BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
___________________________/

VOLUME 1

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PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN GARY F. CLARK COMMISSIONER ART GRAHAM COMMISSIONER ANDREW GILES FAY COMMISSIONER MIKE LA ROSA COMMISSIONER GABRIELLA PASSIDOMO
DATE:	Tuesday, November 2, 2021
TIME:	Commenced: 1:00 p.m. Concluded: 4:36 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	DEBRA R. KRICK Court Reporter and Notary Public in and for the State of Florida at Large

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA

APPEARANCES:

MATTHEW R. BERNIER and STEPHANIE CUELLO ESQUIRES, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, LLC (DEF).

MARIA J. MONCADA, WADE R. LITCHFIELD, RUSSELL A. BADDERS and DAVID M. LEE, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company (FPL) and Gulf Power Company (GULF).

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company (FPUC).

JAMES D. BEASLEY, J. JEFFRY WAHLEN and MALCOLM N. MEANS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company (TECO).

APPEARANCES (CONTINUED):

RICHARD GENTRY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL, PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE, MARY WESSLING and ANASTACIA PIRRELLO, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. 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, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT, JOHN T. LAVIA, III, and TIMOTHY H. PERRY, ESQUIRES, Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper, PA, 1300 Thomaswood Drive, Tallahassee, Florida 32308, on behalf of Florida Retail Federation (FRF).

JAMES W. BREW and LAURA WYNN BAKER, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs (PCS Phosphate).

APPEARANCES (CONTINUED):

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

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

P R O C E E D I N G S

CHAIRMAN CLARK: All right. The 07 docket is closed and we will OPC open the 01 docket. We have five minutes to finish the 01 docket and we can be out of here, right? We are on a roll, come on. I will give everybody a chance to change over.

The considerations that the first four dockets went so well that we should make the prehearing officer Chairman, anybody have any thoughts on that?

MS. KEATING: I second.

CHAIRMAN CLARK: Very smooth. I will acknowledge. Thank you, Commissioner Fay, for the outstanding work you did in the prehearing on the first four. We will reserve judgment and questions on the last one, right.

COMMISSIONER FAY: Time will tell.

CHAIRMAN CLARK: Time will tell. Great job on -- all the parties are to be commended for the work they did in making this a very efficient process. We've all had plenty of time to review the information and y'all did an outstanding job.

All right. Let's open the 01 docket. I didn't know who was in charge for us, Ms. Brownless, but it's you.

MS. BROWNLESS: Yes, sir.

CHAIRMAN CLARK: Any preliminary matters?

MS. BROWNLESS: There are proposed Type 2 stipulations for all of the FPUC, FPL/Gulf and TECO issues as stated in the proposed stipulations, Exhibit 65 on the Comprehensive Exhibit List.

With regard to DEF, there are Type 2 stipulations contained in Exhibit 65 for the following issues: Issues 1A, 1B, 6 through 11, 16 through 22, 23A, 23B, 27 through 36.

The DEF remaining issues to be heard today are issues 1C, which is the Crystal River Unit 42021 outage, and 1D, the Rate Mitigation Plan recovery over two years, which was the subject of Docket No. 20210158-EI that has been voted on immediately prior to this proceeding.

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

CHAIRMAN CLARK: All right. Let's address the prefiled testimony.

MS. BROWNLESS: Yes, sir. It is our understanding that the following witnesses have been excused and the prefiled testimonies of witness Dean, Lewter, McClay, Deaton, Yupp, Curtland, Rote, Chin, Anderson, Young, Cutshaw, Sizemore, Bokor, Smith and Heisey have been stipulated to by the parties.

We would ask that the prefiled testimony of these witnesses be moved into the record at this time.

CHAIRMAN CLARK: All right. The listed prefiled testimony is hereby moved into the record without objection? No objections.

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

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2020 - December 2020

DIRECT TESTIMONY OF
Gary P. Dean

April 1, 2021

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.

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 2020 through December 2020, 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 2020, 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, 2020, were filed with the Commission on January 19, 2021.

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. Per Order No. PSC-2021-0024-FOF-EI, the estimated 2020 fuel adjustment true-up amount was an over-recovery of $61.1 million. The actual over-recovery for 2020 was $21.6 million, resulting in a final fuel adjustment true-up under-recovery amount of $39.5 million. Exhibit No. __(GPD-1T).

Per Order No. PSC-2021-0024-FOF-EI, the estimated 2020 capacity cost recovery true-up amount was an under-recovery of $0.4 million. The actual amount for 2020 was an over-recovery of $6.1 million, resulting in a final capacity true-up over-recovery amount of $6.5 million. Exhibit No. __(GPD-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2020 for fuel cost recovery?

A. The actual ending balance as of December 31, 2020 for true-up purposes is an over-recovery of $21,579,587, as shown on Exhibit No. __(GPD-1T).

Q. How does this amount compare to DEF's estimated 2020 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount for the January 2020 - December 2020 period is an over-recovery of $21,579,587, which is $39,503,838 lower than the re-projected year end over-recovery balance of $61,083,424, 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 on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional net under-recovery of $39,503,838 shown on your Exhibit No. __(GPD-1T)?

A. The $39.5 million is driven primarily by $58.3 million higher fuel and purchased power costs, which resulted from $49.5 million of increased generation costs and $10.9 million increased purchased power costs, offset by $19.1 million higher sales and $2.9 million of coal inventory adjustments from semi-annual aerial surveys.

Q. Please explain the components shown on Exhibit No. __(GPD-1T), sheet 6 of 6, which helps to explain the $55.4 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(GPD-1T), sheet 6 of 6 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the <u>amount</u> (mWh's) of energy required; (2) changes in the <u>heat rate</u> of generated energy (BTU's per kWh); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $55.4 million unfavorable system variance is mainly attributable to increased natural gas generation and firm purchases, partially offset by lower Qualifying Facilities (cogeneration) costs.

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 $13.6 million system ($13.5 million retail) for amortization of the Florida Power Development, LLC qualifying facility regulatory asset partially offset by a credit of approximately $13.3 million system ($13.2 million retail) related to Citrus. These adjustments are shown on Exhibit No. ___(GPD-3T), in the footnotes to Line 6b on page 1 of 2, Schedule A2, and on line 3, page 1 of 2, Schedule A1.

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

A. Yes. DEF included an adjustment of $2.9 million to coal inventory attributable to the semi-annual aerial surveys conducted on May 8, 2020, and October 14, 2020, in accordance with Order No. PSC-1997-0359-FOF-EI, Docket No. 19970001-EI. This adjustment represents 2.28% of the total coal consumed at the Crystal River facility in 2020.

Q. Did DEF exceed the economy sales threshold in 2020?

A. No. DEF did not exceed the gain on economy sales threshold of $1.6 million in 2020. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2020 was $1.2 million. This entire amount was returned to customers through a reduction of total fuel and net purchased power expense recovered through the fuel clause.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2020 hearings been updated to incorporate actual data for all of year 2020?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2018 through 2020, as follows:

Year	Actual Gain
2018	$ 2,269,916
2019	$ 1,649,136
2020	$ 1,233,709
Three-Year Average	$1,717,587

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2020 for capacity cost recovery?

A. The actual ending balance as of December 31, 2020 for true-up purposes is an over-recovery of $6,070,083, as shown on Exhibit No. __(GPD-2T).

Q. How does this amount compare to the estimated 2020 ending balance included in the Company's Actual/Estimated Filing?

A. When the estimated 2020 under-recovery of $463,084 is compared to the $6,070,083 actual over-recovery, the final capacity true-up for the twelve-month period ended

December 2020 is an over-recovery of $6,533,167, 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 over-recovery of $6.5 million?

A. Exhibit No. __ (GPD-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $6.5 million over-recovery is primarily due to higher mWh sales.

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

A. Yes.

DUKE ENERGY FLORIDA, LLC
DOCKET NO. 20210001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2021 through December 2021

DIRECT TESTIMONY OF
GARY P. DEAN

July 27, 2021

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. 20210001-EI?

A. Yes. I provided direct testimony on April 1, 2021.

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 2021 through December 2021.

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 2021 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 2021 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2021 and estimated data from July through December 2021.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2021 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is a $169,535,467 under-recovery. The calculation begins with the actual under-recovered balance of $105,928,013 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2021. This balance plus the estimated July through

December 2021 monthly true-up calculations comprise the estimated $169,535,467 under-recovered balance at year-end. The increase in the currently projected 2021 under-recovery is primarily due to sizable increases in natural gas prices. DEF will continue to monitor natural gas prices and update its 2021 forecast and true-up balance in its 2022 projection filing. The projected December 2021 true-up balance includes interest which is estimated from July through December 2021 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.5% per month.

Q. DEF filed a Petition for a Mid-course Correction on July 9, 2021 in this Docket. Did DEF incorporate the proposed Mid-course Correction into the 2021 Actual/Estimated Filing?

A. Yes. The Total True-Up Balance of $169,535,467 shown on Exhibit GPD-2, Schedule E1-B, Line 13, Page 2 of 2, incorporates the recovery of the requested Midcourse Correction of $39,503,838, beginning in October 2021, as shown on Exhibit GPD-2, Schedule E1-B-1, Line 22. The $39,503,838 is the difference between the $61,083,424 and $21,579,587 on Exhibit GPD-1T, Sheet 1 of 6, in DEF's 2020 FAC True-Up filed on April 1, 2021 in the instant docket. If the Commission were to approve DEF's requested Midcourse adjustment to become effective with September 2021 billing, DEF will incorporate that impact into the Schedule E1-B to be filed with DEF's 2022 Projection Filing on September 3rd.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2021 compare with the same period forecast used in the Company's 2021 Projection Filing approved in Order No. PSC-2021-0024-FOF-EI?

A. Light oil decreased $0.74/mmbtu (-4%). Coal and natural gas increased $0.13/mmbtu (5%) and $0.62/mmbtu (15%), respectively.

Q. Have any adjustments been made to estimated fuel costs for the period January through December 2021?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $13.15 million (grossed up to approximately $13.20 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2021 through December 2021. This adjustment is included on Schedule E1-B, line A5, columns Jan Actual through Dec Estimated. DEF also included an adjustment of approximately $1.94 million to coal inventory attributable to the semi-annual aerial survey conducted on May 4, 2021 in accordance with Order No. PSC-1997-0359-FOF-EI in Docket No. 1997001-EI.

Q: Has DEF made an adjustment to remove the replacement power costs associated with the Spring 2021 unplanned outage at Crystal River Unit 4?

A: No. As detailed in the direct testimony of Joseph Simpson, DEF's actions were prudent and therefore no adjustment has been made.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2021?

A. No. DEF estimates the total gain on non-separated sales during 2021 will be $1,420,960 which does not exceed the three-year rolling average of $1,714,254.

CAPACITY COST RECOVERY

Q. What is DEF's 2021 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an $9,797,053 over-recovery. The estimated true-up calculation begins with the actual under-recovered balance of $16,368,856 as of June 2021. This balance plus the estimated July through December 2021 monthly true-up calculations comprise the estimated $9,797,053 over-recovered balance at year-end. The projected December 2021 true-up balance includes interest which is estimated from July through December 2021 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.5% per month.

Q. What are the primary drivers of the estimated year-end 2021 capacity over-recovery?

A. The $9.8 million over-recovery is primarily attributable to the $6.5 million 2020 Capacity Cost Recovery Clause net over-recovery filed on April 1, 2021 in the instant docket.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210001-EI

Fuel and Capacity Cost Recovery Factors
January 2022 through December 2022

DIRECT TESTIMONY OF
GARY P. DEAN

September 3, 2021

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. 20210001-EI?

A. Yes, I provided direct testimony on April 1, 2021 and July 27, 2021.

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 fuel and capacity cost recovery factors of Duke Energy Florida, LLC ("DEF" or the "Company") for the period of January 2022 through December 2022.

Q. Do you have an exhibit to your testimony?

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

FUEL COST RECOVERY CLAUSE

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

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.986 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.6375 ¢/kWh (adjusted for jurisdictional losses), an estimated prior period under-recovery true-up of 0.3136 ¢/kWh, a GPIF reward of 0.0068 ¢/kWh, and a Clean Energy Connection ("CEC") Program bill credit of 0.0282 ¢/kWh. Using this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated and 1% and 2% metering reduction factors are applied to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the CCR factors.

Schedule E1-D, lines 11-12 show the Company's proposed tiered rates of 3.681 ¢/kWh for the first 1,000 kWh and 4.751 ¢/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 1.281 On-Peak, 0.984 Off-Peak and 0.732 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. Did DEF incorporate its approved mid-course correction into the 2022 Projection Filing?

A. Yes. Per Order No. PSC-2021-0328-PCO-EI, dated August 30, 2021, the Commission approved a mid-course adjustment to DEF's fuel cost recovery factors effective with the first billing cycle of September 2021. The impact of the mid-course adjustment is incorporated into Exhibit GPD-3, Schedule E1-B, which derives the estimated 2021 fuel true-up under-recovery balance of $246,837,576.

Q. What is the total 2021 net true-up and how has DEF included in the fuel cost recovery factor for 2022?

A. The total net true-up under-recovery for 2021 is $246,837,576. Pursuant to the proposed 2022 Rate Mitigation Plan filed in the instant docket, DEF will recover the total 2021 net true-up over 2022 and 2023. As shown on Exhibit GPD-3, Schedule E1-A, line 5, DEF has included an under-recovery of $123,418,788.

Q. Why is there a difference between the estimated 2021 fuel true-up balance in DEF's Actual/Estimated Filing filed on Jul 27, 2021 and Schedule E1-B of Exhibit GPD-3?

A. The estimated 2021 true-up balance of $169,535,467 on Exhibit GPD-2, Schedule E1-B in the Actual/Estimated Filing includes actual amounts for January through June 2021, the impact of the mid-course correction beginning in October 2021, and forward curve prices as of June 14, 2021. The true-up balance of $246,837,576 on Exhibit GPD-3, Schedule E1-B includes actual amounts for January through July 2021, the impact of the mid-course correction beginning in September as approved by the Commission, and forward curve prices as of July 21, 2021. The forward curve prices were updated due to natural gas prices increasing significantly between filing dates.

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

A. The projected levelized residential fuel factor for 2022 of 3.986 ¢/kWh is an increase of 0.477 ¢/kWh or 13.6% from the 2021 revised levelized residential fuel factor of 3.509 ¢/kWh from DEF's mid-course filing.

Q. Please explain the increase in the 2022 fuel factor compared with the 2021 fuel factor.

A. The primary drivers of the increase in the 2022 fuel factor are an increase in jurisdictional fuel and purchased power expense of $153M and an increase in the prior period true-up of $185M.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2022?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ, dated May 8, 2018, DEF included a retail adjustment of $12.28M (grossed up to approximately $12.29M from retail to system) for the January through December 2022 amortization of the Florida Power Development, LLC, qualifying facility regulatory asset.

Per the Stipulation approved in Order No. PSC-2021-0059-S-EI, issued on January 26, 2021, DEF has included $11.1M in cost associated with the 2022 bill credits for the DEF CEC Program as shown on Exhibit GPD-3, Schedule E1, line 25. The CEC Program is a voluntary community solar program that allows participating customers to pay a subscription fee in exchange for receiving bill credits related to the solar generation produced by the CEC Program solar facilities. The bill credit reflects the estimated economic value of the program's solar power plants on DEF's system, which consists of reduced fuel, purchased power, and carbon emission costs. As approved in Order No. PSC-2021-0059-S-EI, the bill credit is recovered through DEF's fuel and purchased power cost recovery clause, partially offset by system savings resulting from the addition of the Program's solar power plants.

Q. Does the 2022 Projection Filing comply with the 2021 Settlement Agreement approved by the Commission in Order No. PSC-2021-0202-AS-EI?

A. Yes, all matters in the 2021 Settlement Agreement impacting the instant docket have been incorporated into this filing.

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 71% of all residential energy is consumed in the first tier and 29% 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 approved by the Commission in Order No. PSC-2021-0202-AS-EI.

Q. How was the inverted fuel rate calculated?

A. Exhibit GPD-3, Inverted Fuel Rates, shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.992 ¢/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 2022 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2022 is estimated to be $2,460,928 which is above the benchmark of $1,408,076. 100% of gains below the benchmark and 80% of gains above the benchmark will be 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, $210,570 of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2019 and 2020 of $1,649,136 and $1,223,709, respectively, and estimated gains for 2021 of $1,351,382 in accordance with Order No. PSC-2000-1744-PAA-EI.

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

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 from the Bureau of Economic and Business Research at the University of Florida, 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.

Q. Is the 2020 GPIF reward discussed in the March 16, 2021 direct testimony of Mary Ingle Lewter included in 2022 rates?

A. Yes. The GPIF reward of $2,657,279 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 2022

Schedule E12-A, page 1, includes estimated 2022 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.

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

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 2021

Schedule E12-B calculates the estimated true-up capacity over-recovered balance for the calendar year 2021 of $2,718,273. This schedule was also included in Exhibit GPD-2, Schedule E12-A to my direct testimony filed on July 27, 2021, as part of the 2021 Actual/Estimated Filing, with a $9,797,053 over-recovered year-end 2021 balance. The difference between the two schedules is due to the inclusion of July actual amounts and revised estimated capacity revenues in Schedule E12-B. The balance on Schedule E12-B is carried forward to Schedule E12-A, page 1, line 34 to be refunded to customers from January through December 2022.

<u>Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class</u>

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.

<u>Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class</u>

Schedule E12-E, page 1 calculates the May – December 2022 CCR factors for capacity costs for each rate class based on the 12CP and 25% annual average demand allocators and ISFSI costs from Schedule E12-D. The factors for the Residential, General Service Non-Demand, General Service (GS-2) and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. The factor for ISFSI in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor, respectively. The factors allocate capacity costs to rate classes in the same way as would be allocated if recovered in base rates. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI. Pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilo-watt (kW) rather than a kilo-watt-hour (kWh) basis. These changes are reflected on Schedule E12-E in columns 11 through 13.

Schedule E12-E, page 2 calculates the January – April 2022 CCR credit factors for the delayed in-service timing of Charlie Creek and Sandy Creek SoBRA III solar facilities in accordance with the 2022 Rate Mitigation Plan. The total amount of the credit is approximately $7.4M. The factors for each rate class are calculated in a similar manner as explained for Schedule E12-E, page 1 above.

Schedule E12-E, page 3 shows the net January – April 2022 CCR factors for the various rate classes in accordance with the 2022 Rate Mitigation Plan.

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 April 2020 through March 2021 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on July 31, 2021.

Q. What is the 2022 projected average retail CCR factor?

A. The 2022 average retail CCR factor for January through April 2022 is $0.970 ¢/kWh, made up of capacity of 1.018 ¢/kWh, ISFSI costs of 0.018 ¢/kWh and the Charlie Creek and Sandy Creek SoBRA credit of 0.066 ¢/kWh.

The 2022 average retail CCR factor for May through December 2022 is $1.036 ¢/kWh, made up of capacity of 1.018 ¢/kWh and ISFSI costs of 0.018 ¢/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 0.970 ¢/kWh for January through April 2022 is 0.263 ¢/kWh, or 21%, lower than the 2021 factor of 1.233 ¢/kWh. This decrease is primarily due to the end of the recovery of the Crystal River South net book value existing as of December 31, 2020 and reduction for the State of Florida Corporate Income Tax Change approved in Order No. PSC-2021-0024-FOF-EI, inclusion of the credit associated with Charlie Creek and Sandy Creek, and the difference in the in the prior period true-up balance.

The total projected average retail CCR rate of 1.036 ¢/kWh for May through December 2022 is 0.197 ¢/kWh, or 16%, lower than the 2021 factor of 1.233 ¢/kWh. This decrease is primarily due to the end of the recovery of the Crystal River South net book value existing as of December 31, 2020 and reduction for the State of Florida Corporate Income Tax Change approved in Order No. PSC-2021-0024-FOF-EI, and the difference in the in the prior period true-up balance.

Q. Does this conclude your testimony?

A. Yes

(Whereupon, prefiled direct testimony of Mary Ingle Lewter was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210001-EI

**GPIF Schedules for
January through December 2020**

DIRECT TESTIMONY OF MARY INGLE LEWTER

March 16, 2021

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. 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 Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC ("DEF" or "Company") are both wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as Manager of Fuels and Fleet Analytics.

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of 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 a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

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 2020. This calculation was based on a comparison of the actual performance of DEF's Six (6) 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. _______ (MIL-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 22-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 $2,657,279. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward/(penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

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

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 14 of my exhibit.

It should be noted that the "target" Generating Performance Incentive Points Tables on pages 9 through 14 and the Osprey Estimated Unit Performance Data on page 21 of DEF's 2020 GPIF Targets and Ranges (Exhibit No. ___(JBD-1P) filed in Docket 20190001-EI) contained errors related to: 1) the Weighting Factors for Equivalent Availability Factor (EAF) and Heat Rate for all units, 2) the average heat rate target and ranges and associated fuel savings/losses for Osprey combined cycle ("CC"), and 3) the monthly operating Btus, heat rate, and heat rate equation for Osprey CC. These errors, which were the result of a report assembly error, did not affect the GPIF targets approved in Commission Order PSC-2019-0484-FOF-EI.

DEF used the correct EAF and heat rate weighting factors, EAF and heat rate targets and maximum/minimum values, and associated maximum and minimum fuel savings/losses from pages 4 through 7 of "target" Exhibit No. ____(JBD-1P) in the calculation of the GPIF true-up results. As such, a comparison of the "target" and "true-up" Generating Performance Incentive Points Tables and Unit Performance Data tables from their respective exhibits will show deviations due to these errors, but the correct information is documented in "true-up" Exhibit No. ___(MIL-1T) sponsored as part of this testimony.

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 late November until late December 2020 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 2020 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 21 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 22 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 2020

FPSC DOCKET NO. 20210001-EI

GPIF TARGETS AND RANGES FOR
JANUARY THROUGH DECEMBER 2022

DIRECT TESTIMONY OF
MARY INGLE LEWTER

September 3, 2021

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. 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 Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC ("DEF" or "Company") are both wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. What are your responsibilities in that position?

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of 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 a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

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 2020, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2022. 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, 2021 testimony for the period January through December 2020?

A. DEF's calculated GPIF incentive amount for this period was a reward of $2,657,279. Please refer to my testimony filed March 16, 2021 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. _____ (MIL-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 2022 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Unit 4, Crystal River Unit 5, and Hines Units 1 through 4. Combined, these units account for 83% of the estimated total system net generation for the period, excluding Citrus CC units. Citrus CC Units 1 and 2 were not included for the upcoming projection period since they do not meet the inclusion of performance history to use in setting targets and ranges for these units.

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. ___ (MIL-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 41-76 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. ___ (MIL-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 26-40 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 2021?

A. The estimated maximum incentive for the Company is $17,648,481. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MIL-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Renae B. Deaton was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20210001-EI

APRIL 2, 2021

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Senior Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. I have over 30 years' experience in retail and wholesale regulatory affairs, rate design and cost of service. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. In 2016, I assumed my current position, where my duties include providing direction as to the appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery. Prior to joining FPL, I was employed at the South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years, where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Department and in generation plant operations. As part of the various roles I have held with FPL, I have testified before this Commission on rate design and cost of service in base rate and clause recovery dockets. I have also testified before the Federal Energy Regulatory Commission supporting rates for wholesale power sales agreements and Open Access Transmission Tariffs.

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 net true-up amounts for the period January 2020 through December 2020.

The 2020 net true-up for the FCR Clause is an under-recovery, including interest, of $72,891,803. On April 1, 2021, the Commission approved the inclusion of the 2020 FCR Clause net true-up under-recovery of $72,891,803 in FPL's 2021 midcourse correction FCR factors effective May 1, 2021.

The 2020 net true-up for the CCR Clause is an over-recovery, including interest, of $3,863,612. FPL is requesting Commission approval to include this 2020 CCR Clause true-up over-recovery in the calculation of the CCR factors for the period January 2022 through December 2022.

Finally, FPL is requesting Commission approval to include $3,681,030 in the calculation of the FCR factors for the period January 2022 through December 2022, which represents FPL's share of the 2020 Asset Optimization Incentive Mechanism gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

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

A. Yes, I have. Exhibit RBD-1 contains the FCR-related schedules and Exhibit RBD-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2020 through December 2020 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.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2020 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Calculation of Net True-Up," shows the calculation of the FCR net true-up for the period January 2020 through December 2020, an under-recovery of $72,891,803.

The summary of the FCR net true-up amount shows the actual end-of-period true-up under-recovery for the period January 2020 through December 2020 of $41,940,023 on line 1. The actual/estimated true-up over-recovery for the same period of $30,951,780 is shown on line 2. Line 1 less line 2 results in the final net true-up under-recovery for the period January 2020 through December 2020 of $72,891,803 shown on line 3. On April 1, 2021, the Commission approved the inclusion of the 2020 FCR Clause net true-up under-recovery of $72,891,803 in FPL's 2021 midcourse correction FCR factors effective May 1, 2021.

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

Q. Have you provided a schedule showing the calculation of the 2020 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-Up Amount," shows the calculation of the FCR actual true-up by month for January 2020 through December 2020.

Q. Have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2020?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 40 and 41) compares the actual end-of-period true-up under-recovery of $41,940,023 (column 4) to the actual/estimated end-of-period true-up over-recovery of $30,951,780 (column 5) resulting in a net under-recovery of $72,891,803 (column 6). Exhibit RBD-1, page 3 shows that the variance consists of an increase in jurisdictional fuel costs of $132.8 million (line 39) partially offset by an increase in revenues of $58.8 million (line 29).

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.231 billion for 2020 (Exhibit RBD-1, page 3, line 39, column 5). The actual jurisdictional total fuel costs and net power transactions for that period are $2.364 billion (Exhibit RBD-1, page 3, line 39, column 4). Jurisdictional total fuel costs and net power transactions are $132.8 million, or 6.0% higher than previously projected (Exhibit RBD-1, page 3, line 39, column 6) and jurisdictional fuel revenues net of revenue taxes for 2020 are $58.8 million, or 2.6% higher than previously projected (Exhibit RBD-1, page 3, line 29, column 6).

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

A. Below are the primary reasons for the $132.8 million variance.

<u>Fuel Cost of System Net Generation: $140.1 million increase (Exhibit RBD-1, page 3, line 1, column 6)</u>

The table below provides the detail of this variance.

Fuel Variance	2020 Final True-Up	2020 Actual Estimated True-Up	Difference
<u>Heavy Oil</u>			
Total Dollar	$6,864,055	$13,866,418	(7,002,363)
Units (Mmbtu)	595,280	1,271,430	(676,150)
$ per Unit	11.5308	10.9062	0.6246
Variance Due to Consumption			(7,796,551)
Variance Due to Cost			794,189
Total Variance			(7,002,363)

Fuel Variance	2020 Final True-Up	2020 Actual Estimated True-Up	Difference
Light Oil			
Total Dollar	$8,723,336	$14,804,568	(6,081,232)
Units (Mmbtu)	522,494	1,053,796	(531,301)
$ per Unit	16.6956	14.0488	2.6468
Variance Due to Consumption			(8,870,368)
Variance Due to Cost			2,789,136
Total Variance			(6,081,232)
Coal			
Total Dollar	$52,698,208	$50,709,323	1,988,886
Units (Mmbtu)	19,291,009	19,137,147	153,862
$ per Unit	2.7317	2.6498	0.0820
Variance Due to Consumption			420,312
Variance Due to Cost			1,568,573
Total Variance			1,988,886
Gas			
Total Dollar	$2,320,121,351	$2,169,620,295	150,501,056
Units (Mmbtu)	672,790,461	640,798,422	31,992,039
$ per Unit	3.4485	3.3858	0.0627
Variance Due to Consumption			110,324,710
Variance Due to Cost			40,176,346
Total Variance			150,501,056
Nuclear			
Total Dollar	$148,402,742	$147,687,701	715,041
Units (Mmbtu)	306,991,995	307,086,334	(94,339)
$ per Unit	0.4834	0.4809	0.0025
Variance Due to Consumption			(45,605)
Variance Due to Cost			760,646
Total Variance			715,041
Total			
Total Variance Due to Consumption			94,032,499
Total Variance Due to Cost			46,088,889
Total Variance			140,121,388

Note: The total fuel cost of system net generation for the 2020 final true-up does not tie to the amount provided on the 2020 final true-up E1b schedule due to various adjustments that impacted A1/A2 and A3/A4 schedules in 2020. These adjustments were included on the impacted A-Schedules in the months in which they occurred.

<u>Fuel Cost of Stratified Sales: $5.3 million decrease (Exhibit RBD-1, page 3, line 2, column 6)</u>

The variance for the fuel cost of stratified sales is primarily attributable to lower than projected revenues from stratified contracts.

<u>Fuel Cost of Power Sold: $4.1 million decrease (Exhibit RBD-1, page 3, line 4, column 6)</u>

The variance of $4,124,219 for the Fuel Cost of Power Sold was primarily attributable to lower than projected fuel costs for economy power sales. The average unit fuel cost on economy power sales was $1.33/MWh lower than projected, resulting in a cost variance of $3,747,982. In addition, FPL sold 22,011 MWh less of economy power, resulting in a volume variance of $366,304. The combination lower fuel costs attributable to economy power sales and lower than projected economy power sales resulted in a net variance for economy power sales of $4,114,286. The remaining variance of $9,933 was primarily attributable to lower than projected fuel costs on St. Lucie Plant Reliability Exchange sales that were partially offset by higher than projected St. Lucie Plant Reliability Exchange sales.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.072 million decrease (Exhibit RBD-1, page 3, line 13, column 6)</u>

The variance for variable power plant O&M avoided due to economy purchases was attributable to lower than projected economy power purchases.

Fuel Cost of Purchased Power: $1.0 million increase (Exhibit RBD-1, page 3, line 6, column 6)

The variance for the Fuel Cost of Purchased Power was primarily attributable to higher than projected firm purchases and higher than projected costs associated with these firm purchases. In total, FPL purchased 29,850 MWh more than projected, resulting in a volume variance of $546,223. The unit cost of these firm purchases was $0.31/MWh higher than projected, resulting in a cost variance of $468,464. The combination of higher firm purchases and higher costs for firm purchases resulted in a net variance of $1,014,687.

Energy Cost of Economy Purchases: $0.8 million decrease (Exhibit RBD-1, page 3, line 8, column 6)

The variance for the Energy Cost of Economy Purchases was attributable to lower than projected economy purchases and higher than projected costs for economy power. FPL purchased 111,510 MWh less of economy power, resulting in a volume variance of ($3,175,708). The average cost of economy power purchases was $9.18/MWh higher than projected, resulting in a cost variance of $2,370,851. The combination of lower economy power purchases coupled with higher costs for economy power purchases resulted in a net variance of ($804,857).

Gains from Off-System Sales: $0.7 million increase (Exhibit RBD-1, page 3, line 5, column 6)

The variance for Gains from Off-System Sales was primarily attributable to higher than projected margins on economy power sales. Margins on economy power sales averaged $0.30/MWh higher than projected, resulting in a revenue variance of $850,337. FPL sold 22,011 MWh less of economy power, resulting in a volume variance of ($193,429). The combination of higher margins on economy power sales and lower economy power sales resulted in a total variance for Gains from Off-System Sales of $656,908.

Energy Payments to Qualifying Facilities: $0.6 million decrease (Exhibit RBD-1, page 3, line 7, column 6)

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 6,482 MWh less than projected, resulting in a volume variance of ($87,404). The average unit fuel cost for these purchases was $1.50/MWh lower than projected, resulting in a cost variance of ($512,155). The combination of lower purchases and lower fuel costs for Qualifying Facilities resulted in a net variance of ($599,559).

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

A. As shown on Exhibit RBD-1, page 3, line 29, actual 2020 jurisdictional FCR revenues, net of revenue taxes, are approximately $58.8 million higher than the actual/estimated projection. This is primarily due to jurisdictional sales that are 1,995,799,848 kWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $3,681,030 as its 60% share of 2020 Asset Optimization Incentive Mechanism

gains over the $40 million threshold. 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 2020 Asset Optimization Incentive Mechanism gains through the 2022 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2022 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2022 through December 2022 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2020 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2020 through December 2020, an over-recovery of $3,863,612, which FPL is requesting to be included in the calculation of the CCR factors for the January 2022 through December 2022 period.

The actual end-of-period over-recovery for the period January 2020 through December 2020 of $11,252,066 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $7,388,454 shown on line 2 that was approved by the Commission in Order No. PSC-2020-0439-FOF-EI, results in the net true-up over-recovery for the period January 2020 through December 2020 of

$3,863,612 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2020 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, titled "Calculation of Final True-Up" shows the calculation of the CCR end-of-period true-up for the period January 2020 through December 2020 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 2020?

A. Yes. Exhibit RBD-2, pages 5 and 6, titled "Calculation of Variances," shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2020 through December 2020.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 5, line 13, column 5, the variance related to total system capacity costs is a decrease of $2.3 million or 0.9%. Below are the primary reasons for the decrease.

<u>Incremental Plant Security Costs – O&M: $2.5 million decrease (Exhibit RBD-2,</u>

page 5, line 9, column 5)

The variance for incremental plant security is primarily attributable to the implementation of cost savings initiatives at the St. Lucie and Turkey Point plants resulting in lower security force costs and less cyber security maintenance than originally planned.

Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $0.7 million decrease (Exhibit RBD-2, page 5, line 5, column 5)

Incremental Nuclear NRC Compliance Costs were lower by $712,506 due to the following: (1) Turkey Point flooding modifications to seal manholes at the site began later in the year than originally projected. The work is expected to be completed by the second quarter of 2021 and (2) the annual Regional Response Center fees were lower than originally budgeted.

Transmission of Electricity by Others: $0.5 million decrease (Exhibit RBD-2, page 5, line 7, column 5)

The variance is due primarily to the reimbursement of counterparty transmission expense associated with a wholesale power sale in December of approximately ($409,000). In addition, lower costs than originally projected for the purchase of third-party transmission utilized to facilitate wholesale power sales during the period resulted in an approximately ($116,000) variance. The combination of lower overall third-party transmission costs and the reimbursement of costs for a December transaction resulted in a net variance of (525,267).

<u>Transmission Revenues from Capacity Sales: $1.4 million decrease (Exhibit RBD-2, page 5, line 8, column 5)</u>

Approximately ($235,000) of the total variance is attributable to higher revenues from capacity premiums associated with power capacity sales. Lower than originally projected transmission revenues from economy sales resulted in a variance of approximately $1,672,000. Higher revenues from capacity premiums, offset by lower transmission revenues from economy sales resulted in a total variance of $1,436,362.

Q. Please describe the variance in 2020 CCR revenues.

A. As shown on page 6, line 33, column 5, actual 2020 CCR revenues (net of revenue taxes), are $1.7 million higher than projected in the actual/estimated true-up filing. This is primarily due to 1,995,799,848 kWh higher than projected jurisdictional sales.

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 RBD-2 as pages 17 and 18. Page 17 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2020 through December 2020. Page 18 provides the short term capacity payments for the period January 2020 through December 2020.

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 FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2020 through December 2020 are included on pages 19 and 20 of Exhibit RBD-2.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20210001-EI

JULY 27, 2021

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Senior Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs 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 Commission review and approval the calculation of the actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2021 through December 2021.

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 RBD-3 and RBD-4. Exhibit RBD-3 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2021 through December 2021. FCR Schedules

A1 through A9 provide actual data for the period January 2021 through June 2021. 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 RBD-3 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2021 through December 2021.

Exhibit RBD-4 contains the CCR schedules, which provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2021 through December 2021.

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 2021 through June 2021 and revised estimates for July 2021 through December 2021 to the data reflected in FPL's 2021 FCR midcourse correction approved by

Order No. PSC-2021-0142-PCO-EI, issued on April 21, 2021.

The CCR actual/estimated true-up calculation compares actuals for January 2021 through June 2021 and revised estimates for July 2021 through December 2021 to the data reflected in FPL's original projection for the period January 2021 through December 2021 filed on September 3, 2020.

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 2021, which reflects the interest rate from the last business day in June 2021.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2021 actual/estimated true-up by month?

A. Yes. Exhibit RBD-3, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2021 through December 2021.

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 RBD-3, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2021 end-of-period net true-up amount to be carried forward to the 2022 FCR factors is an under-recovery of $105,692,340 (page 1, line 44, column 15), which is based on the actual/estimated true-up under-recovery, including interest, of $105,692,340 (Exhibit RBD-3, page 1, lines 38 plus 39, column 15) for the period January 2021 through December 2021. The 2020 final net true-up under-recovery of $72,891,803 filed on April 2, 2021, has been included in FPL's 2021 FCR midcourse correction approved in Order No. PSC-2021-0142-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 2021?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2021 actual/estimated period data by component to the same components from the midcourse correction filing.

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

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $2.790 billion for 2021 (Exhibit RBD-3, page 2, line 44, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.929 billion for that period (Exhibit RBD-3, page 2, line 44, 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 $139.5 million, or 5.0% higher than the midcourse correction estimates (Exhibit RBD-3, page 2, line 44, column 5), and jurisdictional fuel revenues applicable to the period, net of revenue taxes are projected to be $33.9 million, or 1.2% higher than the midcourse correction estimates (Exhibit RBD-3, page 2, line 40, 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 of $105.6 million (Exhibit RBD-3, page 2, line 45, column 5).

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

A. Below are the primary reasons for the $139.5 million variance in jurisdictional total fuel costs.

Fuel Cost of System Net Generation - $132.7 million increase (Exhibit RBD-3, page 2, line 2, column 5)

The table below provides the detail of this variance.

Fuel Variance	2021 Actual/Estimated	2021 Midcourse Correction	Difference
Heavy Oil			
Total Dollar	$12,525,920	$4,720,381	$7,805,539
Units (MMBTU)	1,071,548	413,896	657,652
$ per Unit	11.6896	11.4048	0.2848
Variance Due to Consumption			7,687,658
Variance Due to Cost			117,881
Total Variance			7,805,539
Light Oil			
Total Dollar	$10,612,881	$2,009,737	$8,603,144
Units (MMBTU)	693,115	133,048	560,067
$ per Unit	15.3119	15.1053	0.2065
Variance Due to Consumption			8,575,664
Variance Due to Cost			27,480
Total Variance			8,603,144
Coal			
Total Dollar	$73,566,315	$70,983,848	$2,582,466
Units (MMBTU)	27,359,653	27,597,038	(237,385)
$ per Unit	2.6889	2.5722	0.1167
Variance Due to Consumption			(638,295)
Variance Due to Cost			3,220,762
Total Variance			2,582,466
Gas			
Total Dollar	$2,864,561,626	$2,753,019,048	$111,542,578
Units (MMBTU)	611,124,075	590,197,256	20,926,819
$ per Unit	4.6874	4.6646	0.0228
Variance Due to Consumption			98,091,640
Variance Due to Cost			13,450,938
Total Variance			111,542,578
Nuclear			
Total Dollar	$149,526,153	$147,364,272	$2,161,881
Units (MMBTU)	302,285,375	297,449,116	4,836,258
$ per Unit	0.4947	0.4954	(0.0008)
Variance Due to Consumption			2,392,266
Variance Due to Cost			(230,385)
Total Variance			2,161,881
Total			

Fuel Variance	2021 Actual/Estimated	2021 Midcourse Correction	Difference
Total Dollar	$3,110,792,894	$2,978,097,286	$132,695,608
Units (MMBTU)	942,533,766	915,790,355	26,743,411
$ per Unit	3.3005	3.2519	0.0485
Variance Due to Consumption			88,265,498
Variance Due to Cost			44,430,110
Total Variance			132,695,608

<u>Energy Cost of Economy Purchases - $10.6 million increase (Exhibit RBD-3, page 2, line 9, column 5)</u>

The variance for the Energy Cost of Economy Purchases is attributable to higher than projected economy power purchases and higher than projected costs for economy purchases. FPL now projects to purchase 149,932 MWh more of economy power, resulting in a volume variance of $4,266,876. The average cost of economy purchases is now projected to be $12.59/MWh higher than originally projected, resulting in a cost variance of $6,290,406. The combination of higher economy power purchases coupled with higher costs for economy power purchases results in a total variance of $10,557,282.

<u>Fuel Cost of Stratified Sales - $4.9 million decrease (Exhibit RBD-3, page 2, line 4, column 5)</u>

The variance for the fuel cost of stratified sales is primarily attributable to lower than originally projected stratified sales.

<u>Fuel Cost of Purchased Power - $1.7 million increase (Exhibit RBD-3, page 2, line 7, column 5)</u>

The variance of $1,721,720 for the Fuel Cost of Purchased Power is primarily attributable to higher than projected purchases from the Solid Waste Authority ("SWA"). FPL now projects to purchase 111,645 MWh more from SWA, resulting in a volume variance of $3,510,970. The volume variance is partially offset by lower than projected fuel costs for SWA purchases. FPL now projects that the average unit fuel cost for SWA purchases will be $2.18/MWh lower than originally projected, resulting in a cost variance of ($2,214,813). The combination of higher SWA purchases and lower fuel costs for SWA purchases results in a net variance for SWA purchases of $1,296,157. The remaining variance of $425,563 is primarily attributable to higher than projected fuel costs for St. Lucie Plant Reliability Exchange purchases.

<u>Fuel Cost of Power Sold - $1.4 million decrease (Exhibit RBD-3, page 2, line 5, column 5)</u>

The variance of $1,365,588 for the Fuel Cost of Power Sold is attributable to lower than projected economy power sales and lower than projected fuel costs on economy power sales. FPL now projects to sell 23,688 MWh less of economy power, resulting in a volume variance of $529,151. The average unit fuel cost on economy power sales is now projected to be $0.35/MWh lower than originally projected, resulting in a cost variance of $795,472. The combination of lower economy power sales and lower fuel costs attributable to economy power sales results in a total variance for economy power sales of $1,324,623. The remaining variance of $40,965 is attributable to lower than projected St. Lucie Plant

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

<u>Gains from Off-System Sales - $2.2 million increase (Exhibit RBD-3, page 2, line 6, column 5)</u>

The variance for Gains from Off-System Sales is primarily attributable to higher than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $1.09/MWh higher than originally projected, resulting in a cost variance of $2,447,900. The cost variance is partially offset by lower than projected economy power sales. FPL now projects to sell 23,688 MWh less of economy power, resulting in a volume variance of $204,811. The combination of higher margins on economy power sales and lower economy power sales results in a net variance for Gains from Off-System Sales of $2,243,089.

<u>Energy Payments to Qualifying Facilities - $0.344 million decrease (Exhibit RBD-3, page 2, line 8, column 5)</u>

The variance of ($344,315) for Energy Payments to Qualifying Facilities is primarily attributable to lower than projected fuel costs from As-Available Co-Gen facilities. FPL now projects that fuel costs from As-Available Co-Gen facilities will be $1.35/MWh lower than originally projected.

<u>Variable Power Plant O&M Avoided due to Economy Purchases - $0.097 million increase (Exhibit RBD-3, page 2, line 15, column 6)</u>

The variance of $97,456 is attributable to higher than originally projected economy power purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2021 actual/estimated true-up by month?

A. Yes. Exhibit RBD-4, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2021 through December 2021.

Q. Please explain the calculation of the CCR 2021 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-4, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2021 through June 2021 reflects actual data, while the data for July 2021 through December 2021 is based on updated estimates) compared to the original projection filing for the January 2021 through December 2021 period. The CCR revenues (net of revenue taxes) are projected to be $0.687 million (Exhibit RBD-4, page 5, line 28, column 5) lower than FPL's original projection filing. Jurisdictional total capacity costs are estimated to be $5.592 million lower than the original projection filing (Exhibit RBD-4, page 5, line 23, column 5). The $5.592 million over-recovery due to lower jurisdictional capacity costs and the $0.687 million decrease in revenues, results in the 2021 actual/estimated true-up over-recovery amount of $4,916,997 including interest

(Exhibit RBD-4, page 5, lines 30 plus 31, column 5).

As shown on Exhibit RBD-4, page 3, the 2021 end-of period net true up amount to be carried forward to the 2022 CCR factors is an over-recovery of $8,780,610 (line 14, column 15). This $8,780,610 net over-recovery is comprised of the 2020 final net true-up over-recovery of $3,863,612 (line 11, column 15), and the actual/estimated true-up over-recovery, including interest, of $4,916,997 for the period January 2021 through December 2021 (lines 8 plus 9, 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 RBD-4, page 5, line 1, column 5, total system capacity costs are estimated to be $5,840,976 or 2.4% lower than projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is also a 2.4% decrease from the original projection (page 5, line 23, column 6). Below are the primary reasons for the estimated $5.8 million decrease in total system capacity costs.

<u>Transmission Revenues from Capacity Sales - $1.6 million increase (Exhibit RBD-4, page 4, line 5, column 5)</u>

Approximately ($2,015,000) of the total variance is attributable to higher revenues from capacity premiums associated with power capacity sales. Lower than originally projected transmission revenues from economy sales resulted in a variance of approximately $394,000. Higher revenues from capacity premiums, offset by lower transmission revenues from economy sales resulted in a total variance of ($1,621,454).

<u>Transmission of Electricity by Others - $0.538 million increase (Exhibit RBD-4, page 4, line 4, column 5)</u>

The variance is primarily due to a sign reversal for the original projection amount of ($375,581), which should have been reflected as $375,581, offset by lower than originally projected costs of $162,610 for the purchase of third-party transmission utilized to facilitate wholesale power sales during the period.

<u>Incremental Nuclear NRC Compliance Costs – Capital - $0.431 million decrease (Exhibit RBD-4, page 4, line 9, column 5)</u>

The variance for incremental nuclear NRC compliance capital costs is primarily attributable to $3 million in salvage recorded in late 2020, which reduced return requirements in 2021.

<u>Incremental Plant Security Costs – Capital - $0.474 million decrease (Exhibit RBD-4, page 4, line 7, column 5)</u>

The variance for incremental plant security capital costs is primarily attributable to the deferral of Turkey Point Force-On-Force plant modifications from 2020, which lowered the beginning balance in the 2021 original projections, thereby reducing

2021 revenue requirements.

<u>Incremental Plant Security Costs - O&M - $2.3 million decrease (Exhibit RBD-4, page 4, line 6, column 5)</u>

The variance for incremental plant security O&M costs is primarily attributable to a shift in security officer support charges to the capital projects which lowered the amount charged to the Capacity Clause.

<u>Incremental Nuclear NRC Compliance Costs - O&M - $0.208 million decrease (Exhibit RBD-4, page 4, line 8, column 5)</u>

The variance for incremental nuclear NRC compliance O&M costs is primarily attributable to lower than projected annual Regional Response Center fees.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20210001-EI

SEPTEMBER 3, 2021

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Senior Director, Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs 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 in this docket is to present for Commission review and approval the calculations of FPL's Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause factors for the period January 2022 through December 2022, which are based on unified rates for FPL and Gulf Power ("Gulf").

FPL and Gulf will be operationally and functionally integrated in 2022. On March 12, 2021, FPL filed with the Commission a Petition for Base Rate Increase and Unification in Docket No. 20210015 ("2021 Rate Case") that requested, among other things, authority to consolidate and unify the FPL and Gulf base rates effective January 1, 2022. On August 10, 2021, FPL, the Office of Public Counsel, Florida Retail Federation, Florida Industrial Power Users Group and Southern Alliance for Clean Energy filed a Joint Motion for Approval of Settlement Agreement ("Settlement Agreement") to resolve all matters pending in the 2021 Rate Case. Vote Solar, the CLEO Institute and the Federal Executive Agencies subsequently also signed on to the Settlement Agreement. The Settlement Agreement provides that, in addition to base rate unification, clause rates will also be unified effective January 1, 2022. Therefore, FPL is requesting recovery of unified 2022 FCR and CCR factors that have been calculated based on the consolidation of FPL and Gulf fuel and power cost projections, contingent upon the Commission's approval of the Settlement Agreement. Because FPL and Gulf remain separate ratemaking entities through 2021, the 2022 FCR and CCR factors include the separate FPL and Gulf standalone prior and current period true-up amounts.

My testimony addresses the following subjects:

- Revised 2021 FCR actual/estimated true-up amounts for FPL and Gulf, which are incorporated into the calculation of the unified 2022 FCR factors;
- Unified FCR clause factors for the period January 2022 through December 2022;
- The calculation of the jurisdictional amount of FPLs portion of the 2020 asset optimization gains to be recovered through the 2022 FCR factors;

- Unified CCR clause factors for the period January 2022 through December 2022 including refunds for the true-up of the 2019 and 2020 SoBRAs and the Okeechobee Clean Energy Center limited scope adjustment ("OCEC LSA");
- Proposed cogeneration as-available energy ("COG-1") tariff sheets, which reflect updated variable operation and maintenance expense and loss factors for the consolidated company; and
- Items from the Settlement Agreement that impact the 2022 FCR and CCR factors.

Finally, I have reviewed the testimonies and exhibits that were filed by Mr. Richard L. Hume on behalf of Gulf in this docket on April 2, 2021 (2020 Final True-Up) and July 27, 2021 (2021 Actual/Estimated True-Up). Those testimonies and exhibits are accurate to the best of my knowledge and belief, and with the exception of the portions relating specifically to Mr. Hume's background and experience, I adopt them as my own.

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 RBD-5 (Appendix II)

- Schedules E1, E1-A, E1-C, E1-D, E1-E, E2, Calculation of Jurisdictional Asset Optimization Gains – Company Portion, RS-1 Inverted Rate Calculation, which provide the calculation of unified FCR factors for January 2022 through December 2022, and Schedules E10 and H1;

- Pages 9 through 13, which provide the consolidated 2022 Projected Energy Losses by Rate Class;
- Pages 140 through 143, which provide updated COG-1 tariff sheets;

Exhibit RBD-6 (Appendices III-A and III-B)

- Revised E1b schedules for FPL and Gulf, which provide the calculation of revised 2021 Actual/Estimated true-up amounts;

Exhibit RBD-7 (Appendix IV)

- Pages 1 through 4 provide the calculation of unified 2022 CCR factors including refunds for the 2019 and 2020 SoBRA true-ups and the OCEC LSA true-up;
- Pages 5 through 9 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 10 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 11 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory asset related to the Indiantown Transaction;
- Page 13 provides the calculation of the amortization and return on the regulatory asset related to the recording of safety-related expenses and

incremental bad debt incurred due to COVID-19 by Gulf as approved in Order No. PSC-2021-0267-S-PU in Docket No. 20200194-PU ("COVID-19 Regulatory Asset");

- Page 14 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 2022 through December 2022; and
- Pages 17 through 30 provide the calculations of unified separation factors.

FUEL COST RECOVERY CLAUSE

Q. Has the Company revised FPL's and Gulf's 2021 FCR actual/estimated true-up amounts that were filed on July 27, 2021?

A. Yes. The 2021 FCR actual/estimated true-up amounts for FPL and Gulf have been revised to include July 2021 actual data and to update the cost of system net generation for August through December 2021 due to increases in natural gas prices, as explained in the testimony of FPL witness Gerard J. Yupp. The revised 2021 actual/estimated true-up also includes updated FPL SolarTogether subscription credit amounts that reflect July 2021 actual data and updated estimates for August through December 2021.

FPL's 2021 FCR actual/estimated true-up amount has been revised to an under-recovery of $288,304,271 (see Exhibit RBD-6, Appendix III-A). FPL's 2020 final true-up under-recovery of $72,891,803 that was filed on April 2, 2021 was included and is being recovered in the 2021 midcourse correction factors approved in Order PSC-2021-0142-PCO-EI issued on April 21, 2021. FPL's revised 2021 actual/estimated true-up under-recovery of $288,304,271 is being included in the calculation of unified 2022 FCR factors.

Gulf's 2021 FCR actual/estimated net true-up amount has been revised to an under-recovery of $65,641,361 (see Exhibit RBD-6, Appendix III-B). This $65,641,361 under-recovery includes Gulf's 2020 final true-up over-recovery of $6,085,680 that was filed on April 2, 2021.

The total net true-up amount to be included in the 2022 FCR factors is an under-recovery of $353,945,632, as shown on line 33 of Schedule E1.

Q. What adjustments are included in the calculation of the unified 2022 FCR factors shown on Schedule E1 included in Appendix II?

A. The unified 2022 FCR factors include the following adjustments: (1) a total net true-up, which reflects the sum of FPL's and Gulf's revised 2021 actual/estimated net true-up amounts, (2) a consolidated Generating Performance Incentive Factor ("GPIF") which reflects the sum of FPL's and Gulf's GPIF results for 2020, (3) the jurisdictional amount associated with FPL's share of the 2020 asset optimization gains and (4) the cost associated with the projected 2022 Subscription Credit for the FPL SolarTogether Program.

As discussed above, the total net true-up amount to be included in the 2022 FCR factors is an under-recovery of $353,945,632. The total net $353,945,632 under-recovery, divided by the projected retail sales of 122,096,501 MWh for January 2022 through December 2022, results in an increase of 0.2899 cents per kWh.

The FPL and Gulf GPIF testimonies of witness Charles R. Rote, filed on March 16, 2021, propose a reward of $6,390,846 for FPL and a penalty of $1,642,650 for Gulf for the period ending December 2020. The total of these amounts, which represents a net reward of $4,748,196, is reflected on line 37 of Schedule E1. This $4,748,196 reward, divided by the projected retail sales of 122,096,501 MWh for January 2022 through December 2022, results in an increase of 0.0039 cents per kWh.

FPL is including $3,503,210 for the jurisdictional amount associated with its share of 2020 asset optimization gains in the calculation of its unified 2022 FCR factors, as shown on line 38 of Schedule E1. As presented and explained in the direct testimony and exhibits of witness Yupp filed on April 2, 2021 in this docket, FPL's activities under the asset optimization program in 2020 delivered $46,135,050 in total gains. Of these total gains, FPL is allowed to retain $3,681,030 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013 and Order No. PSC-16-0560-AS-EI dated December 15, 2016. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $3,503,210, in each month's Schedule A2 for the period January 2022 through December 2022 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2020 asset optimization gains is shown on page 4 of Appendix II. This $3,503,210, divided by the projected retail sales of 122,096,501 MWh for January 2022 through December 2022, results in an increase of 0.0029 cents per kWh.

FPL has included $113,512,426 associated with the projected 2022 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 included in the Settlement Agreement. This $113,512,426, divided by the projected retail sales of 122,096,501 MWh for January 2022 through December 2022, results in an increase of 0.0930 cents per kWh.

Schedule E2 provides the monthly unified FCR factors as well as the unified levelized FCR factor for 2022. Schedule E-1E provides the calculation of the unified 2022 FCR factors by rate group for each period.

Q. Please explain the fuel cost of stratified sales amount reflected on line 2 of Schedule E1.

A. FPL has included a credit of $54,128,274 associated with consolidated stratified wholesale power sales contracts in effect in 2022. 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.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested consolidated CCR costs for the projected period of January 2022 through December 2022?

A. Yes. Pages 1 and 2 of Appendix IV provides this summary. Total recoverable capacity costs for the period January 2022 through December 2022 on a consolidated basis are $275,309,761 (page 2, line 37). This includes $291,876,857 of 2022 projected consolidated jurisdictional capacity costs (page 2, line 28), the combined net true-up over-recovery for 2020 and 2021 of $11,306,429 (page 2, line 31 plus line 32), the true-up refund for the OCEC LSA of $5,055,917 (page 2, line 33) and the true-up refund associated with the 2019 and 2020 SoBRAs of $204,750 (page 2, line 34).

Q. **What adjustments are included in the calculation of the combined 2022 CCR factors included in Appendix IV?**

A. The total net true-up to be included in the unified 2022 CCR factors is an over-recovery of $11,306,429, as shown on page 2, line 31 plus line 32. This over-recovery is comprised of FPL’s 2020 final net true-up over-recovery of $3,863,612 filed on April 2, 2021, FPL’s 2021 actual/estimated true-up over-recovery of $4,916,997 filed on August 27, 2021, Gulf’s 2020 final net true-up over-recovery of $838,127 filed on April 2, 2021, and Gulf's 2021 actual/estimated true-up over-recovery of $1,687,693 filed on August 27, 2021.

Pursuant to the 2016 Base Rate Settlement Agreement, a true-up of the OCEC LSA and SoBRA is required if actual capital costs are lower than projected. As such, FPL has included a credit of $5.1 million, including interest (Appendix IV, page 2, line 33) for the OCEC LSA true-up and a credit of $0.205 million, including interest, (Appendix IV, page 2, line 34) for the true-up of the 2019 and 2020 SoBRAs as a reduction in the calculation of unified 2022 CCR factors. These true-up amounts were calculated pursuant to Order No. PSC-16-0560-AS-EI, as discussed in the declarations of Jason Chin and Edward J. Anderson.

Q. Do the unified 2022 CCR factors include costs associated with the COVID-19 Regulatory Asset?

A. Yes. Pursuant to Order No. PSC-2021-0267-S-PU in Docket No. 20200194-PU, Gulf established a regulatory asset of $13.2 million for recovery of safety-related expenses and incremental bad debt incurred due to COVID-19 through June 30, 2021. The COVID-19 Regulatory Asset is to be amortized over a three-year period and recovered through the fuel and purchased power cost recovery clause mechanism commencing January 2022 (see page 13 of Exhibit RBD-7, Appendix IV).

Q. Please describe the Weighted Average Cost of Capital ("WACC") that is used in the calculation of the return on the 2022 capital investments included for recovery.

A. FPL calculated and applied a projected 2022 WACC in accordance with the methodology established in Commission Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU, issued on May 20, 2020 ("2020 WACC Order"). This projected WACC is based on the 2022 Test Year Rate Case forecast and an ROE of 10.60%, as provided in the Settlement Agreement. The WACC is used to calculate the rate of return applied to the 2022 CCR capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 14 of Exhibit RBD-7 in Appendix IV.

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

A. Yes. Page 3 of Appendix IV 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. What are the effective dates that FPL is requesting for the new unified FCR and CCR factors for 2022?

A. FPL is requesting that unified FCR factors and CCR factors for the period January 2022 through December 2022 become effective starting with meter readings made on or after January 1, 2022. These factors should remain in effect until modified by this Commission.

<u>Proposed Settlement Agreement</u>

Q. Have you made any adjustments to the 2022 FCR and CCR factors to reflect the proposed Settlement Agreement?

A. Yes. In addition to the filing of unified FCR and CCR factors that take effect January 1, 2022, subject to the Commission's approval, the calculation of the 2022 FCR and CCR factors include the following adjustments proposed in the Settlement Agreement:

- Regulatory Assessment Fee ("RAF") - Remove the RAF from the calculation of the FCR and CCR factors.
- Return on Equity ("ROE") – The WACC reflects an ROE of 10.60% used in the CCR Clause.
- FPL SolarTogether Subscription Credits – Recover updated subscription credit amount as provided in the Settlement Agreement.
- Indiantown Generating Facility Non-Fuel Revenue Requirements – discontinue recovery of Indiantown base revenue requirements through the CCR and instead recover Indiantown site revenue requirements through base rates.

Q. How would the 2022 FCR and CCR costs be impacted if the Settlement Agreement is not approved or modified?

A. The FCR and CCR costs included in the 2022 actual/estimated and final true-up amounts will reflect the relevant provisions approved in the 2021 Rate Case.

Q. Are there any adjustments in the Settlement Agreement that you have not included in the calculation of the 2022 FCR or CCR factors?

A. Yes. As part of the Settlement Agreement FPL has proposed changes in depreciation rates that will impact the amounts to be recovered through the 2022 CCR Clause. The revised depreciation rates are not included in the calculation of the 2022 capital revenue requirements due to the timing needed to prepare the CCR schedules, but the approved depreciation rates will be reflected in the CCR costs in the 2022 actual/estimated and final true-up amounts to be included in the 2023 CCR factors.

Proposed 2022 Residential Bill Based on Unified Rates

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2022 through December 2022 for the consolidated company?

A. The proposed residential 1,000 kWh bill for January through December 2022 for customers in the former FPL service area is $113.85. This proposed bill includes a base rate charge of $75.82, which reflects base rates proposed in the Settlement Agreement, an FCR charge of $28.22, a CCR charge of $2.39, an environmental cost recovery charge of $2.99, a conservation cost recovery charge of $1.34, a storm protection plan cost recovery charge of $2.14, the transition rider credit of $1.98 and the gross receipts tax and regulatory assessment fee of $2.93. FPL's proposed 2022 residential 1,000 kWh bill for customers in the former FPL service area is provided on Schedule E-10, which is page 137 of Appendix II.

The proposed residential 1,000 kWh bill for January through December 2022 for customers in the former Gulf service area is $148.78. This proposed bill includes a base rate charge of $75.82, which reflects base rates proposed in the Settlement Agreement, an FCR charge of $28.22, a CCR charge of $2.39, an environmental cost recovery charge of $2.99, a conservation cost recovery charge of $1.34, a storm protection plan cost recovery charge of $2.14, a storm restoration charge of $11.00, the transition rider surcharge of $21.06, and the gross receipts tax and regulatory assessment fee of $3.82. FPL's proposed 2022 residential 1,000 kWh bill for customers in the former Gulf service area is provided on Schedule E-10, which is page 138 of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY
TESTIMONY OF RICHARD L. HUME
DOCKET NO. 20210001-EI
APRIL 2, 2021

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

A. My name is Richard Hume. My business address is One Energy Place Pensacola, FL 32520. I am the Regulatory Issues Manager for Florida Power & Light Company ("FPL"), as successor by merger with, Gulf Power Company ("Gulf Power").

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Florida in 1991 with a Bachelor of Science degree in Business Administration with a Finance Major and earned a Master of Business Administration degree with a Finance Concentration from the University of Florida in 1995. In 1998, I worked for New-Energy Associates, (which became a subsidiary of Siemens Power Generation), a consulting firm that works with electric and gas utilities across the United States. During that time, I consulted in the area of financial forecasting and budgeting as well as cost of service and rate forecasting. In 2007, I joined Oglethorpe Power and after a year was promoted to the position of Director of Financial Forecasting. In that position I was primarily responsible for the long-range financial forecast and resource plan. In 2012, I joined FPL managing a data analytics team. In that position part of what my team was responsible for was customer rate and bill impact analysis and worked in partnership with the Regulatory Affairs team. In 2019, I joined Gulf Power as the Regulatory Issues Manager where my current responsibilities include oversight of Gulf Power's fuel and purchase power cost recovery clause, calculation of cost recovery factors and the related regulatory filings.

Q. Please describe the relationship of Gulf Power to FPL.

A. Gulf Power was acquired by FPL's parent company, NextEra Energy, Inc., on January 1, 2019. Gulf Power was subsequently merged with FPL on January 1, 2021. Following the acquisition, and even prior to the legal combination of FPL and Gulf Power, the two companies began to consolidate their operations; however, the companies remained separate ratemaking entities. On March 12, 2021, FPL filed with the Florida Public Service Commission ("FPSC" or " the Commission") a Petition for Unification of Rates and for a Base Rate Increase, in which FPL requested that the Commission approve the placement of FPL's rates into effect for all customers currently served pursuant to the rates and tariffs on file for Gulf Power. If the Commission approves FPL's request, Gulf Power will no longer exist as a separate ratemaking entity.

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

A. The purpose of my testimony is to present the final true-up amounts for the period January 2020 through December 2020 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will summarize Gulf Power's fuel expenses, net power transaction expense, purchased power capacity costs, and certify that these expenses were properly incurred during the period January 2020 through December 2020. Lastly, I will present the actual benchmark level for the calendar year 2021 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2020 through December 2020.

Q. Have you prepared any exhibits to which you will refer in your testimony?

A. Yes, I have. Exhibit RLH-1consists of 8 schedules which includes 2 schedules related to the fuel and purchased power cost recovery final true-up, 1 schedule that relates to Gulf Power's natural gas fuel hedging activities for 2020 and 5 schedules that relate to the capacity cost recovery final true-up. Exhibit RLH-2 contains Schedules A-1 through A-9 and A-12 for the period December 2020, previously filed with the Commission.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power. 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 Commission. Based on the information in these documents and the foregoing testimony, the recoverable fuel and purchased power costs, and hedging activities are reasonable and prudent.

I. FUEL

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedules 1 and 2 of my Exhibit RLH-1 relate to the fuel and purchased power cost recovery true-up calculation for the period January 2020 through December 2020.

These schedules compare twelve months of actual data to the actual/estimated true-up filed in last year's fuel docket which included six months of actual and six months of re-projected data. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2020 are incorporated herein as Exhibit RLH-2. The A-schedules compare twelve months of actual data to twelve months of projected data from a combination of the original 2020 fuel projection for the period January through June, and the 2020 estimated true-up re-projections for the period July through December.

Q. What is the final fuel and purchased power cost true-up amount related to the period January 2020 through December 2020 to be addressed through the fuel cost recovery factors in the period January 2022 through December 2022?

A. A net over-recovery amount of $6,085,680 will be included in the calculation of the 2022 fuel cost recovery clause rates, as shown on Schedule 1 of Exhibit RLH-1.

Q. How was this amount calculated?

A. The $6,085,680 is calculated on Schedule 1 of my Exhibit RLH-1 by taking the difference between the estimated and actual over/under-recovery amounts for the period January 2020 through December 2020. The estimated under-recovery amount was $9,968,285 as compared to the actual under-recovery amount of $3,882,605, resulting in a net over-recovery of $6,085,680. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2020-0439-FOF-EI, dated November 16, 2020.

Q. What are the primary factors which contributed to the final fuel and purchased power cost true-up amount?

A. Gulf Power experienced lower than estimated fuel and net power expense and higher than estimated jurisdictional fuel clause revenue. These variances are discussed in more detail below and are summarized on Schedule 2 of Exhibit RLH-1.

<u>Fuel Clause Revenue</u>

Q. Please explain the variance in fuel revenue applicable for 2020.

A. Gulf Power's jurisdictional fuel revenue was $305,319,719 which was $4,005,263 or 1.33% above the actual/estimated.

<u>Total Fuel and Net Power Transactions</u>

Q. During the period January 2020 through December 2020, how did Gulf Power's recoverable total fuel and net power transaction expenses compare with the actual/estimated expenses?

A. Gulf Power's recoverable total fuel cost and net power transaction expense was $308,815,472 which is $1,455,615 or 0.47% below the estimated amount of $310,271,087. Actual fuel and net power transaction energy was 17,806,382 MWh compared to the estimated net energy of 21,151,772 MWh or 15.82% lower than the estimated amount. The lower total fuel and net power transactions expense is attributed to a lower quantity of fuel and net power transaction energy than projected for the period presented above. This information is summarized on Schedule 2 of my Exhibit RLH-1.

Total Fuel Cost of Generated Power

Q. During the period January 2020 through December 2020, how did Gulf Power's recoverable fuel cost of net generation compare with the actual/estimated expenses?

A. Gulf Power's recoverable fuel cost of system net generation was $190,842,864 or 11.26% below the estimated amount of $215,050,454. This information is summarized on Schedule 2 of Exhibit RLH-1 and the table below provides the detail of the variance.

Fuel Variance	2020 Final True-up	2020 Actual / Estimated	Difference
OIL - C.T.			
Total Dollar	$43,427	$56,283	(12,856)
Units	2,871	3,607	(736)
$ per Units	15.1261	15.6038	(0.48)
Variance Due to Consumption			(11,133)
Variance Due to Cost			$ (1,723)
Total Variance			(12,856)
GAS			
Total Dollar	$109,050,227	$118,192,873	(9,142,646)
Units	40,783,185	45,994,831	(5,211,646)
$ per Units	2.6739	2.5697	0.10
Variance Due to Consumption			(13,935,429)
Variance Due to Cost			4,792,783
Total Variance			(9,142,646)
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$81,160,388	$96,188,953	(15,028,565)
Units	23,637,582	30,484,736	(6,847,154)
$ per Units	3.4335	3.1553	0.28
Variance Due to Consumption			(23,509,921)
Variance Due to Cost			8,481,355
Total Variance			(15,028,565)
Other Adjustments to Fuel Costs			
Total Variance	$588,822	$612,346	(23,523)
Total Variance			
Total Variance Due to Consumption			**(37,456,482)**
OIL - C.T.			(11,133)
GAS			(13,935,429)
COAL + GAS B.L. + OIL B.L.			(23,509,921)
Total Variance Due to Cost			**13,248,893**
OIL - C.T.			(1,723)
GAS			4,792,783
COAL + GAS B.L. + OIL B.L.			8,481,355
Other Adjustments to Fuel Costs			(23,523)
Total			**(24,207,590)**

Total Cost of Purchased Power

Q. During the period January 2020 through December 2020, how did Gulf Power ’s recoverable fuel cost of purchased power compare to actual/estimated cost?

A. Gulf Power’s recoverable fuel cost of purchased power for the period was $177,881,592 or 1.68% below the estimated amount of $180,925,065. Total megawatt hours of purchased power were 7,073,921 MWh compared to the estimate of 7,549,910 MWh or 6.30% below estimates. The resulting average fuel cost of purchased power was 2.515 cents per kWh or 4.93% above the estimated amount of 2.396 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2020 included in Exhibit RLH-2 and summarized on Schedule 2 of Exhibit RLH-1.

Q. What are the reasons for the difference between Gulf Power’s actual fuel cost of purchased power and the actual/estimated costs?

A. The lower total fuel cost of purchased power is primarily due to lower megawatt hours purchased by Gulf Power through purchased power agreements than estimated.

Power Sales

Q. During the period January 2020 through December 2020 how did Gulf Power ’s recoverable fuel cost of power sold compare with the actual/estimated costs?

A. Gulf Power’s recoverable fuel cost of power sold for the period is $56,082,677 or 34.30% lower than the estimated amount of $85,357,812. The total quantity of power sales was 3,065,477 MWh compared to Gulf Power’s estimated sales of 4,668,264 MWh, or 34.33% below estimates. The resulting average fuel cost of power sold was 1.829 cents per kWh or 0.06% above the estimated amount of 1.828

cents per kWh. The 2020 actual information is from Schedule A-1, period-to-date, for the month of December 2020 and summarized on Schedule 2 of RLH-1.

Q. What are the reasons for the difference between Gulf Power's actual fuel cost of power sold and the actual/estimated costs?

A. The lower actual fuel cost of power sold is primarily due to a lower quantity of generation available for non-territorial sales after meeting Gulf Power's territorial load.

Gains on Non-Separated Wholesale Energy Sales Benchmark

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2019 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2018 through 2020 is calculated as follows:

Year	Actual Gain
2018	589,410
2019	159,393
2020	202,489
Three-Year Average	$317,097

Q. What is the actual threshold for 2021?

A. The actual threshold for 2021 is $317,097.

II. HEDGING

Q. Did Gulf Power's fuel hedging activity during 2020 follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. As part of the Stipulation and Settlement Agreement, in Docket No. 20160186-EI, Gulf Power agreed to continue its existing moratorium for new natural gas financial hedges until January 1, 2021. Although Gulf Power did not enter into any new financial hedge contracts in 2020, hedges that settled in 2020 were entered into prior to the current moratorium on natural gas financial hedges and complied with previously approved Risk Management Plans. Gulf Power has had no hedging activities since March 2020.

Q. For the period in question, what volume of natural gas was hedged using a fixed price contract or financial instrument?

A. Gulf Power hedged 990,000 MMBtu of natural gas based upon plant Smith 3 and the Central Alabama PPA combined cycle unit projected burns in 2020 using financial instruments. This represents 5% of Gulf Power's 18,600,279 MMBtu actual gas burn for these resources during the period. The total amount of natural gas burn by month for these resources is reported on Schedule 3 of Exhibit RLH-1.

Q. What types of hedging instruments were used by Gulf Power, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swap contracts that were entered into prior to the current moratorium. These swaps settled against the NYMEX Last Day Final Settlement price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, future gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2020 through December 2020?

A. No fees, commissions, or premiums were paid by Gulf Power on the financial hedge transactions during this period. Gulf Power's 2020 hedging program activities for the period January through March 2020 resulted in a net hedge settlement cost of $1,605,420 as shown on line 2 of the December 2020 Schedule A-1, period-to-date of Exhibit RLH-2.

III. PURCHASED POWER CAPACITY

Q. Mr. Hume, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?

A. Schedules CCA-1, CCA-2, CCA-3, CCA-4 and CCA-5 of Exhibit RLH-1 relate to the purchased power capacity cost recovery true-up calculation for the period January 2020 through December 2020. Schedules CCA-1 and Schedule CCA-2 summarize the calculation of the final true-up amount. Schedules CCA-3 through CCA-5 provides the monthly calculation of the actual over/under-recovery of purchased power capacity costs, monthly calculation of the interest provision and additional details related to purchased power capacity contracts which also appear on Lines 1 and 2 of Schedule CCA-3. In addition, Schedule A-12 of Exhibit RLH-2 contains purchased power capacity cost information for the period January 2020 through December 2020.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2020 through December 2020 to be addressed in the period January 2022 through December 2022?

A. An over-recovery amount of $838,127 will be included in the calculation of the 2022 purchased power capacity clause rates, as shown on Schedule CCA-1 of Exhibit RLH-1.

Q. How was this amount calculated?

A. The $838,127 was calculated by taking the difference between the estimated January 2020 through December 2020 under-recovery of $2,700,587 and the actual under-recovery of $1,862,460. This true up amount is also the sum of lines 11, 12, and 15 under column 1 of Schedule CCA-2 of Exhibit RLH-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2020-0439-FOF-EI dated November 16, 2020.

Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 27, 2020.

Q. During the period January 2020 through December 2020, how did Gulf Power's actual total purchased power capacity costs and jurisdictional capacity clause revenue compare with the actual/estimated amounts?

A. The actual total capacity payments for the period January 2020 through December 2020, as shown on line 5 of Schedule CCA-2 contained in Exhibit RLH-1, was $84,446,374. Gulf Power's total estimated net purchased power capacity cost for the same period was $85,345,135, as indicated on line 5 of Schedule CCE-1B the Exhibit RLH-3 filed July 27, 2020 in Docket No. 20200001-EI. The difference between the actual net capacity cost and the estimated net capacity cost for the recovery period is $898,761 or 1.05% less than the estimated amount. Jurisdictional capacity clause revenue for the period January 2020 through December 2020, as shown on line 10 of Schedule CCA-2, was $80,260,003 or $35,964 lower than the estimate of $80,533,916. Jurisdictional capacity clause revenue and expense variances were less than one percent for the period.

Q. Mr. Hume, does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20210001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume

Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 1st day of april, 2021.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF RICH L. HUME

DOCKET NO. 20210001-EI

JULY 27, 2021

Q. Please state your name and address.

A. My name is Richard Hume. My business address is One Energy Place Pensacola, FL 32520. I am the Regulatory Issues Manager for Florida Power & Light Company ("FPL"), as successor by merger with, Gulf Power Company ("Gulf Power").

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2021 through December 2021.

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 Exhibit RLH-3 and Exhibit RLH-4. Exhibit RLH-3 contains the FCR schedules and Exhibit RLH-4 contains the CCR schedules.

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 Gulf Power. 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 Gulf has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2021 through June 2021 and revised estimates for July 2021 through December 2021 to the data reflected in Gulf's original projection for the period January 2021 through December 2021 filed on September 3, 2020. Likewise, the CCR true-up calculation compares actual/estimated data consisting of actuals for January 2021 through June 2021 and revised estimates for July 2021 through December 2021 to the data reflected in Gulf's original projections for the period January 2021 through December 2021 filed on September 3, 2020.

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 estimated months is the actual rate published on the first business day in July 2021, which reflects the interest rate from the last business day in June 2021.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2021 actual/estimated true-up by month?

A. Yes. Exhibit RLH-3, Schedule E-1B shows the calculation of the FCR actual/estimated true-up by month for the period January 2021 through December 2021.

Q. What has Gulf calculated as the fuel cost recovery true-up factor to be applied in the period January 2021 through December 2021?

A. The fuel cost recovery true-up factor for this period is 0.3713 cents per kWh. As shown on Schedule E-1A, this calculation includes an estimated under-recovery for the January through December 2021 period of $46 million. It also includes a final over-recovery for the January through December 2020 period of $6 million (see Schedule 1 of Exhibit RLH-1 filed in this docket on March 1, 2021). The resulting total under-recovery of $40 million will be incorporated into Gulf's proposed 2022 fuel cost recovery factors.

Q. Have there been any other notable changes to the recoverable costs for the actual period January 2021 through June 2021?

A. Yes, Gulf made an adjustment that increased fuel clause revenues by $1.2 million. The adjustment of represents a reclassification of base retail revenue to clause revenue. Subsequent to the close of the general ledger for the period ending

December 31, 2020, it was identified that base retail revenues were overstated by $2.0 million and clause revenues were understated by the same amount. The fuel portion of this revenue adjustment is $1.2 million, which was moved from base to clause revenue in January 2021. (Exhibit RLH-3, Schedule E-1B, lines 6 plus 7 plus 8, column 15).

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

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections for 2021?

A. Yes. Exhibit RLH-3, Schedule E-1B-1 provides a variance calculation that compares the 2021 actual/estimated period data by component to the same components from the 2021 original projection filed on September 3, 2020.

Q. Please summarize the variance Schedule E-1B-1 of Exhibit RLH-3.

A. Gulf originally projected jurisdictional total fuel costs and net power transactions to be $327.3 million for 2021 (Exhibit RLH-3, page 3, line 21, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $378.8 million for that period (Exhibit RLH-3, page 3, line 21, column 3). The estimated variance is due to higher than projected costs of generated and purchased power as well as lower than expected revenue from power sales. Jurisdictional total fuel costs and net power transactions are estimated to be $51.4 million, or 15.73% higher than the original projection (Exhibit RLH-3, page 3, line 21, column 5). The net impact due to the increase in jurisdictional fuel costs results in the actual/estimated true-up under-recovery of $46 million (Exhibit RLH-3, page 2, line 9, column 15).

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

A. The summary below shows the primary drivers for the $51.4 million increase in jurisdictional total fuel costs.

Description		**Variance (millions)**
Fuel Costs of System Net Generated	$	25.3
Lower Gain on Power Sales	$	24.8
Total Cost of Purchased Power	$	2.1
Other Generation Power	$	(0.7)
Total	**$**	**51.4**

<u>Fuel Cost of System Net Generation: $25.3 million increase (Exhibit RLH-3, Schedule E-1B-1, line 1 column 5):</u>

The primary driver for the increase in cost of System Net Generation is higher prices than projected for natural gas. The table below outlines the variances in more detail and is also shown on Schedule E3.

Fuel Variance by Major Fuel Type	2021 Actual Estimated	2021 Projection	Variance
OIL - C.T.			
Total Dollar	$29,499	$44,528	$ (15,029)
MMBTU	1,942	2,905	(963)
$ per MMBTU	15.19	15.33	$ (0.14)
		Variance Due to Consumption	$ (14,628)
		Variance Due to Cost	$ (401)
NATURAL GAS			
Total Dollar	$208,557,813	$188,746,851	$ 19,810,962
MMBTU	57,547,791	63,081,885	(5,534,094)
$ per MMBTU	3.62	2.99	$ 0.63
		Variance Due to Consumption	$ (20,033,420)
		Variance Due to Cost	$ 39,844,382
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$62,501,810	$56,837,821	$ 5,663,989
MMBTU	21,773,737	20,453,213	1,320,524
$ per MMBTU	2.87	2.78	$ 0.09
		Variance Due to Consumption	$ 3,789,904
		Variance Due to Cost	$ 1,874,085
Other Adjustments to Fuel Costs			
Total Variance	941,329	1,135,469	$ (194,140)
		Total Variance Due to Consumption	$ (16,258,144)
		Total Variance Due to Cost	$ 41,523,926
		Total Variance	$ 25,265,783

Total Gains on Power Sales: $24.8 million decrease (Exhibit RLH-3, Schedule E-1B-1, line 12, column 5):

The decrease for Gains on Power Sales is primarily attributed to 1,496,556 MWh or 27.89% lower than projected power sales. The projected price for the fuel cost and gains on power sales is 2.6023 cents per kWh, which is 11.30% higher than the original projection.

Total Cost of Purchased Power: $2.1 million increase (Exhibit RLH-3, Schedule E-1B-1, line 7, column 5):

The variance for the Cost of Purchased Power is primarily attributed to the higher payments to qualifying facilities estimated to be $1.7 million higher than the projection filing. In addition, although economy purchases decreased, the remaining variance is attributed to a higher economy purchase price in the Southern Company Power Pool which is estimated to be 3.3216 cents/kWh or 12.81% higher than originally projected. The higher price was offset by the decrease in lower MWh purchases now estimated to be 10.5% lower than projected.

<u>Other generated power: $0.7 million decrease (Exhibit RLH-3, Schedule E-1B-1, lines 1b, 2 and 3, column 5):</u>

Other costs of generated power variances are those related to wholesale kWh sales credit, other generation, and miscellaneous adjustments to fuel costs.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2021 actual/estimated true-up by month?

A. Yes. Exhibit RLH-4, Schedule CCE-1E provides the calculation of the CCR actual/estimated true-up by month for the period January 2021 through December 2021.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2021 through December 2021?

A. The true-up for this period is (0.0233) cents per kWh, as shown on Schedule CCE-1E. This calculation includes an estimated over-recovery of $1.7 million for January 2021 through December 2021. It also includes a final over-recovery of $0.8 million for the period January 2020 through December 2020 (see Schedule CCA-1 of Exhibit RLH-1 filed in this docket on March 2, 2021). The resulting total over-recovery of $2.5 million will be incorporated into Gulf Power's proposed 2022 purchased power capacity cost recovery factors.

Q. Please explain the calculation of the CCR 2021 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RLH-4, CCE-1B shows the actual/estimated capacity costs and applicable revenues (January 2021 through June 2021 reflects actual data, while the data for July 2021 through December 2021 is based on updated estimates) compared to the original projection filing for the January 2021 through December 2021 period. The $2.5 million over-recovery is due to lower than projected retail sales. The total jurisdictional capacity payments are projected to be $1.9 million or 2.2% lower than Gulf's original projection filing.

Description	2021 Actual/Estimated	2021 Projection	Variance
Total Jurisdictional Capacity Payments/(Receipts)	$ 81,690,344	$ 83,552,876	$ (1,862,532)

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

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery with Generating Performance Incentive Factor	Docket No. 20210001-EI Filed: October 7, 2021

ERRATA SHEET

APRIL 2, 2021 TESTIMONY OF GERARD J. YUPP

PAGE No.	LINE No.	
Page 1	Line 12	Strike “Have you previously testified in this docket?” and replace with “Please summarize your educational background and professional experience.”
Page 1	Line 13	Replace “Yes.” with “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 (“EMT”) 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 Incentive Mechanism.”

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20210001-EI

April 2, 2021

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 and 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. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2020 results of FPL's activities under the Asset Optmization Program Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-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 exhibits:

- 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 Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that 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 Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These 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 Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 rate case. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism. Under the modified Incentive Mechanism, customers continue to receive 100% of the gains up to the new sharing threshold of $40 million. Incremental gains above $40 million continue to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

The second modification that was made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case). Under the modified Incentive Mechanism, FPL nets economy sales and purchases and recovers the net amount of variable power plant O&M incurred during the year. For example, if economy purchases are greater than economy sales, customers receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL uses to calculate these costs, as described in FPL's 2017 Test Year MFRs filed with the 2016 Rate Petition is $0.65/MWh. FPL continues to be allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2020.

A. FPL's activities under the Incentive Mechanism in 2020 delivered $46,135,050 in total gains. During 2020, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation. Additionally, FPL entered into several Asset Management Agreements related to a small portion of upstream gas transportation during 2020. The total gains of $46,135,050 exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2020.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2020.

A. The details of FPL's 2020 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $25,419,391 on wholesale sales and savings of $2,740,526 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2020.

A. The details of FPL's 2020 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $17,975,132 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2020?

A. Yes. FPL incurred personnel expenses of $480,859 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $31,467 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $512,326 in 2020.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,552,979 MWh (2,811,241 MWh of economy sales and 258,262 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,659,436 for 2020.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2020?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2020. On the wholesale power side, suitable market conditions in the winter period helped drive strong wholesale power sales and high demand across the summer period provided the opportunity to purchase power from the market to avoid running more expensive generation. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $28 million in customer benefits. Market opportunities for asset optimization activities related to natural gas were fairly consistent throughout the year (peaking in November and December) and resulted in significant customer benefits of nearly $18 million. In total, these activities delivered $46,135,050 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $2,171,762.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause and Generating Performance Incentive Factor	Docket No. 20210001-EI Filed: October 27, 2021

ERRATA SHEET

SEPTEMBER 3, 2021 TESTIMONY OF GERARD J. YUPP

Page No.	Line No.	
Page 3	Line 9	Strike “2021” and replace with “2022”

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20210001-EI

SEPTEMBER 3, 2021

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 and 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 the following exhibits and schedules:

- GJY-3: Appendix I;
- Schedules E3 through E9 of Appendix II included in Renae Deaton's Exhibit RBD-5;
- Schedules E3 through E5 of Appendix III-A included in Exhibit RBD-6;
- Schedules E3 through E5 and E9 of Appendix III-B, included in Exhibit RBD-6; and

I am co-sponsoring:

- Schedule E2 and H1 of Appendix II included in Exhibit RBD-5

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 Incentive Mechanism results for 2020 and the Incremental Optimization Costs included in FPL's 2022 Projection Filing pursuant to the Incentive Mechanism that was approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016 ("2016 Base Rate Settlement Agreement") and proposed as an on-going program in the Stipulation and Settlement Agreement filed in FPL's rate case Docket No. 20210015-EI on August 10, 2021.

<u>CONSOLIDATION OF FUEL AND POWER COST PROJECTIONS</u>

Q. Does FPL's 2022 Fuel Projection Filing incorporate the consolidation of fuel and power costs for both FPL and the former Gulf Power Company ("Gulf")?

A. Yes. The costs reflected in this filing represent the consolidation of the FPL and Gulf systems.

Q. How will you refer to FPL and Gulf in your testimony?

A. All references to FPL in my testimony are meant to represent the consolidated company unless otherwise noted. I utilize the term Gulf only when necessary to distinguish certain information related to the time period during which the former Gulf system operates as part of the Southern Company System Intercompany Interchange Contract ("IIC" or "Southern Pool").

Q. Please describe how Gulf's participation in and exit from the Southern Pool is reflected in FPL's 2022 Fuel Projection Filing.

A. FPL's 2022 Fuel Projection Filing contemplates that Gulf will continue as a member of the Southern Pool through June 2022 and will exit from the IIC starting on July 1, 2021. This date coincides with the projected in-service date of the North Florida Resiliency Connection ("NFRC"). The NFRC is a new transmission line that is being constructed to enhance the existing electrical connection between the two systems and to provide operational benefits by allowing for the joint dispatch of the FPL and Gulf systems.

Q. Please further elaborate on how FPL included Gulf in its 2022 Projection Filing.

A. FPL's 2022 fuel projections are comprised of two distinct periods. First, for the January through June 2022 period, the projected fuel costs for Gulf were estimated by Southern Company and represent Gulf's projected costs as a member of the Southern Pool. FPL's fuel cost projections for this same period were developed on a stand-alone basis. For the July through December 2022 period, the projections represent estimated fuel and power costs for a consolidated system that is jointly dispatched after the NFRC goes into service.

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2022 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. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. 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 2, 2021 for calculating its 2022 Fuel Cost Recovery ("FCR") Clause factors. This forecast methodology and the resulting fuel forecast was utilized to develop cost projections for FPL as a stand-alone system during the January 2022 through June 2022 time period and for FPL and Gulf during the consolidated period of July 2022 through December 2022.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. Did Southern Company utilize the same forward curve date in its fuel forecast to develop Gulf's cost projections as a member of the Southern Pool during the January 2022 through June 2022 period?

A. Yes. In an effort to synchronize cost projections for the period during which Gulf is dispatched as part of the Southern Pool, Southern Company also utilized underlying forward curve prices from the close of business on August 2, 2021 in its fuel forecast.

Q. Were forward curve prices from the close of business on August 2, 2021 also utilized to update cost projections for FPL and Gulf for the August through December 2021 period?

A. Yes. The revised 2021 Actual/Estimated true-up amounts for FPL and Gulf for the August through December 2021 period, as described in the testimony of FPL witness Renae B. Deaton, were calculated based on underlying forward curve prices from the close of business on August 2, 2021.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2022 period?

A. In general, the key physical 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.

In its August 2021 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts Henry Hub natural gas spot prices will average approximately \$3.71 per MMBtu in the third quarter of 2021 and \$3.42 per MMBtu for all of 2021. Higher natural gas prices in 2021 reflect growth in liquefied natural gas exports and rising consumption for sectors other than electric power. The EIA forecasts that Henry Hub spot prices will average \$3.08 per MMBtu in 2022, amid rising U.S. natural gas production. U.S. dry natural gas production is estimated to increase from a forecasted average of 92.2 billion cubic feet ("BCF") /day in 2021 to 94.9 BCF/day in 2022.

Natural gas consumption is forecast to decrease by approximately 1% in 2021 (compared to 2020 levels). For 2021, the decrease in natural gas consumption occurs, in part, due to natural gas to coal switching in the electric power sector as a result of rising gas prices. Overall, natural gas consumption in 2022 is projected to increase compared to 2021 consumption levels. Natural gas storage levels ended July 2021 at roughly 2.8 trillion cubic feet, or 6% lower than the five-year average. Natural gas storage levels are expected to reach approximately 3.6 trillion cubic feet at the end of October 2021, or 4% below the five-year average.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2022 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, LP ("Gulf South") pipelines to deliver natural gas to its generation facilities. FPL's total firm transportation capacity ranges from 1,237,000 to 1,361,000 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. Additionally, FPL projects that during the January through December 2022 period, varying levels of non-firm natural gas transportation capacity will be available, depending on the month.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 80,000 MMBtu/day (January through March) and 180,000 MMBtu/day (April through December) of firm transport on the Southeast Supply Header ("SESH") pipeline, 121,500 MMBtu/day of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, and 329,000 MMBtu/day (January through March), 444,000 MMBtu/day (April), 345,000 MMBtu/day (May through October), and 200,000 MMBtu/day (November through December) of firm transport on the Gulf South pipeline. FPL's firm transportation rights on these pipelines provide access for up to 646,500 MMBtu/day during the summer season of on-shore 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. The current contract with Southern Pines is set to expire March 31, 2022. As part of its Fuel Policy requirements as a member of the Southern Pool, Gulf currently holds firm natural gas storage capacity in Bay Gas (0.58 BCF), Leaf River Energy Center (0.85 BCF), and Petal Gas Storage (0.50 BCF). Southern Company will retain this storage capacity upon Gulf's exit from the Southern Pool and FPL is currently evaluating its future storage requirements for the consolidated company.

While the acquisition of upstream transportation capacity has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. As FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. 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 2022 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 3 of Appendix I.

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 nearly 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 2022 period.

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

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

A. FPL's projected dispatch costs are based on FPL's price projection for spot coal delivered to the plant.

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer and Plant Daniel for the January through December 2022 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by month, is shown on page 3 of Appendix I.

Q. Do the fuel costs reflected on Schedule E3 for light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

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.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the GenTrader model (Southern Company model for Gulf from January 2022 through June 2022). 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 (Southern Company model for Gulf from January 2022 through June 2022) 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, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2022?

A. Yes. This data is shown on page 4 of Appendix I.

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 2022.

Q. Please describe the significant planned outages for the January through December 2022 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 4 is scheduled to be out of service from March 12, 2022 until April 10, 2022, or 29 days during the period. St. Lucie Unit 1 is scheduled to be out of service from September 3, 2022 until October 3, 2022, or 30 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2022 period.

A. As shown in FPL's 2021 Ten Year Power Plant Site Plan (Table ES-1, page 16), FPL projects a net increase in its 2022 summer firm capacity of 678 MW. This increase is attributable to the addition of 469 MW of battery storage, 316 MW of solar generation, 1,163 MW of combined cycle generation, 938 MW of simple cycle CTs, and 58 MW of combined cycle upgrades. The additions are off-set by the retirement of Manatee Units 1 and 2 (1,626 MW), Scherer 4 (634 MW), and solar degradation (6 MW).

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

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2022?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II 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 FCRClause. 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.

Gulf is forecasted to have Associated Interchange Energy ("Associated Interchange") purchases and sales during the January 2022 through June 2022 period while it remains a member of the Southern Pool. Associated Interchange represents energy transfers that occur between Southern Pool members as a result of centralized integrated system economic dispatch. The Associated Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the incremental resource(s) that serve the collective obligations of the Southern Pool members. A Southern Pool member supplying Associated Interchange receives a payment that is determined by multiplying the Associated Interchange Energy Rate by the megawatt hours sold to the Southern Pool each hour. A Southern Pool member receiving Associated Interchange is charged an amount that is determined by multiplying the Associated Interchange Energy Rate by the megawatt hours purchased from the Southern Pool each hour.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales and Associated Interchange 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. The projections for Associated Interchange purchases and sales are a direct output of the model used by Southern Company to simulate the integrated economic dispatch of the Southern Pool.

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

A. FPL has projected 2,434,468 MWh of wholesale (off-system) power sales for the period of January through December 2022. The projected fuel cost related to these sales is $59,976,726. The projected transaction revenue from these sales is $88,199,148. After taking into account the transmission costs, the projected gain is $22,704,934. Associated Interchange sales are projected to be 2,853,251 MWh with related fuel costs of $72,251,139.

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

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales as well as the total MWh of energy and total dollars for fuel adjustment of Associated Interchange sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases and Associated Interchange purchases for the January to December 2022 period?

A. The costs of these economy purchases and Associated Interchange purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 467,567 MWh at a cost of $12,323,306. If FPL generated this energy, FPL estimates that it would cost $14,275,577. Therefore, these purchases are projected to result in savings of $1,952,271. Associated Interchange purchases are projected to be 71,789 MWh at a cost of $2,012,972.

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"). FPL also projects to purchase energy from the Central Alabama Generating Station ("Central Alabama") under a Power Purchase Agreement with Shell Energy North America ("Shell PPA") and under two wind energy purchase agreements ("Kingfisher I" and "Kingfisher II") with Morgan Stanley Capital Group. In addition, FPL contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission ("OUC") 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 2022 period.

A. Energy purchases under the SWA agreements are projected to be 892,980 MWh for the period at an energy cost of $30,388,548. FPL projects to purchase 4,372,775 MWh at an energy cost of $133,732,287 under the Shell PPA from Central Alabama and 1,031,280 MWh at an energy cost of $46,850,888 from Kingfisher I and Kingfisher II combined. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 633,858 MWh at a cost of $2,926,719. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 685,635 MWh at a cost of $24,793,908.

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 578,523 MWh of energy at a cost of $2,996,664. These projections are shown on Schedule E6 of Appendix II.

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2020, 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 16 of the 2016 Base Rate Settlement Agreement, FPL's fuel hedging program is under a moratorium. Therefore, FPL had no hedging activity to report for 2020.

Q. Has FPL filed a comprehensive risk management plan 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. Yes. FPL has filed a comprehensive risk management plan for 2022.

Q. Will FPL's proposed 2022 risk management plan change if the Commission approves the Stipulation and Settlement Agreement filed in FPL's rate case Docket No. 20210015-EI on August 10, 2021?

A. Yes, pursuant to the terms of that proposed Stipulation and Settlement Agreement, if it is approved, FPL will terminate natural gas financial hedging during the term of the Agreement, which includes 2022. FPL would make a filing to implement that termination following approval of the Stipulation and Settlement Agreement, if that occurs.

<u>THE INCENTIVE MECHANISM</u>

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2020?

A. FPL's asset optimization activities in 2020 delivered total benefits of $46,135,050. The total gains exceeded the sharing threshold of $40 million and, therefore, the gains above $40 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $42,109,564 (net of FPL's share of the gain above the $40 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $3,681,030. FPL's share of the gain is included for recovery in FPL's 2022 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2020?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the Incentive Mechanism. For the purpose of this comparison, I have included the same savings of approximately $29.99 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $29.76 million, while FPL would have received $0.23 million in benefits because the three-year rolling average threshold for wholesale sales would have been exceeded.

In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated slightly more than $17.98 million of additional savings in 2020. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received slightly more than $42.11 million of savings under the Incentive Mechanism. This is $12.35 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Has FPL included in its 2022 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

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 E3) for 2022.

Q. Has FPL included in its 2022 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2022 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 $444,343 in 2022 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism.

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

A. FPL has included for recovery in its 2022 FCR factors, VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Appendix II, FPL projects to sell 2,434,468 MWh and purchase 467,567 MWh of economy power. Therefore, applying FPL's VOM rate of $0.48/MWh, FPL projects to incur VOM expenses of $1,168,545 associated with its economy sales and to avoid ($224,432) with its economy purchases. FPL has included for recovery the net of these two figures, $944,113 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2022 FCR factors.

Q. Does this conclude your testimony?

A. Yes it does.

(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. 20210001-EI

SEPTEMBER 3, 2021

Q. Please state your name and address.

A. My name is Dean Curtland. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

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

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

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional areas of Engineering, Operations, Maintenance, Chemistry, Radiation Protection, Regulatory Affairs, Security, Training, Outages and Projects.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I hold a Bachelor of Science degree in Mechanical Engineering from Purdue University. I also held a Senior Reactor Operator license from the Nuclear Regulatory Commission at Duane Arnold for thirteen years, and I completed the Institute of Nuclear Power Senior Plant Management Course.

I have spent over 36 years in the nuclear industry, beginning at Duane Arnold Energy Center as Operations Director. I held numerous positions of increasing responsibility including Training Manager, Engineering Director and Plant General Manager. I was also the General Manager of Fleet Engineering for the NextEra nuclear fleet and the Site Vice President of NextEra Energy's Seabrook and Duane Arnold Nuclear Plants before serving in my current role as Vice President, Nuclear.

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 ("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 2022 through December 2022. I am also supporting FPL's projected 2022 incremental plant security and Fukushima-related costs.

<u>Nuclear Fuel Costs</u>

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 2022 through December 2022.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2022 through December 2022.

A. FPL projects the nuclear units will burn 305,036,436 MMBtu of energy at a cost of $0.4837 per MMBtu for the period January 2022 through December 2022. Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-

4, starting on page 17, which is attached as an exhibit to FPL witness Deaton's testimony.

<u>Nuclear Plant Incremental Security Costs</u>

Q. What is FPL's projection of incremental security costs at its nuclear power plants for the period January 2022 through December 2022?

A. FPL projects that it will incur $34.2 million in incremental nuclear power plant security costs in 2022. The costs consist of $7.0 million of capital investment and $27.2 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 costs incurred in maintaining a security force as a result of implementing the NRC's fitness-for-duty rule under 10 CFR Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintenance of the physical upgrades resulting from implementing the NRC's physical security rule under 10 CFR Part 73; and implementation of 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 adversary tactics and capabilities employed by the NRC's Composite Adversary Force, as required by NRC inspection procedures.

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2022 through December 2022?

A. FPL's current projection of Fukushima-related costs for 2022 is approximately $0.8 million of 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, it does.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY
TESTIMONY OF CHARLES R. ROTE
DOCKET NO. 20210001-EI
MARCH 16, 2021

Q. Please state your name, business address.

A. My name is Charles R. Rote. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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 and Gulf Power Company's ("Gulf" or "the Company") fossil generating assets. Since 2013, I have also overseen the preparation and filing of the Generating Performance Incentive Factor ("GPIF") documents including testimony, exhibits, audits and discovery.

Q. Please describe the relationship of Gulf Power to Florida Power & Light Company.

A. Gulf Power was acquired by FPL's parent company, NextEra Energy, Inc., on January 1, 2019. Gulf was subsequently merged into FPL on January 1, 2021. Following the acquisition, and even prior to the legal combination of FPL and Gulf Power, the two companies began to consolidate their operations; however, the companies remained separate ratemaking entities. On March 12, 2021, FPL filed with the Florida Public Service Commission ("FPSC" or "the Commission") a Petition for Unification of Rates and for a Base Rate Increase, in which FPL requested that the Commission approve the placement of FPL's rates into effect for all customers currently served pursuant to the rates and tariffs on file for Gulf. If the Commission approves FPL's request, Gulf will no longer exist as a separate ratemaking entity.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report Gulf's actual 2020 performance for Equivalent Availability Factor and Average Net Operating Heat Rate for the twelve generating units used to determine its GPIF and to calculate the resulting GPIF reward. I compared the performance of each unit to the targets approved in Commission Order No. PSC-2019-0484-FOF-EI issued November 18, 2019 for the period January through December 2020 and performed the reward/penalty calculations prescribed by the GPIF Manual.

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

A. Yes, Exhibit CR-1 consisting of five schedules shows the reward/penalty calculations.

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of Schedule 5 of Exhibit CR-1 incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

On January 20, 2021, Plant Crist was renamed Gulf Clean Energy Center (GCEC) with the completion of the plant's gas conversion. Plant Crist Unit 7 is now reflected as GCEC 7 in my exhibit.

Q. Are there any issues related to the GPIF targets for this period that were filed with the Commission on September 3, 2019, in Docket No. 20190001-EI that may affect the validity of those targets for this period?

A. Yes. The target filing takes 3 years of historical unit specific heat rate data to develop the heat rate targets for each unit. The historical data used to develop the 2020 targets do not take into consideration damage that occurred at the Gulf Clean Energy Center (GCEC) on September 16th from Hurricane Sally. GCEC Unit 7 remained offline until January 10, 2021. As a result of GCEC Unit 7 being offline, Smith Unit 3 had to provide more generation than forecasted and this drove heat rate performance outside of its normal historical ranges during that period. The 2020 GPIF projections did not contemplate operating Smith Unit 3 in this manner.

The GPIF process was not established to reward or penalize units for performance demands as result of catastrophic events; therefore, the heat rate targets set for the period of September through December 2020 were adjusted for Smith Unit 3.

Q. Please describe how this change in generation mix is being addressed in this filing.

A. In accordance with past Commission Orders pertaining to the burning of low Btu coal in Daniel Units 1 and 2 , including Commission Orders PSC-04-1276-FOF-EI and PSC-05-1252-FOF-EI, Plant Daniel Units 1 and 2 are excluded from the GPIF heat rate calculations for the months when the low-Btu fuel mix was burned. This was accomplished by setting the units' Adjusted Actual Heat Rates equal to their respective Target Heat Rates. This resulted in producing neither a reward nor a penalty for heat rate for these two units for these months when the units were burning the low-Btu fuel mix.

Gulf believes that due to extensive damage sustained at GCEC 7 and the higher generation demand on Smith Unit 3 resulting in a higher heat rate for period September through December 2020 the target heat rate should be used in place of actual heat rate.

Q. Were there any other circumstances that the Company did not make any adjustments for?

A. Yes. The GCEC 7 target was based on the lateral gas line being in-service by July 1, 2020. The lateral line didn't go into service until December 31, 2020. After GCEC 7 came out of outage at the end of May, the unit ran on minimum load for the months of June through August burning to conserve coal. The result of running on minimum load, the unit produces a higher heat rate than a unit running at optimal load. This higher heat rate contributed to the GPIF penalty.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established in Commission Order No. PSC-2019-0484-FOF-EI is on page 8 of Schedule 2. The results are Scherer 3, (10.00) points; GCEC 7, (10.00) points; Daniel 1, 0.00 points; Daniel 2, (10.00) points; and Smith 3, (10.00) points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2019, are shown on page 13 of Schedule

3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points:
Scherer 3, 0.00 points; GCEC 7, (10.00) points; Daniel 1, 10.00 points;
Daniel 2, 5.33 points, and Smith 3, (2.35) points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was (2.08) as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $1,642,650.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $1,642,650 as provided by the GPIF methodology.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20210001-EI

Before me, the undersigned authority, personally appeared Charles Rote, who being first duly sworn, deposes and says that he is the Power Generation Division Director Business Services of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Charles Rote

Charles Rote
Power Generation Division Director Business Svcs

Sworn to and subscribed before me by means of X physical presence or ____ online notarization this 12th day of March, 2021.

K Carey

Notary Public, State of Florida at Large

Notary Public State of Florida
Kristen Carey
My Commission HH 026570
Expires 08/02/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20210001-EI

MARCH 16, 2021

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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 and filing of the Generating Performance Incentive Factor ("GPIF") documents 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 2020 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the twelve generating units used to determine its GPIF and to calculate the resulting GPIF reward. I compared the performance of each unit to the targets approved in the final Commission Order No. PSC-2019-0484-FOF-EI issued November 18, 2019 for the period January through December 2020, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $12,780,585 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $6,390,846.

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 GPIF reward/penalty amount was calculated.

A. The steps involved in making this calculation are provided in Exhibit CRR-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.3814, $12,780,585 in fuel savings and a GPIF reward of $6,390,846. 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 EAF and ANOHR, the weighting factors, and the associated GPIF unit points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the twelve GPIF units, the actual outage factors and the actual EAF for each unit. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 19. 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 19. These tables are based on the targets and target ranges approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2020 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAF for six out of the twelve GPIF units were better than their targets. In addition, three out of the twelve 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 99.9%, compared to its target of 87.4%. This results in +10.0 points, which corresponds to a GPIF reward of $1,863,540.

St. Lucie Unit 2 operated at an adjusted actual EAF of 91.4%, compared to its target of 85.7%. This results in +10.0 points, which corresponds to a GPIF reward of $1,287,090.

Turkey Point Unit 3 operated at an adjusted actual EAF of 85.2% compared to its target of 85.7%. This results in -1.67 points, which corresponds to a GPIF penalty of $200,718.

Turkey Point Unit 4 operated at an adjusted actual EAF of 83.4% compared to its target of 82.7%. This results in +2.33 points, which corresponds to a GPIF reward of $261,954.

In total, the nuclear units' EAF performance results in a net GPIF reward of $3,211,866.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,444 Btu/kWh compared to its target of 10,421 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 10,272 Btu/kWh compared to its target of 10,262 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 10,440 Btu/kWh compared to its target of 11,228 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 $332,640.

Turkey Point Unit 4 adjusted actual ANOHR is 10,801 Btu/kWh compared to its target of 10,865 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a net GPIF reward of $332,640.

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

A. $3,544,506.

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

A. Regarding EAF performance, three of the eight fossil generating units performed better than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $892,080. The other five performed worse than their availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $638,820. Thus, the total fossil units' EAF performance results in a net GPIF reward of $253,260.

Regarding ANOHR, six of the eight fossil units operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties. The other two operated below the dead band so they received a combined reward of $2,593,080. Thus, the total fossil units' heat rate performance results in a net GPIF reward of $2,593,080.

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

A. The net GPIF fossil availability performance reward of $253,260 plus the net GPIF heat rate fossil performance reward of $2,593,080 results in a total GPIF reward for FPL's fossil units of $2,846,340.

Q. To recap, what is the total GPIF result for the period January through December 2020?

A. The total GPIF result for the period January through December 2020 is $12,780,585 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $6,390,846.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20210001-EI

SEPTEMBER 3, 2021

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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 of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil/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 2022.

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 2022 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 as approved by the Commission.

Q. Are you including the former Gulf Power Company (“Gulf”) generating units in your GPIF preparation?

A. Yes, I am.

Q. Do any generating units from the former Gulf qualify for GPIF when combined with the FPL units?

A. No, they do not. When the former Gulf generating units are combined with the FPL units, they are below the top 80% threshold of the combined total forecasted system net generation which is required to qualify for the GPIF in accordance with the GPIF Manual.

Q. Please summarize the 2022 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 2022, FPL projects a weighted system equivalent planned outage factor (“EPOF”) of 4.6% and a weighted system equivalent unplanned outage factor (“EUOF”) of 7.7%, which yield a weighted system EAF target of 87.7%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,225 Btu/kWh for the same period. 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 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the fifteen generating units that FPL proposes to be considered as GPIF units for the period January through December 2022. 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, each unit's estimated net generation is ranked from highest to lowest. Then, those units, which the cumulative net generation represent no less than the top 80% of the total estimated system net generation, are included in the GPIF calculation. The estimated net generation 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 fifteen units which FPL proposes to use for the period January through December 2022 represent the top 82.2% of the total forecasted system net generation for this period including the former Gulf generating units but excluding Okeechobee ("OCEC") and Dania Beach ("DBEC") Clean Energy Centers. OCEC went in service in April 2019 and DBEC is expected to be in service in the second quarter of 2022. Consequently, they were excluded from the GPIF calculation because there is insufficient historical data to include them. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2022 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20210001-EI

DECLARATION OF JASON CHIN

1. My name is Jason Chin, and my business address is Florida Power & Light Company ("FPL"), 9250 West Flagler Street, Miami, Florida, 33174.

2. I am employed by FPL as Senior Manager, Regulatory Accounting.

3. 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 (MBA) 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 in regulatory accounting and the calculation of revenue requirements. Specifically, I have provided accounting support in multiple FPL retail base rate filings and other regulatory dockets filed at the Florida Public Service Commission ("FPSC" or the "Commission") as well as the Federal Energy Regulatory Commission. My responsibilities have included the management of the accounting for FPL's, Gulf's and FCG's cost recovery clauses and the preparation, review and filing of both FPL's and FCG's monthly Earnings Surveillance Reports ("ESR") at the FPSC.

4. The purpose of my declaration is to provide the revised revenue requirement calculations for the Okeechobee Clean Energy Center ("OCEC"), the 2019 Solar Project and the 2020 Solar Project based on actual capital costs as required by FPL's Stipulation and Settlement

Agreement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 20160021-EI, issued on December 15, 2016 ("Settlement Agreement").

<u>Okeechobee Clean Energy Center Limited Scope Adjustment</u>

5. As more fully described in Paragraph 9(d) of the Settlement Agreement, once OCEC's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial OCEC LSA factor, the factor would be recalculated and a one-time credit would be made to customers through the Capacity Cost Recovery Clause.

6. Pursuant to Paragraph 9(a) of the Settlement Agreement, the authorized jurisdictional annualized base revenue requirement for the first 12 months of operations for OCEC used for the initial LSA factor was $200 million.

7. As reflected on Attachment JC-1, the actual capital costs for OCEC are $1,223.3 million resulting in a revised jurisdictional annualized base revenue requirement for the first 12 months of operations of $198.3 million. This represents a decrease in jurisdictional annualized base revenue requirement of $1.736 million.

<u>2019 and 2020 Solar Base Rate Adjustments</u>

8. The Commission approved the estimated jurisdictional revenue requirements for the 2019 and 2020 Solar Base Rate Adjustments (SoBRA) in Order No. PSC-2018-0610-FOF-EI (Docket No. 20180001-EI) and Order No. PSC-2019-0484-FOF-EI, (Docket No. 20190001-EI), and placed into service during 2019 and 2020, respectively. The final jurisdictional revenue requirement computations are based on actual capital costs for the 2019 and 2020 Projects as required by the Settlement Agreement.

9. Paragraph 10(g) of the Settlement Agreement states the following:

“In the event that the actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised SoBRA Factor will be computed using the same data and methodology incorporated in the initial SoBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based.”

10. As reflected in the 2019 SoBRA Final Revenue Requirement Calculation on page 1 of Attachment JC-2, the final jurisdictional annualized revenue requirement associated with the 2019 SoBRA is $51.659 million.

11. With the exception of capital costs, the final revenue requirement computation for the 2019 SoBRA is based on the same inputs used for the initial 2019 SoBRA Factor included in FPL witness Castaneda’s testimony filed on August 24, 2018, Docket No. 20180001-EI, and approved by this Commission in Order No. PSC-2018-0610-FOF-EI. As reflected on page 2 of Attachment JC-2, the projected total per book capital cost of $413.063 million used in the initial 2019 SoBRA Factor was replaced with the actual total per book costs of $412.804 million, resulting in a decrease in revenue requirements of $26,890.

12. As reflected within the 2020 SoBRA Final Revenue Requirement Calculation on page 1 of Attachment JC-3, the final jurisdictional annualized revenue requirement associated with the 2020 SoBRA is $50.384 million.

13. With the exception of capital costs, the final revenue requirement computation for the 2020 SoBRA is based on the same inputs used for the initial 2020 SoBRA Factor included in FPL witness Fuentes’s testimony filed on September 3, 2019, Docket No. 20190001-EI,

and approved by this Commission in Order No. PSC-2019-0484-FOF-EI. As reflected on page 2 of Attachment JC-3, the projected total per book capital cost of $410.699 million used in the initial 2020 SoBRA Factor was replaced with the actual total per book cost of $409.488 million, resulting in a decrease in revenue requirements of $107,294.

14. The refund calculations associated with the decreases in revenue requirements for the OCEC LSA, the 2019 SoBRA, and 2020 SoBRA are discussed in FPL witness Edward Anderson's declaration.

15. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

Jason Chin
JASON CHIN

Date: 09/02/2021

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20210001-EI

DECLARATION OF EDWARD J. ANDERSON

1. My name is Edward J. Anderson, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408. I have personal knowledge of the matters stated in this declaration.
2. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Manager-Regulatory Rate Development.
3. I hold a Bachelor of Arts in Economics and Business, from the Virginia Military Institute. In November 2016, I joined FPL as Principal-Rate Development within the Company's Regulatory Affairs Organization and assumed my current role in March 2018. 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 the Company's rates witness for several generation adjustment and fuel rate proceedings.

4. The purpose of my declaration is to provide, for the generation listed below, revised Generation Base Rate Adjustment ("GBRA") and Solar Base Rate Adjustment ("SoBRA") factors as well as the amounts to be refunded through the Capacity Cost Recovery Clause ("CCRC"):

   a. the Okeechobee Clean Energy Center ("OCEC");

   b. the 2019 Solar Project; and

   c. the 2020 Solar Project.

5. FPL is employing the identical mechanism it has employed to true-up the capital expenditures associated with the Cape Canaveral Energy Center, Port Everglades Energy Centers the 2017 Solar Project, and the 2018 Solar Project.

OCEC Factor

6. As presented on page 1 of Attachment JC-1, to the Declaration of Jason Chin, the OCEC final jurisdictional annualized base revenue requirement based on the actual capital costs for the OCEC is $198.264 million.

7. Except for the revenue requirement associated with the actual capital costs, the revised OCEC Factor is computed using the same data used in computation of the initial OCEC Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,578.103 million, as shown in the OCEC filing, Docket No. 20180001-EI.

8. The revised OCEC Factor using the updated revenue requirement of $198.264 million is 3.014%. The computation of this revised factor is provided in Attachment EJA-1, page 1 of 3.

2019 SoBRA Project Factor

9. As presented on page 1 of Attachment JC-2, to the Declaration of Jason Chin, the 2019 SoBRA Project's final jurisdictional annualized base revenue requirement based on the actual capital costs is $51.659 million.

10. Except for the revenue requirement associated with the actual capital costs, the revised 2019 SoBRA Project Factor is computed using the same data used in computation of the initial 2019 SoBRA Project Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,501.950 million, as shown in the 2019 SoBRA Project filing, Docket 20180001-EI.

11. The revised 2019 SoBRA Project Factor using the updated revenue requirement of $51.659 million is 0.7945%. The computation of this revised factor is provided in Attachment EJA-2, page 1 of 3.

2020 SoBRA Project Factor

12. As presented on page 1 of Attachment JC-3, to the Declaration of Jason Chin, the 2020 SoBRA Project final jurisdictional annualized base revenue requirement based on the actual capital costs is $50.384 million.

13. Except for the revenue requirement associated with the actual capital costs, the revised SoBRA Factor is computed using the same data used in the computation of the initial SoBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,896.706 million, as shown in the initial SoBRA Filing, Docket No. 20190001-EI.

14. The revised 2020 SoBRA Factor using the updated revenue requirement of $50.384 million is 0.731%. The computation of this revised factor is provided in Attachment EJA-3, page 1 of 3.

Refund Amounts

15. Pursuant to FPL's 2016 Rate Settlement approved by Order No. PSC-16-0560-AS-EI, and consistent with the initial filings associated with OCEC, the 2019 SoBRA Project and 2020 SoBRA Project, once the actual capital costs are known, if the actual capital costs are less than the projected costs used to develop the initial Factors, a one-time credit is to be made through the Capacity Clause. The difference between the cumulative base revenues that have been collected since the implementation of the initial factors through December 31, 2021, and the cumulative base revenues that would have resulted if the revised Factors had been implemented will be credited to customers through the CCRC with interest through December 31, 2021 at the 30-day commercial paper rate as specified in Rule 25-6.109. The amounts of the refund with interest are as follows:

Plant	Refund ($MM)	Reference
OCEC	$5.056	Attachment EJA-1, Page 3 of 3
2019 SoBRA Project	$0.085	Attachment EJA-2, Page 3 of 3
2020 SoBRA Project	$0.120	Attachment EJA-3, Page 3 of 3
Total	$5.261	

The total refund amount with interest to be credited to the CCRC will be $5.261 million.

16. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

EDWARD J. ANDERSON

Date: 9/1/2021

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20210001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2020 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 2020 through December 2020.

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 2020 through December 2020?

A. For the Consolidated Electric Division the final remaining true-up amount is an over recovery of $2,937,906.

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 2020 period and the total true-up amount to be collected or refunded during the January - December 2021 period.

Q. What was the actual end of period true-up amount for January - December 2020?

A. For the Consolidated Electric Division it was $3,235,074 over recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2021 period?

A. A consolidated over-recovery of $297,168 to be collected.

Q. The beginning true-up balance from your Schedule E1-b differs from the amount that appeared in your Final True-Up Amount for 2019, please explain?

A. It was discovered that our monthly Fuel filing for December 2018 as well as the 2018 Final True-up filing had errors with regards to Fuel Revenues. In that fourth quarter, we were still in the midst of restoring services to our many customers impacted by damages resulting from Hurricane Michael. Part of this process entailed applying several adjusting transactions within our billing system. The Company did not bill its customers in the affected areas of the hurricane during the months of October and November. In December, a majority of the services had been restored and the Company resumed its billing processes. Subsequently, due to the suspension of billing for a specific area, adjustments were made to the billing system and accounting financials to correct any billing issues. Around the same time, the Company also received Commission approval to apply a portion of its 2018 Tax Cuts and Jobs Act settlement to its fuel and purchased power cost under- recovery. In the course of preparing the monthly fuel filing for December 2018, some adjustments were not accurately reflected in the fuel revenues causing the true-up to be overstated. This finding was not immediately detected and the discrepancy carried forward in our reported fuel filings, which necessitated FPUC performing a thorough reconciliation to correct the fuel filings and determine the appropriate true-up balance.

Q. Is the $3,952,348 under-recovery that appears as your beginning true-up balance on your Schedules A, E1-b and C-1 the correct final true-up-amount for 2019?

A. Yes.

Q. How was this correction implemented in this filing?

A. I prepared revised monthly Fuel true-up filing for each of the months from January 2020 to June 2020 in Exhibit CDY-3 of the previous filing which further illustrated the monthly computations of the 2020 true-up recoveries.

Q. What was the net impact of this correction to your 2020 beginning true-up balance?

A. The correction resulted in a $14,280 to the Company's fuel cost recovery balance.

Q. Is the $14,280 recovery correction the only adjustment to the Company's fuel true-up balance during 2020?

A. No. In response to related Orders approved by the Commission, the Company was allowed to apply amounts derived from settlement agreements to reduce its existing fuel and purchased power cost recovery balance and further reduce its fuel cost recovery factors in subsequent years. Order No. PSC-2019-0010-AS-EI in Docket No. 20180048-EI granted the Company permission to apply some of the income tax benefits associated with the Tax Cuts and Jobs Act of 2017 towards reducing its fuel and purchased power cost recovery balance. The amount applied during 2020 totaled $80,317, $27,870 of which was attributed to 2019. Additionally, Order No. PSC-2020-0347-AS-EI in Docket No. 20190156-EI allowed the Company to refund its customers through its fuel clause for the over-collected interim rates associated with its storm cost recovery for Hurricane Michael. During 2020, the refund to the customers totaled $975,260.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-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 2021 – December 2021 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 2020 – December 2020?

A. The final remaining true-up amount was an over-recovery of $2,937,906.

Q. What is the estimated true-up amount for the period January 2021 – December 2021?

A. The estimated true-up amount is an under-recovery of $680,436.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2022 – December 2022?

A. At the end of December 2021, based on six months actual and six months estimated, the Company estimates it will over-recover $2,257,470 in purchased power costs, which will be refunded from January 2022 – December 2022.

Q. Has the Company made any revisions to its 2021 estimated six month projection data?

A. Yes, we made changes to the estimated fuel costs since our original projection filing for 2021. The Company is expecting a transmission rebate from its purchased power supplier, FP&L, for approximately $223,800 by year end and has included this amount in our 2021 true-up computation. FPUC has also included the annual tax savings addressed in the amended settlement approved by Order No. PSC-2020-0083-PAA-EI in Docket No. 20200033-EI to be applied to its 2021 fuel and purchased power cost recovery balance at year's end.

The current estimate of $75,358 has been added to our 2021 true-up computation.

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 are being developed 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 and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. The Company incurred approximately $95,000 in the consulting and legal fees linked to this project in 2020 and another $57,000 to date in 2021. We roughly estimate to spend another $55,000 by year-end.

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

A. At this point, much depends upon the time frames for the necessary operating agreements, regulatory approvals, and permits. The current target is to have the necessary approvals and agreements in place on a schedule that would enable the necessary major components to be ordered in the first quarter of 2022. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2022 Projection Testimony of Curtis D. Young

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, FL 33411.

Q. By whom are you employed?

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

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

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. My testimony will establish the "true-up" collection amount, based on actual January 2020 through June 2021 data and projected July 2021 through December 2022 data to be collected or refunded during January 2022 – December 2022. My testimony will also summarize the computations that are contained in composite exhibit CDY-3 supporting the January through December 2022 projected levelized fuel adjustment factors for its consolidated electric divisions. Additionally, these factors include a refund to customers per the settlement agreement for the corporate state income tax savings approved in Docket No. 20200033-EI by Order No. PSC-2020-0083-PAA-EI, issued on March 20, 2020, as well as additional costs incurred as a result of the COVID-19 pandemic and deemed recoverable in terms of the settlement approved by Order No. PC-2021-0266-S-PU, as amended, issued in Docket No. 20200194-PU.

Q. What is the monetary impact of the state tax savings refund adjustment to your 2021 true-up balance?

A. The adjustment is a $75,358 over-recovery to the true-up balance.

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 CDY-3, which is appended 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 2022 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. 20160001-EI, 20170001-EI, 20180001-EI, 20190001-EI, 20200001-EI and 20210001-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. In addition to the fuel-related endeavors mentioned above, has the Company included any other costs in your projected amounts?

A. Yes, the Company has also included costs related to the settlement agreement regarding COVID-19 regulatory asset in Docket No. 20200194 and approved in Order No. PSC-2021-0266-S-PU.

The settlement agreement, which was approved by the Commission on July 8, 2021, allows Florida Public Utilities Company to recover $2,085,759 of pandemic–related incremental expenses. Beginning with the factors established for the calendar year 2022, FPUC is allowed to amortize over two years and recover the allocated regulatory asset of approximately $1,354,120 for the electric division, through the Fuel and Purchased Power Cost Recovery Clause mechanism. The annualized amount, $677,060, is included among the Company's 2022 projected costs.

Q. What are the final remaining true-up amounts for the period January – December 2020?

A. The final remaining consolidated true-up amount was an over-recovery of $2,937,906.

Q. What are the estimated true-up amounts for the period of January – December 2021?

A. There is an estimated consolidated under-recovery of **$680,436.**

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2022 year?

A. The Company has determined that at the end of December 2021, based on six months actual and six months estimated, we will have a consolidated electric **over-recovery of $2,257,470.**

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 **4.580¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2022 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 CDY-3, a residential customer using 1,000 KWH will pay **$127.91**. This is an increase of **$0.13** above 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. 20210001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2022 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 and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company 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 in both the Northeast and Northwest Florida Divisions. 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 2019 I moved into my current role as Director, Generation and Pipeline Development.

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

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI. Most recently, I provided written, pre-filed testimony in Docket No. 20210001-EI, the Commission's regular fuel cost recovery proceeding, and also provided pre-filed testimony the prior year, in Docket No. 20200001-EI, the Commissions' regular fuel cost recovery. I have also been involved in and filed testimony in Docket No. 20191056 for the Limited Proceeding to Recover Incremental Storm Restoration Costs.

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 Gulf Power Company ("Gulf")/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. 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 regularly pursues opportunities to achieve energy resiliency and reduced purchased power costs for the benefit of our customers. During 2018, FPUC began by executing a transmission interconnection agreement and a new purchased power agreement with Florida Power & Light (FPL) for our Northeast

Florida Division. During 2019, a purchased power agreement with Gulf/FPL for our Northwest Florida Division was executed along with an amendment of the existing FPL purchased power agreement for our Northeast Florida Division.

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

A. The existing agreement for our Northwest Florida Division with Gulf/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 amended in 2019 to continue in effect through the December 31, 2026, unless extended by FPUC.

Q. Can you provide background on the new purchased power agreement with FPL for the Northwest Florida Division and the amendment of the purchased power agreement for the Northeast Florida Division that became effective January 1, 2020?

A. Yes. Informal solicitations occurred with four providers that were capable of providing wholesale power to the Northwest Florida Division delivery points located in Jackson, Calhoun and Liberty Counties. Additional consideration was given to the ability to combine agreements for the Northeast and Northwest Florida Divisions in order to provide additional flexibility, reduced cost and energy resiliency between divisions. Proposals were received from four parties and the evaluation and discussions began immediately thereafter. Based on the differences in the bids submitted, the evaluation required additional time for soliciting additional information to allow for further assessment. After the evaluation was completed, FPL was determined to be the most appropriate selection and additional negotiations were conducted in order to develop a comprehensive purchased power agreement that impacted both the Northwest and Northeast Florida Divisions. On August 12, 2019, the "Native Load Firm All Requirements Power and Energy Agreement" ("Agreement") for the Northwest Florida Division was executed by both parties with an effective date of January 1, 2020, and will continue in effect through at least December 31, 2026. Additionally, on August 12, 2019, the "First Amendment to the Native Load Firm All Requirements Power and Energy Agreement" ("Amendment") for the Northeast Florida Division was executed by both parties. The "Amendment" will have the effect of extending the existing agreement for the Northeast Florida Division through December 31, 2026. Both the "Agreement" and "Amendment" include a provision that will allow FPUC the sole right to extend the agreements through December 31, 2030.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to increased energy resiliency and reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects, potential Solar Photovoltaic ("PV") projects and associated utility scale battery projects.

More specifically, Pierpont & McLelland has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. 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, including customers with Combined Heat and Power ("CHP") capability, to further reduce the overall purchased power impact to all FPUC customers. Christensen Associates also assisted the Company with analysis regarding the purchase power agreements.

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" with FPL, the already quantifiable benefits of the existing project has piqued the interest of others to contemplate partnering with a new CHP-based project. Given that FPUC would again be the recipient of any power generated by such project, FPUC has been actively involved in the initial development and engineering of a new project located on Amelia Island. Significant efforts have continued to develop this CHP which, similar to Eight Flags, will be located on Amelia Island and will allow FPUC to provide additional reliability and resilience to its electricity supply for its customers on Amelia Island. This second CHP will provide competitively priced electricity for FPUC's customers while providing high pressure steam and hot water to a local industrial customer. Preliminary engineering, financial modeling, operating agreements and Florida Department of Environmental Protection permitting have been completed for this CHP unit. FPUC anticipates that construction will begin on this project in 2022 with the projected in service date of second quarter of 2023.

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, the cost is 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 for the possibility of a partnership between the parties that would allow for the development of a PV project.

Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects have been difficult to justify economically at this point but are still under consideration by FPUC. Nonetheless, the potential benefits of the PV and battery projects under consideration will be continued.

Q. Does this include your testimony?

A. Yes.

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
FILED: 4/2/2021

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 clauses. During the last 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 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 2020 through December 2020 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 five 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 2020 through December 2020?

A. The final true-up amount for the Capacity Clause for the period January 2020 through December 2020 is an under-recovery of $3,354,779.

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 2020 Through December 2020", provides the calculation for the final under-recovery of $3,354,779. The actual capacity cost under-recovery, including interest, was $1,583,299 for the period January 2020 through December 2020 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $1,771,480 actual/estimated over-recovery approved in Order No. PSC-2020-0439-FOF-EI issued November 16, 2020 in Docket No. 20200001-EI, results in a final under-recovery of $3,354,779 for the period, as identified in Document No. 1, page 4 of 4. This amount will be applied to the calculation of the capacity cost recovery factors for the period January 2022 through December 2022.

Q. What is the estimated effect of this $3,354,779 under-recovery for the January 2020 through December 2020 period on residential bills during the January 2022 through December 2022 period?

A. The $3,354,779 under-recovery will increase a 1,000 kWh residential bill by approximately $0.20.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2020 through December 2020?

A. The final Fuel Clause true-up for the period January 2020 through December 2020 is an over-recovery of $3,769,256. The actual fuel cost under-recovery, including interest, was $21,709,799 for the period January 2020 through December 2020. This $21,709,799 amount, less the $25,479,055 projected under-recovery amount approved in Order No. PSC-2020-0439-FOF-EI, issued November 16, 2020 in Docket No. 20200001-EI, results in a net over-recovery amount for the period of $3,769,256.

Q. What is the estimated effect of the $3,769,256 over-recovery for the January 2020 through December 2020 period on residential bills during the January 2022 through December 2022 period?

A. The $3,769,256 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.19.

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 2020 Through December 2020." It shows the calculation of the final fuel over-recovery of $3,769,256.

Line 1 shows the total company fuel costs of $488,777,177 for the period January 2020 through December 2020. The jurisdictional amount of total fuel costs is $488,777,177, 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 $39,947,745 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 $21,709,799 shown on line 9. The $21,709,799 actual under-recovery amount less the $25,479,055 projected under-recovery amount shown on line 10, results in a final over-recovery amount of $3,769,256 for the period January 2020 through December 2020, 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.* Original Estimates for the Period January 2020 Through December 2020." 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 2020 through December 2020?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $3,208,019 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2020 through December 2020?

A. As shown on line C3 of Document No. 3, the company collected $11,600,930, or 2.7 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. Regarding Document 4, Schedule A-12, has been updated from that provided to the Commission on January 25, 2021 to reflect capacity costs associated with three short-term contracts that became effective on December 1, 2020 but were not included in error. The updated amount increased capacity costs by $1,120,000 and is reflected in Document 4.

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. Total gains were $6,642,047. Under the sharing mechanism, Tampa Electric customers receive $5,356,819, and the company earned an incentive of $1,285,228 as a result of the company's Optimization Mechanism activities during 2020. Customers received the gains from these transactions during 2020, and Tampa

Electric requests Commission approval to collect the company's $1,285,228 incentive in its 2022 fuel factors.

Q. Does this conclude your testimony?

A. Yes, it does.

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 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 last 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 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 2021 through December 2021 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the period September 2021 through December 2021, as referenced in Tampa Electric's Petition for Mid-course Correction of its Fuel Cost Recovery Factors and Capacity Cost Recovery Factors ("MCC petition"), filed on July 19, 2021 in this docket, or in the alternative over the January 2022 through December 2022 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2021, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2022 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 four 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 2021 through December 2021, which reflect Tampa Electric's mid-course correction filing, with the projected under-recovery being recovered through the period of September 2021 through December 2021. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2021 through December 2021, which reflect Tampa Electric's mid-course correction filing, with the projected under-recovery being recovered through the period of September 2021 through December 2021. Document No. 3 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 2021 through December 2021, without the proposed mid-course correction. Document No. 4 provides the actual/estimated capacity cost recovery true-up amount for the period January 2021 through December 2021, without the proposed mid-course correction.

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 the January 2022 through December 2022 fuel and purchased power cost recovery factors?

A. If the company's MCC petition is approved, the estimated net true-up amount applicable for the period of January 2021 through December 2021 is an under-recovery of $325,418. In the alternative, if the Commission does not approve Tampa Electric's MCC petition, then Tampa Electric's estimated net true-up amount applicable for the period of January 2021 through December 2021 is an under-recovery of $73,680,277.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2022 through December 2022 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2022 includes the final true-up amount for the period January 2020 through December 2020 and the actual/estimated true-up amount for the period January 2021 through December 2021. The calculations are shown on Schedule E1-A of Exhibit No. MAS-2, Documents No. 1 and No. 3.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery amount for 2020?

A. The final true-up is an over-recovery of $3,769,256. The actual fuel cost under-recovery, including interest is $21,709,799 for the period January 2020 through December 2020. The $21,709,799 amount, less the projected under-recovery amount of $25,479,055 approved in Order No. PSC-2020-0439-FOF-EI, issued November 16, 2020 in Docket No. 20200001-EI results in a net-over recovery amount for the period of $3,769,256.

If the Commission approves Tampa Electric’s MCC petition, the final 2020 true-up amount will be $0 because it is already included in the mid-course factors. If the Commission does not approve the company’s MCC petition, the final 2020 over-recovery amount to be applied to the 2022 factors is an over-recovery amount of $3,769,256 as described above.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2021 through December 2021?

A. If the Commission approves Tampa Electric's MCC petition, the actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $325,418. If the Commission does not approve Tampa Electric's MCC petition, the actual/estimated 2021 fuel true-up amount is an under-recovery amount of $77,449,533 for the January 2021 through December 2021 period. The detailed calculations supporting the actual/estimated current period true-up is shown in Exhibit No. MAS-2, Schedule E1-B on Documents No. 1 and 3.

Q. What are the primary drivers of the expected 2021 fuel under-recovery amount?

A. As described in the company's MCC petition, the primary reason for the expected 2021 under-recovery is a substantial increase in the price of natural gas, compared to the company's original 2021 projection.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2022 through December 2022 capacity cost recovery factors?

A. If the company's MCC petition is approved, the estimated net true-up amount applicable for January 2022 through December 2022 is an under-recovery of $25,180 as shown in Exhibit No. MAS-2, Documents No. 2 and 4, page 1 of 4. In the alternative, if the Commission does not approve Tampa Electric's MCC petition, Tampa Electric's estimated net true-up amount applicable for the period of January 2022 through December 2022 is an under-recovery of $9,628,629.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2022 through December 2022 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2022 capacity cost recovery factors includes the final true-up amount for 2020 and the actual/estimated true-up amount for January 2021 and December 2021.

Q. What did Tampa Electric calculate as the final capacity true-up amount for 2020?

A. The final 2020 true-up is an under-recovery of $3,354,779. The actual capacity cost under-recovery, including interest, was $1,583,299 for the period January 2020 through December 2020. This amount, less the $1,771,480 actual/estimated over-recovery amount approved in Order No. PSC-2020-0439-FOF-EI, issued November 16, 2020 in Docket No. 20200001-EI results in a net under-recovery amount for the period of $3,354,779 as identified in Exhibit No. MAS-2, Documents No. 2 and 4, page 1 of 4.

If the company's MCC petition is approved, the final 2020 true-up amount will be $0 since it is included in the mid-course factors. If the Commission does not approve Tampa Electric's MCC petition, then the final 2020 true-up amount is an under-recovery of $3,354,779 as described above.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2021 through December 2021?

A. If Tampa Electric's MCC petition is approved, then the net capacity cost recovery true-up amount for the period January 2021 through December 2021 is an under-recovery of $25,180. In the alternative, if the Commission does not approve the company's MCC petition, the 2021 net capacity cost recovery true-up amount is an under-recovery of $6,273,850. This calculation is shown on Exhibit No. MAS-2, Documents No. 2 and 4, page 1 of 4.

Q. What are the primary drivers of the 2021 capacity under-recovery?

A. During the first quarter of 2021, Tampa Electric entered three power purchase transactions. The first two transactions are with Florida Power & Light, for 150 MW each, for the periods March 2021 through November 2021 and April 2021 through October 2021. These transactions also incur transmission costs. They are non-firm, must-take transactions.

The third transaction is with Duke Energy Florida for 515 MW of non-firm energy for the period March 2021 through November 2021 and does not include a must-take obligation. The transaction is called on a month-ahead basis, and Tampa Electric has elected to receive energy for June, July and August. The company also anticipates that it will use this transaction for September and October 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
FILED: 09/03/2021

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. Have you previously filed testimony in Docket No. 20210001-EI?

A. Yes, I submitted direct testimony on April 2, 2021 and July 27,2021. I submitted revisions to my April 2, 2021 testimony on July 23, 2021.

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

A. No, they have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2022 through December 2022. 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 2022.

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 2022 through December 2022 as well as Schedule H1 for 2019 through 2022. 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, with one caveat. On August 6, 2021, Tampa Electric filed a 2021 Stipulation and Settlement Agreement ("2021 Agreement") in Docket No. 20210034-EI, Petition for rate increase by Tampa Electric Company, which is currently scheduled for hearing on October 21, 2021. Among other things, the 2021 Agreement includes proposed changes to the company's existing rate design across rate classes. The company plans to file revised fuel and capacity clause schedules that reflect the 2021 Agreement in the coming weeks and request approval of those factors for the period January through December 2022. However, if the settlement agreement is not approved by the Commission, then the company requests approval of the factors provided in Exhibit No. MAS-3, Document Nos. 1 and 2, for the period January 2022 until the issues in Docket No. 20210034-EI are resolved. These factors were prepared under my direction and supervision.

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 2017 Amended and Restated Settlement Agreement approved by the Commission in Docket No. 20170271-EI, which amended and extended the 2013 Stipulation that resolved the company's last base rate case (Docket No. 20130040-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. As previously stated, if the company's 2021 Agreement is not approved, then Tampa Electric seeks approval of the proposed capacity cost recovery factors, prepared under my direction and supervision, that 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 requests recovery of $25,180 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2022.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2022, if the company's 2021 Agreement is not approved, for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.031	
GS and CS Secondary	0.027	
GSD, SBF Standard		
Secondary		0.09
Primary		0.09
Transmission		0.09
IS, IST, SBI		
Primary		0.07

Transmission		0.07
GSD Optional		
Secondary	0.021	
Primary	0.021	
Transmission	0.021	
LS1 Secondary	0.004	

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 0.026 cents per kWh compare to the factor for September 2021 through December 2021?

A. The proposed capacity cost recovery factor of 0.026 cents per kWh beginning in January 2022 is 0.118 cents per kWh (or $1.18 per 1,000 kWh) less than the average capacity cost recovery factor credit of 0.144 cents per kWh for the September 2021 through December 2021 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 2022?

A. As I previously stated, approval of the company's pending 2021 Agreement would require modifications to the rate schedules for these factors. If the Commission does not approve the company's settlement agreement, then the appropriate amount for the period beginning in January 2022 is 3.057 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 2022 through December 2022.

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

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $3,673,726, 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 to be applied during the January 2022 through December 2022 period. The net true-up amount is an under-recovery of $325,418. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,285,228.

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 2022 through December 2022. 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 2022.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.057
Tier I (Up to 1,000 kWh)	2.745
Tier II (Over 1,000 kWh)	3.745
Distribution Primary	3.026
Transmission	2.996
Lighting Service	3.008
Distribution Secondary	3.318(on-peak)
	2.944(off-peak)
Distribution Primary	3.285(on-peak)
	2.915(off-peak)
Transmission	3.252(on-peak)
	2.885(off-peak)

Q. How does Tampa Electric’s proposed levelized fuel adjustment factor of 3.057 cents per kWh compare to the levelized fuel adjustment factor for the September 2021 through December 2021 period?

A. The proposed fuel charge factor of 3.057 cents per kWh is

1.198 cents per kWh (or $11.98 per 1,000 kWh) lower than the average fuel charge factor of 4.255 cents per kWh for the September 2021 through December 2021 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2022 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 2022 projection. However, if the settlement agreement is not approved by the Commission, then Tampa Electric's projected 2022 benchmark for non-separated wholesale sales would be $767,628. The $767,628 is the three-year average of $1,498,686, $422,867 and $381,332 in gains for 2019, 2020 and 2021 (actual/estimated).

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 if the company's 2021 Agreement is not approved?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $12.47 in the period beginning January 2022, when compared to the September 2021 through December 2021 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 2022.

Q. Does this conclude your direct testimony?

A. Yes.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 2nd day of November, 2021.

Debbie R Krick

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