securing the CWP, a false logic signal was developed due to a failed relay that resulted in a trip to another circulating water pump on the "B" side. This condition resulted in lowering condenser vacuum requiring operators to manually trip the unit in accordance with procedures.

Q. What did the investigation of the "B" CWP trip find?

A. The St. Lucie "B" CWP trip was caused by a valve limit switch failure. The original CWP control logic design did not consider the potential for this type of limit switch contact failure and created a system vulnerability. This vulnerability was not visible to the operators and could not have been reasonably detected or prevented.

Q. What actions were taken to address the valve limit switch failure?

A. Prior to restarting the unit, administrative controls were put in to prevent a near-term recurrence of this event. The plant was safely returned to operations in two days and power was maintained at approximately 92% for eight equivalent days for related repairs.

Q. What actions will FPL take to prevent recurrence?

A. A modification to the interlock circuit will be implemented at the next refueling outages for both St. Lucie units to remove this vulnerability. A complete condenser valve limit switch forensics analysis will be performed during the next refueling outage to determine the cause of the limit switch failure.

<u>June 18, 2024 St. Lucie Unit 2</u>

Q. Please describe the circumstances related to the June 18 event.

A. On June 18, 2024, in accordance with FPL procedures operators performed a forced unit shutdown of St. Lucie Unit 2 due to elevated sodium and chloride concentrations in both steam generators as required by FPL's operating procedures.

Elevated measurements of sodium and chloride in the steam generators is typically an indication of a condenser tube leak.

Q. What did the investigation of the condenser tube leak find?

A. After the shell side of the condenser was drained, an internal inspection of the leaking tube revealed that a previously plugged, adjacent tube was severed. In addition, other broken tubes and debris were removed during the inspection. Repeated contact between the severed tube damaged the adjacent tube over time, ultimately leading to the leak. The causal investigation found that there was insufficient industry guidance and no existing standards to assess and mitigate the risks of structural failures of a previously plugged and abandoned condenser tube.

Q. What actions were taken to address the tube failure?

A. During the investigation, the affected and surrounding tubes were plugged to prevent further damage. In addition, FPL conducted leak testing to ensure no other tubes were in a similar condition. The plant was offline for about 6.5 days and subsequently safely returned to operations.

Q. What actions does FPL plan to take to prevent recurrence?

A. A strategy to assess and mitigate the risks of structural failures of a condenser tube, along with the impact on adjacent tubes will be implemented during the next outages. For example, FPL will install tube stakes, stabilizers and remove any damaged components in vulnerable areas for the condenser. This removes the threat of a worn tube severing and impacting adjacent tubes. FPL is updating procedure guidance for securing plugged tubes and will work with the Electric Power Research Institute to develop tube staking industry guidelines.

July 28, 2024 St. Lucie Unit 1

Q. Please describe the circumstances related to the July 28 event.

A. On July 28, 2024, a MSIV to the 'A' steam generator ("SG") closed unexpectedly resulting in an automatic reactor trip. The cause for the MSIV closure was determined to be a result of a failed relay in the Engineered Safety Features Actuation System ("ESFAS"). The ESFAS system contains a subsystem called the Main Steam Isolation Signal ("MSIS"). The affected relay failed in its designed safety-related position to actuate, resulting in a signal to close the MSIV. With a closed MSIV at full power, the reactor protection system will automatically initiate a trip of the unit due to the imbalance in steam output between the two SGs. The MSIS is a very complex instrument and control radiological accident mitigation system.

Q. What did the investigation of the MSIV malfunction find?

A. The investigation determined the relay failed in its intended safety-related position. The complexity of the ESFAS system required extensive troubleshooting of numerous subcomponents to determine the direct cause of the MSIV closure. The investigation found that a MSIS relay had failed in its safe position due to a malfunction of the relay coil. In addition, the investigation determined that there was no OEM guidance for replacement of these relays and thus, a preventative maintenance plan was not established to replace the relays on a periodic basis.

Q. What actions were taken to address the MSIS relay failure?

A. The failed relay was replaced along with the five additional MSIS relays as part of an extent of condition review to determine and correct similar relay vulnerabilities. The unit was safely returned to service within approximately seven days.

Q. What actions does FPL plan to take to prevent recurrence?

A. FPL plans to implement preventative maintenance for these relays that calls for time-based replacement. An Extent of Condition review was performed and other ESFAS vulnerable relays will be replaced on Unit 2 during the upcoming outage to prevent this malfunction at that unit.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Charles Rote was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20240001-EI

MARCH 15, 2024

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 4300 Kyoto Gardens Drive, Palm Beach Gardens, Florida 33410.

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

A. I am employed by Florida Power & Light Company ("FPL") as Business Services Director in the Power Generation Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to 1999, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all budgeting, forecasting, regulatory and internal controls activities for FPL's fossil and solar generating assets.

Since 2013, I have also overseen the preparation of the Generating Performance Incentive Factor ("GPIF") filings, including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report FPL's actual 2023 performance for Equivalent Availability Factors ("EAF") and Average Net Operating Heat Rates ("ANOHR") for the GPIF generating units and to calculate the resulting GPIF reward/penalties. I compared the performance of each unit to the targets approved in the final Commission Order No. PSC-2023-0026-FOF-EI issued January 6, 2023 for the period January through December 2023 and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the results of these calculations: $22,432,570 of fuel savings to FPL's customers and a GPIF reward of $11,216,215.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control, any exhibits in this proceeding?

A. Yes. Exhibit CRR-1 shows the reward/penalty calculations. Page 1 of Exhibit CRR-1 is an index to the contents of the Exhibit.

Q. Please explain in general terms how the total FPL GPIF reward amount was calculated.

A. The steps involved in calculating the reward are provided in Exhibit CRR-1. Page 2 provides the overall GPIF performance of +2.4412 points or $22,432,570 in fuel savings which represents a reward of $11,216,215. Page 3 provides the calculation of the maximum allowed incentive dollars as approved

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by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's weighting factors, and the associated GPIF unit points.

Page 5 shows the actual EAF and adjustments summary. This page lists each of the GPIF units, the targets, the adjusted actual EAF and the Generating Performance Incentive Points for each unit for availability as determined by interpolating from the tables shown on pages 8 through 22. These tables are based on the targets and target ranges previously approved by the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. Columns 2 through 4 show the target heat rate formula, the actual net output factor ("NOF") and ANOHR for each GPIF unit. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 22. These tables are based on the targets and target ranges previously approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2023 period.

A. The primary reason that FPL will receive a reward for the period is that the adjusted actual EAF for thirteen out of the fifteen FPL GPIF units were better than their targets. In addition, two out of the fifteen FPL GPIF units operated with an adjusted actual ANOHR that was below the ±75 Btu/kWh dead band.

Q. Please summarize each nuclear unit's performance as it relates to the EAF.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 100%, compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $4,557,794.

St. Lucie Unit 2 operated at an adjusted actual EAF of 91.2%, compared to its target of 84.8%. This results in +10.0 points, which corresponds to a GPIF reward of $3,932,935.

Turkey Point Unit 3 operated at an adjusted actual EAF of 89.4% compared to its target of 82.8%. This results in +10.0 points, which corresponds to a GPIF reward of $3,818,071.

Turkey Point Unit 4 operated at an adjusted actual EAF of 89.5% compared to its target of 83.2%. This results in +10.0 points, which corresponds to a GPIF reward of $3,909,962.

In total, the nuclear units' EAF performance results in a net GPIF reward of $16,218,762.

Q. Please summarize each nuclear unit's performance as it relates to ANOHR.

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,435 Btu/kWh compared to its target of 10,427 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,343 Btu/kWh compared to its target of 10,307 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,510 Btu/kWh compared to its target of 10,522 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 adjusted actual ANOHR is 10,628 Btu/kWh compared to its target of 10,807 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +3.38 points, which corresponds to a GPIF reward of $214,106.

In total, the nuclear units' heat rate performance results in a net GPIF reward of $214,106.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $16,432,868.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, nine of the eleven fossil generating units performed better than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $1,751,902. The other two performed worse than their availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $625,319. Thus, the total FPL fossil units' EAF performance results in a net GPIF reward of $1,126,583.

Regarding ANOHR, one of the eleven FPL fossil units operated below the ±75 Btu/kWh dead band so it received a reward of $300,484. Seven out of the eleven fossil units operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties and three operated above the ±75 Btu/kWh dead band and consequently received a combined penalty of $6,643,720. Thus, the total fossil unit heat rate performance results in a net GPIF penalty of $6,343,236.

Q. What is the total GPIF reward/penalty for FPL's fossil units?

A. The net GPIF fossil availability performance reward of $1,126,583 minus the net GPIF heat rate fossil performance penalty of $6,343,236 results in a total GPIF penalty for FPL's fossil units of $5,216,653.

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Q. To recap, what is FPL's total GPIF result for the period January through December 2023?

A. The total GPIF result for the period January through December 2023 is $22,432,570 of fuel savings and a GPIF reward of $11,216,215 as a result of the availability and efficiency of the combined GPIF generating units.

Q. Does this conclude your testimony?

A. Yes.

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20240001
ERRATA SHEET

WITNESS: <u>CHARLES R. ROTE</u>
DIRECT TESTIMONY DATED MARCH 15, 2024

Page	Line	Change
2	12	change "$22,432,570" to "$22,292,090"
	13	change "$11,216,215" to "$11,145,919"
	21	change "+2.4412" to "+2.4259"
	22	change "$22,432,570 in fuel savings which represents a reward of $11,216,215" to "$22,292,090 in fuel savings which represents a reward of $11,145,919"
6	6	change "1,751,902" to "1,711,470"
	8	change "$625,319" to "$655,183"
	9	change "$1,126,583" to "$1,056,287"
	19	change "$1,126,583" to "$1,056,287"
	21	change "$5,216,653" to "$5,286,949"
7	4	change "$22,432,570 in fuel savings which represents a reward of $11,216,215" to "$22,292,090 in fuel savings which represents a reward of $11,145,919"

Exhibit No.	Page	Change
CRR-1	2, 4, 5, 6, 8, 9, 10, 11, 12, 13 and 19	Replace with attached corrected pages 2, 4, 5, 6, 8, 9, 10, 11, 12, 13 and 19

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20240001-EI

SEPTEMBER 5, 2024

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 4300 Kyoto Gardens Drive, Palm Beach Gardens, Florida 33410.

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

A. I am employed by Florida Power & Light Company (FPL) as the Business Services Director in the Power Generation Division, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil and solar generating assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December 2025. In addition, I will explain a revision to the data used to calculate the 2023 and 2024 combined cycle units' EAF which when applied to the 2023 GPIF reward calculation results in a reduced reward amount of $11,145,919.

Q. Have you prepared, or caused to have prepared under your direction, supervision or control, any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit CRR-2, CRR-3 and CRR-4. Exhibit CRR-2 supports the development of the 2025 GPIF EAF and ANOHR targets. The first page of this exhibit is an index to its contents. All other pages are numbered according to the GPIF Manual. CRR-3 and CRR-4 support revised calculations for FPL's 2023 and 2024 targets.

Q. Please summarize the 2025 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2025, FPL projects a weighted system equivalent planned outage factor (EPOF) of 4.9% and a weighted system equivalent unplanned outage factor (EUOF) of 6.6% which yield a weighted system EAF target of 88.5%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,103 Btu/kWh for the period January through December 2025. These targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CRR-2, pages 7 and 8, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the seventeen generating units that FPL proposes to be considered as GPIF units for the period

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January through December 2025. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining EAF targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the EPOF and EUOF. The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor and the historical equivalent maintenance outage factor. The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, a set of curves that reflect historical ANOHR and unit net output factors are developed for each GPIF unit. The historical data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historical ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the production costing simulation program, GenTrader. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

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Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected are responsible for no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the seventeen units which FPL proposes to use for the period January through December 2025 represent the units that have at least three years of generation history and are anticipated to generate 80.8% of the total forecasted system net generation based on economic dispatch.

Q. Do FPL's 2025 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes.

Q. Please explain the nature of the revision to the combined cycle data underlying FPL's 2023 and 2024 EAF targets.

A. FPL calculated its 2023 and 2024 EAF targets in accordance with the Commission's GPIF manual. Recently, FPL identified an error in the historical data used as inputs to its combined cycle EAF calculation for those years. Unlike other generation units, a combined cycle unit is composed of at least one combustion turbine and at least one steam turbine generator which generates power from the waste heat of the combustion turbine. As such, whenever the output of the combustion turbine is affected by an outage, the amount of heat exhaust from the combustion turbine is reduced which in turn reduces the output of the steam turbine.

Consequently, outages reduce not only the EAF of the combustion turbine but also the EAF of the steam turbine. The reduced steam turbine output was not captured in the application FPL uses to enter EAF data. As soon as FPL recognized this omission, it made the necessary modifications to the application to prevent recurrence.

Q. Which GPIF filings years are impacted by this data correction?

A. The revised data impacts only FPL's 2023 and 2024 GPIF calculations.

Q. Have you prepared revised GPIF targets for 2023 and 2024?

A. Yes, Exhibit CRR-3 contains the calculations for FPL's 2023 revised GPIF targets, which forms the basis for a revised 2023 GPIF reward calculation. Exhibit CRR-4 contains the calculations for FPL's revised 2024 GPIF targets, which will form the basis for FPL's 2024 GPIF reward/penalty calculation to be filed in next year's Fuel Clause Docket. For completeness, these exhibits reproduce the FPL's target calculations in their entirety though only the EAF targets for combined cycle units have changed.

Q. Is FPL proposing to adjust its 2023 GPIF reward?

A. Yes. FPL's combined cycle units' EAF reward, and correspondingly, its total 2023 GPIF reward is reduced by $70,296 for a total reward of $11,145,919. I have filed an errata to my March 15, 2024 testimony reflecting this reduction and an errata to my Exhibit CRR-1, which sets forth the calculation of this revised reward amount.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Kelly Fagan was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KELLY FAGAN

DOCKET NO. 20240001-EI

APRIL 3, 2024

Q. Please state your name and business address.

A. My name is Kelly Fagan, and my business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by NextEra Energy Resources, LLC as Senior Project Director in the Engineering & Construction division.

Q. Please summarize your educational background and professional experience.

A. In 1994, after serving in the United States Marine Corps, I transitioned into the civilian work force as an electrical apprentice, completing all four years of my apprenticeship while working in the field as construction lead and eventually an Assistant Project Manager. As a journeyman electrician I became a full Electrical Project Manager for large commercial and industrial projects across Northern Florida. In 2000 I also earned my Bachelor of Science Degree in Electrical and Computer engineering from the University of Florida. After obtaining my degree, I worked as a Lead Manufacturing Engineer for Motorola, Inc. and later served in a similar role for Sunbeam Corporation. In 2005, I obtained my electrical contractor's license and started an electrical contracting firm that focused on commercial and industrial projects in South Florida.

I joined Florida Power & Light Company ("FPL") in 2009 as the General Manager of Production Assurance and later held various roles with responsibility for fleet reliability across Florida. In 2014, I joined the Engineering and Construction Department as a Senior Project Manager. In that role, I managed the early-stage engineering and construction of multiple solar sites across Florida. I was responsible for the preliminary design, permitting, approvals, procurement, and contracting of Florida solar sites. This included all aspects of the project from initial due diligence for land acquisition to final permitting for the solar arrays, as well as any associated battery storage, transmission, and substations.

In 2019, I was promoted to Senior Manager responsible for the early-stage objectives for all of FPL's solar and battery storage projects. In this role, I coordinated the work of the early-stage solar project team and site developers to optimize the performance and costs of FPL's solar portfolio. I assumed my current role in late 2021.

Q. **What is the purpose of your testimony?**

A. First, I describe the 12 universal photovoltaic ("PV") solar energy centers expected to begin commercial operation by January 31, 2025 ("2025 Project") for which FPL seeks recovery pursuant to the Solar Base Rate Adjustment

("SoBRA") provision of its 2021 Rate Settlement Agreement approved by Order Nos. PSC-2021-0446-S-EI, PSC-2021-0446A-S-EI and 2024-0078-FOF-EI ("2021 Rate Settlement" or "Settlement"). I provide a description of the solar energy centers, including the technology, engineering design parameters, and overall construction schedules. Second, I demonstrate that FPL satisfies the cost requirements included in the 2021 Rate Settlement that the 2025 Project's costs not exceed the prescribed cost cap and that the estimated cost of the components, engineering, and construction for the 2025 Project is reasonable.

Q. Please summarize your testimony.

A. My testimony demonstrates that FPL has selected components and technology for the 2025 Project that will deliver high levels of efficiency and reliability to serve FPL customers. In addition, FPL has undertaken a competitive procurement process to ensure its costs are reasonable. FPL satisfies the prescribed cost caps by limiting its SoBRA recovery to the amounts authorized by the Settlement, even though, as I will explain, the cost to construct solar remains higher than originally anticipated at the time FPL entered the Settlement.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit KF-1 – List of FPL Solar Energy Centers in Service
- Exhibit KF-2 – FPL 2025 Solar Energy Center Maps
- Exhibit KF-3 – Typical Solar Energy Center Block Diagram

- Exhibit KF-4 – Specifications for 2025 Solar Energy Centers
- Exhibit KF-5 – Construction Schedules for the 2025 Solar Energy Centers
- Exhibit KF-6 – Capital Cost Table
- Exhibit KF-7 – Cost Increase Waterfall

I. 2025 Project Description

Q. Please describe FPL's experience in designing and building solar energy facilities.

A. FPL is leading one of the nation's largest solar programs and is currently Florida's largest generator of solar power. Since 2009 and as of the date of this filing, FPL has completed 88 solar energy centers totaling 6,442 MW_{AC}. The existing FPL solar energy centers range in size from 10 MW_{AC} to 74.5 MW_{AC}. Exhibit KF-1 provides a list of the FPL universal PV solar energy centers currently in service. For all centers installed through 2022 – the centers for which FPL has final costs – FPL successfully completed construction an average of 12 days early and at a total cost that fell approximately 2% or nearly $132.5 million below the cumulative budget. The 38 centers FPL placed in service from 2023 through March of 2024 likewise started commercial operation accordingly to plan, and costs are on track to meet or fall below budget.

Q. Please identify the solar energy centers that comprise the 2025 Project.

A. FPL is constructing 12 additional solar energy centers estimated to be in service by January 31, 2025. These are (i) Holopaw Solar Energy Center in Palm Beach

County, (ii) Speckled Perch Solar Energy Center in Okeechobee County, (iii) Big Water Solar Energy Center in Okeechobee County, (iv) Fawn Solar Energy Center in Martin County, (v) Hog Bay Solar Energy Center in DeSoto County, (vi) Green Pasture Solar Energy Center in Charlotte County, (vii) Thomas Creek Solar Energy Center in Nassau County, (viii) Fox Trail Solar Energy Center in Brevard County, (ix) Long Creek Solar Energy Center in Manatee County, (x) Swallowtail Solar Energy Center in Walton County, (xi) Tenmile Creek Solar Energy Center in Calhoun County, and (xii) Redlands Solar Energy Center in Miami-Dade County. Each center will have a nameplate capacity of 74.5 MW_{AC}. Exhibit KF-2 more fully describes and depicts the solar energy centers.

Q. Has FPL finalized the site layouts and designs for the solar energy centers?

A. Not at this time. Construction drawings are not finalized. Both my testimony and the analysis presented in FPL witness Whitley's testimony are predicated on the base-line designs. FPL does not foresee material changes to the designs and layouts for these sites.

Q. Please describe the solar technology that FPL plans to use for the 2025 Project and the resulting conversion efficiencies.

A. The 2025 Project will utilize approximately 2.1 million crystalline silicon panels that convert sunlight to direct current ("DC") electricity. These panels will have an average conversion efficiency of approximately 21.5%. This simply means that 21.5% of the solar energy reaching the surface of the panels is converted into DC electrical energy. This level of conversion efficiency is an improvement over recent years and reflects the continued advancement of solar generation technology.

In addition, 11 of the 12 solar energy centers will use single-axis tracking configurations deployed according to prudent engineering practices. Recent design and manufacturing improvements in single-axis tracking technology support higher wind loading, thus allowing for further expansion of their use. Single-axis tracking systems allow for the solar panels to follow the movement of the sun from east to west throughout the day, maximizing the amount of energy that can be produced by each panel. All other factors being equal, the use of tracking technology offers higher generation output as well as a higher firm capacity value, which contributes to the economic benefits described in the testimony of FPL witness Whitley. The sole exception is the Redlands Solar Energy Center, which will use a fixed racking configuration due to even higher wind loading design variables in Miami-Dade County relative to other counties in Florida.

The solar panels will be linked together in groups, with each group connected to an inverter, which transforms the DC electricity produced by the PV panels into alternating current ("AC") electricity. The voltage of AC electricity coming out of each inverter is increased by a series of transformers to match the interconnection voltage for each solar energy center. The inverters are paired with a single medium voltage transformer on a common equipment skid

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to form a power conversion unit ("PCU"). Nineteen PCUs will be installed at each solar energy center to produce 74.5 MW_{AC} of capacity. Exhibit KF-3 provides a typical block diagram depicting the basic layout of the major equipment components, and Exhibit KF-4 provides the specifications for the 12 solar energy centers.

Q. Describe the DC/AC ratio for the 2025 Project.

A. The DC/AC ratio is the ratio of the total installed DC capacity of PV panels to the AC capacity of each solar energy center. The DC/AC ratios for the solar energy centers depend on site conditions and environmental features unique to each location. For the 12 centers that comprise the 2025 Project, the DC/AC ratios will range from 1.20 to 1.59.

Q. Why are the DC/AC ratios not the same for all the solar energy centers?

A. Site and equipment characteristics unique to each of the solar energy centers drive variability in the DC/AC ratios. FPL seeks to achieve the highest level of output, reliability, and customer benefit from each unique solar energy center given the selection of major components and the design optimization possibilities that are available at each location at the time of design.

Q. Please describe whether upgrades to the existing FPL bulk transmission system are required to accommodate these 12 proposed solar energy centers.

A. Whether upgrades to FPL's bulk transmission system are required depends on the available transmission capacity in the area. The 12 solar energy centers that comprise the 2025 Project are sufficiently close to transmission corridors with available capacity to carry the energy generated by the centers. As a result, no network upgrade costs are required on the bulk transmission system for the 2025 Project.

Q. What are the proposed construction schedules and in-service dates for the 2025 Project?

A. FPL expects that the Project will be placed into service by January 31, 2025. The construction schedule includes the time necessary to obtain the required permits, procure materials and contract labor, clear and grade each of the sites, construct access pathways and drainage systems, install the solar generating equipment, erect fencing, build and energize the interconnection facilities, and test and startup each solar facility. The current construction schedules as shown in Exhibit KF-5 support the proposed commercial in-service date of January 31, 2025.

Q. As of April 3, 2024, what is the status of the certifications and permits required to begin construction for the solar energy centers?

A. All 12 sites that are part of the 2025 Project, have received federal, state, and local permits required to begin construction. The Florida Department of Environmental Protection ("FDEP") has issued an Environmental Resource Permit ("ERP") for all 12 solar energy centers. Six of the 12 sites also required Section 404 Authorization from the FDEP for impacts to state assumed waters, and all of these permits have been received. Finally, all centers have received the required county site plan approvals.

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Q. Please describe how FPL will manage the centers' operations and monitor their performance once each center enters commercial service.

A. The 2025 Project will benefit from monitoring and performance analysis tools that FPL developed and has continuously improved since it began operating universal solar in 2009. These proprietary tools optimize plant operations and drive process efficiencies. For example, the 12 solar energy centers will be operated and monitored from FPL's Renewable Operations Control Center ("ROCC"), the remote centralized location that interacts with all FPL universal solar and energy storage facilities. The ROCC uses advanced technology to identify potential problems earlier than traditional detection methods, creates automatic directives to investigate and resolve solar field energy losses, and allows the operating teams the opportunity to prevent or mitigate the effects of failures. FPL compares the performance of like components on similar generating units and determines how to make improvements, which often prevents problems before they would otherwise occur. The anomaly detection and artificial intelligence used in the ROCC technology tools improve service reliability for FPL customers.

The ROCC also provides a mechanism to reset inverters automatically and allows for remote technical troubleshooting to restore inverter operation. If remote restoration is not possible, the ROCC will have diagnosed the equipment to identify the key component requiring repair or replacement and will write a corrective order for the site to execute.

In addition, the ROCC interacts with FPL's Center of Work Excellence to create daily work schedules that most efficiently restore equipment, execute work orders, and perform preventative maintenance, with the goal of continuously reducing lost energy and production costs.

Finally, the 12 solar energy centers will be supported by regional operations teams that FPL has staffed across its territory in DeSoto, Clay, and St. Lucie Counties. These regional operations centers support the solar fleet's ongoing maintenance requirements and position resources in locations that ensure a timely response to any loss of production that arises.

II. 2025 Project Costs

Q. Please describe the cost-related requirements in the SoBRA provision that you will address.

A. FPL's 2021 Rate Settlement contains two cost-related requirements associated with solar projects for which FPL seeks recovery pursuant to the SoBRA provision. First, FPL's SoBRA recovery is capped at an average of $1,250 per kW_{AC} for the cost of the 2025 Project's components, engineering, and construction (the "Cost Cap"). In the event that the land component allocated to a solar site is already included as Plant Held for Future Use ("PHFU"), the cost of that land is subtracted from the Cost Cap, resulting in an "Adjusted Cap." Second, the Settlement requires that the cost of the 2025 Project's components, engineering, and construction be reasonable.

Q. Does the 2025 Project meet these two cost requirements?

A. Yes. FPL seeks SoBRA recovery only up to the Cost Cap and the Adjusted Cap, as applicable, for each solar site. In addition, the costs for the 2025 Project are reasonable, even though, as described below, costs have materially increased. The calculation of the associated revenue requirement and SoBRA Factor will be covered by other witnesses at the time of FPL's projection filing in this docket.

Q. Please describe the applicable Cost Cap and Adjusted Cap.

A. The Rate Settlement includes a Cost Cap of $1,250 per kW_{AC}, which is then subject to a reduction in the event the solar energy centers use land that is already included as PHFU as identified in FPL's Rate Case in the Exhibit labeled MV-5. Of the 12 solar energy centers that are part of the 2025 Project, six utilize property identified on FPL's Rate Case Exhibit MV-5. The costs for the remaining six sites and the required easements were included in rate base forecasts for Test Year 2022 and Subsequent Year 2023. Therefore, for purposes of the 2025 Project, FPL has assumed that the land and associated easement costs for all 12 sites are included in its rate base.

To calculate the average Adjusted Cap, FPL subtracted 100% of the land costs for the 2025 Project. The resulting average Adjusted Cap for the 2025 Project – and the amount FPL seeks to recover through the SoBRA – is $1,159 per kW_{AC}, which is $350 per kW_{AC} less than the average total adjusted estimated cost of $1,509 per kW_{AC}. Table 1 below shows the Adjusted Cap associated with each of the 12 applicable sites, the average Adjusted Cap for the 2025 Project, as well as the total and adjusted estimated costs per site and the average adjusted cost for the 2025 Project.

TABLE 1: COSTS PER SITE AND TOTAL AVERAGE COSTS					
	Settlement Cost Cap ($/kWAC)	**Less PHFU value ($/kWAC)**	**Adjusted Cap (SoBRA recovery amount $/kWAC)**	**Estimated Cost ($/kWAC)**	**Estimated Cost Less PHFU value ($/kWAC)**
Big Water	$1,250	$78	$1,172	$1,580	$1,502
Hog Bay	$1,250	$60	$1,190	$1,576	$1,516
Holopaw	$1,250	$189	$1,061	$1,908	$1,720
Green Pasture	$1,250	$60	$1,190	$1,553	$1,493
Thomas Creek	$1,250	$99	$1,151	$1,477	$1,378
Swallowtail	$1,250	$83	$1,167	$1,579	$1,496
Fawn	$1,250	$115	$1,135	$1,606	$1,491
Long Creek	$1,250	$74	$1,176	$1,595	$1,521
Speckled Perch	$1,250	$85	$1,165	$1,560	$1,475
Fox Trail	$1,250	$59	$1,191	$1,542	$1,482
Tenmile Creek	$1,250	$56	$1,194	$1,583	$1,527
Redlands	$1,250	$131	$1,119	$1,639	$1,508
Average Total	$1,250	$91	**$1,159**	$1,600	$1,509

Q. Does FPL's cost estimate include the costs associated with transmission interconnection?

A. Yes. The estimated capital costs include the projected cost for the construction of each solar energy center's unique transmission interconnection configuration.

Q. What was the basis for the $1,250 per kW$_{AC}$ Cost Cap included in the Settlement?

A. The $1,250 per kW$_{AC}$ Cost Cap included in the Settlement was based on an evaluation of the actual costs incurred for FPL's solar energy centers that were placed in service during late 2020 and early 2021, contracted costs for centers expected to be placed in service in 2022, and estimated costs for centers expected to be placed in service in 2023. FPL also evaluated the forward cost estimates, available market and commodity projections, and major equipment cost curves available at that time. FPL forecasted that major solar equipment cost curves would continue to decrease consistent with industry trends as supply chains continued maturing. FPL anticipated that this equipment cost decrease would offset the expected escalation in labor and minor material costs. Based on this analysis, FPL determined that the $1,250 per kW$_{AC}$ Cost Cap was an appropriate and achievable target for solar construction that would occur 24 to 36 months in the future.

Q. Please identify the factors that impacted the cost to build solar since the time FPL projected it could build these solar energy centers at or below $1,250 per kW$_{AC}$.

A. The primary factors that drove the increases in solar construction costs after FPL entered the Settlement are (i) increased solar panel prices due to (a) a U.S. Department of Commerce ("DOC") inquiry with respect to circumvention of anti-dumping and countervailing duties on solar cells and panels manufactured in China ("Circumvention Inquiry"), and (b) increases in the cost of polysilicon, the basic component in solar panel manufacturing; (ii) increased use of single-axis tracker technology in the 2025 Project; and (iii) general cost increases due to inflation, higher interest rates and increased demand for solar.

Q. Please describe the Circumvention Inquiry.

A. To provide background, United States trade law currently imposes duties and trade measures on goods imported from China into the United States. These trade measures include the anti-dumping duty and countervailing duty on PV solar cells and panels that are imported from China into the United States ("China AD/CV Duties"), which range from 0% to 254% depending on the exporter of the solar panel. In response to the China AD/CV Duties, most of the PV solar manufacturing operations that support the United States market have moved out of China.

On February 8, 2022, Auxin Solar requested that the DOC initiate an investigation into whether solar cell and panel imports from Malaysia, Vietnam, Thailand, and Cambodia were circumventing the China AD/CV Duties by undertaking only minor processing outside of China while using primarily Chinese components. The DOC initiated an investigation on April 1, 2022. A Presidential Proclamation instituting a two-year moratorium on China AD/CV Duties stemming from the Circumvention Inquiry was issued June 6, 2022, but final resolution of this matter remains outstanding. A DOC determination that the China AD/CV Duties were circumvented will result in the application of duties of up to 254% on offending panels. The impact of such a determination would be widespread, as the countries associated with DOC's Circumvention Inquiry would have accounted for approximately 80% of panel imports into the United States.

The DOC reached a preliminary determination in the Circumvention Inquiry on December 8, 2022 and a final determination on August 23, 2023 announcing new rules regarding tariff application to solar cells and modules from the four Southeast Asian countries involved in the Inquiry. Litigation regarding the Circumvention Inquiry remains ongoing.

Q. How has the Circumvention Inquiry impacted the cost of panels used in the 2025 Project?

A. The initiation of the DOC's investigation and the associated tariff risk caused an immediate shutdown of the solar panel supply chain, including panel production and shipments. This shutdown lasted approximately five months. The production and delivery of panel imports from Malaysia, Vietnam, Thailand, and Cambodia has now resumed. However, solar panel pricing increased dramatically to account for the perceived risk of tariffs and other U.S. government actions on solar panel imports. While panel pricing is beginning to improve following the Circumvention Inquiry, pricing for panels that will be used for the 2025 Project were impacted by the higher costs and are approximately 40% higher than the pricing that FPL anticipated when it entered the 2021 Rate Settlement.

Q. Please identify the main drivers behind the increased price of polysilicon.

A. The cost of polysilicon has increased due to two main reasons: supply constraints and trade restrictions.

Q. Please describe what you mean by "supply constraints" and explain how these constraints impacted the cost of polysilicon.

A. Since the time FPL entered the 2021 Rate Settlement, the global demand for solar panels has been increasing and, with the passage of the Inflation Reduction Act in August 2022, that demand continued to accelerate through the period in which FPL was procuring panels for the 2025 Project. The polysilicon market was unable to expand fast enough to meet growing demand for raw materials from panel suppliers. For example, from January 2021 through January 2023, the global polysilicon pricing index increased approximately 216%, from $12.41 to $39.19 per kilogram.

Q. Please describe the import restriction associated with polysilicon and how it has led to increased costs.

A. Beginning on June 21, 2022, the United States established a presumption that all goods from the Xinjiang region of China are prohibited from entering the United States. Among sectors designated as high priority for enforcement is polysilicon, the basic component in solar panel manufacturing. As a result, United States Customs and Border Protection ("CBP") began detaining panels at ports of entry to the United States in August 2022. FPL has worked closely with suppliers and CBP to clarify what documentation is required by CBP to trace solar panel raw materials back to the point of origin in order to definitively demonstrate that no materials originated in Xinjiang.

This import restriction caused solar panel suppliers to incur high storage and detainment costs, as well as additional costs for traceability programs and documentation. As a result, panel suppliers that utilize non-Xinjiang polysilicon seized upon this market environment as an opportunity to demand a premium price, since their proof of compliance allows for easier traceability to satisfy CBP documentation requirements and limits the risk of detention at a port.

Q. Please explain how the increased use of single-axis trackers contributed to an increase in the cost of the 2025 Project.

A. The mechanical system for single-axis trackers has higher material and installation costs than a fixed-tilt system. However, the benefits of a single-axis tracking system typically outweigh the costs, because a tracking design yields a higher net capacity factor, and more importantly, a higher firm capacity value than a fixed-tilt design. FPL determined that it was feasible to deploy trackers at 11 of 12 of the 2025 Project locations and elected to make this design change. The sole exception is the Redlands Solar Energy Center in Miami-Dade County which will use a fixed racking configuration due to higher wind loading design variables relative to other counties in Florida. The use of single-axis trackers at 11 of 12 sites for the 2025 Project increased overall Project costs by $66 per kW_{AC}, while raising the net capacity factor of the 2025 Project to

27.3%. As noted by witness Whitley, the higher project costs are offset by significant fuel and emission savings resulting in greater economic benefits for customers.

Q. Please explain how general inflationary pressure, higher interest rates, higher commodity prices and increased demand contributed to an increase in the cost of the 2025 Project.

A. General inflationary pressure impacted the costs for all solar construction which includes solar panels, steel, aluminum, single-axis tracking components, copper, land, and labor. In addition, the tightening of the U.S. job market following the second half of 2020 and the increase in demand for solar generation increased engineering, procurement, and construction ("EPC") contractor costs.

Construction costs also were impacted by higher interest rates. The 30-year United States Treasury Bond yield rate as of August 10, 2021, the date of the Rate Settlement Agreement, was 1.99%. The average rate for the period August 2021 through February 2024 was 3.38%, an increase of nearly 140 basis points. The significant rise in interest rates that followed after FPL entered the 2021 Rate Settlement resulted in higher costs to construct and finance capital projects, including the 2025 Project.

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Q. Please summarize how the market factors you have described impacted the overall cost of the 2025 Project.

A. The largest portion of the increase is due to the rise in solar panel costs due to the Circumvention Inquiry, increases in the price of polysilicon, and inflationary pressure on the solar panels. In total, this contributed $181 per kW_{AC} of incremental project costs. The change to mostly single-axis trackers added an additional $66 per kW_{AC}. The balance of the increase in pricing, about $103 per kW_{AC}, is due to the general inflationary pressures, commodity pricing, and higher interest rates I described. This cost increase summary is depicted visually in Exhibit KF-7.

Q. With these factors causing price increases during this period, were the costs FPL ultimately secured for construction of the 2025 Project reasonable?

A. Yes.

Q. What is the basis for your conclusion?

A. FPL utilized a robust procurement process designed to obtain the best available pricing. The costs for surveying, engineering, equipment, materials, and construction services necessary to complete the solar energy centers were established through competitive bidding processes. The balance of the costs was the result of leveraging existing agreements for engineering services, which themselves were the result of a separate competitive bidding process. Therefore, the vast majority of the 2025 Project's equipment, engineering, and construction costs were subject to competitive solicitations.

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FPL followed a procurement process similar to what it employed for prior SoBRA projects approved by the Commission, this time accounting for the solar market-specific impacts from the Circumvention Inquiry as well as the polysilicon importation restrictions. FPL solicited proposals for the supply of the PV panels, PCUs, and step-up power transformers, as well as the EPC services required to complete the proposed solar energy centers for the 2025 Project.

Q. Please describe the competitive solicitations for 2025 Project's solar panels.

A. FPL's solicitation for solar panels for the 2025 Project was expanded as compared to prior RFPs to include additional suppliers. FPL also requested and received more detailed information from bidders which helped to evaluate the potential impacts of the pending trade actions described above. In total, FPL requested proposals for PV panels from 19 large, industry-leading suppliers, including suppliers from more diverse locations which had not previously participated in FPL's solicitation process. Thirteen suppliers submitted bids that satisfied the requirements of the RFP, FPL evaluated each of these conforming bids, and ultimately contracted with two suppliers.

The two selected panel suppliers for the 2025 Project offered the lowest cost and highest efficiency products, offered some of the highest product quality programs in the industry, and were able to provide strong financial performance security. In addition, the suppliers selected for the 2025 Project, given the location of their manufacturing facilities, each demonstrated their ability to navigate the current regulatory environment with minimal impacts to both cost and schedule. Finally, by timing the execution of solar panel purchase contracts for the third quarter of 2023, FPL was able to avoid the height of market disruptions from the Circumvention Inquiry.

Q. **Please describe the competitive solicitations for 2025 Project's PCU and Step-Up Power Transformers.**

A. FPL solicited proposals from six PCU suppliers. Five of the six suppliers submitted proposals that met the requirements of the RFP and were evaluated. FPL selected the lowest cost bidder to supply the PCUs for the 2025 Project.

FPL solicited proposals from six industry-leading manufacturers of step-up power transformers. FPL evaluated three qualifying proposals and selected the lowest cost bidder to supply the transformers.

Q. **Please describe the competitive solicitations for the 2025 Project's construction contractors.**

A. FPL solicited EPC service proposals for the construction of the solar energy centers from 15 industry-recognized contractors. Eight of the 15 contractors submitted bids, and FPL evaluated these proposals for completeness. Using this method of evaluation, FPL then identified and selected the lowest cost bidder for each site to build the 2025 Project. One contract has been finalized with the selected EPC contractor. The scope of services for the EPC solicitations included the supply of the balance of equipment and other materials.

FPL solicited proposals for construction of substation and interconnection facilities from 20 industry-recognized contractors. Eighteen of the 20 contractors submitted bids and the proposals were evaluated. Similarly, FPL then identified the lowest cost bidder for each site within the 2025 Project and then selected five lowest cost bidders to construct substation and interconnection facilities at the sites.

Q. Are there other benefits associated with the 2025 Project?

A. Yes, there are several other benefits associated with the 2025 Project. For example, approximately 200 individuals will be employed at each of the solar energy centers at the height of construction, creating about 2,400 jobs in total for the 2025 Project. The contractors building the solar energy centers are required to exercise reasonable efforts to use local labor and resources. The jobs associated with the construction of the solar energy centers will therefore provide a secondary benefit by boosting the economy of local businesses in Florida. Additionally, the local communities will benefit from increased property tax revenues following the completion of the solar energy centers. In 2023, FPL paid approximately $24.1 million in property taxes to 24 counties across Florida for the PV solar energy centers that were operational in the 2023 tax year.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

WITNESS: KELLY FAGAN
DIRECT TESTIMONY DATED APRIL 3, 2024

Page	Line	Change
12	Table 1	Change the "Thomas Creek" cost line as follows:

- Under the "Less PHFU value" column, change "$99" to "$101"
- Under the "Adjusted Cap" column, change "$1,151" to "$1,149"
- Under the "Estimated Cost" column, change "$1,477" to "$1,479"

Change the "Tenmile Creek" cost line as follows:

- Under the "Less PHFU value" column, change "$56" to "$55"
- Under the "Adjusted Cap" column, change "$1,194" to "$1,195"
- Under the "Estimated Cost" column, change "$1,583" to "$1,582"

Note: for reference, included below is a Graphic of Table 1 that includes the above errata

TABLE 1:
COSTS PER SITE AND TOTAL AVERAGE COSTS

	Settlement Cost Cap ($/kW$_{AC}$)	Less PHFU value ($/kW$_{AC}$)	Adjusted Cap (SoBRA recovery amount $/kW$_{AC}$)	Estimated Cost ($/kW$_{AC}$)	Estimated Cost Less PHFU value ($/kW$_{AC}$)
Big Water	$1,250	$78	$1,172	$1,580	$1,502
Hog Bay	$1,250	$60	$1,190	$1,576	$1,516
Holopaw	$1,250	$189	$1,061	$1,908	$1,720
Green Pasture	$1,250	$60	$1,190	$1,553	$1,493
Thomas Creek	$1,250	~~$99~~ $101	~~$1,151~~ $1,149	~~$1,477~~ $1,479	$1,378
Swallowtail	$1,250	$83	$1,167	$1,579	$1,496
Fawn	$1,250	$115	$1,135	$1,606	$1,491
Long Creek	$1,250	$74	$1,176	$1,595	$1,521
Speckled Perch	$1,250	$85	$1,165	$1,560	$1,475
Fox Trail	$1,250	$59	$1,191	$1,542	$1,482
Tenmile Creek	$1,250	~~$56~~ $55	~~$1,194~~ $1,195	~~$1,583~~ $1,582	$1,527
Redlands	$1,250	$131	$1,119	$1,639	$1,508
Average Total	$1,250	$91	**$1,159**	$1,600	$1,509

(Whereupon, prefiled direct testimony of Andrew W. Whitley was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ANDREW W. WHITLEY

DOCKET NO. 20240001-EI

APRIL 3, 2024

Q. Please state your name and business address.

A. My name is Andrew W. Whitley. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Engineering Manager of Integrated Resource Planning in the Finance Department.

Q. Please describe your educational background and professional experience.

A. I graduated from Lehigh University in 2004 with a Bachelor of Science in Mechanical Engineering. I joined FPL in 2004 as part of FPL's Distribution Business Unit, and performed various engineering tasks related to providing new service as well as maintaining the reliability of existing services to FPL's customers. In 2007, I joined FPL's Resource Assessment and Planning group (now referred to as the Integrated Resource Planning ("IRP") group). During that time, I have been involved in a variety of resource planning projects for FPL, including FPL's Ten-Year Site Plans (or "TYSP"), Solar Base Rate Adjustment ("SoBRA") filings, several need determination proceedings for new power plants under the Florida Power Plant Siting Act, (the Okeechobee Clean Energy Center in 2015 and the Dania Beach Clean Energy Center in 2018), FPL's Rate Case filings, and the Demand-Side Management ("DSM") Goals proceedings. I became the Manager of the IRP group in 2022 and have served as the project leader for FPL's Ten-Year Site Plan since 2022.

Q. Please describe your duties and responsibilities in your current position.

A. In my current position as Engineering Manager of Integrated Resource Planning, I am responsible for the management and coordination of economic analyses of alternatives to meet FPL's resource needs and maintain system reliability. These analyses are designed to determine the magnitude and timing of resource needs for the FPL system and then develop the integrated resource plan with which those resource needs will be met. The analyses are also designed to identify ways to improve system economics and/or enhance system reliability for customers.

Q. Have you previously testified on resource planning issues before the Florida Public Service Commission ("Commission")?

A. Yes. I testified in FPL's 2019 DSM Goals (Docket No. 20190015-EG). My testimony in that docket focused on FPL's resource planning process and how it related to the development of demand-side management portfolios. I also provided testimony on the economic analysis of FPL's 2024 SoBRA in Docket No. 20230001-EI. In addition, I appeared before the Commission at its 2022 and 2023 workshops on the Florida utilities' Ten-Year Site Plans.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- AWW-1 Load Forecast
- AWW-2 FPL Fuel Price Forecast

- AWW-3 FPL Resource Plans
- AWW-4 CPVRR – Costs and (Benefits)
- AWW-5 Yearly PTC Impact
- AWW-6 Avoided Natural Gas
- AWW-7 Avoided Air Emissions

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

A. The purpose of my testimony is to present the results of the economic analysis, which shows that 894 megawatts alternating current ("MW_{AC}") of universal solar photovoltaic ("PV") generation scheduled to be placed in service in early 2025 (the "2025 Project") is cost-effective. My testimony covers several areas. First, I identify the 12 sites that make up the 2025 Project. Second, I discuss the major assumptions and the methodology used to perform the economic analysis. Third, I present the results of the economic analysis demonstrating that the addition of the 2025 Project is cost-effective. Lastly, I discuss non-economic benefits derived from the construction and operation of these facilities.

Q. Please summarize your testimony.

A. FPL is proposing the construction and operation of the 2025 Project: 894 MW_{AC} of solar PV generation, consisting of one construction project made up of 12 universal solar energy centers which are expected to be in-service by January 31, 2025. FPL performed an economic analysis and determined that the 2025 Project will result in a reduction in the cumulative present value of revenue requirements ("CPVRR") to FPL customers, for a total savings of approximately $911 million. In addition, these centers are projected to result in a significant reduction in the projected use of fossil fuels, which will in turn lower FPL's system reliance on generation fueled by natural gas. The 2025 Project is cost-effective, as required to qualify for a SoBRA under FPL's 2021 Rate Case Settlement ("2021 Rate Settlement") approved by the Commission in Order No. PSC-2021-0446-S-EI, PSC-2021-0446A-S-EI and PSC-2024-0078-FOF-EI.

Q. Please describe the 2025 Project.

A. The 2025 Project comprises 12 solar energy centers with a total nameplate capacity of 894 MW_{AC}, which is expected to be placed in service by January 31, 2025. Each of these centers is projected to generate about 177,500 MWh per year. This is enough energy to serve the annual energy needs of about 13,660 homes. FPL witness Fagan describes each technology to be employed at each center in greater detail and demonstrates that the construction cost for the proposed solar generation is reasonable.

Q. What are the major system assumptions used in this analysis?

A. The major assumptions used in this study are the following:

- **Load Forecast –** The analysis uses FPL's most recent long-term load forecast, approved as FPL's official load forecast in November 2023. This load forecast, including system peaks and net energy for load, is used in FPL's 2024 TYSP and is shown in Exhibit AWW-1;
- **Fuel Price Forecast –** The analysis uses FPL's most recent long-term fuel forecast, based on FPL's standard long-term fuel forecasting methodology, approved as FPL's official fuel price forecast in September 2023. This fuel price forecast is used in FPL's 2024 TYSP and is shown in Exhibit AWW-2; and

- **CO_2 Emission Price Forecast -** The CO_2 cost projections used in this filing are based on ICF's proprietary CO_2 compliance cost forecast dated September 26, 2022. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. This forecast, which assumes that CO_2 compliance costs will start in the year 2036, was used in preparing FPL's 2024 TYSP.

Q. Please describe the resource plans that formed the basis for FPL's cost-effectiveness analysis.

A. For purposes of this filing, FPL developed two resource plans. The first resource plan, called the "No 2025 SoBRA Plan," does not include any new solar facilities beyond those already in-service as of the end of 2025. In this plan, future resource needs are met by combined cycle units and battery storage.

The second resource plan, called the "2025 SoBRA Plan," adds the 2025 Project described above. Because each center is assumed to provide approximately 39% of the nameplate capacity as firm capacity to meet FPL's reliability obligations, 600 MW of batteries in 2029 in the "No 2025 SoBRA Plan" are reduced to 300 MW of batteries in the "2025 SoBRA Plan," and 900 MW of batteries in 2033 in the "No 2025 SoBRA Plan" are reduced to 300 MW in the "2025 SoBRA Plan" These two resource plans are shown in Exhibit AWW-3.

Q. What is the net capacity factor of the facilities in the 2025 Project?

A. The 2025 centers are projected to have an average yearly net capacity factor (or "NCF") of 27.3%.

Q. How did FPL determine the firm capacity that solar facilities will provide?

A. Firm capacity value is based on the expected output of a solar facility at the time of summer peak load, which typically occurs annually in August from 4 p.m. to 5 p.m., and winter peak load, which typically occurs in January from 7 a.m. to 8 a.m. FPL uses a "net peak load" methodology to determine what firm capacity value at FPL's Summer and Winter peak hours would be appropriate to apply to PV facilities. The potential capacity contribution of PV facilities is dependent upon several factors including: site location, technology, design, and the total amount of solar that is operating on FPL's system. FPL applies this same methodology to evaluate all its solar PV facilities, existing or new.

Based on this methodology, the 2025 centers are projected to have an average summer firm capacity value of 39.3% of their nameplate rating. Therefore, the 12 centers with a total nameplate capacity of 894 MW_{AC} are assumed to have a firm capacity value of 351 MW_{AC} at time of summer peak. These solar installations are assumed to have a 1.9% firm capacity value at time of winter peak due to FPL's winter peak occurring in the early morning, when there is little solar generation output.

Q. Please provide an overview of the analytical process that FPL used to determine the cost-effectiveness of the 2025 Project.

A. FPL used the capacity expansion and hourly production cost functions of the Aurora model to forecast the system economics and develop resource plans that include or exclude the 2025 Project. This model has been used by FPL in prior proceedings at the Commission. Each Aurora modeling run is used to determine the optimal resource plan

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and associated generation system costs, consisting of capital costs, fixed operations and maintenance ("O&M") costs, capital replacement costs, fuel costs, variable O&M costs, and emissions costs for a given resource plan. The Aurora model is used to determine the CPVRR for each resource plan.

Q. Please provide the result of the economic analysis.

A. To determine the CPVRR impact of the proposed solar generation, FPL subtracted the CPVRR of the No 2025 SoBRA Plan from the CPVRR of the 2025 SoBRA Plan. As shown in Exhibit AWW-4, the CPVRR benefit to FPL customers from the 2025 Project is approximately $911 million.

Q. Does the economic analysis include the effects of Production Tax Credits ("PTCs")?

A. Yes, the economic analysis includes the effects of PTCs that were part of the Inflation Reduction Act that was passed in 2022. The calculation of the PTCs from the 2025 Project is shown in Exhibit AWW-5.

Q. FPL witness Fagan states that the 2025 Project has a higher NCF as compared to FPL's earlier solar installations. Please explain how the higher NCF impacted the economic analysis.

A. The higher NCF achieved largely by the use of more single axis tracking systems results in higher levels of energy output. As FPL is able to generate more output from the solar energy centers, it results in incremental production tax credits, which in turn reduces the overall CPVRR of the 2025 SoBRA Plan and leads to greater customer savings. In addition, higher levels of energy output from using single axis tracking systems drive larger reductions in fossil fuel usage and emissions, which also reduces the overall CPVRR of the 2025 SoBRA Plan.

Q. Is the 2025 Project cost-effective even though it is over the cost cap in the 2021 Rate Settlement?

A. Yes. Although the estimated installed cost of the 2025 Project is $1,600 per kilowatt alternating current ("kW_{AC}"), which is over the $1,250 per kW_{AC} Cost Cap in the 2021 Rate Settlement, the 2025 Project is projected to save customers approximately $911 million CPVRR and therefore is still significantly cost-effective for FPL customers.

Q. Will the 2025 Project reduce FPL's use of fossil fuel?

A. Yes. As shown on Exhibit AWW-6, the energy from the 2025 Project will displace fossil fuel generation, specifically natural gas. The Project is expected to reduce the annual average use of natural gas by 13,982 million cubic feet. By adding the Project to its generation fleet, FPL reduces its reliance on natural gas and reduces exposure to fuel price volatility.

Q. What effect will these solar energy centers have with respect to greenhouse gases and other air emissions?

A. As shown in Exhibit AWW-7, reducing the use of fossil fuel results in an average annual reduction of 833,427 tons of CO_2. This reduction in CO_2 is equivalent to removing approximately 160,800 cars from the road. Sulfur dioxide emissions are roughly unchanged and nitrogen oxide emissions are reduced by an annual average of 71 tons.

Q. What is your conclusion regarding the 2025 Project?

A. As demonstrated by the economic analysis described in my testimony, the addition of the 2025 Project will result in CPVRR savings of approximately $911 million.

Therefore, the 2025 Project meets the SoBRA cost-effectiveness requirement established in the 2021 Rate Settlement. Additionally, the 2025 Project will reduce the use of fossil fuel, reduce air emissions, and reduce FPL's reliance on natural gas.

Q. Does this conclude your testimony?

A. Yes.

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(Whereupon, prefiled direct testimony of Edward J. Anderson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF EDWARD J. ANDERSON

DOCKET NO. 20240001-EI

SEPTEMBER 5, 2024

Q. Please state your name, business address, employer and position.

A. My name is Edward J. Anderson. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "Company") as Senior Director, Rate Development in the FPL Finance Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Arts in Economics and Business from the Virginia Military Institute. Since joining FPL in 2016, I have held positions of increasing responsibility within the Company's Regulatory & State Governmental Affairs and Finance Departments, including Principal Regulatory Analyst, Manager of Regulatory Rate Development, Senior Manager of Rates and Clauses, and was promoted to my current role in May 2024. I am responsible for all rate development activities for all retail electric rates and charges for FPL. Additionally, I am responsible for proposing and administering the tariff language needed to implement those rates and charges. Prior to joining FPL, I was employed by Dominion Energy for fourteen years. From 2003 to 2007, I worked within Dominion's Trading and Marketing Organization as a Business Operations Support

Associate and Power Market Analyst. My responsibilities included Power Pool (PJM and NE-ISO) reconciliation, analysis, and trading support. In 2007, I was promoted to Hourly Trader where I was responsible for managing and optimizing the hourly operations of Dominion's merchant power plant assets in PJM and NE-ISO. From 2008 to 2016, I worked within Dominion's State Regulation Department as a senior level Regulatory Pricing Analyst and Regulatory Advisor. My responsibilities included providing support and analysis as they related to rate design for all base and rider regulatory filings and I was Dominion's rates witness for several generation adjustment and fuel rate proceedings.

Q. What is the purpose of your testimony?

A. My testimony presents the calculation of the Solar Base Rate Adjustment ("SoBRA") factor and the corresponding changes to base rates needed to recover the annual revenue requirements associated with the 2025 Project.

Q. Have you prepared or caused to be prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes. They are as follows:

Exhibit EJA-1

- Page 1 provides the 2025 SoBRA Factor Calculation;
- Page 2 provides the forecasted retail base revenues for the projected 12-month period beginning February 1, 2025;
- Pages 3 through 48 provide a summary of tariff changes.

Exhibit EJA-2

- Pages 1 through 6 provide Residential and Business Typical Bills for customers in FPL's peninsular service area; and

- Pages 7 through 12 provide Residential and Business Typical Bills for customers in FPL's NW Florida service area.

<u>2025 SoBRA FACTOR</u>

Q. Please explain the calculation of the 2025 SoBRA factor and the purpose it serves.

A. I have calculated the 2025 SoBRA factor as required by the Settlement Agreement approved by the Commission in Order No. PSC-2021-0446-S-EI. The SoBRA factor is equal to the ratio of (i) the Company's jurisdictional revenue requirement of $61.087 million presented by FPL witness Mohomed for the 2025 Project and (ii) the forecasted retail base revenue from electricity sales for the first twelve months of operations. Application of the SoBRA factor will adjust the Company's February 1, 2025 base rates to provide the Company with sufficient revenue to recover the costs associated with the construction and operation of the 2025 Project. The calculation and resulting SoBRA factor of 0.667% is shown in Exhibit EJA-1, page 1 of 48.

Q. Do you have an exhibit that provides the forecasted retail base revenue for the projected 12-month period beginning February 1, 2025?

A. Yes. Exhibit EJA-1, page 2 of 48, provides the forecasted retail base revenue from the sales of electricity for all customer classes for the projected 12-month period beginning February 1, 2025. Forecasted retail base revenues from the sales of electricity include customer, demand and energy charge revenues, base revenues recovered through the Energy Conservation Cost Recovery Clause for the Commercial/Industrial Load Control Program and Commercial/Industrial Demand Reduction Rider credits, and non-clause recoverable credits (*e.g.*, transformation rider credits and curtailable service credits). Thus, all the charges subject to the SoBRA factor are included in these revenue figures. Unbilled retail base revenue is included in total retail base revenue from the sales of electricity in order to account for the collection lag resulting from the billing cycle. The total retail base revenues from the sale of electricity for the twelve months beginning February 1, 2025 are projected to be $9,161.413 million, shown on Exhibit EJA-1, page 1 of 48.

Q. Do you have an exhibit that provides a summary of the retail base rates to become effective for meter readings made on and after February 1, 2025?

A. Yes. Exhibit EJA-1 pages 3 through 48, column 4, provide a summary of the base rates proposed to become effective for meter readings made on and after February 1, 2025. If the SoBRA and the associated charges are approved for the 2025 Project, the Company will submit revised tariff sheets reflecting the Commission-approved charges.

Q. Please explain how the Company will notify the Commission of the 2025 Project's commercial operation date.

A. The Company will submit a letter to the Commission that declares the 2025 Project's commercial operation date. The 2025 SoBRA factor will become effective only on or after that commercial operation date.

C4-368

Q. Did FPL calculate its 2025 SoBRA factor consistent with the calculations presented previously for SoBRAs and approved by this Commission?

A. Yes.

EFFECTIVE DATES

Q. What is the effective date that FPL is requesting for the SoBRA for 2025?

A. FPL is requesting the SoBRA for 2025 become effective after the 2025 Project has entered commercial operation which is expected to occur by February 1, 2025.

BILL IMPACTS

Q. Do you have an exhibit that provides projected residential and business typical bill changes that account for all proposed changes in rates as proposed through February 2025?

A. Yes. Exhibit EJA-2 pages 1 through 12 provides proposed bill changes through February 1, 2025, illustrated for both typical residential and business bills in FPL's peninsular and NW Florida service areas. The typical bills reflect all proposed clause changes to become effective on January 1, 2025 and the proposed base and fuel changes related to the SoBRA for the 2025 Project scheduled to become effective by February 1, 2025.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Britnee Baker was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20240001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Phuong Nguyen
(2023 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Phuong Nguyen. My business address is 500 Energy Lane, Suite 100, Dover, Delaware 19901.

Q. By whom are you employed?

A. I am employed by Chesapeake Utilities Corporation, the parent company of Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I have a Bachelor of Science in Finance and Accounting from the University of New Orleans, and am a Certified Public Accountant licensed in the Commonwealth of Virginia and the State of Louisiana. Prior to my employment with CUC, I was employed at Entergy Corporation as a Regulatory Analyst, where I supported various rate proceedings for the regulated utility retail operations and the regulated utility wholesale operations under the jurisdiction of multiple Public Service Commissions and also the Federal Energy Regulatory Commission ("FERC"). Prior to that role, I was a Lead Analyst in the Utility Operations Accounting department at Entergy Corporation, where I performed accounting and analysis for fuel costs filed in exact recovery riders and other utility costs recovered through special riders. Prior to my employment at Entergy Corporation, I held various roles in accounting and finance briefly as a Consultant for Laporte CPAs firm, and prior to that as Chief Financial Officer at St. Margaret's Daughters, a non-profit entity.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2023 through December 2023.

Q. Have you included any exhibits to support your testimony?

A. Yes. Exhibit (PTN-1) consists of Schedules A, E1-B and C-1 for the Consolidated Electric Division. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2023 through December 2023?

A. For the Consolidated Electric Division the final remaining true-up amount is an over recovery of $1,633,921.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2023 period and the total true-up amount to be collected or refunded during the January 2024 - December 2024 period.

Q. What was the actual end of period true-up amount for January - December 2023?

A. For the Consolidated Electric Division it was $10,002,598 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January 2024 – December 2024 period?

A. A consolidated under-recovery of $11,636,519 to be collected.

Q. Does the Company anticipate requiring a midcourse adjustment for 2024?

A. No, not at this time. Based on the current projections, the Company anticipates an insignificant over-recovery by year end 2024. However, the Company will closely monitor the 2024 results and file a midcourse correction when necessary.

Q. Does this conclude your direct testimony?

A. Yes, it does.

<u>BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION</u>

DOCKET NO. 20240001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Revised Direct Testimony of Brittnee Baker (Estimated/Actual)

<u>On Behalf of Florida Public Utilities Company</u>

Q. Please state your name and business address.

A. My name is Brittnee Baker. My business address is 500 Energy Lane, Dover, DE 19901.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as a Regulatory Analyst.

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science degree in Accounting from Johnson & Wales University. I have been employed with Chesapeake Utilities since 2018. I was hired as a Staff Accountant in 2018 before moving into the regulatory department in 2024. This role includes regulatory analysis and filings before the Florida Public Service Commission ("FPSC" or "Commission") for FPUC.

Q. Have you previously testified in this Docket?

A. Yes, I have testified in this Docket.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the revisions to the schedules being submitted in this docket.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching revised Schedules E1-A, E1-B, and E1-B1 as part of Revised Exhibit BB-1. Revised Schedule E1-B shows the Calculation of Purchased Power Costs and

Calculation of True-Up and Interest Provision for the period January 2024 – December 2024 based on 6 Months Actual and 6 Months Estimated data.

Q. Were these schedules completed by you or under your direct supervision?

A. The schedules were completed by me.

Q. What was the final remaining true-up amount for the period January 2023 – December 2023?

A. The final remaining true-up amount was an over-recovery of $1,633,921.

Q. What is the estimated true-up amount for the period January 2024 – December 2024?

A. The estimated true-up amount is an over-recovery of **$3,060,756.**

Q. What is the total true-up amount estimated to be refunded for the period January 2025 – December 2025?

A. The Company estimates it will refund **$4,694,677** for the period January 2025 – December 2025.

Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will provide low cost, resilient and reliable energy to its customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our

Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements and air permitting have been completed at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

Q. **Has the company incurred any costs during the preliminary stages of this project?**

A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC as well as the law firm of Gunster, Y Oakley, and Stewart PA for their experienced in the aforementioned processes. The Company incurred consulting and legal fees linked to this project amounting to $126,905 in 2021, $116,912 in 2022, $125,828 in 2023, and $10,250 through June of 2024. We roughly estimate to spend another $45,000 by year-end.

Q. When do you anticipate construction to begin on the AIE facility?

A. It is anticipated that decisions can be finalized in 2025. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Why was the Company's 2024 Actual/Est True-Up file revised?

A. The Company revised its 2024 Actual/Est True-Up to reflect updated forecasted fuel costs as well as forecasted billing determinants as reflected in the Company's recent petition for rate increase, Docket No. 20240099-EI.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

2025 Projection Direct Testimony of Brittnee Baker

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Brittnee Baker. My business address is 500 Energy Lane, Dover, DE 19901.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as a Regulatory Analyst.

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science degree in Accounting from Johnson & Wales University. I have been employed with Chesapeake Utilities since 2018. I was hired as a Staff Accountant in 2018 before moving into the regulatory department in 2024. This role includes regulatory analysis and filings before the Florida Public Service Commission ("FPSC" or "Commission") for FPUC.

Q. Have you previously testified in this Docket?

A. Yes, I have testified in this Docket.

Q. What is the purpose of your testimony at this time?

A. My testimony will establish the "true-up" collection amount, based on actual January 2024 through June 2024 data and projected July 2024 through December 2025 data to be collected or refunded during January 2025 – December 2025. My testimony will also summarize the computations that are contained in composite exhibit BB-2 supporting the January through December 2025 projected levelized fuel adjustment factors for its consolidated electric divisions.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching Schedules E1, E1-A, E2, E7, E8, and E10 as part of Exhibit BB-2, which is appended to my testimony.

Q. Were these schedules completed by you or under your direct supervision?

A. Yes, the schedules were completed by me.

Q. What was the final remaining true-up amount for the period January 2023 – December 2023?

A. The final remaining true-up amount was an over-recovery of $1,633,921.

Q. What is the estimated true-up amount for the period January 2024 – December 2024?

A. The estimated true-up amount is an over-recovery of $3,060,756.

Q. What is the total true-up amount estimated to be refunded for the period January 2025 – December 2025?

A. The Company estimates it will refund $4,694,677 for the period January 2025 – December 2025.

Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will provide low cost, resilient and reliable energy to its customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

C12-1127

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Mr. Cutshaw addresses these project assignments more specifically in his testimony.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel and purchased power clause. FPUC engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2025 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Mr. Cutshaw addresses these project assignments more specifically in his testimony.

Q. Please explain how these costs were determined to be recoverable under the fuel and purchased power clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other fuel related costs included in the fuel clause are directly related to purchased power, have not been recovered through base rates. Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of purchased power costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 20180001-EI, 20190001-EI, 20200001-EI, 20210001-EI, 20220001-EI and 20230001-EI, the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce purchased power savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. **Please explain the difference between the over-recovery amount previously reported in the 2024 actual/estimated true-up as compared to the amount in this**

filing?

A. The Company is including, in this filing, its revised 2024 Actual/Estimated True-Up to reflect updated forecasted fuel costs as well as forecasted billing determinants as reflected in the Company's recent petition for rate increase, Docket No. 20240099-EI. The original over-recovery previously reported was $6,037,414 and has been revised to reflect an over-recovery of $4,694,677 in this filing. The Company has revised and submitted with this petition the revised 2024 Actual/Estimated True-Up and Testimony.

Q. What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is **5.550¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2025 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Composite Exhibit Number BB-2, a residential customer using 1,000 KWH will pay **$163.80**. This is a decrease of **$2.18** below the previous period.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of P. Mark Cutshaw was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2025 Projection Testimony of P. Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw, 780 Amelia Island Parkway, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering. My electrical engineering career began with Mississippi Power Company in June 1982. I spent nine years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the

Commission as well as other regulatory issues. During January 2024, I moved into my current role as Manager, Electric Operations for the Northeast Florida Division.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI, as well as rebuttal testimony in Docket No. 20180061-EI and numerous annual proceedings for Fuel and Purchased Power Cost Recovery. Most recently, I provided testimony in Docket Nos. 20220049 and 20240010, in the Storm Protection Plan and Cost Recovery proceedings.

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

A. My direct testimony addresses several aspects of the purchased power cost for our FPUC electric customers. This includes activities to investigate the potential for reduced purchase power costs, execution/amendment of purchased power agreement(s) with Florida Power & Light ("FPL"), billing of purchased power cost to our industrial customers, Combined Heat and Power ("CHP") generation supply located on Amelia Island and investigation into the opportunities of energy provided from solar and battery installations.

Q. Do natural gas costs have a significant impact on the overall cost of purchased power for FPUC?

A. Yes, because FPUC does not own its own generation, it purchases the power it needs to serve its customers from larger, generating utilities. At present, FPUC purchases the majority of the power it needs to serve its customers from FPL. The majority of electricity generated in Florida is generated by natural gas fueled generating facilities. As such, the cost of natural gas directly impacts the cost of power purchased by FPUC.

Q. Has FPUC taken steps to ensure more accurate cost projections based on activity in the natural gas markets?

A. Yes. FPUC, being predominately a natural gas utility, has utilized information from both inside the Company and other external sources to carefully monitor the natural gas markets. Based on the information gained, the Company forecasts 2025 natural gas costs and includes that information in its purchased power cost projections.

Q. What is the status of the purchase power agreements in place with FPL?

A. The previous agreement for our Northwest Florida Division with FPL became effective January 1, 2020, with a termination date of December 31, 2026, unless extended by FPUC. The previous agreement for our Northeast Florida Division with FPL became effective January 1, 2018, was amended in 2019 and was scheduled to terminate December 31, 2026, unless extended by FPUC. During 2023, FPUC and FPL engaged in discussions with a goal of combining the separate purchased power agreements into a single agreement, which would continue to provide reliable, cost effective purchased power to FPUC for its customers. The combined purchased power agreement was developed, executed and became effective on July 1, 2024, replacing the two prior agreements for the each of FPUC's divisions.

Q. What new opportunities has the Company implemented with the intent of achieving energy resiliency and reducing costs for its customers in its consolidated electric divisions?

A. In addition to consolidation of the purchased power agreements, FPUC also engaged with FPL in the review of the transmission agreements and infrastructure currently in place between the two companies. These discussions led to opportunities to change the delivery points at four of the five substations in the Northwest Florida Division, which could reduce purchased power costs to FPUC.

Q. What changes are anticipated to the transmission agreements in the Northwest Florida Division?

A. Under the current transmission agreement for the Northwest Florida Division, the interconnection point between FPUC and FPL is located at the low voltage side of the substation transformer. Based upon the location of the interconnection point, it was necessary for FPL to pass along substation cost associated with providing purchased power to FPUC in the form of a distribution charge which was incorporated into the purchased power cost. In relocating the interconnection point to the high voltage side of the substation transformer, the additional distribution cost was no longer required for four of the five substations which helps reduce purchased power cost. The fifth substation is configured in such a way that two customers are provided service from the same transformer which would not allow the relocation of the interconnection point. The distribution charge at this substation will continue.

Q. Is FPUC proposing any changes to the way purchased power costs are allocated to its two industrial customers?

A. Yes. Under the current billing mechanism, there are a number of considerations and calculations that occur in order to calculate the purchased power billing for the industrial customers. Since this must occur on the first business day of every month and certain critical data is unknown at that point, the bill is estimated. Due to the fact that this estimated billing results in a significant expense, which is actually incurred in the month preceding the bill, it is necessary to place that expense on the books in the form of an accrual to comply with accounting practices. Therefore, FPUC sends an estimated bill to the industrial customers. Later in the month after all the final information is available, a final bill is calculated and provided to the customers. This again results in FPUC and the industrial customers being required to reverse the accrued estimated bill and record the final billing for the month.

FPUC is proposing to change this approach by issuing only a final bill based on customer demand on the first business day of the following month. The Company would continue to keep up with the existing purchased power allocation for the appropriate GSLD1 rate class and then true up the billing parameters at year end. This true up would be handled similarly to what is being done for other FPUC rate classes but would involve only the appropriate GSLD1 rate class.

Q. How will be you able to produce a final bill if you don't have all the appropriate information on the first day of the month?

A. FPUC is proposing to change the basis upon which these customers are billed. The new billing mechanism will be based solely on the customers' maximum KW demand for the previous month, which is data that is known on the first day of the subsequent month. Currently, the purchased power calculations involve the KW demand charges coincident with the FPUC peak, a KW demand coincident with the FPL peak and the energy charges. However, the FPUC peak and FPL peak times can't be confirmed until later in the month, which results in estimated values being used in the preliminary billing.

Q. How will the annual true up for purchased power charges be calculated?

A. For these customers, the proposed billing method will be used during the year as described above. Additionally, during the course of each month, FPUC will continue to calculate the purchased power billing monthly allocation in the current manner so that it will be possible to true up the cost and adjust billing for the new year during this annual proceeding. The GSLD1 customers have traditionally been removed from the annual fuel filing and true-up mechanism for other rate classes. If the Company's proposed billing change is approved, the GSLD1 customers will continue to be handled outside the Fuel Clause but their bill would include an actual monthly charge and the proposed true-up mechanism.

Q Why is FPUC making this change to how it bills its industrial customers?

A. FPUC is proposing this change in order to bill the GSLD1 customers in a prompt and efficient manner while using a similar true-up mechanism used for all other rate classes. This not only makes the billing more timely and efficient but also makes the accounting for these expenses more accurate for both FPUC and the GSLD1 customers.

Q. How will this change impact the two industrial customers?

A. The proposed change will result in a positive impact for the industrial customers. The proposed billing mechanism is intended to allow recovery of the same fuel

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charge as the current mechanism and will be much more efficient and accurate in the processing.

Q. Has the Company made the customers aware of this proposed change?

A. FPUC has not made the customers aware of this proposed change at this time. As we move through this proceeding we will ensure information is provided to the customers regarding any changes that we anticipate being incorporated into the approved purchase power cost recovery clause.

Q. Are there any other modifications the Company is proposing to the Rate Adjustment Rider?

A. Yes. On the Rate Adjustment Rider shown in the tariff page No. 65, we are proposing to remove the Time of Use Rate Class rate schedules. Currently there are no customers remaining on these rate schedules and we do not anticipate future customers.

Q. Are there other efforts underway to identify projects that will lead to energy resiliency and lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to increased energy resiliency and reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects, potential Solar Photovoltaic ("PV") projects and associated utility scale battery projects. More specifically, Pierpont &

McLelland has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. They have also been involved in the structuring of the most effective measures to ensure a reliable and resilient system on Amelia Island which may include additional transmission lines to the Island as well as using existing generation and the addition of new natural gas fired generation. Locke Lord is a law firm with particular expertise in the regulatory requirements of the Federal Energy Regulatory Commission. Attorneys with the firm have provided legal guidance and oversight regarding the contracts and regulatory requirements for generation and transmission-related issues for the Northeast Florida Division. The Company's in-house experience in these areas is limited; thus, without this outside assistance, the Company's ability to pursue potential purchased power savings opportunities would be limited, as would its ability to properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements. Sterling Energy and Christensen Associates have been involved to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, existing and new Combined Heat and Power ("CHP") capability and improvements in the transmission system to Amelia Island to improve the reliability/resiliency on Amelia Island and further reduce the overall purchased power impact to all FPUC customers. In addition to CHP possibilities, FPUC has been investigating how the use of Renewable Natural Gas (RNG) and Hydrogen as future fuel sources for generation assets may provide benefits in the future. The markets for both RNG and Hydrogen are still developing, however, both have the potential to provide environmental benefits compared to existing fuel sources. Although there are currently some operational and cost challenges being addressed within the generation community, it is important that FPUC continue to be involved in the investigation and development of these resources and the long term benefits that are possible.

Q. Can you provide additional information on these CHP projects?

A. Yes. The success of the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with industrial expansion in the area, the already quantifiable benefits of the existing project have piqued the interest of others to contemplate development of a new CHP-based project on Amelia Island. FPUC was actively involved in the initial analysis, development and engineering of a possible new project located on Amelia Island that would support the existing industry. Significant efforts went into the evaluation of this CHP which, similar to Eight Flags, would be located on Amelia Island and would allow the customer, along with transmission line upgrades, to have additional reliability and resilience to its electricity supply for industry and possibly supply customer on Amelia Island. This second CHP would provide electricity, high pressure steam and hot water for a local industrial customer which is a critical component of the local community. Preliminary engineering, financial modeling and Florida Department of Environmental Protection permitting were completed for this possible CHP unit. Although the final agreements and structure of the proposed CHP for the customer has not yet been finalized. No decisions have been made by the customer on how to proceed.

Q. Can you provide additional information on the PV and battery projects you referenced above?

A. Yes. FPUC continues to assess the feasibility of smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors but work continues to investigate alternatives to improve the feasibility. At this time, FPUC is investigating opportunities involving larger PV installations which have proved to be more economically feasible. Not only will this increase the renewable energy available to FPUC, the cost is expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. The new "Agreement" with FPL does have provisions that allow for the development of PV installations by FPUC and provides for the possibility of a partnership between the parties that would allow for the development of a PV project.

Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects have been difficult to justify economically at this point but are still under consideration by FPUC. Nonetheless, the potential benefits of the PV and battery projects under consideration will be continued.

Q. Does this include your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Zel D. Jones was inserted.)

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

2023 FINAL TRUE-UP

TESTIMONY AND EXHIBITS

ZEL D. JONES

FILED: APRIL 3, 2024

C16-1199

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES

Q. Please state your name, address, occupation, and employer.

A. My name is Zel D. Jones. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Civil Engineering with a concentration in Environmental Science from Tennessee State University in 2002, and I received a Master of Business degree in 2006 from City University of Seattle. I joined Tampa Electric in 2011 as the Environmental and Water Systems Engineer at the Big Bend Power Station in Apollo Beach, Florida. In December 2019, I joined the Outage & Project Management (O&PM)

C16-1200

Department as a Project Engineer. I became a Project Manager within the same department in 2020 and managed capital projects for Big Bend and Bayside Power Stations. In 2022, I became the Capital Program Lead at Bayside Power Station – overseeing the capital program budget. I joined the Regulatory Affairs Department in October 2023 as a Manager, Rates. My current duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments and approved environmental projects. I have over 12 years of electric utility experience in power plant operations, operational environmental compliance, large capital project and program management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2023 through December 2023 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause ("Capacity Clause"), as well as the Asset Optimization Mechanism gain sharing allocation for the period.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No. ZDJ-1, consisting of four documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2023 through December 2023?

A. The final true-up amount for the Capacity Clause for the period January 2023 through December 2023 is an under-recovery of $1,888,665.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2023 Through December 2023", provides the calculation for the final under-recovery of $1,888,665. The actual capacity cost under-recovery, including interest, was $9,307,569 for the period January 2023 through December 2023 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $7,418,904 actual/estimated under-recovery approved in Order No. PSC-2023-0343-FOF-EI issued on November 16, 2023, results in a final under-recovery of $1,888,665.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2023 through December 2023?

A. The final Fuel Clause true-up for the period January 2023 through December 2023 is an over-recovery of $30,397,837. The actual fuel cost under-recovery, including interest, was $82,436,187 for the period January 2023 through December 2023. This $82,436,187 amount, less the $112,834,024 under-recovery included in the Company's actual/estimated projection approved in Order No. PSC-2023-0343-FOF-EI issued November 16, 2023, in Docket No. 20230001-EI, results in a net over-recovery amount for the period of $30,397,837.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2023 Through December 2023." It shows the calculation of the final fuel over-recovery of $30,397,837.

Line 1 shows the total company fuel costs of $608,109,216 for the period January 2023 through December 2023. The jurisdictional amount of total fuel costs is $608,109,216, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $386,614,049 over-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual under-recovery amount of $82,436,187 shown on line 9. The $82,436,187 actual under-recovery amount less the $112,834,024 under-recovery included in the company's actual/estimated projection recovery amount and shown on line 10, results in a final net over-recovery amount of $30,397,837 for the period January 2023 through December 2023, as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Mid-course Estimates for the Period January 2023 Through December 2023." It shows the calculation of the actual under-recovery compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2023 through December 2023?

A. As shown on line A6 of Document No. 3, the fuel and net power transaction cost is $176,595,493 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2023 through December 2023?

A. As shown on line C3 of Document No. 3, the company collected $42,082,952, or 4.4 percent greater jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of transactions for each of Commission Schedules A6, A7, A8, A9, as well as capacity information on Schedule A12.

Asset Optimization Mechanism

Q. Was Tampa Electric's sharing of Asset Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Asset Optimization Mechanism gains was allocated in accordance with FPSC Order PSC-2017-0456-S-EI. As a result of the company's Asset Optimization Mechanism activities during 2023, the total gains were $10,045,377. Under the sharing mechanism, Tampa Electric customers receive $6,922,689, and the company earned an incentive of $3,122,688. Customers received the gains from these transactions during 2022, and Tampa Electric requests Commission approval to collect the company’s $3,122,688 incentive in its 2025 fuel factors.

Q. Does this conclude your testimony?

A. Yes, it does.

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2024 THROUGH DECEMBER 2024

TESTIMONY AND EXHIBIT
OF
ZEL D. JONES

FILED: JULY 26, 2024

TAMPA ELECTRIC COMPANY
C16-1237
DOCKET NO. 20240001-EI
FILED: 7/26/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES

Q. Please state your name, address, occupation, and employer.

A. My name is Zel D. Jones. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Civil Engineering with a concentration in Environmental Science from Tennessee State University in 2002, and I received a Master of Business degree in 2006 from City University of Seattle in 2006. I joined Tampa Electric in 2011 as the Environmental and Water Systems Engineer at the Big Bend Power Station in Apollo Beach, Florida. In December 2019, I joined the Outage & Project Management (O&PM) Department as a Project Engineer. I became a Project

Manager within the same department in 2020 and managed capital projects for Big Bend and Bayside Power Stations. In 2022, I became the Capital Program Lead at Bayside Power Station – overseeing the capital program budget. I joined the Regulatory Affairs Department in October 2023 as a Manager, Rates. My current duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments and approved environmental projects. I have over 13 years of electric utility experience in power plant operations, operational environmental compliance, large capital project and program management.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2024 through December 2024 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2025 through December 2025 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2024, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2025 fuel and purchased power and capacity cost recovery factors.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I have prepared Exhibit No. ZDJ-2, which consists of two documents. Document No. 1 includes Schedules E1-A, E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2024 through December 2024. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2024 through December 2024.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in January 2025 through December 2025 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount for 2024 to be applied in January 2025 through December 2025 is an over-recovery of $28,431,329.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2025 through December 2025 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2025 does not include the final true-up amount for the period January 2023 through December 2023 as this amount was returned to customers during 2024 in Tampa Electric's fuel mid-course factors effective June 2024 through December 2024, as approved in Order No. PSC-2024-0172-PCO-EI, issued May 24, 2024, in Docket No. 20240001-EI. The net true-up amount does include the actual/estimated true-up amount, including the over-recovery for the period January 2024 through December 2024. This calculation is shown on Schedule E1-A of Exhibit No. ZDJ-2, Document No. 1.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2024 through December 2024?

A. The actual/estimated 2024 fuel true-up amount is an over-recovery amount of $144,305,986 for the period January 2024 through December 2024. The detailed calculations supporting the actual/estimated current period true-up are shown in Exhibit No. ZDJ-2, on Schedule E1-B, Document No. 1.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2025 through December 2025 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2024 through December 2024 is an under-recovery of $11,236,969 as shown in Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2025 through December 2025 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2025 capacity cost recovery factors includes the final true-up amount for 2023 and the actual/estimated true-up amount for January 2024 and December 2024.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2023?

A. The final 2023 under-recovery of $1,888,665 as shown on Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2024 through December 2024?

A. The actual/estimated true-up amount is an under-recovery of $9,348,304 as shown on Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2024 through December 2024?

A. The net capacity cost recovery true-up amount for the period January 2024 through December 2024 is an under-recovery of $11,236,969. This calculation is shown on Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C16-1242

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2025 THROUGH DECEMBER 2025

TESTIMONY AND EXHIBIT
OF
ZEL D. JONES

FILED: SEPTEMBER 05, 2024

C16-1281

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240001-EI
FILED: 09/05/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES

Q. Please state your name, address, occupation, and employer.

A. My name is Zel D. Jones. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20240001-EI?

A. Yes, I submitted direct testimony on April 3, 2024 and July 26, 2024.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, they have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2025 through December 2025. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2025.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. ZDJ-3, consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2025 through December 2025 as well as Schedule H1 for 2022 through 2025. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 contains additional E-1D and E-1E schedules that reflect the company's proposed time-of-use changes, as filed in Tampa Electric's Petition for Rate Increased, filed in Docket No. 20240026-EI.

Q. Are you requesting Commission approval of the projected fuel and capacity cost recovery factors for the company's various rate schedules?

A. Yes.

Q. How were the fuel and capacity cost recovery clause factors calculated?

A. The fuel and capacity cost recovery factors were calculated as shown on Document Nos. 1 and 2. These factors were calculated based on the current approved rate design and schedules as set out in the 2021 Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2021-0423-S-EI on November 10, 2021 in Docket No. 20210034-EI.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ZDJ-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ZDJ-3, Document No. 1, page 2 of 4, Tampa Electric is requesting recovery of $17,271,328 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2025.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2025 for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.096	
GS and CS Secondary	0.088	
GSD, SBD Standard		
Secondary		0.31
Primary		0.31
Transmission		0.30
GSD Optional		
Secondary	0.075	
Primary	0.074	
Transmission	0.074	
GSLDPR/GSLDTPR/SBLDPR/SBLDTPR		0.26
GSLDSU/GSLDTSU/SBLDSU/SBLDTSU		0.30
LS1 Secondary	0.018	

These factors are shown in Exhibit No. ZDJ-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.084 cents per kWh compare to the factor for January 2024 through December 2024?

A. The proposed capacity cost recovery factor of 0.084 cents per kWh beginning in January 2025 is 0.030 cents per kWh (or $.30 per 1,000 kWh) more than the average capacity cost recovery factor of 0.054 cents per kWh for the January 2024 through December 2024 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the period beginning in January 2025?

A. The appropriate amount for the period beginning in January 2025 through May 2025 is 3.083 cents per kWh before the application of the time of use multipliers for on-peak or off-peak or the proposed super off-peak usage. The appropriate amount for the period beginning in June 2025 through December 2025 is 3.391 cents per kWh before the application of the time of use multipliers for on-peak, off-peak or the proposed super off-peak usage. Schedule E1-E of Exhibit No. ZDJ-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2025 through December 2025. Schedule E1-E of Exhibit No. ZDJ-3, Document No. 4, shows the proposed value for the total fuel and purchased power cost recovery factor for each metering voltage level; including the super off-peak as proposed in Docket No. 20240026-EI.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,830,750 and an Optimization Mechanism gain of $3,122,688, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2024 through December 2024 period is an over-recovery of $28,431,329.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D within Document No. 2, presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2025 through May 2025, which reflects the remaining 2024 over-recovery and June through December 2025. E1-D within Document 4 presents Tampa Electric's on-peak, off-peak and super off-peak factors for January 2025 through December 2025. The schedule also presents

Tampa Electric's levelized fuel cost factors at each metering level.

Q. Please describe the information presented on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak, and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills. Schedule E1-E in Document No. 4 presents the standard, tiered, on-peak, off-peak and super off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ZDJ-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for the period beginning in January 2025 through May 2025.

A. Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.083
Tier I (Up to 1,000 kWh)	2.852
Tier II (Over 1,000 kWh)	3.852
Distribution Primary	3.052
Transmission	3.021
Lighting Service	3.059
Distribution Secondary	3.227(on-peak)
	3.024(off-peak)
Distribution Primary	3.195(on-peak)
	2.994(off-peak)
Transmission	3.162(on-peak)
	2.964(off-peak)

Proposed Factors presented in Document No. 4 as requested in Docket No. 20240026:

Metering Voltage Level	**Proposed Charge Factor (Cents per kWh)**
Lighting Service	3.068
Distribution Secondary	3.238(on-peak)
	3.034(off-peak)
	3.001(super off-peak)
Distribution Primary	3.206(on-peak)

	3.004 (off-peak)
	2.971 (super off-peak)
Transmission	3.173 (on-peak)
	2.973 (off-peak)
	2.941 (super off-peak)

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for the period beginning in June 2025 through December 2025.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.391
Tier I (Up to 1,000 kWh)	3.044
Tier II (Over 1,000 kWh)	4.044
Distribution Primary	3.357
Transmission	3.323
Lighting Service	3.363
Distribution Secondary	3.549 (on-peak)
	3.325 (off-peak)
Distribution Primary	3.514 (on-peak)
	3.292 (off-peak)
Transmission	3.478 (on-peak)
	3.259 (off-peak)

Proposed Factors presented in Document No. 4 as requested in Docket No. 20240026:

Metering Voltage Level	**Proposed Charge Factor (Cents per kWh)**
Lighting Service	3.374
Distribution Secondary	3.561(on-peak)
	3.336(off-peak)
	3.301(super off-peak)
Distribution Primary	3.525(on-peak)
	3.303(off-peak)
	3.268(super off-peak)
Transmission	3.490(on-peak)
	3.269(off-peak)
	3.235(super off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor for January 2025 through May 2025 of 3.083 cents per kWh compare to the levelized fuel adjustment factor for the June 2024 through December 2024 period?

A. The proposed fuel charge factor of 3.083 cents per kWh is 0.074 cents per kWh (or $0.74 per 1,000 kWh) lower than the average fuel charge factor of 3.157 cents per kWh for the June 2024 through December 2024 period.

Q. How does Tampa Electric's proposed levelized fuel adjustment factor from June 2025 through December 2025 of 3.391 cents per kWh compare to the levelized fuel adjustment factor for the January 2025 through May 2025 period?

A. The proposed fuel charge factor of 3.391 cents per kWh is 0.308 cents per kWh (or $3.08 per 1,000 kWh) higher than the average fuel charge factor of 3.083 cents per kWh for the January 2025 through May 2025 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2025 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization Mechanism replaced the short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2025 projection.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its base, capacity, fuel and purchased power, environmental, energy conservation and storm protection cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $0.38 in the period beginning January 2025 through May 2025, when compared to the June 2024 through December 2024 charges. For the period of June 2025 through December 2025, the composite effect on a residential bill for 1,000 kWh is an increase of $2.35. These amounts are shown in Exhibit No. ZDJ-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2025.

Q. Does this conclude your direct testimony?

A. Yes.

(Transcript continues in sequence in Volume 2.)

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 22nd day of November, 2024.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028