BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20230001-EI

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

VOLUME 1
PAGES 1 - 264

PROCEEDINGS: HEARING

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

DATE: Wednesday, November 1, 2023

TIME: Commenced: 9:30 a.m.
Concluded: 9:56 a.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

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

APPEARANCES:

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).

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).

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

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).

APPEARANCES CONTINUED:

WALT TRIERWEILER, PUBLIC COUNSEL; CHARLES J. REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, MARY A. WESSLING and OCTAVIO PONCE, 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).

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

I N D E X
(continued)

P R O C E E D I N G S

CHAIRMAN FAY: All right. That will conclude the 07 docket and we will move back to the 01 docket as our final clause docket this morning, so whenever you are ready, staff, to present, Ms. Brownless.

MS. BROWNLESS: Thank you.

There are proposed Type 2 stipulations for all issues, and the issues for which there are proposed Type 2 stipulations can be voted on today.

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

CHAIRMAN FAY: All right. Thank you, Ms. Brownless.

We will move into prefiled testimony.

MS. BROWNLESS: As stated at the Prehearing Conference, 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 being moved into the record at this time.

CHAIRMAN FAY: Okay. Show the listed testimony moved into the record without objection.

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

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DUKE ENERGY FLORIDA, LLC
DOCKET NO. 20230001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2022 - December 2022

DIRECT TESTIMONY OF
Gary P. Dean

April 3, 2023

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 state, federal and local 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 Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

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A. 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. 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.

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 2022 through December 2022, 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 2022, year-to-date; and Exhibit No. __(GPD-4T), with DEF's capital structure and cost rates. Schedules A1 through A9, and A12 for the year ended December 31, 2022, were originally filed with the Commission on January 17, 2023. The schedules attached hereto were subsequently amended and re-filed with the Commission on March 20, 2023.

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, and 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. On March 7, 2023, the Commission approved DEF's Amended Midcourse Correction, which included the actual 2022 period-ending fuel under-recovery of $1,354,975,755. As explained below, subsequent to that approval, DEF discovered an error that necessitate a slight adjustment to the actual under-recovery for 2022, which is $1,355,123,210, resulting in an additional adjustment to collect the remaining under-recovery amount of $147,455. Exhibit No. __(GPD-1T).

Per Order No. PSC-2023-0026-FOF-EI, the estimated 2022 capacity cost recovery true-up amount was an over-recovery of $6,747,100. The actual capacity true-up amount for 2022 is an over-recovery of $958,102, resulting in a final capacity true-up under-recovery amount of $5,788,998 million. Exhibit No. __(GPD-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2022 for fuel cost recovery?

A. The actual ending balance as of December 31, 2022, for true-up purposes is an under-recovery of $1,355,123,210, as shown on Exhibit No. __(GPD-1T).

Q. How does this amount compare to DEF's 2022 ending balance included in the Company's February 27, 2023 Amended Midcourse Filing?

A. The actual true-up amount for the January 2022 - December 2022 period is an under-recovery of $1,355,123,210, which is $147,455 greater than the year end under-recovery balance of $1,354,975,755 included in DEF's Amended Midcourse filing approved by Order No. PSC-2023-0112-PCO-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 $147,455 in the period-ending jurisdictional net under-recovery shown on your Exhibit No. __(GPD-1T)?

A. The $147,455 under-recovery is driven by corrections to the April and May 2022 interest rate (Commercial Paper) and the updated WACC for 2022 as prescribed in Order No. PSC-2020-0165-PAA-EU.

Q. Please explain the components shown on Exhibit No. __(GPD-1T), sheet 6 of 6, which helps to explain the $88.4 million unfavorable system variance from the actual-estimate projected cost of fuel and net purchased power transactions.

C1-6

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 amount (mWh's) of energy required; (2) changes in the heat rate of generated energy (BTU's per kWh); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $88.4 million unfavorable system variance is mainly attributable to higher coal generation and firm 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 dated May 8, 2018, DEF included an adjustment of approximately $12.6 million system ($12.5 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 $2.7 million reduction to coal inventory attributable to a semi-annual aerial survey conducted on October 24, 2022, in accordance with Order No. PSC-1997-0359-FOF-EI, Docket No. 19970001-EI. This adjustment represents 1.23% of the total coal consumed at the Crystal River facility in 2022.

Q. Did DEF exceed the economy sales threshold in 2022?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.9 million in 2022. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2022 was $5.5 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2022, that amount is approximately $0.7 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2022 hearings been updated to incorporate actual data for all of year 2022?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2020 through 2022, as follows:

Year	Actual Gain
2020	$ 1,223,709
2021	$ 2,855,389
2022	$ 5,458,082
Three-Year Average	$ 3,179,060

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2022, for capacity cost recovery?

A. The actual ending balance as of December 31, 2022, for true-up purposes is an over-recovery of $958,102, as shown on Exhibit No. __(GPD-2T).

Q. How does this amount compare to the estimated 2022 ending balance included in the Company's Actual/Estimated Filing?

A. When the estimated 2022 over-recovery of $6,747,100 is compared to the $958,102 actual over-recovery, the final capacity true-up for the twelve-month period ended December 2022 is an under-recovery of $5,788,998, 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 $5.8 million?

A. Exhibit No. __ (GPD-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $5.8 million under-recovery is primarily due to lower capacity revenue.

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 2022 through December 2022?

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 2022 through December 2022 are shown on Exhibit No. __(GPD-4T).

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

A. Yes.

DUKE ENERGY FLORIDA, LLC
DOCKET NO. 20230001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2023 through December 2023

DIRECT TESTIMONY OF
GARY P. DEAN

July 27, 2023

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. 20230001-EI?

A. Yes. I provided direct testimony on April 3, 2023.

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 2023 through December 2023.

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 2023 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 as required per Order No. PSC-2020-0165-PAA-EU. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2023 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2023 and estimated data from July through December 2023.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2023 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is a $523,971,144 under-recovery. The calculation begins with the actual under-recovered balance of $983,481,157 taken from Schedule E1-B, page 1 of 2, line 13, through the month of June 2023. This balance plus the estimated July through

C1-31

December 2023 monthly true-up calculations comprise the estimated $523,971,144 under-recovered balance at year end. In Order No. PSC-2023-0112-PCO-EI, the Commission approved DEF's Midcourse Correction Filing, which included the recovery of DEF's 2022 under-recovery of approximately $1.2 billion over a 21-month period, from April 2023 through December 2024, as well as a reprojection of fuel costs. The $523,971,144 projected 2023 under-recovered year-end balance is the projected remaining amount of the approved $1.2 billion 2022 under-recovered balance that will be recovered in 2024. The projected December 2023 true-up balance includes interest which is estimated from July through December 2023 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.427% per month.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2023 compare with the same period forecast used in the Company's 2023 Mid-Course Correction Filing approved in Order No. PSC-2023-0112-PCO-EI?

A. Light oil increased $7.65/mmbtu (35%). Coal and natural gas decreased $0.63/mmbtu (13%) and $0.77/mmbtu (16%), respectively.

Q. Have any adjustments been made to estimated fuel costs for the period January 2023 through December 2023?

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A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $12.25 million (grossed up to approximately $12.29 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2023 through December 2023. There was a coal inventory adjustment of approximately $1.5 million attributable to the semi-annual aerial survey conducted on May 10, 2023, in accordance with Order No. PSC-1997-0359-FOF-EI in Docket No. 1997001-EI. There was also an approximate $1.7 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 2023?

A. Yes. DEF estimates the total gain on non-separated sales during 2023 will be $3,377,685 which exceeds the three-year rolling average of $3,179,060. Consistent with Order No. PSC-2000-1744-PAA-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2023, this is estimated to be $39,725.

CAPACITY COST RECOVERY

Q. What is DEF's 2023 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is a $10,551,826 under-recovery. The estimated true-up calculation begins with the actual under-recovered balance of $20,529,492 as of June 2023. This balance plus the estimated July through December 2023 monthly true-up calculations comprise the estimated $10,551,826 under-recovered balance at year-end. The projected December 2023 true-up balance includes interest which is estimated from July through December 2023 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.427% per month.

Q. What are the primary drivers of the estimated year-end 2023 capacity under-recovery?

A. The $10.6 million under-recovery is primarily attributable to decreased forecasted revenues of approximately $4.6M and the $5.8 million Capacity Cost Recovery Clause 2022 net under-recovery filed on April 1, 2023 in the instant docket.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20230001-EI

Fuel and Capacity Cost Recovery Factors
January 2024 through December 2024

DIRECT TESTIMONY OF
GARY P. DEAN

September 5, 2023

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. 20230001-EI?

A. Yes, I provided direct testimony on April 3, 2023, and July 27, 2023.

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 2024 through December 2024.

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 5.239 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.7149 ¢/kWh (adjusted for jurisdictional losses), an estimated prior period under-recovery true-up of 1.4004 ¢/kWh, a GPIF cost of 0.0025 ¢/kWh, a Clean Energy Connection ("CEC")

Program bill credit of 0.1255 ¢/kWh, and a Clean Energy Impact credit of (0.0044) ¢/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 4.947 ¢/kWh for the first 1,000 kWh and 6.017 ¢/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 1.278 On-Peak, 1.007 Off-Peak and 0.712 Super Off-Peak, consistent with paragraph 15 of DEFs 2021 Settlement Agreement approved in Order No. PSC-2021-0202-AS-EI. 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-2023-0112-PCO-EI,[1] the Commission approved a midcourse correction that required DEF to collect its 2022 under-recovery over the remainder of 2023 and 2024, and further adjusted the 2023 fuel factor to recognize that the Company was projecting a greater than 10% over-recovery of its projected 2023 fuel costs. Please explain how the Company's requested 2024 fuel cost recovery accounts for the impacts of this Order.

A. As shown on Schedules E1-A and E1-B, the projected remaining amount of the approved 2022 under-recovery, netted against the projected 2023 over-recovered balance (after the reduction authorized by the Midcourse Order), is $554,889,752 (which is shown on the schedules as an under-recovery, which denotes that it will be collected in addition to the 2024 projected fuel costs).

Q. Why is there a difference between the estimated 2023 fuel true-up balance in DEF's July 27, 2023, Actual/Estimated Filing and Schedule E1-B of Exhibit GPD-3?

A. The estimated 2023 true-up balance of $523,971,144 on Exhibit GPD-2, Schedule E1-B in the Actual/Estimated Filing includes actual amounts for January through June 2023 and forward curve prices as of June 13, 2023. The true-up balance of $554,889,752 on Exhibit GPD-3, Schedule E1-B includes actual amounts for January through July 2023 and forward curve prices as of August 11, 2023.

1 The "Midcourse Order".

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

A. The 2024 projected levelized residential fuel factor of 5.247 ¢/kWh is a decrease of 0.383 ¢/kWh or 6.8% from the 2023 revised levelized residential fuel factor of 5.630 ¢/kWh from DEF's mid-course filing approved in Order No. PSC-2023-0112-PCO-EI.

Q. Please explain the decrease in the 2024 fuel factor compared with the 2023 fuel factor.

A. The primary drivers of the decrease in the 2024 fuel factor are a decrease in year-over-year jurisdictional fuel and purchased power expense of approximately $57M and a decrease in the prior period true-up of approximately $126M.

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

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ, DEF included a retail adjustment of $11.77M for the January through December 2024 amortization of the Florida Power Development, LLC, qualifying facility regulatory asset.

Per Order No. PSC-2021-0059-S-EI, DEF has included $49.7M of costs associated with the 2024 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 $1.8M 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. 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?

C1-66

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 5.247 ¢/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.

Q. How do DEF's projected gains on non-separated wholesale energy sales for 2024 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2024 is estimated to be $4,290,846 which is above the benchmark of $3,891,306. 100% of gains below the benchmark and 80% of gains above the benchmark are distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-2000-1744-PAA-EI. Therefore, since the total gain on non-separated sales is above the benchmark, $399,540 of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2021 and 2022 of $2,855,389 and $5,458,082, respectively, and estimated gains for 2023 of $3,360,445.

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

C1-67

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 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.

C1-69

Q. Is the 2022 GPIF reward discussed in the March 17, 2023, direct testimony of Adam Bingham included in the proposed 2024 rates?

A. Yes. The GPIF reward of $986,550 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 2024

Schedule E12-A, page 1, includes estimated 2024 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 2021 Settlement Agreement approved by the Commission in Order No. PSC-2021-0202-AS-EI.

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 34. The calculation of Total Recoverable Capacity & ISFSI costs are shown on line 35.

C1-70

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 2023

Schedule E12-B calculates the estimated true-up capacity under-recovered balance for the calendar year 2023 of $10,551,826. This schedule was also included in Exhibit GPD-2 to my direct testimony filed on July 27, 2023. The balance on Schedule E12-B is carried forward to Schedule E12-A, page 1, line 32 to be recovered from customers from January through December 2024.

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

C1-71

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 kilo-watt (kW) rather than a kilo-watt-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.

C1-72

Q. What is the 2024 projected average retail CCR factor?

A. The 2024 average retail CCR factor is 0.827 ¢/kWh, made up of capacity of 0.810 ¢/kWh and ISFSI costs of 0.017 ¢/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 0.827 ¢/kWh is 0.297 ¢/kWh, or 26%, less than the current 2023 factor of 1.124 ¢/kWh. This decrease is primarily due to one contract terminating at the end of 2023, two contracts terminating in 2024, as reflected on Schedule E12-A, and the recovery of the DOE spent fuel claim in 2023 as approved in the 2021 Settlement Agreement approved in Order No. PSC-2021-0202-AS-EI.

Q. Does this conclude your testimony?

A. Yes

C1-73

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

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20230001-EI

**GPIF Schedules for
January through December 2022**

DIRECT TESTIMONY OF
ADAM ROSS BINGHAM

March 16, 2023

Q. Please state your name and business address.

A. My name is Adam Bingham. My business address is 526 South Church 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.

C2-120

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 2022. This calculation was based on a comparison of the actual performance of DEF's Seven (7) 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 24-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 $986,550. 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.

C2-121

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 15 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-November 2022 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 2022 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 23 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 24 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 2022

FPSC DOCKET NO. 20230001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2024

DIRECT TESTIMONY OF ADAM ROSS BINGHAM

September 5, 2023

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.

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 provide a recap of actual reward / penalty for the period of January through December 2022, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2024. 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 16, 2023 testimony for the period January through December 2022?

A. DEF's calculated GPIF incentive amount for this period was a reward of $986,550. Please refer to my testimony filed March 16, 2023 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 2024 projection period, the GPIF program includes the following units: Bartow Unit 4, Citrus CC Unit 1, Citrus CC Unit 2, Crystal River Unit 4, Crystal River Unit 5, Hines Units 1, 3 and 4, and Osprey Unit 1. Combined, these units account for 82% 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 rates can then be converted into an overall equivalent unplanned outage factor ("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.

Q. What is the Company's estimated maximum incentive amount for 2024?

A. The estimated maximum incentive for the Company is $18,234,823. 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 2023

FPSC DOCKET NO. 20230001-EI

DIRECT TESTIMONY OF
James McClay

July 27, 2023

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 the Managing Director Natural Gas Trading. I manage the Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Please describe your education background and professional experience.

C3-250

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 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. While DEF does not currently propose to hedge, given opposition from customer interveners, 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 2024 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 2024 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) – 2024 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.

Q. Describe the hedging activities that the Company will execute for 2024.

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. DEF is proposing to continue the hedging moratorium through 2024. However, if the Commission decides that DEF should hedge, DEF is providing its 2024 Risk Management Plan to demonstrate how it would hedge if so ordered. If the 2024 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 2024 the Risk Management Plan outlines the activities DEF would implement to start its hedging program in 2024. REDACTED place and as the hedging program begins to mature it would take DEF all of 2024, 2025 and into the first half of 2026 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 2023?

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 2023.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Gerard J. Yupp was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20230001-EI

APRIL 3, 2023

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Florida Power & Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002.

In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Asset Optimization Program.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2022 results of FPL's activities under the Asset Optimization Program (or "the Program"), an incentive mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI, approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI, and approved as an ongoing program, with further modifications, by Order No. PSC-2021-0446-S-EI, dated December 2, 2021, in Docket No. 20210015-EI.

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

A. Yes, I am sponsoring the following exhibit:

- Exhibit GJY-1, consisting of 4 pages:
    - Page 1 – Total Gains Schedule
    - Page 2 – Wholesale Power Detail

- Page 3 – Asset Optimization Detail
- Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Asset Optimization Program.

A. The Asset Optimization Program is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. The Program includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. Under the original 2012 approval, other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement.

Q. Please describe the modifications that were made to the Asset Optimization Program in FPL's 2021 rate case and approved by Order No. PSC-2021-0446-AS-EI.

A. Five modifications were made to the Program through Order No. PSC-2021-0446-AS-EI. The following modifications are described in Paragraph 21 of the Stipulation and Settlement Agreement:

(i) FPL may optimize all fuel sources – beyond just natural gas supply and capacity – when it is reasonable and in the best interests of customers to do so based on the system requirements, market demand, and market price of the fuel or capacity at the time;

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(ii) FPL may monetize its renewable energy credits ("RECs");

(iii) The number of annual savings thresholds is reduced from four to three for reporting purposes. Threshold 1: FPL customers receive 100% of the asset optimization gains up to $42.5 million. Threshold 2: FPL will retain 60% and customers will receive 40% of incremental gains between $42.5 million and $100 million. Threshold 3: FPL will retain 50% and customers will receive 50% of incremental gains in excess of $100 million.

(iv) The per-MWh variable power plant O&M rate shall be $0.48/MWh;

(v) Optimization activities, variable power plant O&M rates, and savings thresholds shall be considered "adjustable parameters" such that FPL may request that the Commission review and adjust these parameters every four years in the Fuel Cost Recovery Docket.

Q. Please summarize the activities and results of the Asset Optimization Program for 2022.

A. FPL's activities under the Asset Optimization Program in 2022 delivered $130,180,330 in total gains. During 2022, FPL's optimization activities consisted of wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, the capacity release of firm natural gas transportation, and the sale of RECs. Additionally, FPL entered into several Asset Management Agreements related to a portion of upstream gas transportation during 2022. The total gains of $130,180,330 exceeded the sharing thresholds of $42.5 million and $100 million. Therefore, the incremental gains above $42.5 million and up to $100 million will be shared between customers and FPL, 40% and 60%, respectively, with all gains above $100 million shared on a 50% - 50% basis. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels, and the final gains allocation for 2022.

Q. Please provide the details of FPL's wholesale power activities under the Asset Optimization Program for 2022.

A. The details of FPL's 2022 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $66,580,934 on wholesale sales and savings of $16,928,048 on wholesale purchases for the year.

Q. Please provide the details of FPL's other asset optimization activities under the Program for 2022.

A. The details of FPL's 2022 asset optimization activities unrelated to wholesale power are shown on Page 3 of Exhibit GJY-1. FPL had a total of $46,671,347 of gains that were the result of nine different forms of asset optimization.

Q. Did FPL incur incremental O&M expenses related to the operation of the Asset Optimization Program in 2022?

A. Yes. FPL incurred personnel expenses of $527,488 related to the costs associated with an additional two and one-half personnel required to support FPL's activities under the Program.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,475,273 MWh (2,733,252 MWh of economy sales and

257,979 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,188,070 for 2022.

Q. Overall, were FPL's activities under the Asset Optimization Program successful in 2022?

A. Yes. FPL's activities under the Program were highly successful in 2022. On the wholesale power side, suitable market conditions helped drive strong wholesale power sales consistently throughout the year, with the winter season delivering the highest benefits. FPL was also able to purchase power from the market to avoid running more expensive generation, predominantly during maintenance season and during the height of the summer. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $83.5 million in customer benefits. Market opportunities for asset optimization activities related to natural gas were also fairly consistent throughout the year and coupled with the sale of RECs, which occurred sporadically over the course of the year, delivered nearly $46.7 million in benefits. In total, all optimization activities delivered significant benefits of $130,180,330, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,715,557.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20230001-EI

SEPTEMBER 5, 2023

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Florida Power & Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

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 Exhibit GJY-3. I am co-sponsoring the following schedules included in the Exhibits of FPL witness Anderson:

- Schedules E2 through E9 and H1 included in Exhibit EJA-7
- Schedule E2 included in Exhibits EJA-8 and EJA-9; and
- Schedule E12 included in Exhibit EJA-10.

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 light fuel oil, coal, and natural gas; (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 Asset Optimization Program results for 2022 and the Incremental Optimization Costs included in FPL's 2024 Projection Filing. The Asset Optimization Program results for 2022 and the Incremental Optimization Costs included in FPL's 2024 Projection Filing are calculated pursuant to the Asset Optimization Program that was approved in Order No. PSC-2021-0446-S-EI dated December 2, 2021 ("2021 Rate Settlement").

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2024 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, 2023 for calculating its 2024 Fuel Cost Recovery ("FCR") factors. This forecast methodology and the resulting fuel forecast was utilized to develop cost projections for FPL during the January 2024 through December 2024 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 2024 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 $2.41 per MMBtu for the first half of 2023, compared with an annual average of $6.42 per MMBtu in 2022. In its August 2023 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts that Henry Hub natural gas spot prices will average $2.58 per MMBtu for 2023 and $3.22 per MMBtu in 2024.

The EIA forecasts that demand for natural gas will decline by nearly 2% in 2024, dropping from roughly 89.3 billion cubic feet per day ("BCF/day") in 2023 to 87.9 BCF/day in 2024. LNG exports are forecast to increase by more than 12% in 2024 compared to 2023. Dry natural gas production averaged more than 102 BCF/day during the first half of 2023, which is a 6 BCF/day increase compared to the same period in 2022. The EIA forecasts that dry natural gas production will average 104 BCF/day in 2024.

Domestic natural gas inventories ended July 2023 at 12% above the five-year average and 22% above the same period last year. The EIA forecasts natural gas inventories to end the 2023 injection season (end of October) at 3.9 trillion cubic feet, or 7% above the five-year average.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2024 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 ranges from 1,387,000 to 1,511,000 MMBtu/day on FGT, 695,000 MMBtu/day on Gulfstream, 600,000 MMBtu/day on Sabal Trail/FSC, and 30,000 MMBtu/day on Gulf South.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to onshore gas supply. FPL has 225,000 MMBtu/day (January through October) and 125,000 MMBtu/day (November through December) 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 (January through December) of firm transport on the Gulf South and Destin Pipeline Company, LLC ("Destin") pipelines combined, 75,000 MMBtu/day (January through December) of firm transport on the Midcontinent Express Pipeline LLC ("MEP") and Destin pipelines combined, 50,000 MMBtu/day (January through December) on the FGT pipeline, and 150,000 MMBtu/day (January through December) on the Trunkline Gas Company, LLC ("Trunkline") pipeline. FPL's firm transportation rights on these pipelines provide access for up to 1,046,500 MMBtu/day during the summer season of onshore natural gas supply, 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 and 1.0 BCF of firm natural gas storage capacity in Southern Pines Energy Center ("Southern Pines"), located in southeast 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 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 2024 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 GJY-3.

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

A. FPL primarily utilizes light fuel oil (or ultra-low sulfur diesel, "ULSD") 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 2024 period.

A. FPL's projection for the system average dispatch cost of light fuel oil, by month, is provided on page 1 of Exhibit GJY-3.

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.

C4-381

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2024 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 GJY-3.

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 GJY-3?

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 EJA-7.

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 due to plant upgrades and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2024?

A. Yes. This data is shown on page 2 of Exhibit GJY-3.

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 2024.

Q. Please describe the significant planned outages for the January through December 2024 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 March 9, 2024 until April 18, 2024, or 40 days during the period. St. Lucie Unit 2 is scheduled to be out of service from August 24, 2024 until October 7, 2024, or 44 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 5, 2024 until December 15, 2024, or 71 days during the period.

Q. Please identify any changes to FPL's generation capacity projected to take place during the January through December 2024 period.

A. As shown in FPL's 2023 Ten Year Power Plant Site Plan (Schedule 8, page 169), FPL projects a net increase in its 2024 summer firm capacity of 358 MW. This increase is attributable to the addition of 773 MW of solar generation and 94 MW of combined cycle upgrades. The additions are off-set by solar degradation (7 MW) and the retirement of coal-fired generation (502 MW).

<u>WHOLESALE (OFF-SYSTEM) POWER AND</u>

<u>PURCHASED POWER TRANSACTIONS</u>

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2024?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Exhibit EJA-7 of this filing.

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

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. 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) power purchases and sales.

A. Wholesale (off-system) 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) power sales?

A. FPL has projected 2,773,000MWh of wholesale (off-system) power sales for the period of January through December 2024. The projected fuel cost related to these sales is $72,709,619. The projected transaction revenue from these sales is $121,109,369. After taking into account the transmission costs and capacity revenues, the projected gain is $38,681,158.

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

A. Schedule E6 of Exhibit EJA-7 provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2024 period?

A. The costs of these economy purchases are shown on Schedule E9 of Exhibit EJA-7. For the period, FPL projects it will purchase a total of 241,480 MWh at a cost of $10,564,200. If FPL generated this energy, FPL estimates that it would cost $15,200,143. Therefore, these purchases are projected to result in savings of $4,635,943.

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 a Power Purchase Agreement with Southern Company ("Southern Company PPA") for 250 MW of capacity and energy. The Southern Company PPA runs from January 1, 2024 through February 29, 2024. 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 2024 period.

A. Energy purchases under the SWA agreements are projected to be 806,133 MWh for the period at an energy cost of $30,778,354. FPL projects to purchase 1,031,280 MWh at an energy cost of $52,076,181 from Kingfisher I and Kingfisher II combined and 1,788 MWh at an energy cost of $303,061 under the Southern Company PPA. 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 540,963 MWh at an energy cost of $2,589,958. These projections are shown on Schedule E7 of Exhibit EJA-7.

In addition, as shown on Schedule E8 of Exhibit EJA-7, FPL projects that purchases from Qualifying Facilities for the period will provide 569,200 MWh at a cost of $25,106,252.

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 562,286 MWh of energy at a cost of $2,842,310. These projections are shown on Schedule E6 of Exhibit EJA-7.

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2022, 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 2022.

Q. Has FPL filed a comprehensive risk management plan for 2024, 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 27, 2023, FPL filed its comprehensive risk management plan for 2024, as Exhibit GJY-2.

THE ASSET OPTIMIZATION PROGRAM

Q. Has FPL included in its 2024 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 2024.

Q. Has FPL included in its 2024 FCR factors projections of the Incremental Optimization Costs that it will incur under the Asset Optimization Program?

A. Yes. FPL has included in its 2024 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. 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 $532,664 in 2024 for the salaries and expenses related to employees that 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 2024 FCR factors VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Exhibit EJA-7, FPL projects to sell 2,773,000 MWh and purchase 241,480 MWh of economy power. Therefore, applying FPL's VOM rate of $0.48/MWh, FPL projects to incur VOM expenses of $1,331,040 associated with its economy sales and to avoid $115,910 with its economy purchases. FPL has included for recovery the net of these two figures, $1,215,130 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2024 FCR factors.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE COMMERCIAL OPERATION OF NEW SOLAR GENERATION

Q. Please describe the solar generation that FPL will put into commercial operation during 2024 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, 2024. These twelve sites consist of Terrill Creek, Silver Palm, Ibis, Orchard, Beautyberry, Turnpike, Monarch, Caloosahatchee, White Tail, Prairie Creek, Pineapple, and Canoe.

Q. Will the operation of the new solar generation during 2024 result in fuel savings for FPL's customers?

A. Yes. For the February through December 2024 period, the operation of the twelve solar energy centers is projected to result in fuel savings for FPL's customers of $51,110,452.

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 $51,110,452 lower in the case that included the twelve new solar energy centers.

Q. Does this conclude your testimony?

A. Yes, it does.

C4-391

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DEAN CURTLAND

DOCKET NO. 20230001-EI

SEPTEMBER 5, 2023

Q. Please state your name and address.

A. My name is Dean Curtland. My 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") as Management Consultant in the Nuclear Business Unit.

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"). 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 2024 through December 2024. I am also supporting FPL's projected 2024 incremental plant security and Fukushima-related costs.

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 2024 through December 2024.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2024 through December 2024.

A. FPL projects the nuclear units will burn 285,526,278 MMBtu of energy at a cost of $0.5071 per MMBtu for the period January 2024 through December 2024. Projections by nuclear unit and by month are listed in Schedule E-4 of Exhibit EJA-7 which is attached to FPL witness Anderson'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 2024 through December 2024?

A. FPL projects that it will incur $34.2 million in incremental nuclear power plant security costs in 2024. The costs consist of $5.1 million of capital expenditures and $29.1 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

C5-397

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 2024 through December 2024?

A. FPL's current projection of Fukushima-related costs for 2024 is approximately $0.94 million 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).

Q. Does this conclude your testimony?

A. Yes.

C5-398

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20230001-EI

MARCH 16, 2023

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 2022 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-2021-0442-FOF-EI issued November 30, 2021 for the period January through December 2022 and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the results of these calculations: $21,638,304 of fuel savings to FPL's customers and a GPIF reward of $10,818,303.

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 +4.1755 points or $21,638,304 in fuel savings which represents a reward of $10,818,303. Page 3 provides the calculation of the maximum allowed incentive dollars as approved 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 2022 period.

A. The primary reason that FPL will receive a reward for the period is that the adjusted actual EAF for eleven out of the fifteen FPL GPIF units were better than their targets. In addition, three 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 86.4%, compared to its target of 81.4%. This results in +10.0 points, which corresponds to a GPIF reward of $2,487,264.

St. Lucie Unit 2 operated at an adjusted actual EAF of 95.9%, compared to its target of 93.6%. This results in +7.67 points, which corresponds to a GPIF reward of $1,562,054.

Turkey Point Unit 3 operated at an adjusted actual EAF of 100.0% compared to its target of 92.9%. This results in +10.0 points, which corresponds to a GPIF reward of $1,937,993.

Turkey Point Unit 4 operated at an adjusted actual EAF of 92.1% compared to its target of 85.7%. This results in +10.0 points, which corresponds to a GPIF reward of $1,741,085.

In total, the nuclear units' EAF performance results in a net GPIF reward of $7,728,396.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,420 Btu/kWh compared to its target of 10,437 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 10,335 Btu/kWh compared to its target of 10,297 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 10,546 Btu/kWh compared to its target of 10,512 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 10,568 Btu/kWh compared to its target of 10,900 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +10.0 points, which corresponds to a GPIF reward of $523,362.

In total, the nuclear units' heat rate performance results in a net GPIF reward of $523,362.

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

A. $8,251,758.

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

A. Regarding EAF performance, seven 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 $485,016. The other four performed worse than their availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $126,695. Thus, the total FPL fossil units' EAF performance results in a net GPIF reward of $358,321.

Regarding ANOHR, two of the eleven FPL fossil units operated below the ±75 Btu/kWh dead band so they received a combined reward of $2,208,224. The other nine operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties. Thus, the total fossil unit heat rate performance results in a net GPIF reward of $2,208,224.

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

A. The net GPIF fossil availability performance reward of $358,321 plus the net GPIF heat rate fossil performance reward of $2,208,224 results in a total GPIF reward for FPL's fossil units of $2,566,545.

C6-404

Q. To recap, what is FPL's total GPIF result for the period January through December 2022?

A. The total GPIF result for the period January through December 2022 is $21,638,304 of fuel savings and a GPIF reward of $10,818,303 as a result of the availability and efficiency of the combined GPIF generating units.

Q. Does this conclude your testimony?

A. Yes.

C6-405

ERRATA SHEET

WITNESS: <u>CHARLES R. ROTE</u>
DIRECT TESTIMONY DATED MARCH 16, 2023

Page	Line	Change
2	12	change "$21,638,304" to "$21,772,680"
	13	change "$10,818,303" to "$10,885,407"
	21	Change "+4.1755" to "+4.2014"
	22	change "$21,638,304 in fuel savings which represents a reward of $10,818,303" to "$21,772,680 in fuel savings which represents a reward of $10,885,40"
4	8	change "86.4%" to "91.4%"
	12	change "95.9%" to "96%"
	13	change "+7.67" to "+8.00"
	14	change "$1,562,054" to "$1,629,158"
5	2	change "$7,728,396" to "$7,795,500"
	5	change "10,420 Btu/kWh" to "10,424 Btu/kWh"
	9	change "10,335 Btu/kWh" to "10,339 Btu/kWh"
6	2	change "$8,251,758" to "$8,318,862"
7	4	change "$21,638,304 of fuel savings and a GPIF reward of $10,818,303" to "$21,772,680 of fuel savings and a GPIF reward of $10,885,407"
	After line 5	After line 5, insert the following: **Q. What is the total GPIF reward that FPL is seeking?** A. FPL requests that a $10,818,303 GPIF reward be included in recovery in its 2024 Fuel Cost Recovery Factor. This is the amount FPL originally calculated in March of this year. FPL later discovered an error in some of the performance data for St. Lucie Units 1 and 2. However, FPL has elected to forgo the additional $67,104 GPIF reward amount that represents the increase between the original March calculation and the corrected calculation of $10,885,407.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20230001-EI

SEPTEMBER 5, 2023

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 2024.

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. This Exhibit supports the development of the 2024 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 approved by the Commission.

Q. Please summarize the 2024 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 2024, FPL projects a weighted system equivalent planned outage factor (EPOF) of 9.3% and a weighted system equivalent unplanned outage factor (EUOF) of 6.7% which yield a weighted system EAF target of 84.0%. The targets for this period reflect planned refuelings for St. Lucie Unit 1, St. Lucie Unit 2, and Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 7,084 Btu/kWh for the period January through December 2024. 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 sixteen generating units that FPL proposes to be considered as GPIF units for the period January through December 2024. 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.

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 sixteen units which FPL proposes to use for the period January through December 2024 represent the top 80.6% of the total forecasted system net generation for this period excluding the Dania Beach Energy Center (DBEC). DBEC was declared to be in commercial operation status on May 31, 2022. Consequently, it was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2024 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes.

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. 20230001-EI

JUNE 5, 2023

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 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 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, 2024 ("2024 Project") for which FPL seeks recovery pursuant to the Solar Base Rate Adjustment Provision of the Company's 2021 Rate Settlement Agreement approved by

Order Nos. PSC-2021-0446-S-EI and PSC-2021-0446A-S-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 2024 Project's costs not exceed the prescribed cost cap and that the estimated cost of the components, engineering, and construction for the 2024 Project is reasonable.

Q. Please summarize your testimony.

A. My testimony demonstrates that FPL has selected components and technology for the 2024 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 required by the Settlement, even though, as I will explain, the cost to construct solar projects has increased significantly.

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 2024 Solar Energy Center Maps
- Exhibit KF-3 – Typical Solar Energy Center Block Diagram
- Exhibit KF-4 – Specifications for 2024 Solar Energy Centers
- Exhibit KF-5 – Construction Schedules for the 2024 Solar Energy Centers

- Exhibit KF-6 – Capital Cost Table
- Exhibit KF-7 – Cost Increase Waterfall

I. 2024 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, FPL has completed 63 solar energy centers totaling approximately 4,580 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. FPL completed construction of the 63 solar energy centers an average of nine days early and at a total cost that fell 2.1% or $132.4 million below the cumulative budget. By the middle of 2023, FPL will place three additional solar sites into service, bringing the total to 66 solar energy centers in service with a total nameplate rating of 4,803 $MW_{AC.}$

Q. Please identify the solar energy centers that comprise the 2024 Project.

A. FPL is constructing 12 additional solar energy centers estimated to be in service by January 31, 2024. These are (i) Terrill Creek Solar Energy Center in Clay County, (ii) Silver Palm Solar Energy Center in Palm Beach County, (iii) Ibis Solar Energy Center in Brevard County, (iv) Orchard Solar Energy Center which is located on land that straddles the border between St. Lucie County and Indian River County, (v) Beautyberry Solar Energy Center in Hendry County,

(vi) Turnpike Solar Energy Center in Indian River County, (vii) Monarch Solar Energy Center in Martin County, (viii) Caloosahatchee Solar Energy Center in Hendry County, (ix) White Tail Solar Energy Center in Martin County, (x) Prairie Creek Solar Energy Center in DeSoto County, (xi) Pineapple Solar Energy Center in St. Lucie County, and (xii) Canoe Solar Energy Center in Okaloosa 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 2024 Project and the resulting conversion efficiencies.

A. The 2024 Project will utilize a combination of approximately two million crystalline silicon and 30,000 thin-film solar panels that convert sunlight to direct current ("DC") electricity. These panels will have an average conversion efficiency of approximately 20.8%. This simply means that 20.8% 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, each 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 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 to form a power conversion unit ("PCU"). Depending on the inverter rating, between 19 and 24 PCUs will be installed at each solar energy center to produce the 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.

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Q. Describe the DC/AC ratio for the 2024 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 2024 Project, the DC/AC ratios will range from 1.20 to 1.45.

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 2024 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 transmission system for the 2024 Project.

Q. What are the proposed construction schedules and in-service dates for the 2024 Project?

A. FPL expects that the Project will be placed into service by January 31, 2024. 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, 2024.

Q. As of April 3, 2023, what is the status of the certifications and permits required to begin construction for the solar energy centers?

A. Of the 12 sites that are part of the 2024 Project, ten have received all 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. Eight 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, ten of the 12 centers have received the required county site plan approvals with the final two approvals expected by early May 2023.

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

A. The 2024 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 monitored at FPL's Fleet Performance and Diagnostics Center ("FPDC"), which uses advanced technology to identify potential problems earlier than traditional detection methods, create 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 FPDC technology results in improved service reliability for FPL customers.

In addition, each of the centers that comprise the 2024 Project will be monitored and operated at FPL's Renewable Operations Control Center ("ROCC"), which was established in 2017 to serve as the centralized, remote operations center for all FPL universal solar and energy storage facilities. The ROCC provides a mechanism to efficiently manage daily work activities and ensure effective deployment of best operating practices at all of FPL's renewable energy centers. FPL also utilizes their Center of Work Excellence which centralizes work schedules and works closely with the ROCC and FPDC to most efficiently create daily work schedules to restore equipment, execute work orders, and perform preventative maintenance in the most efficient way possible with the goal of continuously reducing lost energy and production costs.

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

II. 2024 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 2024 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 2024 Project's components, engineering, and construction be reasonable.

Q. Does the 2024 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. 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. In addition, the costs for the 2024 Project are reasonable, even though, as described below, costs have materially increased.

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 2024 Project, ten utilize property identified on MV-5. In addition, FPL's 2021 rate case included rate base forecasts for Test Year 2022 and Subsequent Year 2023 that reflected PHFU and easements that were not included in MV-5. Therefore, for SoBRA purposes, FPL has assumed that the land costs for all 12 sites and associated easements are included in its rate base.

To calculate the average Adjusted Cap, FPL subtracted 100% of the land costs for the 2024 Project. The resulting average Adjusted Cap for the 2024 Project – and the amount FPL seeks to recover through the SoBRA – is $1,160 per kW_{AC}, which is $385 per kW_{AC} less than the average total adjusted estimated cost of $1,545 per kW_{AC}. Table 1 below shows the Adjusted Cap associated with the ten applicable sites, the average Adjusted Cap for the 2024 Project, as well as the total and adjusted estimated costs per site and on average for the 2024 Project.

TABLE 1: COSTS PER SITE AND TOTAL AVERAGE COSTS					
	Settlement Cost Cap ($/kWAC)	Less land value ($/kWAC)	Adjusted Cap (SoBRA recovery amount $/kWAC)	Estimated Cost ($/kWAC)	Estimated Cost Less land value ($/kWAC)
Terrill Creek	$1,250	$82	$1,168	$1,634	$1,552
Silver Palm	$1,250	$129	$1,121	$1,637	$1,508
Ibis	$1,250	$68	$1,182	$1,557	$1,489
Orchard	$1,250	$40	$1,210	$1,576	$1,536
Beautyberry	$1,250	$209	$1,041	$1,714	$1,505
Turnpike	$1,250	$44	$1,206	$1,528	$1,484
Monarch	$1,250	$95	$1,155	$1,487	$1,392
Caloosahatchee	$1,250	$80	$1,170	$1,827	$1,748
White Tail	$1,250	$105	$1,145	$1,732	$1,627
Prairie Creek	$1,250	$88	$1,162	$1,755	$1,667
Pineapple	$1,250	$40	$1,210	$1,513	$1,473
Canoe	$1,250	$103	$1,147	$1,661	$1,558
Average Total	$1,250	$90	**$1,160**	$1,635	$1,545

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

A. Yes. The estimated capital cost for each of the solar energy centers includes the projected cost for the construction of its unique transmission interconnection configuration.

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

A. The \$1,250 per kWac 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 24-36 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 2024 Project; and (iii) general cost increases due to inflation.

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. One such trade measure are 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, PV solar manufacturing operations which support the United States market have predominantly moved out of China and into other southeast Asia locations.

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

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duties of up 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.

Q. How has the Circumvention Inquiry impacted the cost of panels used in the 2024 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 has increased dramatically to account for the perceived risk of tariffs and other U.S. government actions on solar panel imports. Pricing for panels that will be used for the 2024 Project increased by approximately 40% compared to pricing that was anticipated at the time FPL 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 has continued to accelerate. The polysilicon

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market experienced delayed capacity expansions that have constrained polysilicon suppliers from meeting this larger panel demand. As a result, from January 2021 through October 2022, the global polysilicon pricing index increased approximately 240%, from $12.41 to $42.24 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 has 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 have 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 2024 Project.

A. FPL initially expected to use a blend of fixed-tilt and single-axis tracking systems for the 2024 Project but by working with equipment suppliers, FPL determined that it was feasible to deploy trackers at all 2024 Project locations and elected to make this design change. 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. The change from a mixture of fixed and tracking sites to the exclusive use of single-axis trackers for the 2024 Project increased overall Project costs by $85 per kW_{AC}, while raising the net capacity factor of the 2024 Project to 27.5%.

Q. Please explain how general inflationary pressure combined with commodity price increases contributed to an increase in the cost of the 2024 Project.

A. General inflationary pressure impacted the costs for all solar construction which includes solar panels, steel, aluminum, single-axis tracking components, copper, 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 raised labor costs, which resulted in incrementally higher engineering, procurement, and construction ("EPC") contractor costs.

Q. Please summarize how the market factors you have described impacted the overall cost of the 2024 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 \$210 per kW_{AC} of incremental project costs. The change to exclusive use of single-axis trackers added an additional \$85 per kW_{AC}. The balance of the increase in pricing, about \$90 per kW_{AC}, is due to the general inflationary pressures 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 2024 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 were 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 2024 Project's equipment, engineering, and construction costs were subject to competitive solicitations.

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 2024 Project.

Q. Please describe the competitive solicitations for 2024 Project's solar panels.

A. FPL's solicitation for solar panels for the 2024 Project was expanded as compared to prior RFPs in order to include additional suppliers. FPL also requested and received more detailed information from bidders which helped to evaluate the potential impacts from the pending trade actions described above. In total, FPL requested proposals for PV panels from 21 large, industry-leading suppliers. Ten suppliers submitted bids that satisfied the requirements of the RFP, FPL evaluated each of these conforming bids, and ultimately contracted with three suppliers.

The three selected panel suppliers for the 2024 Project offered the lowest cost and highest efficiency products, offer 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 2024 Project 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 fourth quarter of 2022, which is slightly later than in previous construction efforts, FPL was able to avoid the height of market disruptions from the Circumvention Inquiry.

Q. Please describe the competitive solicitations for 2024 Project's PCU and Step-Up Power Transformers.

A. FPL solicited proposals from four PCU suppliers. The proposals submitted by each of the four suppliers met the requirements of the RFP and were evaluated. FPL selected the lowest cost bidder to supply the PCUs for the 2024 Project.

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

Q. Please describe the competitive solicitations for 2024 Project's construction contractors.

A. FPL solicited EPC service proposals for the construction of the solar energy centers from twelve industry-recognized contractors. Five of the twelve contractors submitted bids and FPL evaluated these proposals for completeness. FPL then identified the lowest cost bidder for each site within the 2024 Project and selected three EPC contractors to build the 2024 Project based on this method of evaluation. Contracts have been finalized with these three selected EPC contractors. The scope of services for the EPC solicitations included the supply of the balance of equipment and other materials.

FPL solicited proposals for the construction of the substation and interconnection facilities from sixteen industry-recognized contractors. Twelve of the sixteen contractors submitted bids and the proposals were evaluated. Similarly, FPL then identified the lowest cost bidder for each site within the 2024 Project and then selected five lowest cost bidders to construct the substation and interconnection facilities at the sites.

Q. Are there other benefits associated with the 2024 Project?

A. Yes, there are several other benefits associated with the 2024 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 2024 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. For instance, in 2022 FPL had 50 operational solar energy centers which generated over $26 million in property taxes paid to 24 counties across Florida.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

WITNESS: KELLY FAGAN
DIRECT TESTIMONY DATED JUNE 5, 2023

Page	Line	Change
11	21	Change "$1,160" to "$1,161"
	22	Change "$385" to "$384"
12	Table 1	Change the "Canoe" cost line as follows:

- Under the "Less land value" column, change "$103" to "$89"
- Under the "Adjusted Cap" column, change "$1,147" to "$1,161"
- Under the "Estimated Cost" column, change "$1,661" to "$1,647"

Change the "Average Total" cost line as follows:

- Under the "Less land value" column, change "$90" to "$89"
- Under the "Adjusted Cap" column, change "$1,160" to "$1,161"
- Under the "Estimated Cost" column, change "$1,635" to "1,634"

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}$)	Less land value ($/kW$_{AC}$)	Adjusted Cap (SoBRA recovery amount $/kW$_{AC}$)	Estimated Cost ($/kW$_{AC}$)	Estimated Cost Less land value ($/kW$_{AC}$)
Terrill Creek	$1,250	$82	$1,168	$1,634	$1,552
Silver Palm	$1,250	$129	$1,121	$1,637	$1,508
Ibis	$1,250	$68	$1,182	$1,557	$1,489
Orchard	$1,250	$40	$1,210	$1,576	$1,536
Beautyberry	$1,250	$209	$1,041	$1,714	$1,505
Turnpike	$1,250	$44	$1,206	$1,528	$1,484
Monarch	$1,250	$95	$1,155	$1,487	$1,392
Caloosahatchee	$1,250	$80	$1,170	$1,827	$1,748
White Tail	$1,250	$105	$1,145	$1,732	$1,627
Prairie Creek	$1,250	$88	$1,162	$1,755	$1,667
Pineapple	$1,250	$40	$1,210	$1,513	$1,473
Canoe	$1,250	~~$103~~ $89	~~$1,147~~ $1,161	~~$1,661~~ $1,647	$1,558
Average Total	$1,250	~~$90~~ $89	~~**$1,160**~~ **$1,161**	~~$1,635~~ $1,634	$1,545

C7-508

:21526034

(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. 20230001-EI

APRIL 3, 2023

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" or the "Company") 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, Solar Base Rate Adjustment ("SoBRA") filings, several need determination proceedings for new power

C8-540

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 in 2022 and 2023.

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 through which 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?

A. Yes. I have 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 appeared before the Commission at its workshop on Florida utilities' 2022 Ten Year Site Plans to discuss FPL's 2022 Plan.

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 2024 (the "2024 Project") is cost-effective. My testimony covers several areas. First, I identify the 12 sites that make up the 2024 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 2024 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 2024 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, 2024. FPL performed an economic analysis and determined that the 2024 Project will result in a reduction in the cumulative present value of revenue requirements ("CPVRR") to FPL customers, for a total savings of approximately $561 million. In addition, these centers are projected to result in a significant reduction in air emissions – primarily carbon dioxide ("CO_2") – resulting from a reduction in the projected use of fossil fuels, which will in turn lower FPL's system reliance on generation fueled by natural gas. The 2024 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.

Q. Please describe the 2024 Project.

A. The 2024 Project comprises 12 solar energy centers with a total nameplate capacity of 894 MW_{AC}, which will be constructed and placed in service by January 31, 2024. Each of these centers is projected to generate about 179,000 MWh per year. This is enough energy to serve the annual energy needs of about 13,800 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 September 2022.

This load forecast, including system peaks and net energy for load, is used in FPL's 2023 Ten Year Site Plan ("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 2022. This fuel price forecast is used in FPL's 2023 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 costs 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 2023 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 2024 SoBRA Plan," does not include any new solar facilities beyond those already in-service as of the end of 2024. In this plan, future resource needs are met by combined cycle units and battery storage.

The second resource plan, called the "2024 SoBRA Plan," adds the 2024 Project described above. Because each center is assumed to provide FPL approximately 46% of the nameplate capacity as firm capacity to meet the Company's reliability obligations, 1,100 MW of battery storage units were deferred one year (from 2025 through 2027 in-service dates to 2026 through 2028 in-service dates), and the combined cycle was deferred one year from 2028 to 2029. In addition, 1,900 MW of batteries in 2031 and 2032 in the "No 2024 SoBRA Plan" are reduced to 800 MW of batteries being added in 2032 in the "2024 SoBRA Plan." These two resource plans are shown in Exhibit AWW-3.

Q. What is the net capacity factor of the facilities in the 2024 Project?

A. The 2024 centers are projected to have an average yearly net capacity factor (or "NCF") of 27.5%, which is an improvement over recent years.

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 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 all its solar PV facilities, existing or new.

Based on this methodology, the 2024 centers are projected to have an average summer firm capacity value of 46% 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 409 MW_{AC} at time of summer peak. These solar installations are assumed to have a 3.8% 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 2024 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 2024 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 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 2024 SoBRA Plan from the CPVRR of the 2024 SoBRA Plan. As shown in Exhibit AWW-4, the CPVRR benefit to FPL customers from the 2024 Project is approximately $561 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 2024 Project is shown in Exhibit AWW-5.

Q. FPL witness Fagan states that the 2024 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 exclusive use of 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 2024 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 2024 SoBRA Plan.

Q. Is the 2024 Project cost-effective even though it is over the cost cap in the 2021 Rate Settlement?

A. Yes. Although the installed cost of the 2024 Project is $1,635 per kilowatt alternating current ("kW_{AC}"), which is over the $1,250 per kW_{AC} in the 2021 Rate Settlement, the 2024 Project is projected to save customers approximately $561 million CPVRR and therefore is still significantly cost-effective for FPL's customers.

Q. Will the 2024 Project reduce FPL's use of fossil fuel?

A. Yes. As shown on Exhibit AWW-6, the energy from the 2024 Project will displace fossil fuel generation, specifically natural gas. The Project is expected to reduce the annual average use of natural gas by 13,680 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 814,916 tons of CO_2. This reduction in CO_2 is equivalent to removing approximately 157,000 cars from the road. Sulfur dioxide and nitrogen oxide emissions are reduced by an annual average of 3 tons and 92 tons, respectively.

Q. What is your conclusion regarding the 2024 Project?

A. As demonstrated by the economic analysis described in my testimony, the addition of the 2024 Project will result in CPVRR savings of approximately $561 million. Therefore, the 2024 Project meets the SoBRA cost-effectiveness requirement established in the 2021 Rate Settlement. Additionally, the 2024 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.

(Whereupon, prefiled direct testimony of Jason Chin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JASON CHIN

DOCKET NO. 20230001-EI

SEPTEMBER 5, 2023

Q. Please state your name and business address.

A. My name is Jason Chin, and my business address is Florida Power & Light Company, 7200 NW 4th Street, Plantation, Florida 33317.

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 Senior Manager, Regulatory Accounting.

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

A. I am responsible for the management of the accounting for FPL's cost recovery clauses.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting and a Bachelor of Science degree in Finance from Florida State University. I also hold a Master's degree in Business Administration in Finance from Nova Southeastern University. I have been employed by FPL since 2008. During my tenure at the Company, I have held various accounting and regulatory positions of increasing responsibility with most of my career focused on regulatory accounting and the calculation of revenue requirements. Specifically, I provided accounting support in multiple FPL retail base rate filings and other regulatory dockets filed at the ("FPSC" or the "Commission") and the Federal Energy Regulatory Commission. I have previously filed declarations before the Commission, most recently for the revised revenue requirement calculations for the Okeechobee Clean Energy Center, and the final jurisdictional revenue requirements for FPL's 2019 and 2020 Solar Base Rate Adjustments ("SoBRA") in Docket No. 20210001-EI.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to present the computation of the incremental jurisdictional annualized base revenue requirement associated with the SoBRA related to the 12 universal photovoltaic solar energy centers expected to be placed in service in 2024 (the "2024 Project" or "Project"), which is based on the first 12-months of operations of the 2024 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 and amended by PSC-2021-0446A-S-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 2024 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. Please summarize your testimony.

A. The incremental jurisdictional revenue requirement for the first 12 months of operations related to the 2024 Project is $71.392 million. As required by the 2021 Rate Settlement, this revenue requirement is calculated based on an installed cost cap at an average of $1,250 per kilowatt alternating current (“kW_{AC}”) (the “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 Docket No. 20210015-EI (the “Adjusted Cap”).

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

A. Yes. I am sponsoring Exhibit JC-1 – 2024 SoBRA Revenue Requirement Calculation.

Q. What is the revenue requirement for the 2024 SoBRA?

A. As reflected on page 1 of Exhibit JC-1, the amount of FPL’s requested base revenue increase for the first 12 months of operations of the 2024 Project is $71.392 million.

Q. Please briefly describe the basis for the 2024 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 2024 Project. The cost of the components, engineering and construction for the 2024 Project are subject to a $1,250 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 2024 SoBRA is expected to be implemented on February 1, 2024.

Q. Please explain how FPL adhered to the Adjusted Cap in its 2024 SoBRA revenue requirement calculation.

A. The Adjusted Cap ($\$/kW_{AC}$) for each solar energy center in the 2024 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 2024 SoBRA revenue requirement calculation. The adjusted amount of capital costs is $1.038 billion, which is reflected as the total amount of plant in service on Exhibit JC-1, 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 $1.038 billion plant in service to the proper functions.

A. FPL allocated the $1.038 billion to three plant functions – (i) Other Production, (ii) Transmission, and (iii) Transmission GSU – based on the following steps:

1. Based on the total construction costs for each site reflected on Exhibit KF-6 from witness Fagan's testimony, FPL categorized the capital components into Other Production, Transmission, Transmission GSU, and 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 Other Production, Transmission, and Transmission GSU 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 Other Production, Transmission, and Transmission GSU functions. This total is used to calculate jurisdictional plant in service, accumulated depreciation, and depreciation expense.

Q. Please describe the inputs utilized to compute the revenue requirement for the 2024 SoBRA.

A. In addition to the capital cost calculation described above, the revenue requirement computations for the 2024 SoBRA, are based on the following inputs:

- <u>Depreciation rates</u>: FPL utilized the depreciation rates approved by the Commission in FPL's 2021 Rate Agreement to compute depreciation expense and related accumulated depreciation for solar generation and transmission plant.
- <u>Operating expenses</u>: 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. In addition, as a result of the Inflation Reduction Act ("IRA"), 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 2024 Project as that is the most economic tax credit and therefore, has not included any ITC in its incremental cost of capital for the 2024 Project. FPL's incremental cost of capital for the 2024 Project includes long-term debt and equity based on the same ratios and cost rates reflected in FPL's 2024 Capacity Cost Recovery Clause Projection filing in this docket.
- Accumulated deferred income taxes: As described above, ADIT are included as a component of rate base. The ADIT for the 2024 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, 2024. 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 SoBRA revenue requirement calculations. The calculation of ADIT for the 2024 Project, based on the adjusted capital costs, is reflected on Page 5 of Exhibit JC-1.

Q. Please describe the PTCs associated with the revenue requirement calculation for the 2024 SoBRA.

A. In accordance with Section 45 of the IRC, the Company forecasts it will claim a PTC of approximately $55.5 million associated with the 2024 Project, thereby reducing total income tax expense. The PTC is calculated by multiplying projected net generation of approximately 2,016,413 MWh associated with the first calendar year of operation for the 2024 Project times a PTC rate of $27.50/MWh. The calculated PTC rate is based on the 2023 published Internal Revenue Service annual rate adjusted for an Inflation Adjustment Factor and Prevailing Wage Requirements. This is consistent with the PTC rate utilized by FPL in its Petition for Approval of Refund and Rate Reduction Resulting From Implementation of the Inflation Reduction Act, which was approved by the Commission in Order No. PSC-2022-0433-TRF-EI (issued December 21, 2022).

Q. Did FPL calculate its 2024 SoBRA revenue requirement consistent with the revenue requirements for SoBRAs previously approved by this Commission?

A. Yes. With the exception of applying the Adjusted Cap and electing to receive the PTC instead of the ITC as described above, the 2024 SoBRA revenue requirement is calculated consistent with the methodology 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 2024 Project in its monthly earnings surveillance report?

A. As authorized in paragraph 12(j) of FPL's 2021 Rate Agreement, FPL will include the total amount of actual capital and operating costs associated with the 2024 Project in its monthly earnings surveillance reports.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

WITNESS: JASON CHIN
DIRECT TESTIMONY DATED: SEPTEMBER 5, 2023

Page	Line	Change
3	3	Change "$71.392" to "$68.128"
	18	Change "$71.392" to "$68.128"

Exhibit No.	Page	Change
JC-1	Page 1 of 5	Replace with attached corrected page bearing the same header (Page 1 of 5)
	Page 4 of 5	Replace with attached corrected page bearing the same header (Page 4 of 5)

(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. 20230001-EI

APRIL 3, 2023

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 Manager, Rates and Clauses in the Regulatory & State Governmental Affairs 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 Department, including Principal Regulatory Analyst, Manager of Regulatory Rate Development, and was promoted to my current role in August 2022. 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 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 2022 through December 2022.

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

A. Yes. Exhibit EJA-1 contains the FCR-related schedules and Exhibit EJA-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2022 through December 2022 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 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 2022 FCR and CCR net true-up amounts.

A. The 2022 true-up for the FCR Clause is an under-recovery, including interest, of $2,138,370,998 (Exhibit EJA-1, page 1). On March 7, 2023, the Commission approved the inclusion of this amount in FPL's mid-course correction petition filed on January 23, 2023, to be recovered over 21 months beginning April 2023 through December 2024. Order No. PSC-2023-0108-PCO-EI.

The FCR true-up calculation reflects the Commission's decision in Order No. PSC-2023-0026-FOF-EI which authorized FPL to defer recovery of its actual/estimated 2022 under-recovery until the final cost amount was known. Accordingly, the actual/estimated under-recovery amount of $1,658,287,443 filed on July 27, 2022 is excluded from the true-up calculation.

The 2022 net true-up for the CCR Clause is an over-recovery, including interest, of $8,047,503 (Exhibit EJA-2, page 1). FPL is requesting Commission approval to include this 2022 CCR Clause true-up over-recovery in the calculation of the CCR factors for the period January 2024 through December 2024.

Finally, FPL is requesting Commission approval to include $49,590,165 in the calculation of the FCR factors for the period January 2024 through December

2024, which represents FPL's share of the 2022 Asset Optimization gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

2022 FCR FINAL TRUE-UP CALCULATION

Q. Please explain the calculation of the 2022 FCR true-up amount.

A. As previously stated, FPL was authorized to defer recovery of its 2022 under-recovered fuel cost until the final cost amount was known. Therefore, the FCR true-up for the period January 2022 through December 2022 is equal to the end-of-period true-up under-recovery of $2,138,370,998, summarized and shown on line 5 of page 1 of Exhibit EJA-1.

The calculation of the FCR actual true-up by month for January 2022 through December 2022 is shown on pages 2 and 3 of Exhibit EJA-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."

C10-576

Q. Though it is not included as part of the 2022 FCR true-up calculation, have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2022?

A. Yes. Exhibit EJA-1, page 4 (sum of lines 47 and 48) compares the actual end-of-period true-up under-recovery, including interest, of $2,138,370,998 (column 3) to the actual/estimated end-of-period under-recovery of $1,658,287,443 (column 4) resulting in an increased under-recovery of $480,083,555 (column 5). Exhibit EJA-1, page 4 shows a variance in jurisdictional fuel costs of $550 million (line 46) offset by an increase in revenues of $86 million (line 41).

Q. Please summarize the variance schedule for the jurisdiction on page 4 of Exhibit EJA-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $5.543 billion for 2022 (Exhibit EJA-1, page 4, line 46, column 4). The actual jurisdictional fuel costs and net power transactions for the 2022 period are $6.093 billion (Exhibit EJA-1, page 4, line 46, column 3). The resulting jurisdictional fuel costs and net power transactions are $550 million or 9.9% higher than previously projected (Exhibit EJA-1, page 4, line 46, column 5). Jurisdictional fuel revenues for 2022 are $86 million or 2.2% higher than previously projected (Exhibit EJA-1, page 4, line 41, column 5).

Page 4 of Exhibit EJA-1 also presents the variance on a total system basis. Total system fuel costs and net power transactions were previously projected to be

$5.789 billion for 2022 (Exhibit EJA-1, page 4, line 26, column 4). The actual system fuel costs and net power transactions for the 2022 period are $6.370 billion (Exhibit EJA-1, page 4, line 26, column 3). The resulting fuel costs and net power transactions are $581.1 million or 10.0% higher than previously projected (Exhibit EJA-1, page 4, line 26, column 5).

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

A. Below are the primary reasons for the $581.1 million (total system) variance of total fuel costs and net power transactions.

<u>Fuel Cost of System Net Generation: $600.9 million increase (Exhibit EJA-1, page 4, line 2, column 5)</u>

Fuel Variance	Final True-Up	Actual/Estimated	Difference
<u>Heavy Oil</u>			
Total Dollar	$1,059	$79	$980
Units (MMBTU)	80	6	74
$ per Unit	13.2230	13.8762	(0.6531)
Variance Due to Consumption			$1,032
Variance Due to Cost			($52)
Total Variance			$980
<u>Light Oil</u>			
Total Dollar	$33,881,320	$20,262,731	$13,618,589
Units (MMBTU)	2,196,995	5,666,031	(3,469,036)
$ per Unit	15.4217	3.5762	11.8455
Variance Due to Consumption			($12,405,887)
Variance Due to Cost			$26,024,476
Total Variance			$13,618,589
<u>Coal</u>			
Total Dollar	$69,153,103	$80,055,769	($10,902,666)
Units (MMBTU)	21,550,958	24,307,379	(2,756,421)
$ per Unit	3.2088	3.2935	(0.0847)
Variance Due to Consumption			($9,078,206)

Fuel Variance	Final True-Up	Actual/Estimated	Difference
Variance Due to Cost			($1,824,461)
Total Variance			($10,902,666)
Gas			
Total Dollar	$6,210,959,662	$5,611,368,724	$599,590,938
Units (MMBTU)	710,882,379	682,372,501	28,509,878
$ per Unit	8.7370	8.2233	0.5137
Variance Due to Consumption			$234,445,904
Variance Due to Cost			$365,145,034
Total Variance			$599,590,938
Nuclear			
Total Dollar	$146,173,989	$147,569,890	($1,395,901)
Units (MMBTU)	318,242,482	309,874,804	8,367,678
$ per Unit	0.4593	0.4762	(0.0169)
Variance Due to Consumption			$3,984,891
Variance Due to Cost			($5,380,792)
Total Variance			($1,395,901)
Total			
Total Dollar	$6,460,169,132	$5,859,257,194	$600,911,939
Units (MMBTU)	1,052,872,894	1,022,220,721	30,652,173
Variance Due to Consumption			$216,947,734
Variance Due to Cost			$383,964,205
Total Variance			$600,911,939

Note: Difference in total fuel cost of system of net generation shown in the table above compared to the amount shown on Exhibit EJA-1, page 2, line 2, of $57,746 is due to 1) $15,720 fuel-used transaction recorded in December 2022 which was reclassed to base in January 2023 and 2) $42,041 related to FPL and Gulf Power pre-consolidation accounting corrections made in March 2022 when pre-consolidated FPL and Gulf Power accounting data was combined.

Fuel Cost of Purchased Power, Exclusive of Economy: $60.9 million increase (Exhibit EJA-1, page 4, line 7, column 5)

The variance of $60,875,633 for the Fuel Cost of Purchased Power was primarily attributable to higher than projected purchases and higher than projected costs associated with these purchases under the Central Alabama Power Purchase Agreement ("Central Alabama PPA"). FPL purchased 827,054 MWh more than projected, resulting in a volume variance of

$48,567,419. The unit cost of these purchases was $3.61/MWh higher than projected, resulting in a cost variance of $13,935,081. The combination of higher purchases and higher costs for purchases under the Central Alabama PPA resulted in a net variance of $62,502,500. The primary offset to this variance was due to lower than projected purchases and lower than projected costs under FPL's two energy contracts with the Solid Waste Authority of Palm Beach County ("SWA"). FPL purchased 39,352 MWh less from SWA at a unit cost that was $2.09/MWh less than projected.

<u>Fuel Cost of Power Sold: $40.2 million increase (Exhibit EJA-1, page 4, line 5, column 5)</u>

The variance of ($40,238,357) for the Fuel Cost of Power Sold was primarily attributable to higher than projected Associated Interchange and economy power sales and higher than projected fuel costs for Associated Interchange and economy power sales. In combination, FPL sold 479,976 MWh more of Associated Interchange and economy power, resulting in a volume variance of ($19,765,619). In addition, the average unit fuel cost on Associated Interchange and economy power sales was $4.24/MWh higher than projected, resulting in a cost variance of ($20,800,773). The combination of higher than projected Associated Interchange and economy power sales and higher than projected fuel costs on Associated Interchange and economy power sales resulted in a net variance for economy power sales of ($40,566,393). The remaining variance of $328,035 was attributable to lower than projected St. Lucie Plant Reliability

Exchange sales and lower than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

Gains from Off-System Sales: $26.8 million increase (Exhibit EJA-1, page 4, line 6, column 5)

The variance for Gains from Off-System Sales was attributable to higher than projected economy power sales and higher than projected margins on economy power sales. FPL sold 233,721 MWh more of economy power, resulting in a volume variance of $3,518,512. Margins on economy power sales averaged $8.52/MWh higher than projected, resulting in a cost variance of $23,280,178. The combination of higher economy power sales and higher margins on economy power sales resulted in a total variance for Gains from Off-System Sales of $26,798,690.

Energy Cost of Economy Purchases: $16.5 million increase (Exhibit EJA-1, page 4, line 9, column 5)

The variance of $16,546,262 was primarily attributable to higher than projected costs for economy power purchases. The unit costs for economy power purchases were $49.20/MWh higher than expected for the period.

Fuel Costs of Stratified Sales: $14.5 million increase (Exhibit EJA-1, page 4, line 4, column 5)

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The variance of $14,489,217 was primarily attributable to higher than projected cost of natural gas for the period.

Optimization Credits: $8.9 million increase (Exhibit EJA-1, page 4, line 16, column 5)

The variance of $8,864,078 was attributable to higher than projected gains from natural gas optimization activities and renewable energy credits sales.

Energy Payments to Qualifying Facilities: $3.8 million decrease (Exhibit EJA-1, page 4, line 8, column 5)

The variance for Energy Payments to Qualifying Facilities was attributable to lower than projected purchases and lower than projected costs from Qualifying Facilities. In total, FPL purchased 26,242 MWh less than projected, resulting in a volume variance of $1,321,349. The average unit fuel cost for these purchases was $4.18/MWh lower than projected, resulting in a cost variance of $2,473,896. The combination of lower purchases and lower fuel costs for Qualifying Facilities resulted in a net variance of $3,795,245.

Q. What is the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit EJA-1, page 4, line 41, actual 2022 jurisdictional FCR revenues are approximately $86.3 million higher than the actual/estimated projection. This is primarily due to 1,717,260,474 kWh higher than projected jurisdictional sales (page 4, line 29, column 5).

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $49,590,165 as its share of 2022 Asset Optimization Program 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 2022 Asset Optimization Program gains through the 2024 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized gains amount in the calculation of the 2024 FCR factors and will reflect recovery of one-twelfth of the approved amount in each month's Schedule A2 for the period January 2024 through December 2024 as a reduction to jurisdictional fuel revenues applicable to each period.

2022 CCR FINAL TRUE-UP CALCULATION

Q. Please explain the calculation of FPL's 2022 CCR net true-up amount.

A. Exhibit EJA-2, page 1 provides the calculation of the CCR net true-up for the period January 2022 through December 2022, an over-recovery of $8,047,503, which FPL is requesting to be included in the calculation of the CCR factors for the January 2024 through December 2024 period.

The actual end-of-period over-recovery for the period January 2022 through December 2022 of $5,125,434, shown on line 3 less the actual/estimated end-of-period under-recovery for the same period of $2,922,069 shown on line 7 that was approved by the Commission in Order No. PSC-2023-0026-FOF-EI, results in the net true-up over-recovery for the period January 2022 through December 2022 of $8,047,503 shown on line 9.

Q. Have you provided a schedule showing the calculation of the 2022 CCR actual true-up by month?

A. Yes. Exhibit EJA-2, pages 2 through 4, shows the calculation of the CCR true-up for the period January 2022 through December 2022 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 2022?

A. Yes. Exhibit EJA-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 2022 through December 2022.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit EJA-2, page 5, line 15, column 5, the variance related to total system capacity costs is a decrease of $5.4 million or 1.7%. Below are the primary reasons for the decrease.

<u>Transmission Revenues from Capacity Sales: $3.8 million increase (Exhibit EJA-2, page 5, column 5)</u>

Approximately $2.1 million of the total variance is attributable to higher than projected revenues from capacity premiums associated with power capacity sales. The remaining variance of approximately $1.7 million is attributable to higher than projected economy power sales which resulted in higher than projected transmission revenues from economy power sales.

<u>Transmission of Electricity by Others: $1.4 million increase (Exhibit EJA-2, page 5, column 5)</u>

The variance is primarily due to higher than projected purchases, $792,000, of transmission service to move energy associated with purchased power agreements into FPL's service area. The balance of the variance, $612,000, is due to higher than projected purchases of third-party transmission service used to facilitate economy power sales during the period.

<u>Incremental Plant Security Costs O&M: $3.3 million decrease (Exhibit EJA-2, page 5, column 5)</u>

The variance is related to delayed Fleet Control Center construction, minimized force on-force drill activities due to COVID and lower than planned security and training costs.

Incremental Nuclear Compliance Costs O&M: $.043 million decrease (Exhibit EJA-2, page 5, column 5)

Incremental Nuclear Regulatory Commission Compliance Costs were lower by $43,652 due to costs being lower than originally budgeted.

Q. Please describe the variance in 2022 CCR revenues.

A. As shown on page 6, line 23, column 5, actual 2022 CCR revenues are $5.1 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 EJA-2 as pages 16 and 17. Page 16 shows the actual capacity payments for FPL's Power Purchase Agreements for the period January 2022 through December 2022. Page 17 provides the short-term capacity payments for the period January 2022 through December 2022.

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 2022 through December 2022 are included on pages 18 and 19 of Exhibit EJA-2.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF EDWARD J. ANDERSON

DOCKET NO. 20230001-EI

JULY 27, 2023

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 Manager, Rate Development in the FPL Finance Department.

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 2023 through December 2023.

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 EJA-5 and EJA-6. Exhibit EJA-5 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2023 through December 2023. FCR

Schedules A1 through A9 provide actual data for the period January 2023 through June 2023. 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 EJA-5 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2023 through December 2023.

Exhibit EJA-6 contains the CCR schedules, which provide the calculation of FPL's actual/estimated true-up amount and actual/estimated variances for the period January 2023 through December 2023.

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 are taken from the 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 2023 through June 2023 and revised estimates for July 2023 through December 2023 to the data reflected in FPL's 2023 FCR midcourse correction filed on May 22, 2023 and approved by Order No. PSC-2023-0185-PCO-EI, issued on June 27, 2023.

The CCR actual/estimated true-up calculation compares actuals for January 2023 through June 2023 and revised estimates for July 2023 through December 2023 to the data reflected in FPL's original projection for the period January 2023 through December 2023, which was filed on September 2, 2022 and approved by Order No. PSC-2023-0026-FOF-EI, issued on January 6, 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 2023, which reflects the interest rate from the last business day in June 2023.

FUEL COST RECOVERY CLAUSE

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

A. Yes. Exhibit EJA-5, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2023 through December 2023.

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

A. Exhibit EJA-5, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2023 end-of-period net true-up amount is an under-recovery of $993,754,116 (Exhibit EJA-5, page 1, line 49, column 15), which is based on the actual/estimated true-up over-recovery, including interest, of $207,586,520 (Exhibit EJA-5, page 1, lines 42 plus 43, column 15) for the period January 2023 through December 2023 plus $1,201,340,636 (Exhibit EJA-5, page 1, line 46, column 15), which was deferred for recovery in 2024 as approved by Order No. PSC-2023-0108-PCO-EI.

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 2023?

A. Yes. Exhibit EJA-5, page 2 provides a variance calculation that compares the 2023 actual/estimated period data by component to the same components from the 2023 midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit EJA-5.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $2.967 billion for 2023 (Exhibit EJA-5, page 2, line 46, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.993 billion for that period (Exhibit EJA-5, page 2, line 46, column 3). The estimated variance is due to higher than projected costs combined with higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $25.8 million, or 0.9% higher than the midcourse correction estimates (Exhibit EJA-5, page 2, line 46, column 5), jurisdictional fuel revenues applicable to the period are projected to be $26.9 million, or 0.8% higher than the midcourse correction estimates (Exhibit EJA-5, page 2, line 41, column 5), and the interest expense is projected to be $1.8 million higher, or 2.5% (Exhibit EJA-5, page 2, line 48, column 5). The net impact due to the increase in jurisdictional fuel costs and the increase in jurisdictional fuel revenues applicable to the period result in the actual/estimated true-up under-recovery, including interest is $0.670 million (Exhibit EJA-5, page 2, line 54, column 5).

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

A. Below are the primary reasons for the $25.8 million increase in jurisdictional total fuel costs.

<u>Fuel Cost of System Net Generation - $53.0 million increase (Exhibit EJA-5, page 2, line 2, column 5)</u>

1 The table below provides the detail of this variance.

Fuel Variance	2023 Actual/Estimated	May 2023 Mid-Course Projections	Difference
Heavy Oil			
Total Dollar	$90	$90	$0
Units (MMBTU)	6	6	0
$ per Unit	14.2519	14.2519	0.0000
Variance Due to Consumption			$0
Variance Due to Cost			$0
Total Variance			$0
Light Oil			
Total Dollar	$9,840,941	$5,491,917	$4,349,024
Units (MMBTU)	547,986	309,572	238,415
$ per Unit	17.9584	17.7404	0.2180
Variance Due to Consumption			$4,229,560
Variance Due to Cost			$119,464
Total Variance			$4,349,024
Coal			
Total Dollar	$11,190,024	$2,914,148	$8,275,876
Units (MMBTU)	3,383,502	640,608	2,742,894
$ per Unit	3.3072	4.5490	(1.2418)
Variance Due to Consumption			$12,477,513
Variance Due to Cost			($4,201,637)
Total Variance			$8,275,876
Gas			
Total Dollar	$3,055,487,382	$3,016,230,649	$39,256,733
Units (MMBTU)	698,524,014	688,902,609	9,621,405
$ per Unit	4.3742	4.3783	(0.0041)
Variance Due to Consumption			$42,125,514
Variance Due to Cost			($2,868,781)
Total Variance			$39,256,733
Nuclear			
Total Dollar	$143,739,823	$142,620,030	$1,119,793
Units (MMBTU)	305,753,808	301,988,228	3,765,580
$ per Unit	0.4701	0.4723	(0.0022)
Variance Due to Consumption			$1,778,371
Variance Due to Cost			($658,578)
Total Variance			$1,119,793

Fuel Variance	2023 Actual/Estimated	May 2023 Mid-Course Projections	Difference
Total			
Total Dollar	$3,220,258,260	$3,167,256,834	$53,001,426
Units (MMBTU)	1,008,209,316	991,841,023	6,368,293
$ per Unit	3.1940	3.1933	0.0007
Variance Due to Consumption			$60,610,958
Variance Due to Cost			($7,609,532)
Total Variance			$53,001,426

<u>Fuel Cost of Stratified Sales - $8.2 million increase (Exhibit EJA-5, page 2, line 4, column 5)</u>

The increase of $8.2 million for the Fuel Cost of Stratified Sales is primarily attributable to the addition of a new wholesale contract, the cost of which is a credit to retail customers.

<u>Fuel Cost of Power Sold - $10.8 million decrease (Exhibit EJA-5, page 2, line 5, column 5)</u>

The decrease of $10.8 million for the Fuel Cost of Power Sold is primarily attributable to lower than projected fuel costs on economy power sales. The average unit fuel cost on economy power sales is now projected to be $4.02/MWh lower than originally projected, resulting in a decrease of approximately $14.7 million. This decrease is partially offset by higher than projected economy power sales. FPL now projects to sell approximately 135,000 MWh more of economy power, resulting in an increase of $4.0 million. The combination of lower fuel costs associated with economy power sales and higher economy power sales results in a net increase of approximately $10.7 million. The remainder of the variance is due to higher MWh sales and lower than projected fuel costs under the

St. Lucie Reliability Exchange.

Gains from Off-System Sales - $2.1 million increase (Exhibit EJA-5, page 2, line 6, column 5)

The $2.1 million increase in Gains from Off-System Sales is primarily attributable to higher than projected economy power sales. FPL now projects to sell approximately 135,000 MWh more of economy power, resulting in a volume increase of approximately $2.72 million. This increase is partially offset by lower than originally projected margins on economy power sales. FPL now projects that margins on economy power sales will be $0.23/MWh lower, resulting in a decrease of approximately $0.66 million. The combination of higher economy power sales and lower margins on economy power sales results in a net increase for Gains from Off-System Sales of $2.1 million.

Fuel Cost of Purchased Power - $2.6 million decrease (Exhibit EJA-5, page 2, line 7, column 5)

The $2.6 million decrease for the Fuel Cost of Purchased Power is primarily attributable to lower than projected purchases from its purchased power agreement ("PPA") with Shell and lower than projected costs associated with purchases from the Solid Waste Authority ("SWA"). FPL purchased nearly 71,000 MWh less than projected from the Shell PPA. Additionally, the unit cost of purchases from SWA are now estimated to be approximately $2.50/MWh less than originally projected.

Energy Payments to Qualifying Facilities - $4.3 million decrease (Exhibit EJA-5, page 2, line 8, column 5)

The $4.3 million decrease for Energy Payments to Qualifying Facilities is primarily attributable to lower than projected fuel costs and purchases from As-Available Co-Gen facilities.

Energy Cost of Economy Purchases - $4.9 million decrease (Exhibit EJA-5, page 2, line 9, column 5)

The $4.9 million decrease for the Energy Cost of Economy Purchases is primarily attributable to lower than projected economy power purchases. FPL now projects to purchase approximately 110,000 MWh less of economy power than originally projected. In addition, FPL now projects the unit cost of economy purchases will be approximately $2.00/MWh lower than originally projected. The combination of lower economy purchases and lower unit costs for economy power purchases results in a decrease of $4.9 million.

Variable Power Plant O&M Costs Attributable to Off-System Sales - $0.065 million increase (Exhibit EJA-5, page 2, line 14, column 5)

The $0.065 million increase is attributable to higher than originally projected economy power sales.

Variable Power Plant O&M Costs Avoided due to Economy Purchases - $0.053 million increase (Exhibit EJA-5, page 2, line 15, column 5)

The $0.053 million increase is attributable to lower than originally projected economy power purchases.

<u>Optimization Credits - $14.6 million increase (Exhibit EJA-5, page 2, line 16, column 5)</u>

The $14.6 million increase for Optimization Credits is attributable to higher than projected gains and activity associated with natural gas optimization and the sale of RECs.

CAPACITY COST RECOVERY CLAUSE

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

A. Yes. Exhibit EJA-6, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2023 through December 2023.

Q. Please explain the calculation of the CCR 2023 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit EJA-6, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2023 through June 2023 reflects actual data, while the data for July 2023 through December 2023 is based on updated estimates) compared to the original projection filing for the January 2023 through December 2023 period. Jurisdictional total capacity costs are estimated to be $0.106 million lower than the original projection filing (Exhibit EJA-6, page 5, line 23, column 5), jurisdictional CCR revenues are projected to be $3.335 million (Exhibit EJA-

6, page 5, line 28, column 5) higher than FPL's original projection filing, and the interest expense is projected to be $0.161 million higher than FPL's original projection filing (Exhibit EJA-6, page 5, line 31, column 5). The net impact due to the reduction in jurisdictional capacity costs and the increase in jurisdictional CCR revenues applicable to the period, including interest, result in the 2023 actual/estimated true-up over-recovery of $3.280 million (Exhibit EJA-6, page 5, lines 30 plus 31, column 5).

As shown on Exhibit EJA-6, page 3, the 2023 end-of period net true up amount to be carried forward to the 2024 CCR factors is an over-recovery of $11,327,158 (line 18, column 15). This $11,327,158 net over-recovery is comprised of the actual/estimated true-up over-recovery, including interest, of $3,279,655 for the period January 2023 through December 2023 (lines 10 plus 11, column 15) and the 2022 final net true-up over-recovery of $8,047,503 (line 13, column 15).

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 EJA-6, page 5, line 1, column 5, total system capacity costs are estimated to be $108,764 or 0.04% lower than projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is a 0.04% decrease from the original projection (page 5, line 23, column 6). Below are the primary reasons for the estimated $0.109 million decrease in total system capacity costs.

<u>Payments to Non-Cogenerators - $1.4 million decrease (Exhibit EJA-6, page 4, line 1, column 5)</u>

The $1.4 million decrease between the actual and projected payments to Non-Cogenerators is due to the projection amount including a full monthly capacity payment to Central Alabama in May, while the actual payment was calculated based on a partial month, with a contract end date of May 23.

<u>Transmission of Electricity by Others - $5.5 million increase (Exhibit EJA-6, page 4, line 3, column 5)</u>

The $5.5 million increase is primarily due to transmission costs associated with the Central Alabama PPA. The Central Alabama PPA contract included a $3.04 million transmission payment at the end of the transaction, which was not included in the original projections. Approximately $0.218 million of the increase is due to higher costs than originally projected for the purchase of third-party transmission utilized to facilitate wholesale power activity during the period. Approximately $2.23 million of the increase is due to transmission costs associated to delivering energy to customers in FPL-NW that was not included in the original 2023 projections.

<u>Transmission Revenues from Capacity Sales - $3.8 million increase (Exhibit EJA-6, page 4, line 4, column 5)</u>

The $3.8 million increase was primarily attributable to higher than projected transmission revenues from economy sales resulted in an increase of approximately $3.6 million. The remaining $0.18 million of the increase was due to higher revenues from capacity premiums associated with power capacity sales.

Incremental Plant Security Costs - O&M - $0.856 million decrease (Exhibit EJA-6, page 6, line 5, column 5)

The decrease of $0.856 million for incremental plant security O&M costs is primarily attributable to a reduction in security roles due to automation and a decrease in scheduled trainings. This was partially offset by an increase in force-on-force drills required by the NRC. The required triannual drills were omitted from the filed projections. Additionally, there were higher than anticipated costs for travel for the Joint Composite Adversary Force used in the force-on-force drills required to train the security staff.

Incremental Plant Security Costs – Capital - $0.272 million decrease (Exhibit EJA-6, page 4, line 6, column 5)

The $0.272 million decrease for incremental plant security capital costs is primarily attributable to delays to a protected area fencing project at St. Lucie and change in related supplemental security and support costs. Milestone payments have been delayed until August and November 2023 partially because the vendor was not able complete the projected scope of work in a timely manner due to an installation issue. Project work scope is expected to be completed in November 2023.

Incremental Nuclear NRC Compliance Costs - O&M - $0.027 million decrease (Exhibit EJA-6, page 4, line 7, column 5)

The $0.027 million decrease for incremental nuclear NRC compliance O&M costs is primarily attributable to lower Fukushima emergency preparedness costs than originally projected.

Incremental Nuclear NRC Compliance Costs – Capital - $0.261 million increase (Exhibit EJA-6, page 4, line 8, column 5)

The $0.261 million increase for incremental nuclear NRC compliance capital costs is primarily attributable to equipment retirements which were higher than the original projection.

Cedar Bay and Indiantown Transactions - Regulatory Asset - Amortization and Return - $0.450 million increase (Exhibit EJA-6, page 4, line 9, column 5 and page 4, line 11, column 5)

The Amortization and Return associated with the Cedar Bay and Indiantown Transactions increased by $0.177 million and $0.273 million, respectively, due to the change in FPL's authorized return on equity from 10.6% to 10.8% beginning September 1, 2022 as approved by Order No. PSC-2022-0358-FOF-EI. Pursuant to the stipulation approved in that Order, FPL did not apply the 10.8% ROE to clause cost recovery factors implemented in January 2023, and instead agreed to reflect it in these true-up calculations which will be included for recovery commencing 2024.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF EDWARD J. ANDERSON

DOCKET NO. 20230001-EI

SEPTEMBER 5, 2023

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 Manager, Rate Development in the FPL Finance Department.

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 2024 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, 2024 ("2024 Project"); and, (ii) February 2024 through December 2024, which include an incremental adjustment to reflect the ongoing fuel savings associated with the 2024 Project. These factors are referred to collectively as the "2024 FCR factors";

- The 2024 FCR factors based on the traditional factor calculation method, which spreads the fuel savings associated with the 2024 Project over the entire calendar year, for informational purposes;
- The calculation of the jurisdictional amount of FPL's portion of the 2022 asset optimization gains to be recovered through the 2024 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2024 through December 2024 with and without the revenue requirement reduction to reflect incremental Inflation Reduction Act ("IRA") savings for January 2023 through December 2024 proposed in Docket No. 20220165-EI on June 13, 2023;
- 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 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 2024 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-7

- Schedules E1, E1-E, the RS-1 Inverted Rate Calculation, E2, and E10 provide the calculation of the FCR factors for January 2024, which exclude the fuel savings of the 2024 Project;

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- Schedules E1-A, E1-C, E1-D, Asset Optimization Gains, and H1, which pertain to the entire 2024 calendar year;
- Pages 10 through 14, which provide the 2024 Projected Energy Losses by Rate Class;
- Pages 150 through 153, which provide updated COG-1 tariff sheets.

Exhibit EJA-8

- Schedules E1, E1-E, the RS-1 Inverted Rate Calculation, E-2, and E10 for the period February 2024 through December 2024, which include the incremental ongoing fuel savings for the 2024 Project.

Exhibit EJA-9

- Schedules E1, E1-E, RS-1 Inverted Rate Calculation, E2, and E10 that provide the calculation of FCR factors for the period January 2024 through December 2024 based on the traditional factor calculation methodology, which spreads fuel savings for the 2024 Project over the entire calendar year for informational purposes.

Exhibit EJA-10

- Pages 1 through 4 provide the calculation of 2024 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 Cedar Bay Transaction;

- Page 12 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 13 provides the calculation of amortization and return on the regulatory asset related to the Indiantown Transaction;
- Page 14 provides the calculation of the amortization and return on the COVID-19 regulatory asset;
- Page 15 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 2024 through December 2024;
- Page 18 provides the calculation of the portion of the CCR factors related to the IRA revenue requirement reduction;
- Page 19 combines the results from page 4 and page 18 to provide the total 2024 CCR factors including the IRA revenue requirement reduction;
- Pages 20 through 31 provide the calculations of stratified separation factors.

Exhibit EJA-11

- Page 1 provides the 2024 SoBRA Factor Calculation;
- Page 2 provides the forecasted retail base revenues for the projected 12-month period beginning February 1, 2024;
- Pages 3 through 48 provide a summary of tariff changes.

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Exhibit EJA-12

- Page 1 provides Schedule E10 Residential Bill Impacts through April 2024 for customers in FPL's peninsular and NW Florida service area.

Exhibit EJA-13

- 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.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2024 FCR factors shown on Schedule E1?

A. The 2024 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 2022 asset optimization gains and (iv) the cost associated with the projected 2024 Subscription Credit for the FPL SolarTogether Program.

The total net true-up amount to be included in the 2024 FCR factors is a $993,754,116 under-recovery. This amount is reflected on line 35 of Schedule E1. The $993,754,116 under-recovery, divided by the projected retail sales of

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124,596,627 MWh for January 2024 through December 2024, results in a charge of 0.7976 cents per kWh.

The testimony of FPL witness Rote, filed on March 16, 2023, presents a GPIF reward of $10,818,303 for the period ending December 2022. This amount is reflected on line 37 of Schedule E1. This $10,818,303 reward, divided by the projected retail sales of 124,596,627 MWh for January 2024 through December 2024, results in a charge of 0.0087 cents per kWh.

FPL is including $47,353,597 for the jurisdictional amount associated with its share of 2022 asset optimization gains in the calculation of its 2024 FCR factors, as shown on line 38 of Schedule E1. As presented and explained in the direct testimony and exhibits of FPL witness Yupp filed on April 3, 2023 in this docket, FPL's activities under the asset optimization program in 2022 delivered $130,180,330 in total gains. Of these total gains, FPL is allowed to retain $49,590,165 (system amount) per 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 futher modifications, by Order No. PSC-2021-0446-S-EI, dated December 2, 2021. The system amount of total gains of $49,590,165 has be allocated to the retail jurdisdiction based on its load ratio share of system sales for 2022. The resulting jurisdictional amount to be recovered is $47,353,597 which is calculated and shown on page 4 of Exhibit EJA-7. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount in each month's

Schedule A2 for the period January 2024 through December 2024 as a reduction to jurisdictional fuel revenues applicable to each period. This $47,353,597, divided by the projected retail sales of 124,596,627 MWh for January 2024 through December 2024, results in a charge of 0.0380 cents per kWh.

FPL has included $203,511,528 associated with the projected 2024 Subscription Credit for the FPL SolarTogether Program, as shown on line 39 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. This $203,511,528 divided by the projected retail sales of 124,596,627 MWh for January 2024 through December 2024, results in a charge of 0.1633 cents per kWh.

Schedule E2 provides the monthly FCR factors as well as the levelized FCR factor for 2024. Schedule E-1E provides the calculation of the January 2024 FCR factors by rate group for each period.

Q. Please explain the fuel cost of stratified sales amount reflected on line 5 of Schedule E1.

A. FPL has included a projected credit of $73,446,394 associated with stratified wholesale power sales contracts in effect in 2024. 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. Please explain how FPL is addressing the estimated 2023 over-recovery amount of $207,586,520.

A. At the time of FPL's second mid-course filing on May 19, 2023, FPL initially estimated a 2023 over-recovery of $211,795,489. FPL updated the estimated over-recovery in its Actual/Estimate filing on July 27, 2023, to be $207,586,520. FPL proposes to include the estimated 2023 over-recovery of $207,586,520 in the the 2024 FCR factors to reduce the 2022 deferred true-up amount of $1,201,340,636 and flow back over the 12 months in 2024.

Calculation of 2024 FCR Factors

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2024 through December 2024 to reflect the impact of the fuel savings associated with the 2024 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 2024 Project. The SoBRA associated with the 2024 Project is expected to be implemented by February 1, 2024. FPL proposes that the corresponding fuel savings associated with the 2024 Project be reflected in the 2024 FCR factors beginning February 1,

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2024, which is concurrent with the SoBRA in order 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 2024 Project impact the 2024 FCR factors?

A. At this time, FPL does not anticipate a delay in the commercial operation date of the 2024 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 2024 SoBRA until those units go into service.

Q. What are the projected 2024 fuel savings associated with the 2024 Project?

A. As explained in the testimony of FPL witness Yupp, the projected 2024 total system fuel savings associated with the 2024 Project are $51,110,452.

Q. Please explain the calculation of 2024 FCR factors reflecting the fuel savings associated with the 2024 Project.

A. FPL first calculates the FCR factors for January 2024 that excludes the fuel savings associated with the 2024 Project. These FCR factors assume the 2024 Project are not yet operating and therefore exclude the associated fuel savings. This adjustment is reflected on line 3 of Schedule E1 in Exhibit EJA-7. The levelized FCR factor for January 2024 is 3.760 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $34.62 during this period.

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Next, FPL calculates the FCR factors for February 2024 through December 2024 that include the fuel savings associated with the 2024 Project scheduled to go in service by February 1, 2024. This adjustment is shown on line 40 of Schedule E1 in Exhibit EJA-8. The levelized FCR factor for February 2024 through December 2024 including this adjustment is 3.718 cents per kWh. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $34.19 for this period.

Schedule E2 provides the monthly fuel factors as well as the levelized FCR factor for 2024. Schedule E-1E provides the calculation of the 2024 FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2024?

A. Yes. Although FPL requests approval of separate FCR factors for two periods, reflecting the impact of the 2024 Project upon commercial operation, FPL provides for informational purposes the calculation of a twelve-month levelized fuel factor for 2024. Exhibit EJA-9 includes Schedules E1, E1-E, RS-1 Inverted Rate Calculation, E2, and E10, which calculate a twelve-month levelized fuel factor of 3.721 cents per kWh by including the fuel savings for the 2024 Project throughout the twelve months of 2024.

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CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested CCR costs for the projected period of January 2024 through December 2024?

A. Yes. Pages 1 and 2 of Exhibit EJA-10 provide this summary. Total recoverable capacity costs for the period January 2024 through December 2024 are $200,713,696 (page 2, line 32). This includes $212,040,854 of 2024 projected jurisdictional capacity costs (page 2, line 27) and the net true-up over-recovery for 2022 and 2023 of $11,327,158 (page 2, line 30 plus line 31). This $200,713,696 excludes the IRA revenue requirement reduction.

Q. Have you also provided a calculation of the 2024 CCR factors by rate class that include a revenue requirement reduction to reflect incremental IRA savings for January 2023 through December 2024?

A. Yes. As proposed in FPL's Petition filed in Docket No. 20220165-EI on June 13, 2023, FPL has included on pages 18 and 19 of Exhibit EJA-10 a calculation of the 2024 CCR factors that include a revenue requirement reduction related to the IRA savings of $7,921,060, including interest. The total amount to be recovered through the CCR factors inclusive of the IRA reduction is $192,792,636.

Q. What adjustments are included in the calculation of the combined 2024 CCR factors included in Exhibit EJA-10?

A. The total net true-up to be included in the 2024 CCR factors is an over-recovery of $11,327,158, as shown on page 2, line 31 plus line 32. This over-recovery is comprised of FPL's 2022 final net true-up over-recovery of $8,047,503, which was filed on April 3, 2023, and FPL's 2023 actual/estimated true-up over-recovery of $3,279,655 filed on July 27, 2023.

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

A. Yes. Page 3 of Exhibit EJA-10 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. Please describe the Weighted Average Cost of Capital ("WACC") that is used in the calculation of the return on the 2024 capital investments included for recovery.

A. FPL calculated and applied a projected 2024 WACC in accordance with the methodology established in Commission Order No. PSC-2020-0165-PAA-EU. This projected WACC is based on FPL's 2024 financial forecast and currently approved midpoint ROE of 10.8%. The WACC is used to calculate the rate of return applied to the 2024 CCR capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 15 of Exhibit EJA-10.

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

A. Yes. The separation factors used in the calculation are consistent with the FPL Ten Year Power Plant Site Plan 2023-2032 filed April 3, 2023. FPL has separated the production-related capacity costs based on stratified separation factors that better

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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 EJA-10 pages 20-31.

2024 SoBRA FACTOR

Q. Please explain the calculation of the 2024 SoBRA factor and the purpose it serves.

A. I have calculated the 2024 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 $71.392 million presented by FPL witness Chin for the 2024 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, 2024 base rates to provide the Company with sufficient revenue to recover the costs associated with the construction and operation of the 2024 Project. The calculation and resulting SoBRA factor of 0.796% is shown in Exhibit EJA-11, 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, 2024?

A. Yes. Exhibit EJA-11, 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, 2024. 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, 2024 are projected to be $8,972.880 million, shown on Exhibit EJA-11, 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, 2024?**

A. Yes. Exhibit EJA-11 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, 2024. If the SoBRA and the associated charges are approved for the 2024 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 2024 Project's commercial operation date.

A. The Company will submit a letter to the Commission that declares the commercial operation date and time. SoBRA will become effective only on or after that commercial operation date.

EFFECTIVE DATES

Q. What are the effective dates that FPL is requesting for the new FCR factors, CCR factors, and SoBRA for 2024?

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 2024 Project become effective January 1, 2024;
- The CCR factors which include the IRA revenue requirement reduction for the period January 2024 through December 2024 become effective January 1, 2024; and
- The FCR factors which include the incremental SoBRA savings associated with the 2024 Project and the 2024 SoBRA become effective after the 2024 Project has entered commercial operations which is expected to be February 1, 2024.

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 April 2024?

A. Yes. Exhibit EJA-12 page 1 of 1 provides a Schedule E10 for proposed typical residential bill changes through April 1, 2024 for customers in FPL's peninsular and NW Florida service areas.

Exhibit EJA-13 pages 1 through 12 provides proposed bill changes through April 1, 2024, illustrated for both typical residential and business bills in FPL's peninsular and NW Florida service areas.

The typical bills in each exhibit reflect all proposed clause changes to become effective on January 1, 2024, the proposed base and fuel changes related to the SoBRA for the 2024 Project scheduled to become effective by February 1, 2024, and reflect the storm restoration recovery charge ending in April 2024.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

WITNESS: EDWARD J. ANDERSON
DIRECT TESTIMONY DATED: SEPTEMBER 5, 2023

Page	Line	Change
13	13	Change "$71.392" to "$68.128"
	18	Change "0.796%" to "0.759%"

Exhibit No.	Page	Change
EJA-8	Page 8 of 8	Replace with attached corrected page bearing the same header (Page 8 of 8)
EJA-9	Page 7 of 7	Replace with attached corrected page bearing the same header (Page 7 of 7)
EJA-11	Pages 1-48 (all)	Replace with attached corrected page bearing the same header (Pages 1-48)
EJA-12	Page 1 of 1	Replace with attached corrected page bearing the same header (Page 1 of 1)
EJA-13	Pages 1-12 (all)	Replace with attached corrected page bearing the same header (Pages 1-12)

C10-714

(Whereupon, prefiled direct testimony of Curtis D. Young was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20230001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2022 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1635 Meathe Road, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

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

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

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 2022 through December 2022.

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

A. Yes. Exhibit________ (CDY-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 2022 through December 2022?

A. For the Consolidated Electric Division the final remaining true-up amount is an under recovery of $9,648,946.

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 2022 period and the total true-up amount to be collected or refunded during the January 2023 - December 2025 period.

Q. What was the actual end of period true-up amount for January - December 2022?

A. For the Consolidated Electric Division it was $30,840,177 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January 2023 – December 2025 period?

A. A consolidated under-recovery of $21,191,231 to be collected. However as approved in Commission Order No. PSC-2023-0026-FOF-EI, only $7,063,744 (1/3 of this amount) is to be recovered during the period January 2023 – December 2023.

Q. Does the Company anticipate requiring a midcourse adjustment for 2023?

A. No, not at this time. Although the 2022 True-up calculations result in an additional under-recovery of $9,648,946, an updated forecast of the Company's 2023 purchased power costs produced lower amounts than what was estimated in the Company's 2023 Projection filing. Therefore, the Company anticipates that, based on our current estimates, the Company can expect a total under-recovery by year end 2023 that is not significantly different from the current under-recovery produced by the Company's 2022 Final True Up calculations, which mitigates the necessity of a midcourse adjustment. The decision not to pursue a mid-course correction is, however, subject to change in the event that a material increase in gas prices occurs in 2023.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C11-1059

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Describe briefly your education and relevant professional background.

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations made in preparation of 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 Schedules E1-A, E1-B, and E1-B1 as part of Exhibit CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2023 – December 2023 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 2022 – December 2022?

A. The final remaining true-up amount was an under-recovery of $9,648,946.

Q. What is the estimated true-up amount for the period January 2023 – December 2023?

A. The estimated true-up amount is an under-recovery of $1,942,079.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2024 – December 2024?

A. At the end of December 2023, based on six months actual and six months estimated, the Company estimates it will under-recover $11,591,025 in purchased power costs, which will be collected from January 2024 – December 2024. The Company's total true-up amount that the Company proposes to collect during the period January 2024 through December 2024 is, however, an under-recovery of $4,887,532 when the appropriate adjustments are applied as reflected in Schedule E-1A.

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 has 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, Yoakley, 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, and $83,873 for the six-months ended June 30, 2023. We roughly estimate to spend another $44,800 by year-end.

Q. When do you anticipate construction to begin on the AIE facility?

A. It is anticipated that decisions can be finalized on these items later in 2023 with major items ordered in early 2024. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Does this conclude your testimony?

A. Yes.

C11-1066

(Whereupon, prefiled direct testimony of Phuong T. Nguyen was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2023001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2024 Projection Testimony of Phuong T. Nguyen

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Phuong Nguyen and business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as a Regulatory Analyst.

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

A. I have a Bachelor of Science degree in Finance and Accounting from the University of New Orleans. I am also a licensed Certified Public Accountant. Prior to my employment with FPUC, I was employed with Entergy Corporation as Regulatory Analyst supporting various rate proceedings for cost of service filings and other formula rate plan filings for regulated utility retail operations, and regulated utility wholesale operations under the jurisdiction of multiple Public Service Commissions and also, the Federal Energy Regulatory Commission. Prior to that role, I was a Lead Analyst in the Utility Operations Accounting department where I performed accounting and analysis for fuel costs 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. I also held accounting positions earlier in my career in the hospitality and maritime service industries.

Q. Have you previously testified in this Docket?

A. No, I have not.

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 2023 through June 2023 data and projected July 2023 through December 2024 data to be collected or refunded during January 2024 – December 2024. My testimony will also summarize the computations that are contained in composite exhibit PTN-1 supporting the January through December 2024 projected levelized fuel adjustment factors for its consolidated electric divisions. In addition, I will explain a revision to the under-recovery calculation previously reported on the 2023 actual/estimated true-up filing. Finally, my testimony will request recovery treatment of the 2022 final remaining under-recovery over one year as opposed to treatment approved in Docket No. 2023001, Order No. 2023-0026-FOF-EI.

Q. Were the schedules filed by the Company completed by you or under your direct supervision?

A. Yes, they were completed by me.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are the Consolidated Electric Schedules E1, E1A, E2, E7, E8, and E10. These schedules are included in my Exhibit PTN-1, which is appended

C12-1071

to my 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 2024 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. What are the final remaining true-up amounts for the period January – December 2022?

A. The final remaining consolidated true-up amount was an under-recovery of $9,648,946.

Q. What are the estimated true-up amounts for the period of January – December 2023?

A. There is an estimated consolidated under-recovery of $1,987,573.

Q. Please address the calculation of the total true-up amount to be collected during the January - December 2024 year?

A. The Company has determined that at the end of December 2023, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $11,636,519.

Q. **Please explain the difference between the under-recovery amount previously reported in the 2023 actual/estimated true-up as compared to the amount in this filing?**

A. In the actual/estimated true-up filed in July 2023, the under-recovery amount to be collected in proposed rates for 2024 was calculated as $4,887,532. However, expenses in the amount of $45,494 were inadvertently omitted, although that amount was reflected in the Company's June 2023 monthly Fuel A-Schedule.

Q. Does that account for the full difference in the amount?

A. No. In addition to the amount that was inadvertently omitted, the Company is now requesting full recovery of the 2022 final remaining deferred balance in 2024. In 2022, the Company experienced a substantial increase in its purchase power costs due to the volatility of the natural gas market. To mitigate the impact to our customers in 2023, the Company proposed and received approval, in Order No. PSC-2023-0026-FOF-EI, to defer $21,191,231 of its projected 2022 under-recovery over three years. The Company included 1/3 or $7,063,744 of the deferred under-recovery in its 2023 rates. The Company's prior actual/estimated true-up assumed that the Company would continue to recover its 2022 under-recovery consistent with the 3-year time frame approved in last year's Fuel proceeding and reflected in Order No. PSC-2023-0026-FOF-EI. Therefore, the Company did not include $7,063,744 or 1/3 of the 2022 deferred under-recovery balance and its associated interest of $360,251.

Q. **Is the entire remainder of the 2022 final remaining under-recovery balance**

included in the 2023 actual/estimated under-recovery amount reflected in this filing?

A. Yes, it is. When all appropriate adjustments are made, including the entire remainder of the 2022 under-recovery balance of $14,127,488, the 2023 under-recovery balance is $11,636,519.

Q. Please explain why the Company is proposing to collect the 2022 final remaining deferred under-recovery in 2024?

A. The Company is now requesting to recover the full remaining deferred balance in 2024 proposed rates for the following reasons. The Company has experienced substantial decreases in its 2023 purchased power costs in contrast to what was originally projected, due to natural gas market stabilizing, resulting in significant impacts towards its monthly under-recovery balances year-to-date. Specifically, it's actual true-up balance of $30,840,177, at December 2022 has decreased to $19,082,275 as reported in its July 2023 monthly true-up filing. Following this trend and based on current cost projections, it would no longer be prudent to defer the Company's 2022 under-recovery. Also, collection of the entire remaining under-recovery will save customers an additional year of incurred interest of approximately $360K on the deferred balance especially since commercial paper rates have been on the rise. In addition, with the full remaining 2022 deferred under-recovery balance included in rates, a typical bill for a residential customer using 1000 kwh will still decrease from $175.46 to $165.98 as shown in the Table 1 below.

Table 1					
Residential Typical Bill per 1000 KWH					
		CURRENT 2023		PROPOSED 2024	
		Rate	Charge	Rate	Charge
Customer Charge	$ per bill	16.95	$ 16.95	16.95	$ 16.95
Base Energy Charge	$ per KWH	0.02373	$ 23.73	0.02373	$ 23.73
Fuel	$ per KWH	**0.11396**	$113.96	**0.10259**	$102.59
Conservation	$ per KWH	0.00113	$ 1.13	0.00144	$ 1.44
Storm Recovery	$ per KWH	0.01280	$ 12.80	0.01280	$ 12.80
Storm Protection	$ per KWH	0.00250	$ 2.50	0.00432	$ 4.32
Gross Receipts Tax		0.02564	$ 4.39	0.02564	$ 4.15
			$175.46		$165.98

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 **7.807¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2024 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 PTN-1, a residential customer using 1,000 KWH will pay **$165.98**. This is a decrease of **$9.48** 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. 2023001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2024 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, 208 Wildlight Avenue, Yulee, Florida 32097.

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 2020, I moved into my current role as Director, Generation Development.

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

C13-1085

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, rebuttal testimony in Docket No. 20180061-EI and numerous dockets for Fuel and Purchased Power Cost Recovery. Most recently, I provided testimony in Docket Nos. 20220049 and 20220010, in the Storm Protection Plan and Cost Recovery.

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 agreements with Florida Power & Light ("FPL"), 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. Based on the fact that natural gas costs have a significant impact on the overall cost of purchased power for FPUC, what actions has FPUC taken to provide accurate cost projections in the natural gas markets?

A. FPUC, being predominately a natural gas utility, has utilized information from both inside the company and other external sources to carefully investigate the future of the natural gas markets. Based on this information, forecast of 2024 natural gas cost have been provided and included in the purchased power cost projections.

Q. What other energy sources are being investigated and what are some of the benefits anticipated?

A. FPUC has been investigating the use of Renewable Natural Gas (RNG) and Hydrogen as future fuel sources for generation assets. 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, it is critical that FPUC continue to be involved in the investigation and development of these resources.

Q. What is the status of the existing purchase power agreements in place with FPL?

A. The existing agreement for our Northwest Florida Division with FPL became effective January 1, 2020, and will continue in effect through December 31, 2026 unless extended by FPUC. The existing agreement for our Northeast Florida Division with FPL, which became effective January 1, 2018, was later amended in 2019 to continue in effect through the December 31, 2026 unless extended by FPUC.

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. The Company is currently involved in discussions with FPL regarding the consolidation and amendment of the existing purchased power agreements. This will include consolidation into a single agreement covering both divisions, investigation of the pricing structure utilized and a review of the transmission infrastructure in place which provides service to two distinct, geographically separated service territories.

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

C13-1087

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.

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 and the ability to do so within the context of the "Agreement" and "Amendment"

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with FPL, the already quantifiable benefits of the existing project have piqued the interest of others to contemplate partnering with a new CHP-based project on Amelia Island. FPUC has been actively involved in the initial analysis, development and engineering of a possible new project located on Amelia Island that would support existing industry. Significant efforts have continued to evaluate this CHP which, similar to Eight Flags, will be located on Amelia Island and would allow FPUC, along with transmission line upgrades, to provide additional reliability and resilience to its electricity supply for industry and customers on Amelia Island. This second CHP would provide electricity, high pressure steam and hot water to a local industrial customer which is a critical component of the local community. Preliminary engineering, financial modeling and Florida Department of Environmental Protection permitting have been completed for this possible CHP unit. Although the final agreements and structure of the proposed CHP has not yet been finalized, efforts are continuing to develop this project.

Q. Can you provide additional information on the PV and battery projects you referenced above?

A. Yes. FPUC is continuing analysis related to 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, but the cost is also expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. The "Agreement" and the "Amendment" have provisions that allow for the development of PV installations by FPUC and provides

C13-1089

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.

C13-1090

(Whereupon, prefiled direct testimony of M. Ashley Sizemore was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

2022 FINAL TRUE-UP
TESTIMONY AND EXHIBITS

M. ASHLEY SIZEMORE

FILED: APRIL 3, 2023

C14-1091

TAMPA ELECTRIC COMPANY
C14-1092
DOCKET NO. 20230001-EI
FILED: 4/3/2023

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. 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 Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental and fuel and capacity cost recovery

C14-1092

clauses. For the following three years, as a Program Manager in Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have over ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel clause and purchased power, capacity, and environmental cost recovery clauses.

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 2022 through December 2022 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause ("Capacity Clause"), as well as the 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. MAS-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 2022 through December 2022?

A. The final true-up amount for the Capacity Clause for the period January 2022 through December 2022 is an under-recovery of $2,216,062.

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 2022 Through December 2022", provides the calculation for the final under-recovery of $2,216,062. The actual capacity cost over-recovery, including interest, was $1,751,764 for the period January 2022 through December 2022 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $3,967,826 actual/estimated over-recovery approved in Order No. PSC-2023-0026-FOF-EI issued on January 6, 2023, results in a final under-recovery of $2,216,062.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2022 through December 2022?

A. The final Fuel Clause true-up for the period January 2022 through December 2022 is an under-recovery of $295,994,153. The actual fuel cost under-recovery, including interest, was $517,989,768 for the period January 2022 through December 2022. This $517,989,768 amount, less the $64,989,253 under-recovery and $157,006,362 projected over-recovery included in the company's Mid-Course Projection approved in Order No. PSC-2023-0107-PCO-EI issued March 23, 2023 in Docket No.

20230001-EI, results in a net under-recovery amount for the period of $295,994,153.

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 2022 Through December 2022." It shows the calculation of the final fuel under-recovery of $295,994,153.

Line 1 shows the total company fuel costs of $1,225,416,677 for the period January 2022 through December 2022. The jurisdictional amount of total fuel costs is $1,225,416,677, 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 $536,118,865 under-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 $517,989,768 shown on line 9. The $517,989,768 actual under-recovery amount less the $64,989,253 under-recovery and 157,006,362 projected over-recovery included in the

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company's Mid-Course Projection recovery amount to be recovered through the period April 2023 through December 2023 and shown on line 10, results in a final net under-recovery amount of $295,994,153 for the period January 2022 through December 2022, 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 2022 Through December 2022." 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 2022 through December 2022?

A. As shown on line A6 of Document No. 3, the fuel and net power transaction cost is $533,933,469 more than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2022 through December 2022?

A. As shown on line C3 of Document No. 3, the company collected $23,554,813, or 3.5 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.

Optimization Mechanism

Q. Was Tampa Electric's sharing of 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 Optimization Mechanism gains was allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI. As a result of the company's Optimization Mechanism activities during 2022, the total gains were $24,569,361. Under the sharing mechanism, Tampa Electric customers receive $14,184,681, and the company earned an incentive of $10,384,680. Customers received the gains from these transactions during 2022, and Tampa Electric requests Commission approval to collect the company's $10,384,680 incentive in its 2024 fuel factors.

Q. Does this conclude your testimony?

A. Yes, it does.

C14-1099

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: JULY 27, 2023

C14-1128

TAMPA ELECTRIC COMPANY
C14-1129
DOCKET NO. 20230001-EI
FILED: 7/27/2023

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. 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 Director, 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 Arts degree in Political Science and a Master of Business Administration degree from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs department working on environmental, fuel and capacity cost recovery clauses. During the following three years as a Program Manager in

Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs department in 2020 as Manager, Rates. I was promoted to my current position in May 2023. My duties entail overseeing the cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental, conservation and storm protection plan projects. I have over 11 years of electric utility experience in the areas of customer experience and project management as well as the management of fuel and purchased power, capacity, and environmental cost recovery clauses.

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 2023 through December 2023 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2024 through December 2024 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2023, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2024 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. MAS-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 2023 through December 2023. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2023 through December 2023.

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 2024 through December 2024 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount for 2023 to be applied in January 2024 through December 2024 is an under-recovery of $112,834,024.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2024 through December 2024 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2024 includes the remaining true-up amount for the period January 2022 through December 2022 and the actual/estimated true-up amount for the period January 2023 through December 2023. This calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. What did Tampa Electric calculate as the remaining fuel and purchased power cost recovery true-up amount for 2022?

A. The remaining final 2022 true-up amount, to be included in the January 2024 through December 2024 fuel and purchased power cost recovery factors is an under-recovery amount of $295,994,153 for the period January 2022 through December 2022. The actual fuel cost under-recovery, including interest, is $517,989,768 for the period January 2022 through December 2022. Tampa Electric received approval in Order No. PSC-2023-0107-PCO-EI, issued on March 23, 2023 in Docket No. 20230001-EI to recover $221,995,615 during the period April 2023 through December 2023.

C14-1132

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2023 through December 2023?

A. The actual/estimated 2023 fuel true-up amount is an over-recovery amount of $340,166,487 for the period January 2023 through December 2023. The detailed calculations supporting the actual/estimated current period true-up are shown in Exhibit No. MAS-2, on Schedule E1-B, Document No. 1.

Q. What are the primary drivers of the expected 2023 fuel over-recovery amount?

A. The primary reason for the expected 2023 over-recovery is a substantial decrease in the price of natural gas, compared to the company's original 2023 mid-course projection.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2024 through December 2024 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January

2024 through December 2024 is an under-recovery of $7,418,904 as shown in Exhibit No. MAS-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 2024 through December 2024 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2024 capacity cost recovery factors includes the final true-up amount for 2022 and the actual/estimated true-up amount for January 2023 and December 2023.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2022?

A. The final 2022 under-recovery of $2,216,062 as shown on Exhibit No. MAS-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 2023 through December 2023?

A. The actual/estimated true-up amount is an under-recovery of $5,202,844 as shown on Exhibit No. MAS-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 2023 through December 2023?

A. The net capacity cost recovery true-up amount for the period January 2023 through December 2023 is an under-recovery of $7,418,904. This calculation is shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TECO
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2024 THROUGH DECEMBER 2024

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: AUGUST 16, 2023

C14-1173

TAMPA ELECTRIC COMPANY
DOCKET NO. 20230001-EI
FILED: 08/16/2023

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. 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 Director, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20230001-EI?

A. Yes, I submitted direct testimony on April 3, 2023 and July 27, 2023.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, they have not.

C14-1174

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 2024 through December 2024. 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 2024.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. MAS-3, consisting of three 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 2024 through December 2024 as well as Schedule H1 for 2021 through 2024. 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.

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. MAS-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. MAS-3, Document No. 1, page 2 of 4, Tampa Electric is requesting recovery of $10,938,282 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2024.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2024 for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.062	
GS and CS Secondary	0.054	
GSD, SBD Standard		

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Secondary		0.20
Primary		0.20
Transmission		0.20
GSD Optional		
Secondary	0.048	
Primary	0.048	
Transmission	0.047	
GSLDPR/GSLDTPR/SBLDPR/SBLDTPR		0.17
GSLDSU/GSLDTSU/SBLDSU/SBLDTSU		0.19
LS1 Secondary	0.012	

These factors are shown in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric’s proposed average capacity cost recovery factor of 0.054 cents per kWh compare to the factor for January 2023 through December 2023?

A. The proposed capacity cost recovery factor of 0.054 cents per kWh beginning in January 2024 is 0.070 cents per kWh (or $.70 per 1,000 kWh) more than the average capacity cost recovery factor of (0.016) cents per kWh for the January 2023 through December 2023 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 2024?

A. The appropriate amount for the period beginning in January 2024 is 3.843 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. MAS-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 2024 through December 2024.

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 penalty of $1,648,937 and an Optimization Mechanism gain of $10,384,680, 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 2023 through December 2023 period is an under-recovery of $112,834,024.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric’s on-peak and off-peak fuel adjustment factors for January 2024 through December 2024. 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.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. MAS-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 2024.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.843
Tier I (Up to 1,000 kWh)	3.536
Tier II (Over 1,000 kWh)	4.536
Distribution Primary	3.805
Transmission	3.766
Lighting Service	3.806
Distribution Secondary	4.045(on-peak)
	3.757(off-peak)
Distribution Primary	4.005(on-peak)
	3.719(off-peak)
Transmission	3.964(on-peak)
	3.682(off-peak)

Q. How does Tampa Electric’s proposed levelized fuel adjustment factor of 3.843 cents per kWh compare to the levelized fuel adjustment factor for the April 2023 through December 2023 period?

A. The proposed fuel charge factor of 3.843 cents per kWh is

0.989 cents per kWh (or $9.89 per 1,000 kWh) lower than the average fuel charge factor of 4.832 cents per kWh for the April 2023 through December 2023 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2024 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 2024 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, and energy conservation 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 decrease of $17.65 in the period beginning January 2024, when compared to the April 2023 through December

2023 charges. These amounts are shown in Exhibit No. MAS-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 2024.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Elena B. Vance was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
TRUE-UP
JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY AND EXHIBIT
OF
ELENA B. VANCE

TAMPA ELECTRIC COMPANY
C15-1235
DOCKET NO. 20230001-EI
FILED: 03/16/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELENA B. VANCE

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

A. My name is Elena B. Vance. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Senior Engineer, Resource Planning.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Chemical Engineering from the University of South Florida in 1999 and a Master of Business Administration with a concentration in Finance in 2003 from the University of Tampa. I have accumulated 25 years of experience in the electric industry, with experience in the areas of plant operations, unit commitment and economic dispatch, and resource planning. In my current role, I am responsible for long term study analysis and project economic analysis.

C15-1235

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2022 through December 2022. I will also compare these results to the targets established for the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I prepared Exhibit No. EBV-1, consisting of two documents. Document No. 1, entitled "GPIF Schedules" is consistent with the GPIF Implementation Manual approved by the Florida Public Service Commission ("FPSC" or "Commission"). Document No. 2 provides the company's Actual Unit Performance Data for the 2022 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Big Bend Unit 4, Polk Units 1 and 2, and Bayside Units 1 and 2 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2022 through December 2022 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 25. Based upon -1.160 Generating Performance Incentive Points ("GPIP"), the result is a penalty amount of $1,648,937 for the period.

Q. Please proceed with your review of the actual results for the January 2022 through December 2022 period.

A. On Document No. 1, page 3 of 25, the actual average common equity for the period is shown on line 14 as $4,232,927,728. This produces the maximum penalty or reward amount of $14,213,625 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the five units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission monthly. A summary of this data for the 12 months provides the basis for the GPIF.

C15-1237

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 25, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in Section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 25, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 4

On this unit, 1,056 planned outage hours were originally scheduled for 2022. Actual outage activities required 839.7 equivalent planned outage hours. Consequently, the actual equivalent availability of 60.3 percent is adjusted to 58.7 percent, as shown on Document No. 1, page 7 of 25.

Polk Unit No. 1

On this unit, 168 planned outage hours were originally scheduled for 2022. Actual outage activities required 161.5 equivalent planned outage hours. Consequently, the actual equivalent availability of 75 percent is adjusted to 74.9

percent, as shown on Document No. 1, page 8 of 25.

Polk Unit No. 2

On this unit, 696 planned outage hours were originally scheduled for 2022. Actual outage activities required 452.1 equivalent planned outage hours. Consequently, the actual equivalent availability of 91.4 percent is adjusted to 88.8 percent, as shown on Document No. 1, page 9 of 25.

Bayside Unit No. 1

On this unit, 1,776 planned outage hours were originally scheduled for 2022. Actual outage activities required 1,957.4 equivalent planned outage hours. Consequently, the actual equivalent availability of 74.8 percent is adjusted to 76.8 percent, as shown on Document No. 1, page 10 of 25.

Bayside Unit No. 2

On this unit, 336 planned outage hours were originally scheduled for 2022. Actual outage activities required 577.6 equivalent planned outage hours. Consequently, the actual equivalent availability of 90.8 percent is adjusted to 93.6 percent, as shown on Document No. 1, page 11 of 25.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 25, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 19 through 23 of 25. Page 4 of 25 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's five GPIF units are shown on Document No. 1, page 6 of 25. The adjustment was developed based on the guidelines of Section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 25, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 19 through 23 of 25. Page 4 of 25 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2022 through December 2022 period?

A. This is shown on Document No. 1, page 2 of 25. The weighting factors shown on page 4 of 25, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 25, column 4, are substituted within the equation found on page 25 of 25. The resulting value of -1.160 is in the GPIF table on page 2 of 25, and the penalty amount of $1,648,937 is calculated using linear interpolation.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $14,213,625 as shown on Document No. 1, page 3 of 25.

Q. Does this conclude your testimony?

A. Yes.

C15-1241

C15-1275

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS
JANUARY 2024 THROUGH DECEMBER 2024

TESTIMONY AND EXHIBIT
OF
ELENA B. VANCE

FILED: SEPTEMBER 5, 2023

C15-1275

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELENA B. VANCE

Q. Please state your name, address, occupation, and employer.

A. My name is Elena B. Vance. 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, Unit Commitment.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Chemical Engineering from the University of South Florida in 1999 and a Master of Business Administration with a concentration in Finance in 2003 from the University of Tampa. I have accumulated 25 years of experience in the electric industry, with experience in the areas of plant operations, unit commitment and economic dispatch, and resource planning. In my current role, I am responsible for long term study analysis and project economic analysis.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric’s methodology for determining the various factors required to compute the Generating Performance Incentive Factor (“GPIF”) as ordered by the Commission.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. EBV-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2024 period.

Q. Which generating units on Tampa Electric’s system are included in the determination of the GPIF?

A. Four natural gas combined cycle (“CC”) units are included. These are Polk Unit 2, Bayside Units 1 and 2, and Big Bend Unit 1 CC.

Q. Does your exhibit comply with the Commission’s approved

GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2024 through December 2024 represent the top 87.3 percent of the total forecasted system net generation for this period. It includes generation from the Big Bend Unit 1 CC, commissioned in December 2022. Tampa Electric included Big Bend Unit 1 CC as it is the most efficient unit and makes up 32 percent of our generation.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, a Polk Unit 2 outage was identified as an outlier and was removed.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please describe how Tampa Electric developed the various factors associated with GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2024 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2024 period, the projected EUOF for Bayside Unit 1 is 2.9 percent, the POF is 19.1 percent. Therefore, the target EAF for Bayside Unit 1 equals 78.0 percent or:

$$100\% - (2.9\% + 19.1\%) = 78.0\%$$

This is shown on Page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived using the following formula:

$$EAF_{MAX} = 1 - [0.80\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (2.9\%) + 0.95\ (19.1\%)] = 79.5\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.9\%) + 1.10\ (19.1\%)] = 74.9\%$$

The equivalent availability maximum and minimum for the other four units are computed in a similar manner.

C15-1281

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January 2024 through December 2024 are shown on page 15 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2024; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from September 13, 2024 to November 21, 2024. There are 1,680 planned outage hours scheduled for the 2024 period, with a total of 8,784 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 19.1 percent or:

$$\frac{1,680}{8,784} \times 100\% = 19.1\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Big Bend CC 1 has a POF of 1.4 percent, Bayside Unit 2 has a POF of 25.1 percent, and Polk Unit 2 has a POF of 6.7 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 2.9 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 13, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(53 + 204)}{8{,}784} \times 100\% = 2.9\%$$

Relative to Bayside Unit 1, the EUOF of 2.9 percent forms the basis of the equivalent availability target

C15-1283

development as shown on pages 4 and 5 of Document No. 1.

Big Bend CC 1

The projected EUOF for this unit is 27.1 percent. The unit will have one planned outage in 2024, and the POF is 1.4 percent. Therefore, the target equivalent availability for this unit is 71.5 percent.

Polk Unit 2

The projected EUOF for this unit is 5.1 percent. The unit will have two planned outages in 2024, and the POF is 6.7 percent. Therefore, the target equivalent availability for this unit is 88.3 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.9 percent. The unit will have one planned outage in 2024, and the POF is 19.1 percent. Therefore, the target equivalent availability for this unit is 78.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.6 percent. The unit will have two planned outages in 2024, and the POF is 25.1 percent. Therefore, the target equivalent availability for this unit is 73.2 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 72.3 percent is shown on page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 13 of Document No. 1. Except for the months of September and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of September and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the afore mentioned agreed upon GPIF methodology.

Q. How were the targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis for the target development. The historical data and the target values are analyzed to assure applicability to current

C15-1286

conditions of operation. This provides assurance that any period of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 22 through 25 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by the computer program for each unit. These curves are also

C15-1287

used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2024 period.

A. The heat rate target for Big Bend CC 1 is 6,513 Btu/Net kWh with a range of ±163 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,186 Btu/Net kWh with a range of ±324 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,401 Btu/Net kWh with a range of ±263 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,505 Btu/Net kWh with a range of ±102 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on pages 7 through 10 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission's requirements?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in determining the GPIF targets?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown in Document No. 1, pages 7 through 10. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $678,034,160 is shown on Document No. 1, page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

Column 4 totals $28,024,910 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 3.71 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 10 of Document

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No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 9 of Document No. 1, if Bayside Unit 1, operates at 7,137 average net operating heat rate, fuel savings would equal $1,039,100 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 10. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $28,024,910. The right-hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January 2024 through December 2024 is $4,972,332,352. This produces the maximum allowed jurisdictional incentive of $16,696,450 shown on line 21.

Q. Are there any constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $14,012,453.

Q. Please summarize your direct testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP).

$$\begin{aligned} GPIP = (&0.0059\ EAP_{PK2} &&+ 0.0225\ EAP_{BAY1} \\ &+ 0.0531\ EAP_{BAY2} &&+ 0.3499\ EAP_{BBCC1} \\ &+ 0.2708\ HRP_{PK2} &&+ 0.0371\ HRP_{BAY1} \\ &+ 0.1125\ HRP_{BAY2} &&+ 0.1482\ HRP_{BBCC1}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

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EAP = Equivalent Availability Points awarded/deducted for Polk Unit 2, Bayside Units 1 and 2, and Big Bend CC 1.

HRP = Average Net Heat Rate Points awarded/deducted for Polk Unit 2, Bayside Units 1 and 2, and Big Bend CC 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2024 through December 2024 period?

A. Yes. Document No. 2 entitled “Summary of GPIF Targets” provides the availability and heat rate targets for each unit.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(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 13th day of November, 2023.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024