BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210007-EI

ENVIRONMENTAL COST RECOVERY
CLAUSE.
___________________________/

VOLUME 1

PAGES 1 - 229

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
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APPEARANCES:

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

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

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).

RICHARD GENTRY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL, PATRICIA A. CHRISTENSEN, MARY A. 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).

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).

PETER J. MATTHEIS and MICHAEL K. LAVANGA, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007, on behalf of Nucor Steel Florida, Inc (Nucor).

CHARLES MURPHY and JACOB IMIG, ESQUIRES, 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

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	226	226
2-49	As identified on the CEL	226	226

P R O C E E D I N G S

CHAIRMAN CLARK: We will open the 07 docket.

Mr. Imig, they left you all alone. It's on you.

Any preliminary matters?

MR. IMIG: There are proposed stipulations of all issue, DEF, FPL/Gulf and TECO support the proposed stipulations. As discussed in more tail in the prehearing order, FIPUG, PCS Phosphate, Nucor and OPC are willing to facilitate a Type 2 stipulation of these issues by taking no position.

All witnesses have been excused, with prefiled testimony and exhibits to be included in the record.

CHAIRMAN CLARK: All right. Prefiled testimony.

MR. IMIG: The prefiled testimony of all witnesses is the subject of a Type 2 stipulation. Staff asks that the prefiled testimony of all witnesses be entered into the record as though read.

CHAIRMAN CLARK: All right. Without objection, so ordered.

(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. 20210007-EI

APRIL 1, 2021

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 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" or the "Company") as the Senior Director of Clause Recovery and Wholesale Rates, Regulatory & State Governmental Affairs.

Q. Please describe your educational background and professional 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?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery Clause ("ECRC") final net true-up amount associated with FPL's environmental compliance activities for the period January 2020 through December 2020.

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

A. Yes, I have. My Exhibit RBD-1 consists of nine forms.

- Form 42-1A reflects the final net true-up for the period January 2020 through December 2020.
- Form 42-2A provides the final true-up calculation for the period.
- Form 42-3A provides the calculation of the interest provision for the period.
- Form 42-4A provides the calculation of variances between actual and actual/ estimated costs for O&M activities for the period.

- Form 42-5A provides a summary of actual monthly costs for O&M activities in the period.
- Form 42-6A provides the calculation of variances between actual and actual/estimated revenue requirements for capital investment projects for the period.
- Form 42-7A provides a summary of actual monthly revenue requirements for the period for capital investment projects.
- Form 42-8A provides the calculation of depreciation and amortization expense and return on capital investment for each capital investment project. Pages 69 through 72 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital investment project for the period.
- Form 42-9A presents the capital structures, components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period.

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

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 FPL's business in accordance with Generally Accepted Accounting Principles and practices, and with the provisions of the Uniform System of Accounts as prescribed by this Commission.

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

A. Form 42-1A, entitled "Calculation of the Final True-up Amount" shows the calculation of the final net true-up for the period January 2020 through December 2020, an over-recovery of $14,657,307, which FPL is requesting be included in the calculation of the ECRC 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 $19,421,091 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period over-recovery for the same period of $4,763,785 (shown on Form 42-1A, Line 6) results in the final net true-up over-recovery for the period January 2020 through December 2020 (shown on Form 42-1A, Line 7) of $14,657,307.

Q. Have you provided a schedule showing the calculation of the end-of-period true-up amount?

A. Yes. Form 42-2A, entitled "Calculation of the Final True-up Amount," shows the calculation of the end-of-period true-up over-recovery amount of $19,421,091 for the period January 2020 through December 2020. The $19,205,214 over-recovery shown on line 5 plus the interest provision of $215,878 shown on line 6, which is calculated on Form 42-3A, results in the final over-recovery of $19,421,091 shown on line 11.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. Yes.

Q. How did actual project O&M and capital revenue requirements for January 2020 through December 2020 compare with FPL's actual/estimated amounts as presented in previous testimony and exhibits?

A. Form 42-4A shows that the variance in total actual project O&M was $11,368,227 or 27.6% lower than projected. Form 42-6A shows a minor variance in total actual revenue requirements (return on capital investments, depreciation, amortization and income taxes) associated with the project capital investments of $122,450 or 0.08% higher than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Actual revenue requirements for each capital project for the period January 2020 through December 2020 are provided on Form 42-8A, pages 14 through 68. Explanations for significant variances in project costs are addressed by FPL witness Sole.

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. 20210007-EI

JULY 30, 2021

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 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" or the "Company") as Senior Director of Clause Recovery and Wholesale Rates, Regulatory & State Governmental Affairs.

Q. Have you previously filed testimony in the Environmental Cost Recovery Clause ("ECRC") 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 Actual/Estimated True-up associated with FPL's environmental compliance activities for the period January 2021 through December 2021.

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

A. Yes, I have. My Exhibit RBD-2 consists of nine forms, PSC Forms 42-1E through 42-9E, included in Appendix I.

- Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2021 through December 2021.
- Forms 42-2E and 42-3E reflect the calculation of the Actual/Estimated True-up amount for the period.
- Forms 42-4E and 42-6E reflect the Actual/Estimated O&M and capital cost variances as compared to original projections for the period.
- Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and capital project costs for the period.
- Form 42-8E (pages 15 through 70) reflects return on capital investments and depreciation by project. Pages 71 through 73 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital investment project.
- Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investment amounts included for recovery for the period January 2021 through December 2021.

Q. Please explain the calculation of the ECRC Actual/Estimated True-Up amount FPL is requesting this Commission to approve.

A. The Actual/Estimated True-Up amount for the period January 2021 through December 2021 is an over-recovery, including interest, of $2,748,438 (Appendix

I, page 1, line 4). The Actual/Estimated True-Up amount is calculated on Form 42-2E by comparing actual data for January 2021 through May 2021 and revised estimates for June 2021 through December 2021 to original projections for the same period. The over-recovery of $2,734,434 shown on line 5 plus the interest provision of $13,943 shown on line 6, which is calculated on Form 42-3E, results in the final over-recovery of $2,748,378 shown on line 11.

Q. Are all costs listed in Forms 42-4E through 42-8E attributable to environmental compliance projects approved by the Commission?

A. Yes, with the exception of the proposed new project, the FPL Miami-Dade Clean Water Recovery Center, which is discussed in the testimony of FPL witness Michael Sole in this docket.

Q. How do the actual/estimated project costs for January 2021 through December 2021 compare with original projections for the same period?

A. Form 42-4E (Appendix I, page 4) shows that total O&M project costs are $2,978,736 lower than projected, and Form 42-6E (Appendix I, page 9) shows that total capital project revenue requirements are $177,121 lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Revenue requirements for each capital project for the 2021 actual/estimated period are provided on Form 42-8E (Appendix I, pages 15 through 70). Explanations for significant variances in project costs are addressed by FPL witness Sole.

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. 20210007-EI

AUGUST 27, 2021

Q. Please state your name and address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company, 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" or the "Company") as Senior Director, Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony 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 FPL's Environmental Cost Recovery Clause ("ECRC") projections and factors for the January 2022 through December 2022 period.

As explained in the testimony of FPL witness Michael W. Sole in this docket, 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. On August 24, 2021, Vote Solar and the CLEO Institute 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 ECRC factors that have been calculated based on the costs of environmental compliance activities associated with consolidated FPL and Gulf ECRC projects, contingent upon the Commission's approval of the Settlement Agreement. Because FPL and Gulf remain separate ratemaking entities until 2022, the 2022 ECRC factors include the separate FPL and Gulf standalone prior and current period true-up amounts.

Additionally, my testimony discusses items from FPL's Settlement Agreement that have been included in the calculation of the 2022 ECRC factors.

Finally, I have reviewed the testimonies and exhibits that were filed by Mr. Richard L. Hume on behalf of Gulf Power in this docket on April 1, 2021 (2020 Final True-Up) and July 30, 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. Is this filing in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

A. Yes. The costs being submitted for the 2022 projected period are consistent with that order.

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

A. Yes. I am sponsoring Exhibits RBD-3 and RBD-4. Appendix I contains RBD-3, which provides the calculation of proposed unified ECRC factors for the period January 2022 through December 2022 and includes PSC Forms 42-1P through 42-8P. Appendix II contains RBD-4, which provides the calculation of the separation factors used in the calculation of the unified 2022 ECRC factors. FPL witness Michael W. Sole is co-sponsoring Form 42-4P, which is included in Exhibit RBD-3.

Q. Please explain how the costs for the consolidated projected 2022 ECRC revenue requirements were determined.

A. As explained by FPL witness Sole and provided on Exhibit MWS-13, FPL has consolidated the currently approved ECRC projects of FPL and Gulf based on the environmental compliance requirements of each project. The consolidated projects and associated costs are simply the sum of the currently approved FPL and Gulf projects that could be functionally combined, along with any projects proposed for approval in this Docket. Approved projects for FPL and Gulf that could not be functionally combined are reflected separately. The consolidated 2022 ECRC O&M

and capital projects are provided in Forms 42-2P and 42-3P in Exhibit RBD-3.

Q. Have you provided a schedule showing the calculation of projected environmental costs being requested for recovery for the period January 2022 through December 2022?

A. Yes. Form 42-1P (page 1) in Exhibit RBD-3 provides a summary of projected consolidated environmental costs being requested for recovery for the period January 2022 through December 2022. Total jurisdictional revenue requirements including true-up amounts, are $344,979,487 (page 1, line 5). This amount includes the consolidated jurisdictional revenue requirements projected for the January 2022 through December 2022 period, which are $364,050,992 (page 1, line 1c) and 2021 actual/estimated net true-ups for FPL and Gulf.

FPL's net over-recovery of $17,405,684 for the January 2021 through December 2021 period consists of the 2020 final true-up over-recovery of $14,657,306 (Form 42-2A filed on April 1, 2021) and the 2021 actual/estimated true-up over-recovery of $2,748,378 (Form 42-2E filed on July 30, 2021).

Gulf's net over-recovery of $1,665,820 for the January 2021 through December 2021 period consists of the 2020 final true-up under-recovery of $2,150,848 (Form 42-2A filed on April 1, 2021) and the 2021 actual/estimated true-up over-recovery of $3,816,668 (Form 42-2E filed on July 30, 2021). The sum of the net true-up amounts for FPL and Gulf is an over-recovery of $19,071,505 (Form 42-1P, lines 2 + 3).

Q. Please describe the schedules that are provided in Appendix I of Exhibit RBD-3.

A. Forms 42-1P through 42-8P provide the calculation of consolidated ECRC factors for the period January 2022 through December 2022 that FPL is requesting this Commission to approve.

Form 42-1P (page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2022 through December 2022.

Form 42-2P (pages 2 through 4) presents the O&M costs associated with consolidated environmental projects for the projected period, along with the calculation of the total jurisdictional amount of $42,042,146 for these projects.

Form 42-3P (pages 5 through 9) presents the recoverable amounts associated with capital costs for consolidated environmental projects for the projected period, along with the calculation of the total jurisdictional recoverable amount of $322,008,846.

Form 42-4P (pages 10 through 82) presents the detailed calculation of the capital recoverable amounts by project for the projected period. Pages 83 through 87 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital project.

Form 42-5P (pages 88 through 168) provides the description and progress of consolidated environmental projects included in the projected period.

Form 42-6P (page 169) calculates the allocation factors for demand and energy at generation. The average 12CP demand allocation factors are calculated by determining the percentage each rate class contributes to the average of the twelve monthly system peaks. The GCP demand allocation factors are calculated by determining the percentage each rate class contributes to the sum of the classes' group non-coincident peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Form 42-7P (page 170) presents the calculation of the proposed unified 2022 ECRC factors by rate class.

Form 42-8P (page 171) presents the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments included for recovery through the ECRC for the period January 2022 through December 2022.

Q. Have you made any adjustments to the 2022 ECRC factors to reflect the proposed Settlement Agreement filed in Docket No. 20210015-EI on August 12, 2021?

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

- Capital recovery schedules – Recovery of the amortization on the unrecovered net investment balance of the projects impacted by the early retirement of the following plants over a twenty-year period:

- o Martin 1&2 (retired 12/18, capital recovery beginning 1/1/22),
- o Manatee 1&2 (to be retired 1/22, capital recovery beginning 2/1/22),
- o Lauderdale 4&5 (retired 12/18, capital recovery beginning 1/1/22),
- o Scherer 4 (to be retired 1/22, capital recovery beginning 2/1/22),
- o The coal capability components of the Gulf Clean Energy Center Units 4-7 (retired 10/20, capital recovery beginning 1/1/2022)

- Dismantlement accrual – Transfer dismantlement reserves between units, impacting ECRC projects associated with Martin, DeSoto, Space Coast, Gulf Clean Energy Center, Daniel and Scherer plants.
- Scherer ash pond closure costs – Transfer the Scherer Unit 4 coal ash dismantlement reserve balance and related accrual from base rates to the ECRC beginning January 1, 2022, in order to align rate recovery of related assets.
- Groundwater Contamination Investigation and Solid & Hazardous Waste Programs (Gulf) – Move certain ECRC program expenses previously recovered in base rates to the ECRC to align recovery of the program expenses beginning January 1, 2022.
- Property taxes – Remove Gulf property taxes currently recovered through ECRC to base rates, effective January 1, 2022
- Regulatory Assessment Fee (“RAF”) – Remove the RAF from the calculation of the ECRC factor.

- Return on Equity ("ROE") – The weighted average cost of capital ("WACC") reflects an ROE of 10.6%

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

A. The ECRC 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 ECRC factors?

A. Yes. As part of the 2021 Settlement Agreement FPL has proposed changes in depreciation rates that will impact the amounts to be recovered through the 2022 ECRC 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 ECRC schedules, but the approved depreciation rates will be reflected in the ECRC costs in the 2022 actual/estimated and final true-up amounts to be included in the 2023 ECRC factors.

Q. Have you included any other adjustments in the calculation of the 2022 ECRC factors?

A. Yes. Per the settlement agreement between FPL and the Office of Public Counsel for the early shutdown of the St. John's River Power Park ("SJRPP") and early termination of the associated Joint Ownership Agreement with its co-owner JEA approved in Order No. PSC-2017-0415-AS-EI, recovery of the annual amortization expense associated with the clause portion of the regulatory assets is to begin when FPL's base rates are next reset in a general base rate case. As such, FPL has included the ten-year recovery of the amortization of the deferred clause portion of the SJRPP regulatory assets beginning January 2022. This impacts Projects 3, 5, 31, 33 and 54.

Q. Please describe the 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 10.6%, as provided in the Settlement Agreement. The WACC is used to calculate the rate of return applied to the 2022 ECRC capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 171 of Exhibit RBD-3, Appendix I.

Q. Are all costs listed in Forms 42-1P through 42-8P included in Exhibit RBD-3, Appendix I attributable to environmental compliance projects previously approved by the Commission or pending Commission approval?

A. Yes.

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. 20210007-EI

APRIL 1, 2021

Q. Please state your name and address.

A. My name is Richard Hume. My business address is One Energy Place Pensacola, FL 32520.

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

A. I am employed by Florida Power & Light Company ("FPL"), as successor by merger with, Gulf Power Company ("Gulf Power") as Manager of Regulatory Issues, in the Regulatory & State Governmental Affairs Department.

Q. Please describe your educational background and professional 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 NewEnergy 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, 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 Florida Power & Light as Manager of Cost and Performance, managing a data analytics team. In that position, my responsibilities included leading the customer rate and bill impact analysis in partnership with the Regulatory Affairs team. In 2019, I joined Gulf Power as Regulatory Issues Manager where my current responsibilities include oversight of the clause cost recovery, calculation of cost recovery factors and the related regulatory filing functions of Gulf Power.

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?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery Clause ("ECRC") final true-up amount associated with Gulf Power's environmental compliance activities for the period January 2020 through December 2020.

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

A. Yes, I have. My Exhibit RLH-1 consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2020 through December 2020.
- Form 42-2A provides the final true-up calculation for the period.
- Form 42-3A provides the calculation of the interest provision for the period.
- Form 42-4A provides the calculation of variances between actual and actual/ estimated costs for O&M activities for the period.
- Form 42-5A provides a summary of actual monthly costs for O&M activities in the period.
- Form 42-6A provides the calculation of variances between actual and revised actual/estimated revenue requirements for capital investment projects for the period.
- Form 42-7A provides a summary of actual monthly revenue requirements for the period for capital investment projects.

- Form 42-8A provides the calculation of depreciation expense and return on capital investment for each capital investment project. Pages 51 through 53 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital investment project for the period, page 48 provides the costs related to the regulatory asset for retired Plant Smith Units 1 and 2, and pages 49 and 50 provide the investment and return related to emission allowances.
- Form 42-9A presents the capital structures, components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period.

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

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

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

A. Form 42-1A, entitled "Calculation of the Final True-up Amount" shows the calculation of the net true-up for the period January 2020 through December 2020, an under-recovery of $2,150,848, which Gulf Power is requesting be included in the calculation of the ECRC 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 $5,510,896 (shown on Form 42-1A, Line 4) minus the previously revised actual/estimated end-of-period over-recovery for the same period of $7,661,744 (shown on Form 42-1A, Line 5) results in the net true-up under-recovery for the period January 2020 through December 2020 (shown on Form 42-1A, Line 6) of $2,150,848.

Q. Have you provided a schedule showing the calculation of the end-of-period true-up amount?

A. Yes. Form 42-2A, entitled "Calculation of the Final True-up Amount," shows the calculation of the end-of-period true-up over-recovery amount of $5,510,896 for the period January 2020 through December 2020. The $5,523,105 over-recovery shown on line 5 plus the interest provision of $44,650 shown on line 6, which is calculated on Form 42-3A, minus previous period adjustment of $56,859 shown on line 10, results in the final over-recovery of $5,510,896 shown on line 11.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. Yes, they are.

Q. How did actual project O&M and capital revenue requirements for January 2020 through December 2020 compare with Gulf Power's revised actual/estimated amounts as presented in previous testimony and exhibits?

A. Form 42-4A shows that the variance in total actual project O&M was $2,239,329 or 9.2% lower than projected and Form 42-6A shows that the variance in total actual revenue requirements (return on capital investments, depreciation and income taxes) associated with the project capital investments were $316,212 or 0.2% higher than projected. Actual revenue requirements for each capital project for the period January 2020 through December 2020 are provided on Form 42-8A, pages 12 through 50.

Q. Please explain the changes to the accounting for the Crist Closed Ash Landfill project costs for the period January 2020 through December 2020.

A. Plant in service and expenditures associated with the Crist Closed Ash Landfill ("Crist CAL") project were moved from capital accounts to deferred FERC 182 regulatory asset accounts beginning January 2020. Costs associated with the Crist CAL project were recorded to regulatory asset accounts and will be amortized to expense since the costs are not associated with an operating asset that will incur future benefit. The regulatory asset costs will continue to be recovered through ECRC and will be amortized at that same rate previously used for the asset depreciation. Amortization of the regulatory asset began January 2020.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20210007-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 31st day of March, 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 RICHARD L. HUME

DOCKET NO. 20210007-EI

JULY 30, 2021

Q. Please state your name and address.

A. My name is Richard Hume. My business address is One Energy Place Pensacola, FL 32520.

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

A. I am employed by Florida Power & Light Company ("FPL"), as successor by merger with, Gulf Power Company ("Gulf Power") as Manager of Regulatory Issues, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony in the Environmental Cost Recovery Clause ("ECRC") 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 Actual/Estimated True-up associated with Gulf's environmental compliance activities for the period January 2021 through December 2021.

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

A. Yes, I have. My Exhibit RLH-2 consists of nine forms.

- Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2021 through December 2021.

- Forms 42-2E and 42-3E reflect the calculation of the Actual/Estimated True-up amount for the period.
- Forms 42-4E and 42-6E reflect the Actual/Estimated O&M and capital cost variances as compared to projections for the same period.
- Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and capital project costs for the period.
- Form 42-8E (pages 12 through 50) reflect the monthly calculations of recoverable costs associated with each capital project for the current recovery period.
- Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investment amounts included for recovery for the period January 2021 through December 2021.

Q. Please explain the calculation of the ECRC Actual/Estimated True-Up amount Gulf is requesting this Commission to approve.

A. The Actual/Estimated True-Up amount for the period January 2021 through December 2021 is an over-recovery, including adjustments and interest, of $3,816,668 (RLH-2, page 1, line 4). The Actual/Estimated True-Up amount is calculated on Form 42-2E by comparing actual data for January 2021 through May 2021 and revised estimates for June 2021 through December 2021 to projections for the same period. The over-recovery of $3,811,100 shown on page 2, line 5 plus the interest provision of $5,568 shown on line 6, which is calculated on Form 42-3E results in the final over-recovery of $3,816,668, shown on line 11.

Q. How did actual project O&M and capital revenue requirements for January 2021 through December 2021 compare with Gulf Power's projection amounts as presented in previous testimony and exhibits?

A. Form 42-4E shows that the variance in total project O&M is $2,114,583 or 6.6% lower than projected and Form 42-6E shows that the variance in total revenue requirements (return on capital investments, depreciation and income taxes) associated with the project capital investments is $1,373,175 or 1.0% lower than projected. Revenue requirements for each capital project for the period January 2021 through December 2021 are provided on Form 42-8E, pages 12 through 50.

Q. Are all costs listed in Forms 42-4E through 42-8E attributable to environmental compliance projects approved by the Commission?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Michael W. Sole was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL W. SOLE

DOCKET NO. 20210007- EI

APRIL 1, 2021

Q. Please state your name and address.

A. My name is Michael W. Sole 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 NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Marine Biology from the Florida Institute of Technology in 1986. I served as an Officer in the United States Marine Corps from 1985 through 1990, attaining the rank of Captain. I was employed by the Florida Department of Environmental Protection ("FDEP") in multiple roles from 1990 to 2010 and served as the Secretary of the FDEP from 2007-2010. I have been employed by NEE or its subsidiary Florida Power & Light Company ("FPL" or the "Company") since 2010. In November 2016, I assumed the position of Vice President of Environmental Services for NEE. In that role, I am responsible for FPL's environmental licensing and compliance efforts for the Company. In May

2017, I was appointed by Governor Scott to the Florida Fish and Wildlife Conservation Commission ("FWC").

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

A. The purpose of my testimony is to explain the reasons for significant variances in costs associated with operation & maintenance ("O&M") expenses and capital investments which support FPL's Environmental Cost Recovery Clause ("ECRC") final true-up for the period of January 2020 through December 2020. Additionally, my testimony provides a status update for the Turkey Point Cooling Canal Monitoring Plan ("Cooling Canal") Project, addresses recent regulatory actions and environmental compliance activities undertaken by FPL pursuant to this project, and presents for Commission review and approval a modification to the Cooling Canal Project.

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

A. Yes. I am sponsoring the following exhibits:

- MWS-1 – 2015 Miami-Dade County Department of Environmental Resource Management ("MDC") Consent Agreement
- MWS-2 – June 2016 FDEP Consent Order
- MWS-3 – 2016 MDC Consent Agreement Addendum
- MWS-4 – 2019 MDC Consent Agreement Addendum
- MWS-5 – July 2020 Supplemental Salinity Management Plan
- MWS-6 – May 6, 2005 NPDES/IWW Permit Number FL0001562

- MWS-7 – FDEP's April 13, 2020 Notice of Intent to Issue Permit FL0001562
- MWS-8 – FDEP's April 25, 2016 Notice of Violation and Orders for Corrective Action

Variance Explanations

Q. How did actual project O&M and capital revenue requirements for January 2020 through December 2020 compare with FPL's actual/estimated amounts as presented in Docket No. 20200007-EI?

A. Form 42-4A shows that the variance in total actual project O&M was $11.4 million or 27.6% lower than projected, and Form 42-6A shows that the variance in total actual revenue requirements associated with the project capital investments (return on capital investments, depreciation, amortization, and income taxes) were $122.5 thousand or 0.08% higher than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Actual revenue requirements for each capital project for the period January 2020 through December 2020 are provided on Form 42-8A, pages 14 through 68. The calculation of actual revenue requirements is sponsored by FPL witness Renae B. Deaton.

Q. Please explain the reasons for the significant variances in project capital revenue requirements and O&M.

A. There were no significant variances in capital revenue requirements for this period. The significant variances in FPL's 2020 actual O&M expenses from actual/estimated amounts are associated with the following projects.

O&M Variance Explanations

Project 1. Air Operating Permit Fees

Project expenditures are $67,306 or 42.8% higher than estimated. The variance is primarily due to higher than projected gas and oil fuel usage, which resulted in increased air operating permit fees for 2020.

Project 3. Continuous Emissions Monitoring Systems (CEMS)

Project expenditures are $83,174 or 21.7% lower than estimated. The variance is primarily due to lower than projected CEMS maintenance costs at Manatee and Sanford plants.

Project 5a. Maintenance of Stationary Above Ground Fuel Storage Tanks

Project expenditures are $274,843 or 53.8% lower than estimated. The variance is primarily due to cancellation of all major oil storage tank maintenance projects at Manatee Units 1&2 as a result of their retirement.

Project 8a. Oil Spill Clean-up/Response Equipment

Project expenditures were $87,118 or 24.1% lower than estimated. The decrease was primarily due to deferment of retainer fees associated with a pending oil spill removal organization contract. Additionally, COVID-19 related supply chain delays of planned equipment and material purchases was a significant factor in the lower than projected expenditures.

Project 22. Pipeline Integrity Management

Project expenditures were $262,155 or 80% lower than estimated. The variance is primarily due to use of an alternate technology to perform the Manatee Plant pipeline integrity inspection. Planned use of inline inspection was replaced by use of an alternate test that was less costly but still met the requirements for compliance with the Department of Transportation Pipeline and Hazardous Materials Safety Administration regulations.

Project 23. Spill Prevention, Control and Countermeasures (“SPCC”)

Project expenditures were $151,803 or 19.3% higher than estimated. The variance is primarily due to increased repairs of broken SPCC oil diversionary structures at 40 sites, as well as other repairs at various FPL substation facilities.

Project 28. Clean Water Act (“CWA”) 316(b) Phase II Rule

Project expenditures were $172,606 or 16.1% lower than estimated. The variance is primarily due to contractor work associated with required studies for St. Lucie Nuclear Plant being moved from 2020 to 2021 to prioritize the completion of studies associated with other facilities that had earlier permit application deadlines. Also, the projected work for Cape Canaveral Energy Center, Ft. Myers Plant, Ft. Lauderdale Plant, and Port Everglades Energy Center was completed under budget.

Project 29. Selective Catalytic Reduction (“SCR”) Consumables

Project Expenditures were $110,842 or 17.4% lower than estimated. The variance is due to lower than expected equipment repair costs at Manatee Plant following an inspection, and delayed in-person training sessions that were not completed in 2020 as a result of COVID-19 restrictions. The training sessions are expected to be completed in 2021.

Project 33. Mercury and Air Toxics Standards ("MATS")

Project expenditures are $446,790 or 23.7% lower than estimated. The variance is primarily due to lower use of powdered activated carbon consumption for mercury control on Scherer Unit 4 as a result of running the plant less than forecasted for economic reasons.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures are $113,540 or 16.9% lower than estimated. The variance is primarily due to process changes requiring less full-time employee support to the Desoto site, resulting in the redeployment of resources in support of other sites and capital projects. In addition, planned contractor services scheduled for the end of the year have been postponed.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures are $70,210 or 26.1% lower than estimated. The variance is due to the delay of panel replacement and hurricane hardening projects during supplier negotiations. FPL intends to complete installation of deferred panel installations in 2021.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $10,372,669 or 52.7% lower than estimated. The variance is primarily due to increased efficiencies (new cooling canal system sediment removal and thermal efficiency strategy), lower equipment repair costs for monitoring equipment, and decreased monitoring and reporting costs due to hiring field staff to replace more expensive contractors.

Project 45. 800 MW Unit Electrostatic Precipitator ("ESP")

Project expenditures were $119,225 or 76.9% lower than estimated. The variance is due to lower than projected maintenance following a planned inspection of the ESP system at Manatee Plant.

Project 47. National Pollution Discharge Elimination System ("NPDES") Permit Renewal Requirements

Project expenditures were $111,643 or 119% higher than estimated. The variance is primarily due to St. Lucie Nuclear Plant inadvertently including costs associated with chemicals, which are normally recovered through base rates, in an ECRC recoverable account. A correction will be reflected in April 2021.

Cooling Canal Project Regulatory Compliance

Q. Please provide an update on the status of the Cooling Canal Project.

A. FPL remains in compliance with all regulatory requirements associated with the Cooling Canal Project. In July 2020, FPL submitted a supplemental salinity management plan to the FDEP to further assist with achieving and maintaining the 2016 FDEP Consent Order's annual average salinity threshold of at or below 34 practical salinity units ("PSU") for the Turkey Point Cooling Canal System ("CCS"). FPL's freshening actions have been effective in moderating CCS salinity, but additional freshening is needed. To date, freshening has reduced CCS salinity by over 20 PSU on average from levels that would have occurred had freshening measures not been implemented. The average annual salinity remains above 34 PSU, but it is trending downward. For example, the average CCS salinity for June 1, 2020 through March 18, 2021 (281 days, or 77%, into the current compliance year) is 38.5 PSU, the lowest recorded salinity for this time of the year in the ten-year period of record.

The 2016 Consent Order contemplated additional measures might be needed to achieve the salinity threshold and provided a process for FPL to submit a plan detailing those measures. The plan is undergoing permitting with the FDEP, and FPL expects permit issuance in the second quarter of 2021. FPL is also currently in the process of renewing its NPDES/IWW Permit for the Turkey Point facility. FDEP noticed an intent to issue a permit in April 2020, but administrative challenges were filed, resulting in litigation concerning the issuance of the final permit. The hearing was held in January 2021, and a final decision is expected in the third quarter of 2021. Since the NPDES/IWW permit is an integral piece of FPL's compliance with the 2016 Consent Order, FPL is requesting the Commission approve a modification to the Cooling Canal Project to include costs associated with litigating the NPDES/IWW permit challenges.

Q. Please summarize FPL's regulatory compliance activities related to the Cooling Canal Project since your testimony in Docket No. 20170007-EI.

A. FPL continues to move forward with compliance and implementation of actions associated with activities required under the 2015 MDC Consent Agreement, the 2016 Consent Order, and the 2016 and 2019 addenda to the 2015 MDC Consent Agreement (attached as MWS-1 through MWS-4, respectively). FPL has remained in compliance with all regulatory environmental requirements imposed by these agreements.

Q. What are the specific environmental objectives of the 2016 Consent Order?

A. The three objectives of the 2016 Consent Order are to cease discharges from the CCS that impair the reasonable beneficial use of adjacent G-II groundwater to the west of the CCS, prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards, and mitigate impacts related to historic operation of the CCS.

Q. Is FPL in compliance with all actionable items required in the 2016 Consent Order?

A. Yes. FPL has substantially accomplished the objectives of the 2016 Consent Order and continues successful execution on all requirements within it.

Q. Please describe the activities FPL has taken since 2016 to achieve compliance with the 2016 Consent Order's objective to cease discharges from the CCS that impair the reasonable and beneficial use of adjacent G-II groundwaters.

A. Under the 2016 Consent Order, FPL is required to achieve an average annual salinity of the CCS surface waters at or below 34 PSU, develop and submit a thermal efficiency plan, and implement a Recovery Well System ("RWS"). FPL has undertaken significant activities since 2016 to achieve compliance. FPL has licensed and constructed six low salinity Floridan aquifer freshening wells, modified the site license to authorize the use of up to 14 million gallons per day ("MGD") of low salinity Floridan aquifer water to replace water lost to evaporation and reduce CCS salinity, and has implemented the approved CCS salinity reduction plan continuously since November 28, 2016. These wells have positively impacted the CCS by moderating salinity concentrations. FPL also optimized our existing Floridan allocation, as allowed under the site license, by diverting an estimated 7 MGD of the unutilized portion of Turkey Point Units 1-5 Floridan process water allocation to the CCS to aid in salinity reduction. FPL also constructed an additional low salinity Floridan aquifer well to provide additional freshening water for the CCS.

In addition, FPL has been implementing the Thermal Efficiency Plan as required by the 2016 Consent Order since it received FDEP's approval on July 7, 2017. The annual average thermal efficiency has been maintained above the 2016 Consent Order target level of 70% since implementing the plan. The annual average thermal efficiency was 84.6%, 85.1%, 85.0%, and 86.0% for years 2017, 2018, 2019, and 2020 respectively.

As required by the 2016 Consent Order, FPL permitted and constructed an RWS, which became operational on May 15, 2018. After the first two-and-a-half years of operations and based on the results of the second Continuous Surface Electromagnetic Mapping survey, the RWS has reduced the hypersaline plume volume by 34%. The results indicate the RWS is functioning as designed and is on track to achieve the objectives outlined in the 2016 Consent Order.

Q. The 2016 Consent Order includes an average annual salinity threshold for the CCS surface waters at or below 34 PSU to be achieved by November 28, 2020. Did FPL achieve this salinity threshold by that date?

A. No. While CCS annual salinity levels have been moderated due to freshening activities, cooling canal salinity did not meet the average annual salinity threshold of 34 PSU by November 28, 2020. However, as referenced above, the average CCS salinity for June 1, 2020 through March 18, 2021 (281 days, or 77%, into the current compliance year) is 38.5 PSU, the lowest recorded salinity for this time of the year in the period of record.

Q. Why was the salinity threshold not achieved?

A. Cooling canal salinity is affected by many factors. During most of the freshening timeframe since 2016, the cooling canals experienced lower than average rainfall, which resulted in CCS evaporation exceeding freshwater inputs (rainfall plus freshening) for numerous months each year. When evaporation exceeds freshwater inputs, CCS salinity increases.

Q. Are there other factors impacting the ability to meet the salinity threshold?

A. Yes, the original freshening model utilized data collected from 2010-2012, which was the best available data at the time the salinity management plan was developed. FPL now has a longer data record that represents a wider range of hydrologic conditions. CCS salinity responses have shown that offsetting evaporative losses is more beneficial on a monthly basis, rather than on an annual average basis. These data also indicate that additional freshening is needed during low rainfall months to prevent the CCS salinity from rising. By stabilizing CCS salinity during dry times using greater volumes of freshening water, combined with wet season rainfall, the CCS salinity levels are anticipated to achieve the 34 PSU annual average salinity threshold.

Q. Does the 2016 Consent Order address what FPL is required to do when the average annual salinity of the CCS surface waters is not at or below 34 PSU at the completion of the fourth year of freshening activities?

A. Yes. The 2016 Consent Order recognizes that additional measures might be needed and provides a process to supplement CCS salinity reduction measures to achieve the salinity threshold. As set forth in the 2016 Consent Order, within 30 days of the date to reach the required threshold (November 28, 2020), FPL must submit a plan to the FDEP detailing additional measures, and a timeframe for those measures, that FPL will implement to achieve the required salinity threshold.

Q. Since the salinity threshold was not met, what actions is FPL taking pursuant to the 2016 Consent Order?

A. In July 2020, ahead of the December 28, 2020 deadline, FPL submitted a supplemental salinity management plan to FDEP outlining the actions FPL will take to achieve the threshold. The proposed activities included optimizing FPL's existing freshening wellfield operations and seeking an increase to the wellfield's water use allocation. A copy of the plan is included as Exhibit MWS-5.

Q. Please describe what activities have occurred since FPL submitted its supplemental salinity management plan to FDEP.

A. FPL has taken steps to optimize its existing freshening wellfield operations to reach the full permitted allocation of 14 MGD. Wellfield production was increased through well acidization treatments and installation of a pump and motor on one well. FPL also submitted a petition to FDEP to modify its Site Certification License to implement the plan and increase the wellfield's water use allocation. As part of the permitting process, FPL will work with FDEP and other agencies to further reduce CCS salinity, and additional measures may be required as a result.

Q. Is it common for environmental remediation activities and costs to evolve over time?

A. Yes. Remediation practices rely on monitoring the actual responses in the environment to identify the level of success and, where applicable, when appropriate adjustments are needed. The ability to monitor and adjust remediation activities is an integral activity in ensuring projects meet environmental goals considering the numerous variables and assumptions inherent in the initial design.

Cooling Canal Project Background

Q. Has FPL submitted updates to the Commission regarding the scope and costs of the Cooling Canal Project since it was approved in Order No. PSC-09-0759-FOF-EI?

A. Yes. Throughout the period since the Cooling Canal Project was approved, including in my current testimony, FPL has filed updates concerning the Cooling Canal Project. As required, FPL has annually filed all cost data concerning the project, including information relating to actual and estimated costs, and final true-up amounts. FPL has also filed project description and progress reports annually to provide the Commission with information concerning project accomplishments and expenditures. FPL also discussed regulatory actions and compliance activities related to the Cooling Canal Project at length in testimony filed in Docket Nos. 160007-EI and 20170007-EI. Finally, FPL provided an update to project costs and expenditures in Docket No. 20180007-EI.

Q. What were FPL's actual 2020 costs associated with required Cooling Canal Project activities?

A. In 2020, FPL incurred $7.4 million in capital expenditures and $9.3 million in O&M expenses for the Cooling Canal Project.

Q. What is FPL's current estimate of 2021 costs associated with required Cooling Canal Project activities?

A. In 2021, FPL estimates that it will incur approximately $9.8 million in capital expenditures and $9.7 million in O&M expenses for the Cooling Canal Project activities.

Q. How much costs were incurred in 2020 for Cooling Canal Project compliance related to additional actions needed to achieve the CCS salinity threshold?

A. FPL incurred $7.1 million on additional actions needed to achieve the CCS salinity threshold, including actions to optimize its existing Floridan allocations for freshening and for process water at Turkey Point Units 1-5 and to prepare for and seek the requested increase in water use allocation.

Q. Going forward, how much does FPL expect to incur on Cooling Canal Project compliance related to the supplemental salinity management plan?

A. Since the ultimate solution for the supplemental salinity management plan is yet to be approved by FDEP, total estimated costs are not known. The associated agencies are reviewing the site license modification, and FPL and the agencies are working through the permitting process.

However, based on the actions identified in FPL's July 30, 2020 letter and the petition for site license modification to FDEP, preliminary estimates of capital investment costs associated with further optimizing and increasing the wellfield's water use allocation are $3.5 million. Preliminary O&M expenses are $11.7 million over the remaining approximately 30-year expected operation of the wellfield. Depending on what solution is ultimately required, FPL may incur additional costs associated with the design, permitting, testing, and implementation of that solution. FPL will provide updated estimates in its regular filings once they are available.

National Pollution Discharge Elimination System/Industrial Wastewater Permit Renewal

Q. Does FPL hold environmental permits that apply to operation of the CCS?

A. Yes, the CCS is a permitted industrial wastewater ("IWW") facility. FPL is the permittee and operates the CCS under NPDES/IWW Permit Number FL0001562. The Environmental Protection Agency ("EPA") issued the facility's initial permit on September 23, 1973. The Florida Department of Environmental Regulation (now FDEP) issued an IWW permit on October 15, 1982. These permits were combined following the delegation of the NPDES program from EPA to the FDEP on May 1, 1995. The permit has been timely renewed by the facility, as required, and the current version of the permit was approved in 2005. A copy of the current permit is attached as Exhibit MWS-6.

Q. Is FPL currently in the process of applying for renewal of the NPDES/IWW permit for Turkey Point?

A. Yes, FPL is currently in the process of renewing its NPDES/IWW Permit for the Turkey Point facility. On October 22, 2009, prior to the expiration of the current permit, FPL timely filed its application for renewal of the permit. The current permit, approved in 2005, has been administratively extended since 2010 while FPL's application for renewal is pending approval by FDEP.

Q. Please describe the status of the application.

A. On April 13, 2020, the FDEP noticed an intent to issue a permit for the Turkey Point facility, finding that, based upon the application and supplemental information, FPL provided reasonable assurances that the wastewater treatment and effluent disposal facilities at Turkey Point complied with the appropriate provisions of Chapter 403 of the Florida Statutes and Title 62 of the Florida Administrative Code (F.A.C.). A copy of FDEP's notice of intent to issue a permit is attached as Exhibit MWS-7. These provisions include a determination that the issuance of the permit will not cause a violation of the groundwater quality standards or criteria nor impair the designated use of contiguous surface waters (see Exhibit MWS-7, Conditions I.1 and I.2).

On June 4, 2020, the Florida Keys Aqueduct Authority ("FKAA") and the Florida Keys Fishing Guides Association ("FKFGA") filed administrative petitions challenging the permit and requesting formal administrative hearing and denial of the permit. Monroe County also intervened and became a petitioner. The Administrative Law Judge ("ALJ") held a two-week hearing ending on January 29, 2021. FPL expects a Recommended Order from the ALJ in the second quarter of 2021 and a Final Order from FDEP in the third quarter.

Q. Are the NPDES/IWW Permit and the 2016 Consent Order interrelated?

A. Yes. The 2016 Consent Order was a direct result of the FDEP's April 25, 2016 Notice of Violation and Orders for Corrective Action ("NOV"). Paragraph 18 of the NOV specifically identifies a violation of 403.161(1)(b), F.S., for failing to comply with Condition IV.1 of the NPDES/IWW Permit. A copy of the April 25, 2016 NOV is attached as Exhibit MWS-8.

Q. Does the challenge of the NPDES/IWW Permit impact FPL's ability to comply with the 2016 Consent Order?

A. Yes. The NPDES/IWW permit is an integral piece of FPL's compliance with the 2016 Consent Order. The 2016 Consent Order presumes continued authorization of the CCS. Further, the proposed NPDES/IWW permit specifically incorporates certain 2016 Consent Order deadlines related to retraction of the hypersaline plume as well as monitoring and reporting requirements. These 2016 Consent Order conditions will be enforceable by FDEP, and potentially third parties, when the permit is issued. The specific conditions added from the 2016 Consent Order into the permit by FDEP include:

- On page 18 of the permit, FDEP added three conditions (VI (8), VI (9) and VI (10)) verbatim from the 2016 Consent Order directly into the permit. These conditions include the requirement for FPL to 'halt the westward migration of the hypersaline plume from the CCS within three years of the commencement of the remediation project (May 15, 2018).' These conditions also require that FPL 'retract the hypersaline plume to the L-31E canal within ten years of the commencement of the remediation project (May 15, 2018).'
- FDEP added Condition I.1., on page 2, which requires that FPL discharges to groundwater shall not cause a violation of the groundwater quality standards. FDEP inserts a footnote, number 1, to clarify that this condition is being satisfied by the remedial actions and timelines for achieving compliance with groundwater minimum criteria in the Consent Order. In other words, without the 2016 Consent Order, FDEP would not have reasonable assurance regarding groundwater quality criteria, and FDEP would not be able to issue the permit.
- In condition II.B.4, on page 10, FDEP cites the 2016 Consent Order as the basis

for the monitoring and reporting requirements for analyzing salinity levels in the CCS.

- In condition II.D.20, on page 17, FDEP cites the 2016 Consent Order for the proper selection of laboratories to analyze samples.
- In Condition VIII.D.4, on page 27, FDEP specifically states that 'the permittee (FPL) and the Department entered into a Consent Order (OGC File #16-0241) on June 20, 2016. The Department may revise the permit to include certain provisions of the Consent Order upon its completion.' This is a reopener clause that allows FDEP to revise the permit to include certain provisions of the 2016 Consent Order upon its completion.

As is evident from the number of conditions imposed by FDEP in the permit, or taken directly by FDEP from the 2016 Consent Order, the permit and the 2016 Consent Order are closely related and rely upon each other to allow for operation of the CCS and implementation of the remedial actions under the 2016 Consent Order.

Q. Please describe the administrative challenges filed by FKAA, FKFGA, and Monroe County.

A. FKAA, FKFGA, and Monroe County challenged whether FPL had provided reasonable assurances that FPL can satisfy FDEP's regulatory requirements to receive the permit. Many of the petitioners' allegations are based on the 2016 Consent Order, and a significant portion of the hearing focused on FPL's ability to comply with the 2016 Consent Order. The petitioners' primary argument was that the remedial actions required by the 2016 Consent Order are not working and therefore FPL is not entitled to the permit. If the ALJ found that FPL is violating groundwater standards or impairing the beneficial use of surface water, FPL may be required to amend the terms of the 2016 Consent Order. Third parties may then be able to challenge the revised 2016 Consent Order. The re-litigation of the 2016 Consent Order could result in the imposition of additional requirements on FPL under an "Amended Consent Order" to perform additional actions associated with the CCS. This could result in regulatory conflicts with the 2016 Consent Order, which in turn could result in additional requirements and costs associated with the CCS and the Cooling Canal Project. Therefore, litigating the NPDES/IWW permit challenges is required to defend the 2016 Consent Order and to ensure compliance with the 2016 Consent Order, while reducing risk for unnecessary and costly new requirements.

Q. Is FPL requesting a modification to the Cooling Canal Project?

A. Yes. Since FPL must defend its NPDES/IWW permit through administrative litigation in order to remain in compliance, FPL is requesting the Commission approve a modification to the Cooling Canal Project to include costs associated with litigating the NPDES/IWW permit challenges.

Q. How much does FPL expect to spend on costs associated with the NPDES/IWW permit litigation?

A. In 2020, FPL incurred $1 million in O&M costs related to the NPDES/IWW permit litigation. In 2021, FPL expects to incur approximately $800,000 in O&M costs related to the NPDES/IWW permit litigation. FPL's estimated costs for 2021 do not include any costs that would result from an appeal of the ALJ's Order. FPL is only seeking ECRC recovery for litigation costs associated with the NPDES/IWW permit that were performed following its July 31, 2020 filing in Docket 20200007-EI.

Q. Is FPL recovering the costs associated with the NPDES/IWW permit litigation activities through any other mechanism?

A. No.

Q. How does the net overall projected cost of the Cooling Canal Project today compare to the projected costs presented in Docket 20170007-EI?

A. The net overall projected cost of the Cooling Canal Project presented in Docket 20170017-EI and approved in Order No. PSC-2018-0014-FOF-EI has not increased.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL W. SOLE

DOCKET NO. 20210007-EI

JULY 30, 2021

Q. Please state your name and address.

A. My name is Michael W. Sole 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 NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of the testimony that you are filing at this time?

A. The purpose of my testimony is to present for Commission review and approval Florida Power & Light Company's ("FPL" or the "Company") request for recovery through the Environmental Cost Recovery Clause ("ECRC") of a new project, the FPL Miami-Dade Clean Water Recovery Center ("CWRC") Project. My testimony also explains the variances in costs associated with operation & maintenance ("O&M") expenses and capital investments included in FPL's ECRC Actual/Estimated True-up for the period of January 2021 through December 2021.

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

A. Yes, I am sponsoring the following exhibits:

- Exhibit MWS-9 – MDC and FPL Agreement
- Exhibit MWS-10 – Turkey Point Conditions of Certification
- Exhibit MWS-11– South Florida Water Management District letter to FPL
- Exhibit MWS-12 – MDC Board of County Commissioners Resolution and Memorandum recommending approval

<u>CWRC Project</u>

Q. Please briefly describe FPL's proposed CWRC Project.

A. Pursuant to an agreement with Miami-Dade County ("MDC"), and to further compliance with environmental and reclaimed water reuse requirements, FPL plans to construct and operate a wastewater reuse system comprised of a waterline from Miami-Dade County Water and Sewer Department's South District Wastewater Treatment Plant to the Turkey Point Clean Energy Center ("Turkey Point"), an advanced reclaimed water treatment facility, and an underground injection control ("UIC") system. The wastewater reuse system will transport and further treat reclaimed water for use at Turkey Point's natural gas plant, Unit 5.

Q. Did the Florida Legislature recently revise the definition of environmental compliance costs to include the type of costs that will be associated with the CWRC Project?

A. Yes. On June 29, 2021, Governor DeSantis signed legislation that revised the definition of "environmental compliance costs" to include "costs or expenses prudently incurred by an electric utility after July 1, 2021, pursuant to an agreement between the electric utility and a governmental wastewater utility for the exclusive purpose of the electric utility constructing and operating a wastewater reuse system where operation of the system will serve to further compliance with environmental laws or regulations that apply to the electric utility and where the system fully or partially satisfies a local government's reclaimed water reuse requirements under s. 403.064 or s. 403.806." That new definition is codified at Section 366.8255(1)(d)9 of the Florida Statutes ("F.S."). The new statutory language also requires that "at least 50 percent of the reclaimed water the system produces must be used in conjunction with the water requirements of an electrical generating facility or facilities owned by the electric utility in order to offset all or part of the electric utility's water use authorized by permit." Section 366.8255(1)(d)9, F.S.

Q. Please describe what activities related to the CWRC Project FPL needs to complete.

A. FPL plans to design, permit, finance, construct, own, operate and maintain in good working order, a water reuse system comprised of an approximately eight-mile waterline, an advanced reclaimed water treatment facility at the Turkey Point site with capacity to treat up to 15 million gallons per day ("MGD") of reclaimed water for Unit 5 cooling tower makeup, a UIC well system, and any other infrastructure necessary to transport, treat, and utilize the reclaimed water.

Q. Do the costs associated with the CWRC meet the requirements provided in Section 366.8255(1)(d)9, F.S.?

A. Yes. The CWRC Project meets all the requirements outlined in Section 366.8255(1)(d)9, F.S. On July 6, 2020, MDC and FPL entered into an agreement for the exclusive purpose of FPL constructing and operating an advanced wastewater reuse system to transport, treat, and use reclaimed water at the FPL Turkey Point Clean Energy Center. Under the agreement, MDC will provide up to 15 MGD of water to FPL for treatment and use by FPL in Unit 5's cooling towers. FPL intends to utilize 100% of the water generated by the CWRC for the purpose of cooling Unit 5. The CWRC Project will assist Florida in achieving the state's objective to reuse reclaimed water, further FPL's compliance with Turkey Point's Conditions of Certification ("COC"), offset Unit 5's groundwater use authorized by the COC, and partially satisfy MDC's reclaimed water reuse requirements under 403.064 and 403.086, F.S. The agreement is attached as Exhibit MWS- 9.

Q. Does the CWRC serve to further compliance with environmental laws or regulations applicable to FPL?

A. Yes. FPL's Turkey Point Clean Energy Center is permitted through the COC issued by the Florida Department of Environmental Protection ("FDEP") pursuant to the Power Plant Siting Act. The COC contains the South Florida Water Management District's ("SFWMD") groundwater use authorization, which includes an allocation of 14.06 MGD of Floridan aquifer groundwater for use as cooling water for Unit 5 and process water for Units 1, 2, 3, 4 and 5.

Condition XIII.C.2. of the COC requires that, "Upon written notification from the SFWMD that a reliable source of reclaimed water is available at the project site to serve Unit 5 in a quantity and quality acceptable to the Licensee for cooling purposes for Unit 5, the Licensee shall provide the SFWMD with a schedule for use of reclaimed water, for the SFWMD's review and approval, within 90 days of such notification. Once the use of reclaimed water has been established, the use of Floridan Aquifer water shall be reduced in proportion to the volume of reclaimed water made available to Unit #5…"

This condition implements SFWMD's lowest quality water source requirement (Applicant's Handbook for Water Use Permit Applications, incorporated by reference in Rule 40E-2.091, F.A.C.), which prescribes that consideration must be given to the availability of the lowest quality water which is acceptable for the intended use. If a water source of lower quality is available and feasible, this lower quality water must be used. A copy of Turkey Point's COC is attached as Exhibit MWS-10.

Q. Has FPL received written notification from the SFWMD related to Condition XIII.C.2?

A. Yes. FPL received written notification from the SFWMD on June 29, 2021 pursuant to COC Condition XIII.C.2. The notification requires FPL provide the SFWMD with a schedule for use of reclaimed water. See Exhibit MWS-11.

Q. How does the CWRC partially satisfy MDC's reclaimed water use requirements under Sections 403.064 and 403.086, Florida Statutes?

A. Section 403.064, F.S., requires MDC to implement wastewater reuse to the degree it is feasible. Furthermore, Section 403.086(10)(c), F.S. ("Ocean Outfall Statute") requires MDC to implement a functioning reuse system that provides 117.5 MGD of reuse capacity that is environmentally, economically, and technically feasible. As noted in the agreement between FPL and MDC, and the June 16, 2020 memorandum from MDC Mayor Carlos Gimenez recommending approval of the agreement to the MDC Commission, the CWRC partially satisfies MDC's requirements by providing a feasible reuse project with a capacity of up to 15 MGD. The June 16, 2020 memorandum and the MDC resolution approving the FPL and MDC agreement are attached as Exhibit MWS-12.

Q. Will at least 50% of the reclaimed water the system produces be used in conjunction with the water requirements of an electric generating facility

owned by FPL to offset all or part of the FPL facility's water use authorized by permit?

A. Yes. Turkey Point's groundwater use is permitted via the facility's COC. It is anticipated that 100% of the reclaimed water produced by the CWRC will be utilized to meet the water requirements of Turkey Point's Unit 5 cooling towers. As required by the COC, use of this reclaimed water will reduce Turkey Point's groundwater use authorized by the COC in proportion to the amount of reclaimed water made available for use in the Unit 5 cooling towers.

Q. Will groundwater still be used for Turkey Point Unit 5's cooling towers?

A. Yes. Groundwater will still be available as a secondary source to meet Turkey Point Unit 5's cooling water demands when reclaimed water is not available in the quantity or quality that is required for plant operations.

Q. Will the CWRC increase the resiliency of Unit 5 operations?

A. Yes. The provision of reclaimed water to cool Unit 5 increases the resiliency of Unit 5 operations by providing primary (reclaimed) and backup (groundwater) sources of cooling water.

Q. What is the estimated O&M expense associated with the proposed CWRC Project that FPL is requesting to recover through the ECRC?

A. FPL does not anticipate it will incur any O&M expenses in 2021. O&M expenses will be incurred once the facility becomes operational, which is anticipated to occur at the end of 2024. Pursuant to the agreement with MDC, FPL will receive $6.5 million annually from MDC to support operations of the

Project. The O&M payment provided by MDC will be reflected as a revenue credit in the ECRC. FPL will only recover incremental O&M expenses associated with the CWRC Project if the annual amount exceeds $6.5 million.

Q. What are the main drivers of O&M expenses for the CWRC Project?

A. The main drivers of the O&M expenses for the Project include water treatment chemicals, equipment preventive/corrective maintenance, and operating expenses.

Q. Does FPL expect to incur any capital costs associated with the proposed CWRC project?

A. Yes. FPL estimates that the total capital cost associated with the CWRC Project will be approximately $315 million. FPL expects that these expenditures will be incurred between 2021 and the end of 2025.

Q. What are the main components of capital costs associated with the proposed CWRC Project?

A. The main components of the capital costs associated with the project include the design, procurement, and installation of the reclaimed waterline, the advanced wastewater treatment systems associated with the CWRC, and the interconnection facilities at the Miami-Dade County South District Wastewater Treatment facility.

Q. Please describe the capital costs that FPL expects to incur for the CWRC Project in 2021.

A. The 2021 capital expenditures are estimated to be $2,644,000 for engineering and permitting efforts.

Q. Please describe the measures FPL is taking to ensure that costs of the CWRC Project are reasonable and prudently incurred.

A. In general, FPL competitively bids the procurement of materials and services. FPL benefits from strong market presence allowing it to leverage corporate-wide procurement activities to the specific benefit of individual procurement activities. For the CWRC project, FPL will competitively bid the engineering, procurement and construction of the project. FPL's Project Controls group maintains the project scope, budget, and schedule and tracks project costs through various approval processes, procedures, and databases.

Q. Did FPL anticipate that it would need to perform these activities at the time that it prepared the Minimum Filing Requirements ("MFR") for its 2021 rate case?

A. No. The legislation that allowed for recovery of the type of costs associated with this project did not exist at the time FPL prepared the MFRs for its 2021 rate case.

Q. Is FPL recovering through any other mechanism the costs for the CWRC Project for which it is petitioning for ECRC recovery?

A. No.

Variance Explanations

Q. How do the actual/estimated project costs for January 2021 through December 2021 compare with original projections for the same period?

A. Form 42-4E (Appendix I, page 4) shows that total O&M project costs are $2,978,736 lower than projected, and Form 42-6E (Appendix I, page 9) shows that total capital project revenue requirements are $177,121 lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Revenue requirements for each capital project for the 2021 actual/estimated period are provided on Form 42-8E (Appendix I, pages 15 through 70).

Q. Please explain the reasons for any significant variance in costs associated with O&M and capital investments.

A. The significant variances in FPL's 2021 recoverable O&M expenses and capital revenue requirements from projection amounts are associated with the following projects:

O&M Variance Explanations

Project 1 – Air Operating Permit Fees

Project expenditures are estimated to be $45,450, or 24.6% higher than previously projected. The variance is primarily due to higher than originally projected gas and oil fuel usage, which resulted in increased permit fees paid in 2021 for unit operation in 2020. FPL pays permit fees based on the actual tons of pollutants emitted in the prior year. The annual Title V fee projection calculation is based on FPL fuel consumption projections and the Department of Environmental Protection's ("DEP") per ton fee for pollutant tons emitted.

Project 5 – Maintenance of Stationary Above Ground Fuel Storage Tanks

Project expenditures are estimated to be $142,141, or 36.2% lower than previously projected. The variance is primarily due to an error in forecasting maintenance costs for Port Everglades Tank #3 in clause recovery and subsequently determining that this tank is not recoverable through ECRC. This is partially offset by higher vendor quotes on Manatee Terminal Tank #1272 for painting and repairs, and lower than estimated costs for tank inspections and repairs at the Fort Myers site.

Project 19a - Substation Pollutant Discharge Prevention & Removal – Distribution

Project expenditures are estimated to be $444,789, or 15.2% higher than projected. The variance is primarily due to the ability to obtain equipment clearances (i.e., de-energize equipment) required for equipment repair, which is resulting in a higher than projected number of transformers being repaired. FPL obtained additional equipment clearances by utilizing a mobile transformer.

Project 22 - Pipeline Integrity Management

Project expenditures are $77,502, or 100% lower than previously projected. The decrease is a result of no findings noted in the 2020 inspection that needed attention in 2021. No post-inspection confirmatory digs were required from the 2020 inspection report.

Project 24 - Manatee Plant Reburn

Project expenditures are estimated to be $208,861, or 98.4% lower than previously projected. The decrease is primarily due to the anticipated dismantlement of Manatee Units 1&2 and the determination that scheduled inspections on the reburn systems are no longer needed.

Project 28 - CWA 316(b) Phase II Rule

Project expenditures are estimated to be $106,327, or 21.1% lower than previously projected. The decrease is primarily due to the delayed renewal of the Industrial Wastewater ("IWW") Permit for the Port Everglades Energy Center ("PEEC"). PEEC was projected to begin a two-year Impingement Optimization Study ("IOS") during calendar year 2021. However, the renewed IWW permit was not issued during the second quarter of 2021 as anticipated, thereby delaying the study. FPL anticipates the renewed IWW permit will be issued in the end of 2021/early 2022 and will contain the requirement to complete the IOS.

Project 33 - MATS Project

Project expenditures are estimated to be $802,154, or 33.1% lower than previously projected. The variance is primarily due to lower than projected operation of Scherer Unit 4, which resulted in lower operating costs for the sorbant injection system.

Project 37 - DeSoto Next Generation Solar Energy Center

Project expenditures are estimated to be $157,834, or 28.9% lower than previously projected. The variance is primarily due to less full-time employee support required to maintain the Desoto site than originally projected. Additionally, planned contractor services for the combiner boxes and tracker assemblies were deemed to be capital work in nature and removed from the O&M forecast.

Project 42 - Turkey Point Cooling Canal Monitoring Plan

Project expenditures are estimated to be $1,579,504, or 16.2% lower than previously projected. The variance is primarily due to the reduced need for well maintenance and testing and the decision to maintain, rather than increase, the current sediment removal rate to achieve desired thermal efficiency for the cooling canal system.

Project 45 - 800 MW Unit ESP

Project expenditures are estimated to be $189,099, or 71.6% lower than previously projected. The decrease is primarily due to the anticipated dismantlement of Manatee Units 1&2 and the determination that scheduled ESP work was no longer required.

Project 47 - NPDES Permit Renewal Requirements

Project expenditures are estimated to be $85,230, or 105.2% lower than estimated. The variance is primarily due to St. Lucie Nuclear Plant projections inadvertently including costs associated with chemicals which are recovered through base rates.

Project 123 - The Protected Species Project

Project expenditures are $100,000, or 100% lower than estimated. All costs associated with the manatee calf rehabilitation activities were removed from ECRC recovery.

Capital Variance Explanations

Project 47 – NPDES Permit Renewal Requirements

Project revenue requirements are estimated to be $68,806, or 22.8% higher than previously projected. The variance is primarily due to materials & equipment and engineering costs which were not known at the time of the 2021 Projection Filing.

Project 50 – Steam Electric Effluent Guidelines Revised Rule

Project revenue requirements are estimated to be $275,511, or 71.5% lower than previously projected. The variance is primarily due to the 2020 Steam Electric Reconsideration Rule, which went into effect subsequent to FPL's last projection filing. The new rule extended compliance dates, which postponed capital expenditures.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL W. SOLE

DOCKET NO. 20210007-EI

AUGUST 27, 2021

Q. Please state your name and address.

A. My name is Michael W. Sole, 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 NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of the testimony that you are filing at this time?

A. The purpose of my testimony is to explain the consolidation of ECRC projects resulting from the merger between Gulf Power and FPL. My testimony also presents for Commission review and approval Florida Power & Light Company's ("FPL" or the "Company") request for recovery through the Environmental Cost Recovery Clause ("ECRC") the modification of an existing approved project, the Lowest Quality Water Source ("LQWS") Project.

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

A. Yes, I am sponsoring the following exhibits:

- MWS – 13 - ECRC Combined Project Summary
- MWS – 14 - Sanford Plant July 13, 2021 Consumptive Use Permit
- MWS – 15 - Sanford Consumptive Use Permit Technical Staff Report

Along with FPL's witness Renae B. Deaton, I am co-sponsoring Project Progress Reports, which are included in Exhibit RBD-3 as Form 42-5P.

Q. Please describe the relationship between FPL and Gulf.

A. Gulf was acquired by FPL's parent company, NextEra Energy, Inc., on January 1, 2019. On January 1, 2021, Gulf was legally merged into FPL; but each remained separate ratemaking entities.

FPL and Gulf will be operationally and functionally integrated in 2022. Consistent with the operational consolidation, on March 12, 2021, FPL filed with the Commission a Petition for Base Rate Increase and Rate Unification in Docket No. 20210015 that requested, among other things, authority to consolidate and unify the rates and tariffs applicable to all customers in peninsular and Northwest Florida. Additionally, 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 docket. On August 24, 2021, Vote Solar and the CLEO Institute also signed on to the Settlement Agreement. If the Commission approves the Settlement Agreement, all Gulf customers will become FPL customers, and Gulf will no longer exist as a separate ratemaking entity.

Q. How does the merger between FPL and Gulf impact the implementation of the companies' ECRC programs?

A. Through the end of 2021, FPL and Gulf continue to operate separately. Beginning in January 2022, FPL will operate as an integrated company. For the purposes of the 2022 projections, FPL is proposing to consolidate the FPL and Gulf ECRC projects for the integrated company. In developing the consolidated projects, FPL combined certain projects by rules or similar subject matter into one integrated project and renumbered some projects so there is no duplication of project numbers. The list of the consolidated ECRC projects for FPL and Gulf is provided in Exhibit MWS-13.

Lowest Quality Water Source Project Modification

Q. Please briefly describe FPL's modification to the LQWS Project.

A. In 2000, FPL was required to utilize the lowest quality water source ("LQWS") in order to comply with St. Johns River Water Management District ("SJRWMD") Consumptive Use Permit ("CU Permit") 9202 for the FPL Sanford Plant. In response to the 2000 permit, the Sanford Plant relinquished 43% of its groundwater allocation and began blending cooling pond water with groundwater to create demineralized process water. FPL petitioned the Commission for approval of costs associated with these activities in Docket 030007-EI, and the costs were approved in Order No. PSC-03-1348-FOF-EI.

On July 13, 2021, the SJRWMD issued a final permit renewing CU Permit 9202. Pursuant to the LQWS requirement, in the renewed permit, the SJRWMD deemed surface water to be the LQWS and required the Sanford Plant to discontinue use of groundwater. Groundwater use at the site will be replaced by St. Johns River surface water for the demineralized water treatment system and by municipally supplied potable water for other service water uses. The permit is attached as Exhibit MWS-14.

Q. Please describe the environmental law or regulation requiring the LQWS Project and its application to the requested modification.

A. Condition 14 of the CU Permit requires use of “the lowest quality water source, such as reclaimed water, surface/storm water, or alternative water supply, to supply the needs of the project when deemed feasible pursuant to District rules and applicable state law.” As part of the permit renewal process, FPL was required to conduct a feasibility evaluation of using reclaimed water or surface water to replace groundwater. Based on this evaluation, the SJRWMD deemed surface water to be a feasible LQWS for the site. Therefore, pursuant to permit conditions 18 and 19, the Sanford Plant is required to transition from groundwater to surface water by August 1, 2023. Beginning August 1, 2023, groundwater can be used only as a backup source, and by August 1, 2024, the groundwater wells must be properly abandoned. The SJRWMD’s Technical Staff Report describing their evaluation and determination is attached as Exhibit MWS-15.

Q. Please describe the activities related to the LQWS Project modification that FPL needs to complete.

A. In order to discontinue use of groundwater, the Sanford Plant will need to install infrastructure to connect the water treatment system to surface water from the St. Johns River. Additionally, FPL will need to increase the volume of potable water purchased for service water purposes. Finally, the Sanford Plant must abandon the two groundwater wells currently being used.

Q. What O&M activities at the Sanford Plant are required to comply with the renewed CU Permit?

A. The main components of O&M associated with the modification to the LQWS project include switching the Land Utilization building from groundwater to potable water and an increase of potable water consumption at the plant for service water purposes.

Q. What is the estimated O&M expense associated with the modification to the LQWS Project for the Sanford Plant that FPL is requesting to recover through the ECRC in 2021 through 2022?

A. In 2022, the annual O&M expenses are estimated to increase by approximately $15,000 as a result of the modified CU Permit. The total 2022 O&M expenses for the modification of the LQWS Project are estimated to be approximately $117,000.

Q. Does FPL expect to incur any capital costs associated with the modification to the LQWS project for the Sanford Plant?

A. Yes. FPL estimates the total capital costs associated with the modification will be $4,985,750. The 2022 capital expenditures are estimated to be $3,968,250. The remainder of the capital expenditures are estimated to occur in the 2023-2024 timeframe.

Q. What capital investments at the Sanford Plant are required to comply with the renewed CU Permit?

A. The main components of the capital investment costs associated with the renewed

CU Permit include the installation of infrastructure such as piping, pumps, electrical equipment, mechanical equipment, and construction costs.

Q. Please describe the measures FPL is taking to ensure that costs associated with the modification to the LQWS Project are reasonable and prudently incurred.

A. In general, FPL competitively bids the procurement of materials and services. FPL benefits from strong market presence allowing it to leverage corporate-wide procurement activities to the specific benefit of individual procurement activities. For the Project, FPL will competitively bid the procurement and construction. FPL's Project Controls group maintains the project scope, budget, and schedule and tracks project costs through various approval processes, procedures, and databases.

Q. Did FPL anticipate that it would need to perform these activities at the time that it prepared the Minimum Filing Requirements ("MFRs") for its 2021 rate case?

A. No. At the time the MFRs were prepared for FPL's 2021 rate case, it was not known when the permit would be issued or what specific activities the permit would require.

Q. Is FPL recovering through any other mechanism the costs for the modification to the LQWS Project for which it is petitioning for ECRC recovery?

A. No.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF MICHAEL W. SOLE

DOCKET NO. 20210007-EI

APRIL 1, 2021

Q. Please state your name and address.

A. My name is Michael W. Sole 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 NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Marine Biology from the Florida Institute of Technology in 1986. I served as an Officer in the United States Marine Corps from 1985 through 1990, attaining the rank of Captain. I was employed by the Florida Department of Environmental Protection ("FDEP") in multiple roles from 1990 to 2010 and served as the Secretary of the FDEP from 2007-2010. I have been employed by NEE or its subsidiary Florida Power & Light Company ("FPL") since 2010. In November 2016, I assumed the position of Vice President of Environmental Services for NEE. In that role, I am responsible for FPL's and Gulf Power

Company's ("Gulf Power") environmental licensing and compliance efforts. In May 2017, I was appointed by Governor Scott to the Florida Fish and Wildlife Conservation Commission ("FWC").

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 proceeding?

A. The purpose of my testimony is to explain the reasons for significant variances in costs associated with O&M and Capital investments which support Gulf Power's Environmental Cost Recovery Clause ("ECRC") final true-up filing for the period January through December 2020.

Q. Please explain the reasons for any significant variance in costs associated with O&M and capital investments.

A. The significant variances in Gulf Power's 2020 actual O&M expenses and capital revenue requirements from revised actual/estimated amounts are associated with the following projects:

Capital Variance Explanation

Project 27. General Water Quality

Project revenue requirements are $59,652 or 13.5% lower than estimated. The variance is primarily due to design and contractor procurement delays associated with the Crist Closed Ash Landfill improvement project. An additional delay occurred in September 2020 as the request for proposals from construction contractors was issued the week before Hurricane Sally made landfall in the Pensacola area. Contractor site visits required to finalize the bid package were delayed several weeks due to initial inaccessibility to the site during storm restoration.

O&M Variance Explanations

Project 6. General Water Quality

Project expenditures are $514,527 or 40.9% lower than estimated. The variance is primarily due to costs for the Plant Smith and Plant Scholz industrial wastewater permit renewals being less than estimated and costs for Plant Daniel's groundwater monitoring being lower during the second half of the year. In addition, costs for substation stormwater pond maintenance and the Plant Crist thermal study were less than estimated.

Project 7. Groundwater Contamination Investigation

Project expenditures are $202,879 or 9.7% higher than estimated. The variance is primarily due to increased scope of work required for the Pittman substation remediation project. Soil excavation and associated disposal costs were higher than originally estimated because the area of soil excavation had to be increased based on the results of additional soil screening conducted during the excavation. The project scope was also extended due to rainfall and wet site conditions, which increased equipment rental costs.

Project 11. General Solid & Hazardous Waste

Project expenditures are $228,752 or 23.9% less than estimated. The variance is primarily due to costs associated with transformer oil spills for Gulf Power's power delivery operations being less than estimated. In addition, labor costs for Gulf Power's waste management and oil spill response program were less than estimated.

Project 20. Air Quality Compliance Program

Project expenditures are $1,647,848 or 9.7% less than estimated. The variance is due to maintenance and chemical expenses associated with the Plant Crist scrubber being less than estimated. Maintenance costs for the Plant Crist scrubber were reduced after Gulf Power determined it would retire the scrubber along with the Plant Crist coal generation assets in October 2020. Additionally, the limestone cost incurred in 2020 was less than estimated.

Project 22. Crist Water Conservation

Project expenditures are $97,038 or 46.5% lower than estimated. The variance is due to chemical costs associated with Plant Crist's reclaimed water system being less than estimated.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20210007-EI

Before me, the undersigned authority, personally appeared Michael W. Sole, who being first duly sworn, deposes and says that he is the Vice President of Environmental 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.

Michael W. Sole

Michael W. Sole
Vice President, Environmental Services

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 31st day of March, 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 MICHAEL W. SOLE

DOCKET NO. 20210007-EI

JULY 30, 2021

Q. Please state your name and address.

A. My name is Michael W. Sole and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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Q. Have you previously filed testimony in this docket?

A. Yes.

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

A. The purpose of my testimony is to explain the reasons for significant variances in costs associated with O&M and Capital investments which support Gulf's Environmental Cost Recovery Clause ("ECRC") actual/estimated true-up filing for the period January through December 2021. This true-up is based on five months of actual data and seven months of estimated data. I will also provide an update on a new Spill Prevention Control and Countermeasures ("SPCC") activity that has been included under Gulf's previously approved project.

Q. Please describe the new Spill Prevention Control and Countermeasures activity Gulf seeks to recover under Project 20.

A. A new oil spill prevention control and countermeasures (SPCC) plan was developed for the Gulf Clean Energy Center ("GCEC"), formerly Plant Crist, in June of 2021 in accordance with the Federal regulation (Title 40, Code of Federal Regulation Part 112). The plan requires installation of permanent oil containment in the 2022-2023 timeframe to capture potential oil spills and prevent oil from reaching surface waters. Engineering and design of the permanent boom installation is currently scheduled for the second half of 2021 in order to begin construction in early 2022. Projected expenses for the GCEC boom installation during the 2021 recovery period total $100,000.

Q. Please explain the reasons for any significant variance in costs associated with O&M and capital investments.

A. The significant variances in Gulf's 2021 recoverable O&M expenses and capital revenue requirements from projection amounts are associated with the following projects:

Capital Variance Explanations

Project 4. Low NOx Burners, GCEC 6 & 7

Project revenue requirements are estimated to be $187,509 or 11.1% lower than previously projected. In January of 2021 portions of the GCEC Unit 6 and Unit 7 low NO_x burner systems were retired as part of the gas conversion project.

Project 17. Smith Water Conservation

Project revenue requirements are estimated to be $408,426 or 15.3% lower than previously projected. The variance is primarily due to postponing construction of the Plant Smith Underground Injection Control ("UIC") wastewater treatment system and associated pump station from 2021 to 2022 due to additional time required to finalize design of the onsite reclaimed water distribution system and to complete additional geotechnical investigations for the reclaimed water supply pipeline between Bay County's North Bay Water Treatment Plant and Plant Smith. Additional delay is due to pending contract negotiations between the County and Gulf Power. The new treatment system and permanent pump station are required for Plant Smith to begin using reclaimed water for the Unit 3 cooling tower water supply. Gulf has completed installation of three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station and for current wastewater discharges.

Project 27. General Water Quality

Project revenue requirements are estimated to be $289,748 or 21.8% lower than previously projected. The variance is due to costs for the GCEC Closed Ash Landfill improvement project being lower than expected in 2020, which lowered the 2021 beginning of period balance for the project. As explained in my final true-up testimony, the 2020 project costs were lower than estimated due to design and contractor procurement delays.

Project 28. Coal Combustion Residual

Project revenue requirements are estimated to be $1,715,693 or 11.2% lower than previously projected. The variance is primarily due to delays placing the Plant Daniel dry bottom ash conversion projects and the new Plant Smith industrial wastewater treatment pond in-service. Gulf initially projected the Plant Daniel dry bottom ash projects would be placed in-service in 2020; however, the projects were placed in-service in 2021. The Plant Smith wastewater pond and piping modifications required to cease discharging process water and stormwater to the ash pond were projected to be placed in-service in late 2020. Plant Smith began utilizing the new wastewater pond and piping modifications in a temporary configuration in the Spring of 2021 to meet the Federal CCR deadline to cease sending wastewater to the pond and to initiate closure; however, the associated workorder will not be placed in-service until 2023 when Plant Smith completes construction of two additional ponds and related modifications to the wastewater system.

Project 30. 316(b) Cooling Water Intake Structure Regulation

Project revenue requirements are estimated to be $93,761 or 19.0% lower than previously projected. The variance is due to cost of removal for the Plant Smith 316(b) intake pump project being inadvertently included in the original projections for the new project additions in 2020 and 2021. The actual cost of removal was booked correctly to a non-ECRC account, resulting in a lower ECRC plant in-service balance in 2021.

O&M Variance Explanations

Project 5. Emission Monitoring

Project expenditures are estimated to be $158,057 or 24.8% lower than previously projected. The variance is due to reducing maintenance costs associated with the Continuous Emissions Monitoring ("CEM") systems at Plant Smith and GCEC by insourcing CEM maintenance.

Project 6. General Water Quality

Project expenditures are estimated to be $334,061 or 20.5% lower than previously projected. The variance is primarily due to costs for the Plant Smith and Plant

Scholz industrial wastewater permit renewals being less than originally projected and costs for Plant Daniel's groundwater monitoring being lower. In addition, less substation stormwater maintenance has been required this year than originally anticipated.

Project 19. FDEP NOx Reduction Agreement

Project expenditures are estimated to be $113,901 or 116.6% lower than previously projected. Maintenance costs associated with the GCEC Unit 7 Selective Catalytic Reduction ("SCR") were reduced due to Gulf retiring the SCR with the GCEC coal generation assets in October 2020.

Project 23. Coal Combustion Residuals

Project expenditures are estimated to be $346,411 or 19.9% lower than previously projected. The variance is primarily due to removing wastewater treatment costs for the Plant Scholz pond closure project from the 2021 O&M budget since completion of the capital project has been delayed until 2022. The wastewater treatment costs will continue to be included under the pond closure capital line item until the capital project is complete.

Project 27. Emission Allowances

Project expenditures are estimated to be $148,734 or 3,825.8% higher than previously projected. The variance is primarily due to the market price per allowance significantly increasing following changes to EPA's Cross State Air Pollution Rule.

Q. Does this conclude your testimony?

A. Yes.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

GARY P. DEAN

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

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, FL 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 ("ECRC").

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 present for Commission review and approval DEF's actual true-up costs associated with environmental compliance activities for the period January 2020 - December 2020.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring Exhibit No.___ (GPD-1), that consists of nine forms, and Exhibit No.___ (GPD-2), that provides details of three capital projects by site.

Exhibit No.___ (GPD-1) consists of the following:

- Form 42-1A: Final true-up for the period January 2020 - December 2020;
- Form 42-2A: Final true-up calculation for the period;
- Form 42-3A: Calculation of the interest provision for the period;
- Form 42-4A: Calculation of variances between actual and actual/estimated costs for O&M Activities;
- Form 42-5A: Summary of actual monthly costs for the period for O&M Activities;
- Form 42-6A: Calculation of variances between actual and actual/estimated costs for Capital Investment Projects;
- Form 42-7A: Summary of actual monthly costs for the period for Capital Investment Projects;
- Form 42-8A, pages 1-17: Calculation of return on capital investment, depreciation expense and property tax expense for each project recovered through the ECRC; and
- Form 42-9A: DEF's capital structure and cost rates.

Exhibit No.___ (GPD-2) consists of detailed support for the following capital projects:

- Above Ground Storage Tank Secondary Containment (Capital Program Detail (CPD), pages 2-7);
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs) (CPD, pages 8-11); and
- CAIR-Crystal River Units 4 & 5 (CPD, pages 12-13).

These exhibits were developed under my supervision and they are true and accurate to the best of my knowledge and belief.

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

A. The actual data is taken from the books and records of DEF. The books and records are kept in the regular course of DEF's 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. What is the final true-up amount DEF is requesting for the period January 2020 - December 2020?

A. DEF requests approval of an actual over-recovery amount of $8,328,666 for the year ending December 31, 2020. This amount is shown on Form 42-1A, Line 1.

Q. What is the net true-up amount DEF is requesting for the period January 2020 - December 2020 to be applied in the calculation of the environmental cost recovery factors to be refunded/recovered in the next projection period?

A. DEF requests approval of an adjusted net true-up over-recovery amount of $231,488 for the period January 2020 - December 2020 reflected on Line 3 of Form 42-1A. This amount is the difference between an actual over-recovery amount of $8,328,666 and an actual/estimated over-recovery of $8,097,179 for the period January 2020 - December 2020, as approved in Order PSC-2020-0433-FOF-EI.

Q. Are all costs listed on Forms 42-1A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. Yes.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections as presented in previous testimony and exhibits?

A. Form 42-4A shows a total O&M project variance of $1,182,935 or 6% lower than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimonies of Timothy Hill, Kim McDaniel, and Jeffrey Swartz.

Q. How did actual capital recoverable expenditures for January 2020 - December 2020 compare with DEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-6A shows a total capital investment recoverable cost variance of $17,738 or 0.1% lower than projected. Individual project variances are on Form 42-6A. Return on capital investment, depreciation and property taxes for each project for the period are provided on Form 42-8A, pages 1-17. Explanations associated with variances are contained in the direct testimonies of Timothy Hill, Kim McDaniel, and Jeffrey Swartz.

Q. Please explain the variance between actual project expenditures and the Actual/Estimated projections for the SO_2/NOx Emissions Allowance (Project 5).

A. The O&M variance is $2,541 or 73% higher than projected. This is primarily due to higher than expected SO_2 Allowance expense.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

GARY P. DEAN

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

July 30, 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, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-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 review and approval, Duke Energy Florida, LLC's ("DEF") actual/estimated true-up costs associated with environmental compliance activities for the period January 2021 through December 2021. I also explain the variance between 2021 actual/estimated cost projections versus original 2021 cost projections for SO_2/NOx Emission Allowances (Project 5).

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __(GPD-3), which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __(GPD-4), which provides details of capital projects by site.

These exhibits provide detail on DEF's actual/estimated true-up capital and O&M environmental costs and revenue requirements for the period January 2021 through December 2021.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2021 through December 2021?

A. The 2021 actual/estimated true-up is an over-recovery, including interest, of $1,596,750 as shown on Form 42-1E, line 4. The final 2020 true-up over-recovery of $231,488 as shown on Form 42-2E, Line 7a, is added to this total, resulting in a net over-recovery of $1,828,238 as shown on Form 42-2E, Line 11. The calculations supporting the 2021 actual/estimated true-up are on Forms 42-1E through 42-9E.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2021 through December 2021?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2021 through December 2021 are shown on Form 42-9E. This form includes the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8E. Form 42-9E also cites the source and includes the rationale for using the particular capital structure and cost rates.

Q. How do actual/estimated O&M expenditures for January 2021 through December 2021 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $21,217,707. This is $1.3M, or 6% lower than originally projected. This form also lists individual O&M project variances. Explanations for these variances are included in the Direct Testimonies of Reginald Anderson, Timothy Hill, and Kim Spence McDaniel.

Q. How do estimated/actual capital recoverable costs for January 2021 through December 2021 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be $25,044,001. This is $131k or 1% lower than originally projected. This form also lists individual project variances. The return on investment, depreciation expense and property taxes for each project for the actual/estimated period are provided on Form 42-8E, pages 1 through 18. Explanations for these variances are included in the Direct Testimonies of Mr. Anderson, Mr. Hill and Ms. McDaniel.

Q. Please explain the O&M variance between actual project expenditures and the Actual/Estimated projections for the SO_2/NOx Emissions Allowance (Project 5).

A. The O&M variance is $2,332, or 24% higher than projected, due to a higher-than-projected SO2 allowance expense.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

GARY P. DEAN

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 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, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

Q. Has your job description, education, background or 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 review and approval, Duke Energy Florida, LLC's ("DEF" or "the Company") calculation of revenue requirements and Environmental Cost Recovery Clause ("ECRC") factors for customer billings for the period January 2022 through December 2022. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2022.

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

A. Yes. I am sponsoring the following exhibit:

Exhibit No.__(GPD-5), which consists of PSC Forms 42-1P through 42-8P

The individuals listed below are co-sponsors of Forms 42-5P, pp. 1 through 4, and 6 through 23 as indicated in their Direct Testimonies. I am sponsoring Form 42-5P, p. 5.

- Ms. McDaniel will co-sponsor Forms 42-5P, pp. 1 through 4, 6 and 8 through 19.
- Mr. Anderson and Ms. McDaniel will co-sponsor Form 42-5P, p. 7.
- Mr. Anderson will co-sponsor Form 42-5P, pp. 20 through 22.
- Mr. Hill will co-sponsor Form 42-5P, p. 23.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average ECRC billing factor of 0.027 cents per kWh, which includes projected jurisdictional capital and O&M revenue requirements for the period January 2022 through December 2022 of approximately $12.3 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $1.8 million from prior periods. My testimony also supports that projected environmental expenditures for 2022 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2022 through December 2022?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $10.4 million as shown on Form 42-1P, line 4 of Exhibit No.__(GPD-5).

Q. What is the total true-up to be applied for the period January 2022 through December 2022?

A. The total true-up applicable to this period is an over-recovery of approximately $1.8 million. This amount consists of the final true-up over-recovery of approximately $231 thousand for the period January 2020 through December 2020, and an estimated true-up over-recovery of approximately $1.6 million for the current period of January 2021 through December 2021. The detailed calculation supporting the 2021 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No.__(GPD-3) filed with the Commission on July 30, 2021.

Q. Are all the costs listed on Forms 42-1P through 42-7P attributable to environmental compliance programs previously approved by the

Commission?

A. Yes, the following ECRC programs were previously approved by the Commission:

The Substation and Distribution System Programs (Project 1 & 2) were previously approved in Order No. PSC-2002-1735-FOF-EI.

The Pipeline Integrity Management Program (Project 3) and the Above Ground Tank Secondary Containment Program (Project 4) were previously approved in Order No. PSC-2003-1348-FOF-EI.

The recovery of Sulfur Dioxide (SO_2) Emission Allowances (Project 5) was previously approved in Order No. PSC-1995-0450-FOF-EI; however, the costs were moved to the ECRC docket from the Fuel docket beginning January 1, 2004, at the request of Staff to be consistent with the other Florida investor-owned utilities.

CAIR was replaced by the Cross-State Air Pollution Rule on January 1, 2015. Consistent with Order No. PSC-2011-0553-FOF-EI, DEF treated the costs associated with unusable NOx emission allowances as a regulatory asset and amortized it over three (3) years, beginning January 1, 2015, until fully recovered on December 31, 2017, with a return on the unamortized investment.

The Phase II Cooling Water Intake 316(b) Program (Project 6) was previously approved in Order No. PSC-2004-0990-PAA-EI, PSC-2018-0014-FOF-EI and PSC-2020-0433-FOF-EI.

DEF's Integrated Clean Air Compliance Plan (Project 7) was approved by the Commission as a prudent and reasonable means of complying with the Clean Air Interstate Rule and related regulatory requirements in Order No. PSC-2007-0922-FOF-EI.

The Arsenic Groundwater Standard Program (Project 8), Sea Turtle Lighting Program (Project 9) and Underground Storage Tanks Program (Project 10) were previously approved in Order No. PSC-2005-1251-FOF-EI.

The Modular Cooling Tower Project (Project 11) was previously approved in Order No. PSC-2007-0722-FOF-EI.

The Crystal River Thermal Discharge Compliance Project (Project 11.1) and Greenhouse Gas Inventory and Reporting Project (Project 12) were previously approved in Order No. PSC-2008-0775-FOF-EI.

The Mercury Total Maximum Loads Monitoring Program (Project 13) was previously approved in Order No. PSC-2009-0759-FOF-EI.

The Hazardous Air Pollutants (HAPs) ICR Program (Project 14) was previously approved in Order No. PSC-2010-0099-PAA-EI.

The Effluent Limitations Guidelines ICR Program (Project 15) was previously approved in Order No. PSC-2010-0683-PAA-EI.

The Effluent Limitations Guidelines Program (Project 15.1) was previously approved in Order No. PSC-2013-0606-FOF-EI.

The National Pollutant Discharge Elimination System (NPDES) Program (Project 16) was previously approved in Order No. PSC-2011-0553-FOF-EI.

The Mercury & Air Toxic Standards (MATS) Program (Project 17), which replaces Maximum Achievable Control Technology (MACT), was previously approved in Order Nos. PSC-2011-0553-FOF-EI, PSC-2012-0432-PAA-EI and PSC-2014-0173-PAA-EI.

The Coal Combustion Residual (CCR) Rule (Project 18) was previously approved in Order No. PSC-2015-0536-FOF-EI, Order No. PSC-2018-0594-FOF-EI, and Order No. PSC-2019-0500-FOF-EI.

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 have been incorporated into the filing.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2022?

A. Yes. Form 42-2P of Exhibit No.__(GPD-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $8.2 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2022?

A. Yes. Form 42-3P of Exhibit No.__(GPD-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $4.1 million. Form 42-4P, pp. 1 through 9, show detailed calculations of these costs.

Q. Have you prepared schedules providing progress reports for all environmental compliance projects?

A. Yes. Form 42-5P, pp. 1 through 23 of Exhibit No.__(GPD-5), provide a description, progress summary and recoverable cost estimates for each project.

Q. What are the total projected jurisdictional costs for environmental compliance projects for the year 2022?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $12.3 million. The costs are calculated on Form 42-1P, line 1c of Exhibit No.__(GPD-5).

Q. Please describe how the proposed ECRC factors are developed.

A. The ECRC factors are calculated on Forms 42-6P and 42-7P of Exhibit No.__(GPD-5). The demand component of class allocation factors is calculated by determining the percentage each rate class contributes to monthly system peaks adjusted for losses for each rate class, which is obtained from DEF's load research study filed with the Commission in July 2021. The energy allocation factors are calculated by determining the percentage each rate class contributes to total kilowatt-hour sales adjusted for losses for each rate class. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

Q. What effect does the 2021 Settlement Agreement Order No. PSC-2021-0202-AS-EI, dated June 4, 2021, have on the ECRC O&M and Capital Investments presented in this Docket (20210007-EI)?

A. Pursuant to the 2021 Settlement Agreement in Docket 20210016-EI and approved in Order PSC-2021-0202-AS-EI, DEF will move the ECRC costs identified in Exhibit 2 of the 2021 Settlement Agreement to base rates as of year-end 2021. The Settlement Agreement provides that effective with the first billing cycle of January 2022, DEF is authorized to remove the Capital and/or O&M ECRC recovery associated with Above Ground Secondary Containment (Projects 4.1, 4.2, 4.3), CAIR/CAMR Peaking (Project 7.2), CAIR/CAMR Crystal River AFUDC Base

(Project 7.4), CAIR/CAMR Crystal River AFUDC A&G (Project 7.4), CAIR/CAMR Crystal River Conditions of Certification (Project 7.4), Sea Turtle Coastal Street Lighting (Project 9), Underground Storage Tanks (Projects 10.1, 10.2) and Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion (Project 17.1), and transfer those to base rates in an amount which will equal the annual retail revenue requirements of the assets in-service as of December 31, 2021. The investments that are not included in the 2021 Settlement Agreement as moving to base will continue to be recovered through ECRC in future Dockets.

Q. What are DEF's proposed 2022 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2022 customer billings is shown on Form 42-7P in Exhibit No.__(GPD-5) as follows:

(Information found on the following page.)

RATE CLASS	ECRC FACTORS
Residential	0.028 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.027 cents/kWh
@ Primary Voltage	0.027 cents/kWh
@ Transmission Voltage	0.026 cents/kWh
General Service 100% Load Factor	0.024 cents/kWh
General Service Demand	
@ Secondary Voltage	0.025 cents/kWh
@ Primary Voltage	0.025 cents/kWh
@ Transmission Voltage	0.025 cents/kWh
Curtailable	
@ Secondary Voltage	0.022 cents/kWh
@ Primary Voltage	0.022 cents/kWh
@ Transmission Voltage	0.022 cents/kWh
Interruptible	
@ Secondary Voltage	0.023 cents/kWh
@ Primary Voltage	0.023 cents/kWh
@ Transmission Voltage	0.023 cents/kWh
Lighting	0.020 cents/kWh

Q. When is DEF requesting that the proposed ECRC billing factors be effective?

A. DEF is requesting that its proposed ECRC billing factors be effective with the first billing cycle of January 2022 and continue through the last billing cycle of December 2022.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Timothy S. Hill was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY S. HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20210007-EI

April 1, 2021

Q. Please state your name and business address.

A. My name is Timothy S. Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

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

A: I am employed by Duke Energy Corporation ("Duke Energy") as Regional General Manager for the Coal Combustion Products ("CCP") Group - Operations & Maintenance. Duke Energy Florida, LLC ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q: What are your responsibilities in that position?

A: I am responsible for oversight of the operation and maintenance of all CCP facilities in the Western Carolinas and Florida, including the CCP facility at the Crystal River Energy Center. This includes operating and maintaining all CCP facilities in compliance with state and federal regulations. The Operations and Maintenance group at each station maintains accountability for overall CCP facility performance which requires close collaboration with other Duke Energy CCP organizations such as Project Implementation, Engineering, and Facility Closure. The Company relies on my opinions and information I provide when making decisions regarding the CCP facilities under my supervision.

Q: Please describe your educational background and professional experience.

A: I have a Bachelor of Science degree in Nuclear Engineering from the University of Florida and a Master of Science degree from the University of Central Florida. I have 18 years of experience in the power generation industry including positions as an Engineering Manager, a Maintenance Manager, and a Plant Manager within Duke Energy's fossil fleet, and as Fleet and Harris Station Maintenance Manager in Duke Energy's nuclear fleet. Prior to joining Duke Energy, I was employed by Delta Air Lines as a General Manager in Engineering and Maintenance, and prior to that I served 21 years as a commissioned officer in the U.S. Navy, serving in the nuclear fleet. In November of 2014, I began my current role as CCP Regional General Manager.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an update on DEF's 2020 Coal Combustion Residual ("CCR") Rule compliance activities and associated 2020 compliance costs for which the Company seeks recovery through the Environmental Cost Recovery Clause ("ECRC").

Q. How did actual O&M project expenditures for the period January 2020 – December 2020 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR Rule O&M variance is $251,850 or 27% lower than projected. This is primarily due to costs associated with the Crystal River landfill ditch remediation work that were incorrectly recorded to a different project. This mischarge will be corrected in the 2021 financial results.

Q. How did actual capital project expenditures for the period January 2020 – December 2020 compare to actual/estimated capital projections for the CCR Rule (Project 18)?

A. The CCR Rule capital variance is $757,452 or 56% higher than projected. This is primarily due to additional engineering measures that were included in the final design and pricing obtained from a competitive bid event for the new lined sedimentation basin / ditch area. This project is part of the groundwater corrective actions as required by the Federal CCR Rule and was approved as recoverable through the ECRC by Commission Order No. PSC-2019-0500-FOF-EI.

The initial cost estimate for this capital project was based on a preliminary design that was developed as part of a feasibility study conducted as part of the CCR Rule's Assessment of Corrective Measures, which has been provided to the Commission as part of previous testimonies. The final engineering design of this facility required adding a second impermeable liner, a cushioning layer over the liner components, and structural fill placement below the groundwater table resulting in substantial groundwater control measures. These measures contributed to the increased cost for materials, equipment, and labor. These additional measures also extended the construction duration from about three months initially estimated to about six months. The extended duration also contributed to the increased costs for labor and equipment. The final factor contributing to the capital variance is that actual contract bids came in higher than the original estimate. The projected cost was estimated based on unit costs from other projects and construction industry cost data reports, whereas the actual costs are based on pricing obtained through a competitive bid event that was opened in late July 2020 and closed in early October 2020.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

July 30, 2021

Q. Please state your name and business address.

A. My name is Timothy Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. By whom are you employed?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Vice President for the Coal Combustion Products ("CCP") Group – Operations, Maintenance and Governance. Duke Energy Florida, LLC ("DEF" or "the Company") is a fully owned subsidiary of Duke Energy.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-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. Yes. In my new role, I continue to oversee all CCP operations in Florida, but have expanded that responsibility to all of Duke Energy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between 2021 actual/estimated cost projections and original 2021 cost projections for environmental compliance costs associated with DEF's Coal Combustion Residual ("CCR") Rule compliance project.

Q. Please explain the O&M variance between actual/estimated project expenditures and original projections for CCR (Project 18) O&M for the period January 2021 through December 2021.

A. O&M expenditures for CCR are expected to be $474,478, or 171% higher than projected. This is primarily due to the reclassification of invoices received in 2020 that were not charged to the ECRC-recoverable portion of this project until 2021, as described in the testimony filed on April 1, 2021, in this Docket. The remaining portion is due to additional engineering to revise and re-certify the Landfill Run-On and Run-Off Control Systems ("ROROCS") Plan and perform the annual landfill inspection as required by the CCR Rule and additional CCR removal from landfill ditches required, as part of the CCR Ash Landfill Project, discussed in further detail below.

Q. Please explain the Capital variance between actual/estimated project expenditures and original projections for CCR (Project 18) Capital for the

period January 2021 through December 2021.

A. Capital expenditures for CCR are expected to be $1,525,036, or 610% higher than projected. This is primarily due to additional engineering measures required in the final design of the new, lined, sedimentation basin and ditch area as described in the testimony filed on April 1, 2021, in this Docket. This project is part of the groundwater corrective actions required by the Federal CCR Rule and determined recoverable as part of the CCR Ash Landfill Project discussed below.

The initial cost estimate for this project was based on a preliminary design developed by a feasibility study as part of the CCR Rule's Assessment of Corrective Measures, which has been provided to the Florida Public Service Commission ("the Commission") as part of previous testimonies. The final engineering design of this facility required adding a second impermeable liner, a cushioning layer, over the liner components and structural fill placement below the groundwater table resulting in substantial groundwater control measures. These measures contributed to the increased cost for materials, equipment and labor. These additional measures also extended the construction duration from approximately three months to six months, which also contributed to the increased costs. Additionally, contract bids came in higher-than-originally estimated. The project is expected to be completed in 2021.

Q. Please provide an update on the CCR Ash Landfill project

A. On July 3, 2019, DEF notified the Commission of a new ECRC project for the CCR Ash Landfill. In Order PSC-2019-0500-FOF-EI, issued on November 22, 2019, the Commission approved the Ash Landfill project as recoverable through the ECRC. On May 6, 2021, DEF posted the Remedy Selection Final Report to the publicly accessible CCR Rule Compliance Data and Information website for the DEF Crystal River Energy Complex. The selected remedies include remediating the ash landfill perimeter ditches to remove accumulated CCR materials, constructing a new lined basin / ditch area to prevent future material accumulation and continued monitoring of natural attenuation. DEF initiated remediating the ash landfill perimeter ditches and constructing the new lined basin / ditch area in 2020. DEF expects to complete both remedy components in 2021.

DEF will continue to monitor groundwater quality as required in the Federal CCR Rule and evaluate the effectiveness of the remedies implemented in 2020 and 2021. DEF will update the Commission about this project if additional corrective actions will be required to meet compliance with the Rule.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

Q. Please state your name and business address.

A. My name is Timothy Hill. My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an update on Duke Energy Florida, LLC's ("DEF" or "the Company") proposed compliance activities and related 2022 estimated costs associated with the Coal Combustion Residual ("CCR")

Rule for which the Company seeks recovery under the Environmental Cost Recovery Clause ("ECRC").

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

A. Yes. I am co-sponsoring the following portion of Exhibit No.__(GPD-5) to Gary P. Dean's Direct Testimony:

- 42-5P, p. 23 – Coal Combustion Residual Rule

Q. What O&M costs does DEF expect to incur in 2022 for the Coal Combustion Residual Rule Program (Project No. 18)?

A. DEF is forecasting $343k in O&M costs for 2022.

Various maintenance and repair work is required for the ash landfill to comply with the rule. This includes maintenance of the landfill cover, vegetation management, fugitive dust mitigation, weekly inspections and cleanout of the lined-sedimentation pond and perimeter ditch which was installed this year as a groundwater corrective measure. DEF will also continue to perform the required groundwater monitoring for ash management units, which includes engineering, sampling, analysis and reporting.

Q. What Capital costs does DEF expect to incur in 2022 for the Coal Combustion Residual Rule Program (Project No. 18)?

A. DEF does not expect capital expenditures in 2022.

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2022?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts and expects to incur costs in 2022 and beyond. Additional compliance activities may be required as a result of ongoing, groundwater-quality monitoring to evaluate the effectiveness of the corrective measures implemented in 2020 and completed in 2021. As these monitoring and evaluation activities are completed, and if any additional compliance activities and costs become known, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

Q. Does this conclude your testimony?

A. Yes.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

REGINALD ANDERSON

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

July 30, 2021

Q. Please state your name and business address.

A. My name is Reginald Anderson. My business address is 299 First Avenue North, St. Petersburg, FL 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 Vice President – Regulated & Renewable Energy Florida.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Regulated & Renewable Energy organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and addition recommendations; major maintenance programs; outage and project management; generation facilities retirement; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvement; retention and inclusion; succession planning; and oversight of numerous employees and hundreds of millions of dollars in assets and capital and O&M budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Electrical Engineering Technology and Master of Business from the University of Central Florida in 1996 and 2008 respectively. I have 23 years of power plant production experience at DEF in various operational, managerial and leadership positions in fossil steam and combustion turbine plant operations. I also managed the new construction and O&M projects team. I have contract negotiation and management experience. My prior experience includes leadership roles in municipal utilities, manufacturing and the United States Marine Corps.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?

A. No, I will be adopting the direct testimony of Jeffrey Swartz filed on April 1, 2021.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between 2021 actual/estimated cost projections and original 2021 cost projections for environmental compliance costs associated with FPSC-approved environmental programs under my responsibility. These programs include the CAIR/CAMR

Crystal River ("CR") Program (Project 7.4), Mercury and Air Toxics Standards (MATS) – Crystal River (CR) 4&5 (Project 17), and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

Q. How do actual/estimated O&M project expenditures compare with original projections for the CAIR/CAMR CR Program (Project 7.4) for the period January 2021 through December 2021?

A. O&M expenditures are expected to be $1,714,203 or 8% lower than originally projected. This projected variance is primarily due to $1.3M lower than projected CAIR – Energy (Reagents) and $591k lower than originally projected CAIR-Conditions of Certification (Energy) costs, slightly offset by $205k higher than originally projected CAIR-Base.

Q. Please explain the variance between actual/estimated O&M expenditures and the original projections for O&M expenditures for the CAIR/CAMR CR-Base Program (Project 7.4) for the period January 2021 through December 2021?

A. O&M expenditures for the CAIR/CAMR CR-Base Program are expected to be $205,327 or 2% higher than originally forecasted. This is primarily due to expected higher maintenance and repairs that will be required due to increased forecasted generation run times at CR 4 & 5.

Q. Please explain the variance between actual/estimated O&M expenditures and the original projections for O&M expenditures for the CAIR/CAMR

CR-Energy (Reagents) Program (Project 7.4) for the period January 2021 through December 2021?

A. O&M expenditures for the CAIR/CAMR CR-Energy (Reagents) Program are expected to be $1,328,948 or 21% lower than originally forecasted. This variance consists of higher forecasted expense for Ammonia ($493k), Limestone ($410k), and Hydrated Lime ($876k) and decreased forecasted expense for Dibasic Acid ($6k) and Caustic ($83k). There is also an increase in the forecasted credit for Gypsum Sale ($3M).

Q. Please explain the variance between actual/estimated O&M expenditures and the original projections for O&M expenditures for the CAIR/CAMR CR-Energy (Conditions of Certification) Program (Project 7.4) for the period January 2021 through December 2021?

A. O&M expenditures for the CAIR/CAMR CR-Energy (Conditions of Certification) Program are expected to be $590,582 or 33% lower than originally forecasted. This is primarily due to a decrease in the forecasted repairs.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for MATS CR4&5 (Project 17) for the period January 2021 through December 2021.

A. O&M expenditures for MATS CR 4&5 are expected to be $115,000 or 32% lower than forecasted. This is primarily due to a decrease in forecasted repairs.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

REGINALD ANDERSON

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

Q. Please state your name and business address.

A. My name is Reginald Anderson. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?

A. Yes. I provided direct testimony on July 30, 2021, and adopted Jeffrey Swartz's testimony filed on April 1, 2021.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of ECRC-recoverable costs that will be incurred in 2022 for Duke Energy Florida, LLC's ("DEF" or "the

Company") environmental compliance programs under my responsibility. These programs include the CAIR/CAMR Crystal River ("CR") Program (Project 7.4), Mercury and Air Toxics Standards (MATS) – Crystal River (CR) 4&5 (Project 17), Mercury and Air Toxics Standards (MATS) – Anclote Gas Conversion (Project 17.1) and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

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

A. Yes. I am co-sponsoring the following portions of Exhibit No. __ (GPD-5) to Gary P. Dean's direct testimony:

- Form 42-5P, p. 7 of 23 – Clean Air Interstate Rule (CAIR)
- Form 42-5P, p. 20 of 23 - MATS – CR4&5
- Form 42-5P, p. 21 of 23 - MATS – Anclote Gas Conversion
- Form 42-5P, p. 22 of 23 - MATS – CR1&2

Q. What O&M costs does DEF expect to incur in 2022 for the CAIR/CAMR Crystal River – Energy Program (Project 7.4)?

A. DEF estimates O&M costs of approximately $7.6M to support reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) for use at the CR Energy Complex ("CREC") as outlined in DEF's Integrated Clean Air Compliance Plan.

Q. What O&M costs does DEF expect to incur in 2022 for the MATS Program

– CR 4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $191k for CR 4&5 MATS compliance. This estimate includes emissions testing, burner inspections, maintenance of emissions monitoring and control technologies, and reagent costs.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

April 1, 2021

Q. Please state your name and business address.

A. My name is Jeffrey Swartz. My business address is 8202 W. Venable St, Crystal River, FL 34429.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Vice President – Regulated & Renewable Energy Florida.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Regulated & Renewable Energy organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and addition recommendations; major maintenance programs; outage and project management; generation facilities retirement; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvement; retention and inclusion; succession planning; and oversight of numerous employees and hundreds of millions of dollars in assets and capital and O&M budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 20 years of power plant and production experience at DEF in various managerial and executive positions in fossil steam, combustion turbine and nuclear plant operations. I also managed new construction and O&M projects. I have extensive contract negotiation and management experience. My prior experience includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management oversight experience with a pulp, paper and chemical manufacturing company.

Q. Have you previously filed testimony before this Commission in connection with DEF's Environmental Cost Recovery Clause ("ECRC")?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between actual and actual/estimated project expenditures for environmental compliance costs associated with DEF's Integrated Clean Air Compliance Program (Project 7.4), Mercury and Air Toxics Standards ("MATS") - Anclote Gas Conversion Project (Project 17.1), and Mercury & Air Toxics Standards (MATS) – CR 1&2 (Project 17.2) for the period January 2020 – December 2020.

Q. How do actual O&M expenditures for January 2020 – December 2020 compare with DEF's actual/estimated projections for the Clean Air Interstate Rule/Clean Air Mercury Rule (CAIR/CAMR) Crystal River Program (Project 7.4)?

A. The CAIR/CAMR Crystal River O&M variance is $74,748 or 0.5% higher than projected. This variance is primarily attributable to $893k higher than expected CAIR Crystal River – Base, and a $778k lower than expected CAIR Crystal River – Energy (Reagents).

Q. Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2020 - December 2020?

A. O&M costs for CAIR Crystal River Project – Base were $892,906 or 8% higher than projected. This was primarily due to $439k to support Units 4&5 for an outage which was not included in the projection, and $454k in contractor costs for increased limestone handling expenses due to higher than forecasted generation run times at Units 4&5.

Q: Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Energy (Reagents) (Project 7.4) for January 2020 - December 2020?

A: O&M costs for CAIR Crystal River Project – Energy (Reagents) were $777,668 or 18% lower than projected. This was primarily due to a $1.5M higher than projected credit for beneficial Gypsum Disposal (Sale). Variance for other reagents were $161k (13%) higher for Ammonia Expense, $131k (5%) lower for Limestone Expense, $15k (216%) higher for Dibasic Acid Expense, $438k (39%) higher for Hydrated Lime Expense, and $221k (100%) higher Caustic Expense.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Kim Spence McDaniel was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KIM SPENCE McDANIEL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

April 1, 2021

Q. Please state your name and business address.

A. My name is Kim S. McDaniel. My business address is 299 First Avenue North, St. Petersburg, FL 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 Manager of Environmental Services.

Q. What are your responsibilities in that position?

A. My responsibilities include managing the work of environmental professionals who are responsible for environmental, technical, and regulatory support during the development and implementation of environmental compliance strategies for regulated power generation facilities and electrical transmission and distribution facilities in Florida.

Q. Please describe your educational background and professional experience.

A. I obtained my Bachelor of Science degree in Wildlife and Fisheries Sciences from Texas A&M University, College Station, Texas. I was employed by the Arizona Department of Environmental Quality ("ADEQ") between 1996 and 2007. At the ADEQ, I managed compliance and enforcement efforts associated with water quality and waste handling activities. During my tenure there I was also responsible for managing the site investigations under state superfund program and writing new regulations governing the management of wastes. I joined Progress Energy, now DEF, in 2008 as the manager of Florida Permitting and Compliance and am currently in this role.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between actual and actual/estimated project expenditures for environmental compliance costs associated with FPSC-approved programs under my responsibility. These programs include the T&D Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") (Project 3), Above Ground Secondary Containment (Project 4), Phase II Cooling Water Intake – 316(b) (Projects 6 & 6a), CAIR/CAMR - Peaking (Project 7.2), Best Available Retrofit Technology ("BART") (Project 7.5), Arsenic Groundwater Standard (Project 8), Sea Turtle Coastal Street Lighting Program (Project 9), Underground Storage

Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Daily Maximum Loads Monitoring (Project 13), Hazardous Air Pollutants Information Collection Request ("ICR") Program (Project 14), Effluent Limitation Guidelines Program (Project 15.1), National Pollutant Discharge Elimination System ("NPDES") (Project 16) and Mercury and Air Toxics Standards ("MATS") – Crystal River ("CR") Units 4&5 (Project 17) for the period January 2020 through December 2020.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the Transmission & Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention Projects (Projects 1 & 1a)?

A. The Substation System Program variance, transmission portion (Project 1) is $25,045 or 198% higher than forecasted. This is primarily due to unexpected expenses incurred as a result of Florida Department of Environmental Protection's ("FDEP") requests for closures of the groundwater wells associated with the Central Florida and West Lake Wales Substations.

The Distribution portion (Project 1a) is complete.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the Cooling Water Intake - 316(b) Project (Projects 6 & 6a)?

A. The Cooling Water Intake - 316(b) (Projects 6 & 6a) O&M variance is 10%, or $32,018 higher than projected.

Project 316(b) – Base (Project 6) variance is 7%, or $10,834 higher than forecasted, and Project 316(b) – Intermediate (Project 6a) is 14%, or $21,183 higher than forecasted. These variances are primarily due to editing of the 316(b) reports following peer review comments received by DEF. Additional consultant time was required to ensure the responses satisfied peer reviewer questions and confirm that calculations and evaluations were updated to address peer review comments prior to submittal of the technical reports to FDEP. Additional costs are not anticipated until FDEP has reviewed the NPDES permit renewal application and 316(b) report.

Q. How did actual Capital expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the Cooling Water Intake - 316(b) Project (Project 6)?

A. The Cooling Water Intake - 316(b) capital variance is $1,122,169 or 19% lower than projected. As stated in my July 31, 2020 testimony filed in Docket No. 20200007-EI, the computer model DEF utilized to develop the original design at Crystal River North did not accurately estimate the expected water flows. The lower than expected water flows have required additional investigation and analysis to identify a viable solution, causing delays. A final resolution has not yet been engineered, and construction was unable to resume in 2020. DEF continues to actively investigate engineering and design solutions at Crystal River

North to identify available means of addressing water flow deficiencies. Construction is expected to resume and complete in 2021 and remain within the original cost estimate.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the Arsenic Groundwater Standard – Base - Project (Project 8)?

A. The Arsenic Groundwater Standard O&M variance is $949,643 or 77% lower than projected primarily due to reduced scope of work and a competitive bid event which allowed DEF to obtain favorable pricing. Material costs and project duration were also reduced following agency authorization to use on-site soils for the soil cap in lieu of purchasing and transporting materials from an off-site source.

Q. How did actual Capital expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the Effluent Limitations Guideline Project (Project 15.1)?

A. The ELG Capital variance is $45,133, or 20% lower than originally forecasted. This is primarily due to final invoices coming in slightly lower than originally estimated. The project is complete, all expected invoices have been received, and project is currently in final reconciliation.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the National Pollutant Discharge Elimination System (NPDES) Project (Project 16)?

A. The NPDES variance is $25,793 or 86% lower than forecasted, primarily due to $20,326 in charges not being processed through ECRC accounting until January 2021. Contributing to the favorability is a credit of $7,733 in February 2020 that originated from Bartow Whole Effluent Toxicity ("WET") testing conducted in in 2019 and mistakenly charged to ECRC, as previously described in my testimony.

Q. How did actual O&M expenditures for January 2020 - December 2020 compare with DEF's actual/estimated projections for the MATS – CR 4&5 Project (Project 17)?

A. The MATS – CR 4&5 O&M variance is $90,000 or 74% lower than forecasted, primarily due to tests and inspections that did not need to be completed in Fall 2020.

Q. In Order No. PSC-2010-0683-FOF-EI issued in Docket No. 20100007-EI on November 15, 2010, the Commission directed DEF to file as part of its ECRC true-up testimony a yearly review of the efficacy of its Plan D and the cost-effectiveness of DEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. Has DEF conducted such a review?

A. Yes. DEF's yearly review of the Integrated Clean Air Compliance Plan is provided as Exhibit No. __ (KSM-1).

Q. Please summarize the conclusions of DEF's review of its Integrated Clean Air Compliance Plan.

A. DEF installed emission controls contemplated in its Integrated Clean Air Compliance Plan on time and within budget. The Flue Gas Desulfurization (wet scrubbers) and Selective Catalytic Reduction systems on CR 4&5 have enabled DEF to comply with Clean Air Interstate Rule ("CAIR") requirements and will continue to be the cornerstone of DEF's integrated air quality compliance strategy. DEF is confident that the Integrated Clean Air Compliance Plan, along with compliance strategies under development, will enable it to achieve and maintain compliance with applicable regulations, including MATS, in a cost-effective manner.

Q. What is the status of the Clean Water Rule?

A. On June 29, 2015 the EPA and the Army Corps of Engineers ("Corps") published the final Clean Water Rule that significantly expanded the definition of the Waters of the United States ("WOTUS"). On October 9, 2015 the U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule effective through the conclusion of the judicial review process. On February 22, 2016 the Sixth Circuit issued an opinion that it has jurisdiction and is the appropriate venue to hear the merits of legal challenges to the rule; however, that decision was contested, and on January 13, 2017 the U.S. Supreme Court decided to review the jurisdictional question. Oral arguments in the U.S. Supreme Court case were conducted in October 2017. On January 22, 2018, the U.S. Supreme Court issued its decision stating federal district courts, instead of federal appellate courts, have jurisdiction over challenges to the rule defining waters of the United States Consistent with the U.S. Supreme Court decision, the U.S. Court of Appeals for the Sixth Circuit lifted its nationwide stay on February 28, 2018. The stay issued by the North Dakota District Court remains in effect, but only within the thirteen states within the North Dakota District. On February 28, 2017, President Trump signed an executive order laying out a new policy direction for how “Waters of the United States” should be defined and directing EPA and the Corps to initiate a rulemaking to either rescind or revise the 2015 Clean Water Rule developed by the Obama administration. Subsequently, the EPA Administrator signed a pre-publication notice reflecting the intent to move forward with rulemaking in response to this directive. In addition, the executive order seeks to have the Department of Justice determine the path forward on the Clean Water Rule litigation in light of the new policy direction.

On January 31, 2018, the EPA and Corps announced a final rule adding an applicability date to the 2015 rule defining “waters of the United States,” thereby deferring implementation of the 2015 WOTUS Rule until early 2020. This rule has no immediate impact to Duke Energy, and the agencies will continue to apply the pre-existing WOTUS definition in place prior to the 2015 rule until 2020.

On February 14, 2019, EPA and Corps published in the Federal Register, the "Revised Definition of 'Waters of the United States,'" which proposed to narrow the extent of Clean Water Act jurisdiction as compared to the 2015 definition adopted by the Obama Administration (Proposed Rule). On January 23, 2020, EPA and Corps released a pre-publication version of *The Navigable Waters Protection Rule: Definition of "Waters of the United States."* On April 21, 2020, the EPA and Corps published the modified definition of the WOTUS in the Federal Register. DEF has reviewed the final rule and determined there are no impacts associated with the 2020 WOTUS Rule with respect to the operation of our existing generation facilities. DEF will continue to monitor the status of the rule and any proposed changes to ascertain any further compliance steps that may be required.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KIM SPENCE McDANIEL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

July 30, 2021

Q. Please state your name and business address.

A. My name is Kim Spence McDaniel. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-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 explain material variances between 2021 actual/estimated cost projections and original 2021 cost projections for environmental compliance costs associated with FPSC-approved programs under my responsibility. These programs include the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management (PIM) (Project 3), Above Ground Secondary Containment (Project 4), Phase II Cooling Water Intake – 316(b) (Project 6), CAIR/CAMR - Peaking (Project 7.2), Best Available Retrofit Technology (BART) (Project 7.5), Arsenic Groundwater Standard (Project 8), Sea Turtle Coastal Street Lighting Program (Project 9), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Daily Maximum Loads Monitoring (Project 13), Hazardous Air Pollutants Information Collection Request (ICR) Program (Project 14), Effluent Limitation Guidelines Program (Project 15.1) and National Pollutant Discharge Elimination System ("NPDES") (Project 16) for the period January 2021 through December 2021.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for Substation Environmental Investigation, Remediation and Pollution Prevention Program (Projects 1 & 1a) for the period January 2021 through December 2021.

A. Total O&M expenditures for the Transmission and Distribution Substation Remediation Projects are estimated to be $2,738 (91%) lower than originally projected. Project 1, Transmission Substation Remediation, is forecasted to be $2,738 lower than originally projected primarily due to final work at the Central

Florida and Lake Wales substations being completed sooner than expected. The final documents for the Central Florida substation, Amended Declaration of Restrictive Covenant ("DRC") was recorded by the Sumter County Clerk of Court in February of this year. No further ECRC-recoverable charges are expected to be charged to this program.

Project 1a, Distribution Substation Remediation, is complete.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for Phase II Cooling Water Intake 316(b) (Projects 6 & 6a) for the period January 2021 through December 2021.

A. O&M expenditures for Phase II Cooling Water Intake 316(b) are expected to be $5,000 (14%) lower than originally forecasted.

Project 6, 316(b) – Base is forecasted to be $4k, or 80% lower than forecasted.

Project 6a, 316(b) – Intermediate is forecasted to be $1k, or 3% lower than originally forecasted. These variances are primarily due to a reduced need for contractor support following the agency review of the 316(b) final report. The original estimate anticipated a longer period of questions and follow up.

Q. Please explain the variance between actual/estimated Capital project expenditures and original projections for Phase II Cooling Water Intake 316(b) (Project 6) for the period January 2021 through December 2021.

A. Capital expenditures for Phase II Cooling Water Intake 316(b) are expected to be approximately $2,173,607, or 100% higher than originally forecasted. As stated in my July 31, 2020, testimony filed in Docket No. 20200007-EI and my April 1, 2021, testimony filed in this Docket, the computer model Duke Energy Florida, LLC ("DEF") utilized to develop the original design at Crystal River North ("CRN") did not accurately estimate the expected water flows. The low-flow resolution requires a modification to the CRN Intake Structure for the continued use of the existing intake pumps and installation of 316(b) compliant static screens. This work is expected to be completed this year.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for Sea Turtle – Coastal Street Lighting (Project 9) for the period January 2021 through December 2021.

A. O&M expenditures for Sea Turtle – Coastal Street Lighting are expected to be $600 (100%) lower than forecasted. Turtle nesting season has recently begun and DEF has not received any new requests from Gulf County or Pinellas County Code Enforcement for any issues regarding new lighting fixtures; therefore, the $600 forecasted for O&M is not expected to be spent.

Q. Please explain the variance between actual/estimated Capital project expenditures and original projections for Sea Turtle – Coastal Street Lighting (Project 9) for the period January 2021 through December 2021.

A. Capital expenditures for Sea Turtle – Coastal Street Lighting are expected to be $600 (100%) lower than forecasted. Turtle nesting season has recently begun and DEF has not received any new requests from Gulf County or Pinellas County Code Enforcement for any issues regarding new lighting fixtures; therefore, the

$600 forecasted for Capital is not expected to be spent.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for National Pollutant Discharge Elimination System (NPDES) (Project 16) for the period January 2021 through December 2021.

A. O&M expenditures for NPDES are expected to be $20,135, or 64% higher than forecasted. As stated in my April 1, 2020, testimony in this Docket, this is primarily due to invoices received in 2020 that were not charged to the project until 2021.

Q. Please provide an update of 316(b) regulations.

A. The 316(b) rule became effective October 15, 2014, to minimize impingement and entrainment of fish and aquatic life drawn into cooling systems at power plants and factories. There are seven pre-approved impingement options. Entrainment compliance is site specific (mesh screen or closed-cycle cooling). Legal challenges to the 316(b) rule have so far been unsuccessful. The U.S. Court of Appeals for the Second Circuit issued an opinion on the consolidated challenges to the 316(b) Rule for Existing Facilities. The court upheld the Rule, the National Marine Fisheries Service and the U.S. Fish and Wildlife Service biological opinions, and the incidental take statement, concluding that each action was based on reasonable interpretations of the applicable statutes and sufficiently supported by the adequate record. The court also found the EPA complied with applicable procedures, including by giving adequate notice of the final rule's provisions to the public.

The regulation primarily applies to facilities that commenced construction on or before January 17, 2002, and to new units at existing facilities that are built to increase the generating capacity of the facility. All facilities that withdraw greater than 2 million gallons per day from waters of the U.S. and where twenty-five percent (25%) of the withdrawn water is used for cooling purposes are subject to the regulation.

Per the final rule, required 316(b) studies and information submittals will be tied to NPDES permit renewals. For permits that expire within 45 months of the effective date of the final rule, certain information must be submitted with the renewal application. Other information, including field study results, are required to be submitted pursuant to a schedule included in the re-issued NPDES permit. Both the Anclote and Bartow stations are within this schedule and the NPDES permit renewal applications, including the studies and information required under 40 CFR 122.21(r)(2-13) as required by the 316(b) rule of the Clean Water Act, were submitted to FDEP for Anclote and Bartow in July and August 2020, respectively. A 316(b) Compliance Plan for Crystal River Units 4 & 5 utilizing the cooling water blowdown from the Citrus Combined Cycle Station as the source of make-up water for Crystal River Units 4&5 is being implemented as part of the current permit renewal for those units.

For NPDES permits that expire more than 45 months from the effective date of the rule, all information, including study results, is required to be submitted as part of the renewal application.

The Bartow Station will require modifications to comply with the 316(b) Rule. DEF is proposing that the Anclote station can meet 316(b) requirements with existing infrastructure, but additional studies to demonstrate compliance will likely be required by the permit. DEF has been conducting 316(b) studies at the Anclote and Bartow stations, and study results along with proposed compliance strategies were filed with the Florida Department of Environmental Protection ("FDEP") in July and August 2020, respectively as part of the NPDES renewal process. Proposed compliance strategies for both are being evaluated by FDEP as part of the NPDES permit renewal.

The full extent of compliance activities and associated expenditures cannot be determined until review of the proposed options by FDEP has been completed and the NPDES permit renewal issued with new compliance requirements and schedules. While unlikely, it is possible preliminary studies could begin as early as the fourth quarter of 2021 if final NPDES renewal is issued by FDEP by the end of this year. Due to the complexity of the 316(b) studies and proposals under review by the agency, it is difficult to assess the timing or the outcome of the final NPDES permit renewal.

DEF will provide the Commission an update on the status of the 316(b) Rule compliance strategies for the Anclote and Bartow stations in the next available

ECRC filing following issuance of the NPDES permit renewal.

Q. Please provide an update on Carbon Regulations.

A. For existing Units, on October 23, 2015, EPA published the final New Source Performance Standards ("NSPS") for CO_2 emissions from existing fossil fuel-fired electric generating units (also known as the "Clean Power Plan" or "CPP"). The final CPP was challenged by 27 states and a number of industry groups, with oral arguments held before the D.C. Circuit Court of Appeals on September 27, 2016. In addition, on February 8, 2016, the U.S. Supreme Court placed a stay on the CPP until all litigation is completed.

Also, on October 23, 2015, the EPA published the final NSPS for CO_2 emissions for new, modified and reconstructed fossil fuel-fired EGUs. The rule includes emission limits of 1,400 lb. CO_2/MWh for new coal-fired units and 1,000 lb. CO_2/MWh for new natural gas combined-cycle units. This rule has also been challenged and is currently on appeal to the D.C. Circuit Court of Appeals.

On March 28, 2017, the president signed an Executive Order ("EO") entitled "Promoting Energy Independence and Economic Growth." The EO directs federal agencies to "immediately review existing regulations that potentially burden the development or use of domestically-produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources." The EO specifically directs the EPA to review the following rules and determine whether to suspend, revise or rescind those rules:

- The final CO_2 emission standards for existing power plants (CPP);
- The final CO_2 emission standards for new power plants (CO_2 NSPS); and
- The proposed Federal Plan and Model Trading Rules that accompanied the CPP.

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of both the CPP and the CO_2 NSPS rules while each is reviewed by EPA. As a result, the D.C. Circuit has granted a number of 60-day extensions holding the CPP litigation in abeyance. The most recent extension was issued on June 20, 2019. Neither the EO nor the abeyance change the current status of the CPP which is under a legal hold by the U.S. Supreme Court. With regard to the CO_2 NSPS, on December 6, 2018, EPA proposed to revise the NSPS for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. After further analysis and review, EPA proposes to determine that the best system of emission reduction ("BSER") for newly constructed coal-fired units is the most efficient demonstrated steam cycle in combination with the best operating practices. EPA did not propose to amend the standards of performance for newly constructed or reconstructed stationary combustion turbines. In January 2021, EPA issued a clear framework for determining when standards are appropriate for GHG emissions from stationary source categories under Clean Air Act ("CAA"), section 111(b)(1)(A). EPA did not take final action to revise the BSER in the 2018 proposal. On March 17, 2021, in line with President Biden's Executive Order

13990 on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," EPA asked the D.C. Circuit to vacate and remand the "significant contribution" final rule. The rule was promulgated without public notice or opportunity to comment. On April 5, 2021, the D.C. Circuit vacated and remanded the January 2021 final rule noted above.

On June 19, 2019, EPA issued the Affordable Clean Energy rule ("ACE"), an effort to provide existing coal-fired electric utility generating units, or EGUs, with achievable and realistic standards for reducing greenhouse gas ("GHG") emissions. This action was finalized in conjunction with two related, but separate and distinct, rulemakings: (1) The repeal of the CPP and (2) Revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of CAA, section 111(d). On January 19, 2021, the court vacated the ACE rule and remanded it back to EPA. Vacatur means that the rule will no longer be in effect once the Mandate is issued; the Mandate is the court's directive to enforce its decision. On February 22, 2021, the court granted EPA's motion to withhold issuance of the mandate with respect to the vacatur of the CPP Repeal Rule until the EPA responds to the court's remand in a new rulemaking action. No party filed for Rehearing regarding the court's January 19th decision. Accordingly, on March 5, 2021, the court issued the Partial Mandate to EPA, officially vacating the ACE rule, but withholding the mandate regarding the CPP repeal. Currently, neither the ACE rule nor Clean Power Plan rule are in effect. Several parties have petitioned asking the Supreme Court to review this case.

Q. Please provide an update on the Waters of the United States ("WOTUS") Rule.

A. On June 29, 2015, the EPA and the Army Corps of Engineers ("Corps") published the final Clean Water Rule that significantly expands the definition of the Waters of the United States ("WOTUS"). On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule effective through the conclusion of the judicial review process. On February 22, 2016, the court issued an opinion that it has jurisdiction and is the appropriate venue to hear the merits of legal challenges to the rule; however, that decision was contested, and on January 13, 2017, the U.S. Supreme Court decided to review the jurisdictional question. Oral arguments in the U.S. Supreme Court were conducted on October 2017. On January 22, 2018, the U.S. Supreme Court issued its decision stating federal courts, rather than federal appellate courts, have jurisdiction over challenges to the rule defining WOTUS. Consistent with the U.S. Supreme Court decision, the U.S. Court of Appeals for the Sixth Circuit lifted its nationwide stay on February 28, 2018. The stay issued by the North Dakota District Court remains in effect, but only within the thirteen states within the North Dakota District. On June 8, 2018, the Southern District Georgia Court entered a Preliminary Injunction enjoining implementation of the WOTUS rule in eleven states including Florida.

On June 27, 2017, the EPA and the Corps published a proposed rule to repeal the 2015 WOTUS rule and re-codify the definition of WOTUS which is currently in place. On January 31, 2018, the EPA and Corps announced a final rule adding an applicability date to the 2015 rule, thereby deferring implementation to early 2020. This rule has no immediate impact to DEF. The agencies will continue to apply the pre-existing WOTUS definition that was in place prior to 2015 rule until 2020. EPA and Corps published a final rule, "Navigable Waters Protection Rule: Definition of 'Waters of the United States'("NWPR"), on April 21, 2020, which became in effect on June 22, 2020. This final rule has no immediate impact to DEF. On June 9, 2021, the U.S. Environmental Protection Agency and the U.S. Army Corps of Engineers ("Agencies") filed in the U.S. District Court for the District of Massachusetts a motion seeking a remand, without vacatur, of the NWPR. The Agencies requested the remand in conjunction with their forthcoming rulemaking to revise or replace the NWPR. If the court grants the Agencies' motion, the NWPR will remain in place for the duration of the new rulemaking process. The case is *Conservation Law Foundation v. EPA*, No. 1:20-cv-10820 (D. Mass.).

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KIM SPENCE McDANIEL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210007-EI

August 27, 2021

Q. Please state your name and business address.

A. My name is Kim Spence McDaniel. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210007-EI?

A. Yes. I provided direct testimony on April 1, 2021, and July 30, 2021.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in 2022 for Duke Energy Florida, LLC's ("DEF" or "the Company") Substation Environmental Investigation, Remediation and Pollution Prevention

Program (Project 1 & 1a), Distribution Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") Program (Project 3), Above Ground Storage Tanks ("AST") Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), CAIR/CAMR Continuous Mercury Monitoring System ("CMMS") Program (Projects 7.2 & 7.3), Best Available Retrofit Technology ("BART") Program (Project 7.5), Arsenic Groundwater Standard Program (Project 8), Sea Turtle – Coastal Street Lighting Program (Project 9), Underground Storage Tanks ("UST") Program (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Compliance (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Maximum Loads Monitoring ("TMDL") (Project 13), Hazardous Air Pollutants ("HAPs") Information Collection Request ("ICR") (Project 14), Effluent Limitation Guidelines CRN (Project 15.1) and National Pollutant Discharge Elimination System ("NPDES") Program (Project 16).

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

A. Yes. I am co-sponsoring the following portions of Exhibit No.__(GPD-5) to Gary P. Dean's Direct Testimony:

- 42-5P, p. 1 of 23 – Substation Environmental Investigation, Remediation and Pollution Prevention Program
- 42-5P, p. 2 of 23 - Distribution System Environmental Investigation, Remediation and Pollution Prevention Program

- 42-5P, p. of 23 – PIM
- 42-5P, p. 4 of 23 - AST
- 42-5P, p. 6 of 23 - Phase II Cooling Water Intake
- 42-5P, p.7 of 23 – Clean Air Interstate Rule (“CAIR”)
- 42-5P, p. 8 of 23 – BART
- 42-5P, p. 9 of 23 - Arsenic Groundwater Standard
- 42-5P, p. 10 of 23 – Sea Turtle – Coastal Street Lighting Program
- 42-5P, p.11 of 23 - UST
- 42-5P, p. 12 of 23 - Modular Cooling Towers
- 42-5P, p. 13 of 23 - Thermal Discharge Permanent Cooling Tower
- 42-5P, p. 14 of 23 - Greenhouse Gas Inventory and Reporting
- 42-5P, p. 15 of 23 - Mercury TMDL
- 42-5P, p. 16 of 23 - HAPs ICR
- 42-5P, p. 17 of 23 - Effluent Limitation Guidelines ICR Program
- 42-5P, p.18 of 23 - Effluent Limitation Guidelines CRN Program
- 42-5P, p. 19 of 23 - NPDES

Q. What O&M costs does DEF expect to incur in 2022 for the Phase II Cooling Water Intake 316(b) Program for Anclote and Bartow CC stations (Projects 6 and 6a)?

A. DEF is forecasting a total of $280k in O&M costs for the Phase II Cooling Water Intake Program 316(b) projects in 2022.

DEF estimates approximately $260k of O&M costs for the Anclote Station to develop and begin implementation of a Plan of Study ("Study"). DEF anticipates receiving the final NPDES permit renewal from the Florida Department of Environmental Protection ("FDEP") by year end 2021. If the permit requirements reflect what was proposed in the application, the permit will require DEF to prepare and implement a Study that evaluates organism mortality associated with the cooling water intake system. The Study will be conducted for a period of one to two years, potentially longer, depending upon results of the Study and FDEP response. The results of the Study will determine whether any future capital investments are necessary. The full extent of compliance activities and associated expenditures could change depending on the conditions of the final NPDES permit when issued.

DEF estimates approximately $20k of O&M for Crystal River North to support consultations related to 316(b) topics, including source waterbody data, impingement, or entrainment data, and/or any threatened or endangered species. This estimate is provided in the event FDEP requests additional information.

Q. What Capital costs does DEF expect to incur in 2022 for the Phase II Cooling Water Intake 316(b) Program for Anclote and Bartow CC stations (Projects 6.1 and 6.2)?

A. DEF estimates the potential for $1.1M of capital costs in 2022 for the Bartow station 316(b) compliance plan for preliminary engineering and design of modified traveling screens and an organism return system. This estimate is preliminary as DEF does not currently have a final NPDES permit renewal, and therefore the compliance strategy and schedule that the permit will require is unknown. The full extent of compliance activities and associated expenditures could change depending on the conditions of the final NPDES permit when issued.

As this estimate is preliminary and dependent on final approval from FDEP, the project scope and associated timeline are still undetermined and may change depending on the conditions required when the final NPDES permit is issued. However, based on assumptions used in the initial permit application, it is likely that the first two years after permit approval will involve selection of an engineering firm and detailed engineering work, along with initiation and selection of the screen vendor bid process, and initiation of procurement of screens and associated components.

Years three through six will likely include procurement of remaining components, contractor mobilization, installation of screens, contractor demobilization, development, submittal and implementation of an impingement optimization study plan and development and submission of the interim report. This is expected to conclude with the final report submittal. This schedule is high-level, and subject to the final permit from FDEP.

No Capital costs are projected for the Anclote Station for 2022, however this estimate is preliminary as DEF does not currently have a final NPDES permit renewal, and therefore the compliance requirements of the permit are unknown.

Q. What costs does DEF expect to incur in 2022 for the Arsenic Groundwater Standard Program (Project 8)?

A. DEF forecasts 2022 O&M expenditures to be $74k. Anticipated costs are associated with post-remediation groundwater monitoring, implementation of a deed restriction and restrictive covenant for the affected area, final analysis and reporting of results to the agency and also monitoring well abandonment.

In accordance with FDEP Consent Order No. 09-3463D executed on March 22, 2016, and FDEP Consent Order No. 09-3463E executed on November 17, 2017, DEF's investigation has identified potential sources of arsenic exceedances in groundwater monitoring wells addressed in the Consent Order. The original Consent Order was issued by the FDEP for exceedance of the arsenic groundwater limit following the 2005 revision of the State's groundwater standard that lowered the arsenic maximum contaminant level from 50 ppb to 10 ppb. As discussed in the prior testimony of DEF Witness Patricia Q. West[1], the results of DEF's monitoring and assessment identified the need for additional compliance activities. On July 26, 2019, DEF submitted a Site Assessment Report Addendum ("SARA") addressing FDEP comments to the Site Assessment Report ("SAR") submitted on August 31, 2018. The SAR and SARA documents all assessment work done under the Consent Order to identify the nature and extent of arsenic in

[1] Please see Ms. West's direct testimony provided in Docket Nos. 2005007-EI, 20080007-EI, 20090007-EI and 20150007-EI.

groundwater. On October 15, 2019, FDEP notified DEF that sediment and soil assessment was complete and that additional ground water delineation was needed. On June 24, 2020, DEF submitted to FDEP a Site Assessment Status Report ("SASR") with additional ground water sampling results to complete the ground water delineation and a Soils and Sediment Management Plan to be implemented for remediation of soils and sediments in the former North Ash Pond area. FDEP approved the plan on August 4, 2020. Remediation of soils and sediments in the North Ash Pond area was completed on January 7, 2021, and completion of the soil cap installation completed on April 6, 2021. On May 26, 2021, DEF submitted to FDEP a Site Assessment Report Addendum No. 2 and Natural Attenuation Monitoring Plan ("NAM"). The purpose of the NAM is to confirm that the arsenic concentrations in the former North Ash Pond Area are stable and/or decreasing after installation of the soil cap. The NAM was approved by FDEP and is being implemented by DEF. The report also included ground water monitoring conducted during March 2021. DEF and FDEP are in the process of amending the Consent Order to change the final date of compliance from December 31, 2021, to December 31, 2023, to allow additional time to obtain a Site Rehabilitation Completion Order ("SRCO") for the former North Ash Pond area.

Q. What costs does DEF expect to incur in 2022 for the NPDES Program (Project No. 16)?

A. DEF estimates $31k of O&M costs for Whole Effluent Toxicity ("WET") testing as required at DEF stations with NPDES permits.

Q. Does this conclude your testimony?

A. Yes.

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

BEFORE THE 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 over ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel clause and purchased power, capacity, and environmental cost recovery clauses.

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

A. The purpose of my testimony is to present, for Commission review and approval, the actual true-up amount for the Environmental Cost Recovery Clause ("Environmental Clause") and the calculations associated with the environmental compliance activities for the January 2020 through December 2020 period.

Q. Did you prepare any exhibits in support of your testimony?

A. Yes. Exhibit No. MAS-1 consists of nine documents prepared under my direction and supervision.

- Form 42-1A, Document No. 1, provides the final true-up for the January 2020 through December 2020 period;

- Form 42-2A, Document No. 2, provides the detailed calculation of the actual true-up for the period;
- Form 42-3A, Document No. 3, shows the interest provision calculation for the period;
- Form 42-4A, Document No. 4, provides the variances between actual and actual/estimated costs for O&M activities;
- Form 42-5A, Document No. 5, provides a summary of actual monthly O&M activity costs for the period;
- Form 42-6A, Document No. 6, provides the variances between actual and actual/estimated costs for capital investment projects;
- Form 42-7A, Document No. 7, presents a summary of actual monthly costs for capital investment projects for the period;
- Form 42-8A, Document No. 8, pages 1 through 29, illustrates the calculation of depreciation expense and return on capital investment for each project recovered through the Environmental Clause.
- Form 42-9A, Document No. 9, details Tampa Electric’s revenue requirement rate of return for capital projects recovered through the Environmental Clause.

Q. What is the source of the data presented in your testimony and exhibits?

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 this Commission.

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

A. The final true-up amount for the Environmental Clause for the period January 2020 through December 2020 is an over-recovery of $4,237,191. The actual environmental cost under-recovery, including interest, is $3,603,985 for the period January 2020 through December 2020, as identified in Form 42-1A. This amount, less the $7,841,176 under-recovery approved in Commission Order No. PSC-2020-0433-FOF-EI, issued November 13, 2020, in Docket No. 20200007-EI, results in a final over-recovery of $4,237,191, as shown on Form 42-1A. This over-recovery amount will be applied in the calculation of the environmental cost recovery factors for the period January 2022 through December 2022.

Q. Are all costs listed in Forms 42-4A through 42-8A incurred for environmental compliance projects approved by the Commission?

A. Yes. All costs listed in Forms 42-4A through 42-8A for which Tampa Electric is seeking recovery are incurred for environmental compliance projects approved by the Commission.

Q. How do actual expenditures for the January 2020 through December 2020 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total costs for O&M activities are $3,216,922, or 18.3 percent less than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $118,847, or 0.3 percent less than the actual/estimated projection costs. Additional information regarding substantial variances is provided below.

<u>O&M Project Variances</u>

O&M expense projections related to planned maintenance work are typically spread across the period in question. However, the company always inspects the units to ensure that the maintenance is needed, before beginning the work. The need varies according to the actual usage and associated "wear and tear" on the units. If an inspection indicates that the maintenance is not yet needed or if additional work is needed, then the company will have a variance when actual amounts expended are compared to the projection. When inspections indicate that work is not needed now, then maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is $108,626 or 38.7 percent less than projected. The variance is due to less maintenance costs incurred than expected while operating the unit on natural gas instead of coal.

- **SO2 Emission Allowances:** The SO2 Emission Allowance variance is $37 or 209.2 percent greater than projected. The variance is primarily attributable to differences in the calculated estimate for 2020 and the actual activity for the period.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is $114,486, or 82.4 percent less than projected. The variance is due to less maintenance costs incurred than expected while operating the unit on natural gas instead of coal.

- **Big Bend PM Minimization and Monitoring:** The Big Bend Minimization and Monitoring project variance is $104,870, or 34.8 percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Big Bend NOx Emission Reduction:** The Big Bend NOx Emission Reduction project variance is $6,000, or 99.9% percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is $16,661, or 17.9 percent greater than projected. The variance is due to the units running more in the summer than projected, increasing ammonia use.

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is $5,400, or 100 percent lower than projected. The variance is due to reduced operating hours for Unit 1 during the year.

- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is $5,400, or 87.4 percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is $6,000, or 88 percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is $16,664, or 59.3 percent less than projected. The variance is due to the delay in receiving final the NPDES Permit leading to fewer expenditure than anticipated.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program project variance is $15,426, or 97.3 percent greater than projected. The variance is due to a replacement well not associated with the program being inadvertently charged during the period. The charge was subsequently reversed and will be reflected in the upcoming Actual/Estimate Projection filing.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $70,977, or 81.1 percent less than projected. The variance is due to reduced operating hours for Unit 1 during the year.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $109,585, or 43.5 percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $108,523, or 23.7 percent less than projected. The variance is due to less maintenance costs while operating on natural gas instead of coal.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $224,108, or 30.8 percent less than projected. The variance is due to fewer unit operating hours than projected, resulting in lower expenditures for SCR consumables and maintenance than projected.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $430,513, or 54.1 percent less than projected. The variance is due to less facility yard maintenance being required than expected as energy generation by coal was less than projected.

- **Big Bend Coal Combustion Residuals Rule:** The Big Bend Coal Combustion Residuals ("CCR") Rule project variance is $1,008,729, or 15809.2 percent greater than projected. This variance is due to timing. Costs associated with activity that was previously deferred were spent in 2020.

- **Big Bend Coal Combustion Residuals Rule Phase II:** The Big Bend Coal Combustion Residuals ("CCR") Rule Phase II project variance is $2,946,683, or 20.7 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Project disposal activities have occurred more slowly than originally projected. The project expenditures are still needed and will be incurred in the future.

<u>Capital Investment Project Variances</u>

- **Big Bend CCR Rule:** The Big Bend CCR Rule project variance is $25,850, or 15 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. The project expenditures are still needed and will be incurred in the future.

- **Big Bend Unit CCR Rule Phase II:** The Big Bend CCR Rule Phase II project variance is $39,406, or 36.3 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. The project expenditures are still needed and will be incurred in the future.

- **Big Bend ELG Compliance:** The Big Bend ELG Compliance Project variance is $52,834, or 66.6 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. FDEP issued its permit regarding the project on April 10, 2020. The project expenditures are still needed and will be incurred in the future.

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 North 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 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2022 through December 2022. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2021, based on six months of actual data and six months of estimated data. This information will be used in the determination of the environmental cost recovery factors for January 2022 through December 2022.

Q. Have you prepared an exhibit that shows the recoverable environmental costs for the actual/estimated period of January 2021 through December 2021?

A. Yes, Exhibit No. MAS-2, containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E, which show the current period actual/estimated true-up amount to be used in calculating the cost recovery factors for January 2022 through December 2022.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied during the period January 2022 through December 2022?

A. The actual/estimated true-up applicable for the current period, January 2021 through December 2021, is an under-recovery of $4,289,623. A detailed calculation supporting the true-up amount is shown on Forms 42-1E through 42-9E of my exhibit.

Q. Is Tampa Electric including costs in the actual/estimated true-up filing for any new environmental projects that were not anticipated and included in its 2021 ECRC factors?

A. No. Tampa Electric is not including costs for any new environmental projects that were not anticipated or included in its 2021 ECRC factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2021 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-2012-0175-PAA-EI, issued on April 3, 2012, in Docket No. 20110131-EI, with two exceptions. For the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects, the company has utilized depreciation rates approved in Order No. PSC-2018-0594-FOF-EI, issued on December 20, 2018.

Q. What capital structure components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2021 through December 2021?

A. Tampa Electric's revenue requirement rate of return for January 2021 through December 2021 is calculated based on the capital structure components and current period cost rates as approved in Order No. PSC-2020-0165-PAA-EU, issued on May 20, 2020 in Docket No. 20200118-EU. The calculation of the revenue requirement rate of return is shown on Form 42-9E.

Q. How did the actual/estimated project expenditures for the January 2021 through December 2021 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $5,770,575 greater than originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $661,286 less than originally projected. Significant variances for O&M costs and capital project amounts are explained below.

<u>O&M Project Variances</u>

O&M expense projections related to planned maintenance work are typically spread across the period in question. However, the company always inspects the units to ensure that the maintenance is needed, before beginning work. The need varies according to the actual usage and associated "wear and tear" on the units. If inspection indicates that the maintenance is not yet needed or if additional work is needed, then the company will have a variance compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **SO_2 Emissions Allowances:** The SO_2 Emissions Allowances project variance is estimated to be $26 or 170.2 percent greater than projected. The variance is due to more cogeneration purchases than projected and the application of a higher SO_2 emission allowance rate than originally projected.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $8,966 or 100 percent greater than projected. The variance is due to Big Bend Unit 2 operating the FGD system when generating by natural gas which was not originally anticipated but is required for cooling gases to protect system ductwork.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring project variance is estimated to be $33,253 or 13.2 percent less than originally projected. This variance is due to the Big Bend units operating for fewer hours and using less coal than originally projected. As a result, less maintenance is required.

- **Big Bend NOx Emissions Reduction:** The Big Bend NOx Emission Reduction project variance is $922 or 45.5 percent greater than originally projected. This variance is due to maintenance required on a secondary damper that was more than originally projected.

- **NPDES Annual Surveillance Fees:** The NPDES Annual Surveillance Fees project variance is $11,000 or 46.8 percent greater than originally projected. This variance is due to Polk NPDES fees not being included in setting the original projection.

- **Polk NOx Emission Reductions:** The Polk NOx Emission Reductions project variance is $595 or 100 percent greater than originally projected. This variance is due to costs being charged to the project work order in error. The amount will be reversed in July 2021.

- **Bayside SCR and Ammonia:** The Bayside Selective Catalytic Reduction (“SCR”) and Ammonia project variance is $20,173 or 17 percent greater than originally projected. This variance is due to Bayside Station generation being greater than originally projected, leading to the need for more consumables.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is $38,980 or 86.6 percent less than originally projected. This variance is due to the delay in receiving the NPDES permit. Once the permit is received, the costs will be incurred.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program project variance is $36,000 or 100 percent less than originally projected. This variance is due to the delay of groundwater monitoring work while awaiting Florida Department of Environmental Protection ("FDEP") approval of the company's plan. Once the permit is received, the costs will be incurred.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $15,680 or 12.9 percent less than originally projected. This variance is due to current estimates of Big Bend Unit 2 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally estimated.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $183,752 or 17.1 percent less than originally projected. This variance is due to current estimates of Big Bend Unit 4 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally projected.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards ("MATS") project variance is $2,494 or 83.1 percent greater than originally projected. This variance is due to higher cost of mercury traps used for stack testing than originally projected.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $555,903 or 47.2 percent less than originally projected. The variance is due to a reduction in coal generation, compared to the original projection, so the amount of gypsum storage processing required is reduced.

- **Big Bend CCR Rule – Phases I & II:** The Big Bend Coal Combustion Residual ("CCR") Rule – Phases I & II project variances are $763,222 and $5,813,349, respectively. Each variance is 100 percent greater than originally projected. The variances are due to timing differences in project schedules when compared to original projections. Earlier delays in project activities were resolved, and 2021 project activities are progressing at a faster pace than original projections. Another contributing factor to the increase is that more CCR material than originally estimated has been removed from the sites.

- **Big Bend ELG Compliance:** The Big Bend Effluent Limitation Guidelines ("ELG") Compliance project variance is $4,800 or 100 percent less than originally projected. This variance is due to timing differences in the project schedule when compared to the original projection. The costs will be incurred in the future.

Capital Project Variances

- **Big Bend CCR Rule – Phases I & II:** The Big Bend CCR Rule Phases I & II project variances are $37,421 and $199,842, or 10.3 and 60.9 percent less than originally projected, respectively. The variances are due to timing differences in the project schedules when compared to the original projections. Because CCR removal activities have experienced project schedule delays early on, the final Project capital activities related to restoration of the site have been delayed. The project expenditures are still needed and will be incurred in the future.

- **Big Bend ELG Compliance:** The Big Bend ELG Compliance project variance is $342,935 or 43.8 percent less than originally projected. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. FDEP issued its permit regarding the project on April 10, 2020. The project expenditures are still needed and will be incurred in the future.

- **Big Bend Unit 1 Section 316(b) Impingement Mortality:** The Big Bend Unit 1 Section 316(b) Impingement Mortality project variance is $32,062 or 7.1 percent greater than originally projected. This variance is due to timing differences in the project schedule when compared to the original projection. Earlier permit and material delivery logistic delays have been resolved and as such, project activities are getting back on track.

Q. Does this conclude your direct 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 North 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. 20210007-EI?

A. Yes, I submitted direct testimony on April 1, 2021, and July 30, 2021.

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

A. No, it has not.

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the revenue requirements and the projected Environmental Cost Recovery Clause ("ECRC") factors for the period of January 2022 through December 2022. The projected ECRC factors have been calculated based on the current allocation methodology. In support of the projected ECRC factors, my testimony identifies the capital and operating & maintenance ("O&M") costs associated with environmental compliance activities for the year 2022.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2022 through December 2022?

A. Yes. Exhibit No. MAS-3, containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contain Forms 42-1P through 42-8P, which show the calculation and summary of the O&M and capital expenditures that support the development of the environmental cost recovery factors for 2022.

Q. Are you requesting Commission approval of the projected environmental 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 cost allocation methodology and midpoint return on equity as well as removal of certain costs from the ECRC to the proposed Clean Energy Transition Mechanism (“CETM”). The company plans to file revised ECRC 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 ECRC factors provided in Exhibit No. MAS-3, Document No. 7, on Form 42-7P 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 environmental cost recovery clause factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. These factors were calculated based on the current approved cost allocation methodology, return on equity, and equity ratio as set out in the 2017 Amended and Restated Settlement Agreement approved by the Commission in Docket No. 20170271, which amended and extended the 2013 Stipulation and Settlement Agreement that resolved the company's last base rate case (Docket No. 20130040).

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2022 to December 2022?

A. The net true-up applicable for this period is an under-recovery of $52,432. This consists of a final true-up over-recovery of $4,237,191 for the period of January 2020 through December 2020 and an estimated true-up under-recovery of $4,289,623 for the current period of January 2021 through December 2021. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. MAS-2 filed with the Commission on July 30, 2021.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2022 through December 2022?

A. No, Tampa Electric did not include costs for any new environmental projects in the factors presented in this testimony. On April 21, 2021, Tampa Electric filed a petition for approval of a new environmental program related to compliance with Section 316(b) of the Clean Water Act for the company’s Bayside facility in Docket No. 20210087-EI. This program is scheduled for a decision at the September 8, 2021 agenda conference. If the Commission approves this program for cost recovery, Tampa Electric will include these costs in its updated environmental cost recovery factors for January 2022 through December 2022 that include the effects of the 2021 Agreement terms.

Q. Are there any other significant changes other than the new project just referenced?

A. No.

Q. What are the capital projects included in the calculation of the ECRC factors for 2022?

A. Tampa Electric proposes to include for ECRC recovery costs for the 29 previously approved capital projects in the calculation of the 2022 ECRC factors. These projects are listed below.

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors
4) Big Bend Fuel Oil Tank No. 1 Upgrade
5) Big Bend Fuel Oil Tank No. 2 Upgrade
6) Big Bend Unit 1 Classifier Replacement
7) Big Bend Unit 2 Classifier Replacement
8) Big Bend Section 114 Mercury Testing Platform
9) Big Bend Units 1 and 2 FGD
10) Big Bend FGD Optimization and Utilization
11) Big Bend NO_x Emissions Reduction
12) Big Bend Particulate Matter ("PM") Minimization and Monitoring
13) Polk NO_x Emissions Reduction
14) Big Bend Unit 4 SOFA
15) Big Bend Unit 1 Pre-SCR
16) Big Bend Unit 2 Pre-SCR
17) Big Bend Unit 3 Pre-SCR
18) Big Bend Unit 1 SCR
19) Big Bend Unit 2 SCR
20) Big Bend Unit 3 SCR

21) Big Bend Unit 4 SCR
22) Big Bend FGD System Reliability
23) Mercury Air Toxics Standards ("MATS")
24) SO_2 Emission Allowances
25) Big Bend Gypsum Storage Facility
26) Big Bend Coal Combustion Residuals ("CCR") Rule – Phase I
27) Big Bend CCR Rule - Phase II
28) Big Bend Unit 1 Section 316(b)Impingement Mortality
29) Big Bend Effluent Limitations Guidelines ("ELG") Rule Compliance

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2022?

A. Yes. Form 42-3P contained in Exhibit No. MAS-3 summarizes the cost estimates for these projects. Form 42-4P, pages 1 through 29, provides the calculations resulting in recoverable jurisdictional capital costs of $46,658,374.

Q. What O&M projects are included in the calculation of the ECRC factors for 2022?

A. Tampa Electric proposes to include for ECRC recovery O&M costs for 27 approved O&M projects in the calculation of the ECRC factors for 2022. These projects are listed below.

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) SO_2 Emission Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk NO_x Emissions Reduction
10) Bayside SCR Consumables
11) Big Bend Unit 4 Separated Overfired Air ("SOFA")
12) Big Bend Unit 1 Pre-SCR
13) Big Bend Unit 2 Pre-SCR
14) Big Bend Unit 3 Pre-SCR
15) Clean Water Act Section 316(b) Phase II Study
16) Arsenic Groundwater Standard Program
17) Big Bend Unit 1 SCR
18) Big Bend Unit 2 SCR
19) Big Bend Unit 3 SCR
20) Big Bend Unit 4 SCR
21) Mercury Air Toxics Standards
22) Greenhouse Gas Reduction Program

23) Big Bend Gypsum Storage Facility
24) Big Bend CCR Rule - Phase I
25) Big Bend CCR Rule - Phase II
26) Big Bend Unit 1 Section 316(b) Impingement Mortality
27) Big Bend ELG Rule Compliance

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2022?

A. Yes. Form 42-2P contained in Exhibit No. MAS-3 presents the recoverable jurisdictional O&M costs for these projects, which total $4,414,497 for 2022.

Q. Did you prepare a schedule providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Project descriptions and progress reports are provided in Form 42-5P, pages 1 through 34.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2022?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-

1P of Exhibit No. MAS-3. These expenditures total $51,072,871.

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand and energy allocation factors were determined by calculating the percentage that each rate class contributes to the total demand or energy and then adjusted for line losses for each rate class. This information was calculated by applying historical rate class load research to 2022 projected system demand and energy. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the ECRC billing factors effective beginning in January 2022, if the company's 2021 Agreement is not approved, for which Tampa Electric is seeking approval?

A. The computation of the billing factors is shown in Exhibit No. MAS-3, Document No. 7, Form 42-7P. The proposed ECRC billing factors are summarized below.

Rate Class	Factors by Voltage Level (¢/kWh)
RS Secondary	0.263
GS, CS Secondary	0.260
GSD, SBF	
Secondary	0.254
Primary	0.252
Transmission	0.249
IS	
Secondary	0.247
Primary	0.244
Transmission	0.242
LS1	0.240
Average Factor	0.259

Q. When does Tampa Electric propose to begin applying these environmental cost recovery factors?

A. The environmental cost recovery factors will be effective concurrent with the first billing cycle for January 2022.

Q. What capital structure components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2022 through December 2022?

A. To calculate the revenue requirement rate of return found on Form 42-8P, Tampa Electric used the weighted average cost of capital ("WACC") methodology approved by the Commission in Order No. PSC-2020-0165-PAA-EU, approving Amended Joint Motion Modifying Weighted Average Costs of Capital Methodology, issued on May 20, 2020.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period beginning in January 2022 consistent with the criteria established for ECRC recovery in Order No. PSC-1994-0044-FOF-EI?

A. Yes. The costs for which ECRC recovery is requested meet the following criteria:

1) Such costs were prudently incurred after April 13, 1993;
2) The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates were based; and,
3) Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your direct testimony.

A. My testimony supports the approval, if the company's 2021 Agreement is not approved, of an average ECRC billing factor of 0.259 cents per kWh. This includes the projected capital and O&M revenue requirements of $51,072,871 associated with the company's 35 ECRC projects and a net true-up under-recovery provision of $52,432. My testimony also explains that the projected environmental expenditure for 2022 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Byron T. Burrows was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
FILED: 08/27/2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BYRON T. BURROWS

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

A. My name is Byron T. Burrows. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Services Department.

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

A. I received a Bachelor of Science degree in Civil Engineering from the University of South Florida in 1995. I have been a Registered Professional Engineer in the state of Florida since 1999. Prior to joining Tampa Electric, I worked in environmental consulting for sixteen years. In January 2001, I joined TECO Power Services as Manager-Environmental with primary responsibility for all power plant environmental permitting, and I have primarily worked in the areas of environmental, health and safety. In 2005, I became Manager of Air Programs. My responsibilities included air permitting and compliance related matters. In 2020, I was promoted to my current position, Director of Environmental Services. My responsibilities include the development and administration of the company's environmental policies and goals. I am also responsible for ensuring resources, procedures, and programs comply with applicable environmental requirements, and that rules and polices are in place, function properly, and are consistently applied throughout the company.

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

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the Environmental Cost Recovery Clause ("ECRC") for the January 2022 through December 2022 projection period are activities related to programs previously approved by the Commission for recovery through the ECRC.

Q. Please provide an overview of the environmental compliance requirements that are the result of the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the

Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice ("the Orders").

A. The general requirements of the Orders provide for further reductions of sulfur dioxide ("SO_2"), particulate matter ("PM") and nitrogen oxides ("NO_x") emissions at Big Bend Station. Tampa Electric has implemented the requirements of the Orders, and now these agreements have been terminated by the corresponding court systems. The ongoing requirements of these projects, which are further described later in my testimony, are now part of the Big Bend Title V operating permit (0570039-128-AV). The projects that are now required under the operating permit are listed below.

- Big Bend Particulate Matter ("PM") Minimization Program
- Big Bend NO_x Emission Reduction Program
- Big Bend Units 1 – 3 Pre-Selective Catalytic Reduction ("SCR") Projects
- Big Bend Units 1 – 4 SCR Projects

Q. Does the termination of the Orders change any of the environmental compliance requirements applicable to the company's generating units?

A. No, the termination of the Orders does not change any of the environmental compliance requirements applicable to the company’s generating units. The requirements of the Orders are now part of the Title V operating permit.

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. The Big Bend PM Minimization and Monitoring Program was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. In the order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. Tampa Electric does not anticipate any capital expenditures for this program during 2022; however, the O&M expenses associated with existing and recently installed Best Operating Practice (“BOP”) and Best Available Control Technology (“BACT”) equipment and continued implementation of the BOP procedures are expected to be $259,560.

Q. Please describe the Big Bend NO_x Emission Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2022 through December 2022.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. In the order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric does not anticipate any capital expenditures for this program in 2022; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $2,089 of O&M expenses during 2022.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. In Docket No. 20040750-EI, Order No. PSC-2004-0986-PAA-EI, issued October 11, 2004, the Commission approved cost recovery of the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Unit 4 SCR projects. The Big Bend Units 1 through 3 SCR projects were approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-PAA-EI, issued May 9, 2005. The purpose of the Pre-SCR technologies is to reduce inlet NO_x concentrations to the SCR systems, thereby mitigating overall SCR capital and O&M expenses. Those Pre-SCR technologies include windbox modifications, secondary air controls, and coal/air flow controls. The SCR projects at Big Bend Unit 1 through 4 encompass the design, procurement, installation, and annual O&M expenses associated with an SCR system for each unit. The SCR for Big Bend Units 1 through 4 were placed in service April 2010, September 2009, July 2008, and May 2007, respectively.

For the period of January 2022 through December 2022, there are not any capital or O&M expenditures anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. There are not any anticipated capital expenditures for the Big Bend Units 1 through 4 SCR. There are no O&M expenses anticipated for Big Bend Unit 1 SCR and Big Bend Unit 2 SCR. The O&M expenses are projected to be $372,522 for Big Bend Unit 3 SCR, and $1,397,376 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases and maintenance.

Q. Please identify and describe the other Commission-approved programs, or those pending Commission approval, that you will discuss.

A. The programs previously approved or pending approval by the Commission that I will discuss include the following projects:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration.
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables
5) Clean Water Act Section 316(b) Phase II Study
6) Big Bend FGD System Reliability
7) Arsenic Groundwater Standard
8) Mercury and Air Toxics Standards ("MATS")
9) Greenhouse Gas ("GHG") Reduction Program
10) Big Bend Gypsum Storage Facility
11) Coal Combustion Residuals ("CCR") Rule
12) Big Bend Unit 1 Section 316(b) Impingement Mortality
13) Big Bend Effluent Limitations Guidelines ("ELG") Rule Compliance
14) Bayside Section 316(b) Compliance (pending approval in Docket No. 20210087-EI, filed on April 21, 2021)

Q. Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 19980693-EI, Order No. PSC-1999-0075-FOF-EI, issued January 11, 1999. In these orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emission requirements of the Phase I and II Clean Air Act Amendments ("CAAA") of 1990. Portions of Big Bend Units 1 & 2 FGD will be retired as part of the Big Bend Modernization project. Specific treatment of the retired ECRC assets is being addressed in the company's current general base rate proceeding, Docket No. 20210034-EI, filed on April 9, 2021.

The company does not anticipate any capital or O&M expenditures during January 2022 through December 2022 for the Big Bend Unit 3 FGD Integration project, nor any capital or O&M expenditures for the Big Bend Units 1 & 2

FGD project during January 2022 through December 2022.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M expenditures for the period of January 2022 through December 2022.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 20010593-EI, Order No. PSC-2001-1847-PAA-EI, issued September 14, 2001. In that order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2022 through December 2022, there are not any projected O&M expenditures for this program. In the intent to issue the permit renewal, dated August 9, 2013, FDEP indicated that the proposed NPDES permit authorizes a thermal variance under Section 316(a) of the Clean Water Act for the permit period. Bayside Power Station applied for renewal of the National Pollutant Discharge Elimination System ("NPDES") Permit in February 2018, and the permit is still pending. If a thermal study is required, Tampa Electric will incur O&M expenses and will include them in the true-up filing.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2022 through December 2022.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 20021255-EI, Order No. PSC-2003-0469-PAA-EI, issued April 4, 2003. For the period of January 2022 through December 2022, Tampa Electric projects O&M expenses associated with the consumable goods, primarily anhydrous ammonia, to be approximately $151,000.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study Program activities and provide the estimated O&M expenditures for the period of January 2022 through December 2022.

A. The Clean Water Act Section 316(b) ("Section 316(b)") Phase II Study program was approved by the Commission in Docket No. 20041300-EI, Order No. PSC-2005-0164-PAA-EI, issued February 10, 2005. The final rule adopted under Section 316(b), the Cooling Water Intake Structures ("CWIS") Rule, became effective October 14, 2014. The rule establishes requirements for CWIS at existing facilities. Section 316(b) requires that the location, design, construction, and capacity of CWIS reflect the best technology available

("BTA") for minimizing adverse environmental impacts. Tampa Electric is working with the regulating authority to determine the scheduling for biological, financial, and technical study elements necessary to comply with the rule. These elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits.

At this time, CWIS Rule compliance alternatives for Bayside Power Station have been evaluated. The biological, financial, and technical study elements have been completed for Bayside Power Station and submitted with the station's NPDES permit renewal application in February 2018. Selected cost effective BTA retrofits for impingement mortality reduction include the installation of screening facilities.

The estimated Clean Water Act Section 316(b) Phase II Study related O&M expenses for Big Bend Station and Bayside Power Station for the period January 2022 through December 2022 are $10,150.

For Big Bend Unit 1, which will be repowered to a clean, natural gas-fired combined cycle unit, the permit will require installation of impingement mortality controls. Therefore, in Order No. PSC-2018-0594-FOF-EI, issued on

December 20, 2018, the Commission approved cost recovery for the Big Bend Unit 1 Section 316(b) Impingement Mortality project.

The estimated O&M expense for NPDES Annual Surveillance Fees for Big Bend, Bayside, and Polk generating plants for the period January 2022 through December 2022 are $34,500.

Q. Are other plants expected to require retrofits to comply with Section 316(b)?

A. Yes. As stated earlier and outlined in the company's Bayside Power Station Section 316(b) Compliance petition, filed with the Commission on April 21, 2021, in Docket No. 20210087-EI, Tampa Electric plans to install traveling screens to reduce impingement mortality to comply with Section 316(b).

Q. Please describe the Big Bend Unit 1 Section 316(b) Impingement Mortality project activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. The Big Bend Unit 1 Section 316(b) Impingement Mortality project was approved by the Commission in Docket No.

20180007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018. In that order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery for prudently incurred costs. For the period of January 2022 through December 2022, Tampa Electric projects capital expenditures for the Big Bend Unit 1 Section 316(b) Impingement Mortality Project to be $1,705,374. There are no O&M expenses anticipated for 2022.

Q. Please describe the Bayside Section 316(b) Compliance project activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. The Bayside Section 316(b) Compliance project petition was filed with the Commission on April 21, 2021, in Docket No. 20210087-EI. The petition relates to impingement mortality reduction methods to be applied to comply with the EPA rule. The petition is currently pending approval. For the period of January 2022 through December 2022, Tampa Electric projects capital expenditures for the Bayside Section 316(b) Compliance Project to be $5,689,564. There are no O&M expenses anticipated during 2022.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenditures for the period of January 2022 through December 2022.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 20050958-EI, Order No. PSC-2006-0602-PAA-EI, issued July 10, 2006. The Commission granted approval for prudent costs associated with this project. For the period of January 2022 through December 2022, there are no anticipated capital expenditures for this project.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated O&M expenditures for the period of January 2022 through December 2022.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 20050683-EI, Order No. PSC-2006-0138-PAA-EI, issued February 23, 2006. In that order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery for prudently incurred costs. This groundwater standard applies to Tampa Electric's Bayside, Big Bend, and Polk Power Stations. A detailed plan of study was submitted to the FDEP, and after reviewing the study, FDEP requested a site wide groundwater evaluation. Tampa Electric submitted the results of this evaluation in 2020 and a proposal for modification of the site groundwater monitoring network to evaluate ongoing compliance. The proposal is under review by FDEP. Once FDEP completes its review, additional O&M expenses may be incurred if additional monitoring and assessment are required. For the period of January 2022 through December 2022, the anticipated O&M expenses associated with the program are $37,080.

Q. Please describe the MATS program activities.

A. The MATS program was approved by the Commission in Docket No. 20120302-EI, Order No. PSC-2013-0191-PAA-EI, issued May 6, 2013. In that order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric approval for cost recovery of prudently incurred costs. Additionally, the Commission granted the subsumption of the previously approved CAMR program into the MATS program.

On February 8, 2008, the Washington D.C. Circuit Court vacated EPA's rule removing power plants from the Clean

Air Act list of regulated sources of hazardous air pollutants under Section 112. At the same time, the court vacated the Clean Air Mercury Rule. On May 3, 2011, the EPA published a new proposed rule for mercury and other hazardous air pollutants according to the National Emissions Standards for Hazardous Air Pollutants section of the Clean Air Act. On February 16, 2012, the EPA published the final rule for MATS. The rule revised the mercury limits and provided more flexible monitoring and record keeping requirements. Additionally, monitoring of acid gases and particulate matter is required. Compliance with the rule began on April 16, 2015. Tampa Electric is currently meeting or exceeding the standards required by the MATS rule for mercury, particulate matter, and acid gases at Polk Power Station and Big Bend Power Station.

Q. Please provide MATS program estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. For 2022, Tampa Electric does not anticipate capital expenditures under the MATS program. O&M expenditures are projected to be approximately $2,000 for testing requirements and equipment maintenance.

Q. Please describe the GHG Reduction program activities and provide the estimated O&M expenditures for the period of January 2022 through December 2022.

A. Tampa Electric's GHG Reduction program, which was approved by the Commission in Docket No. 20090508-EI, Order No. PSC-2010-0157-PAA-EI, issued March 22, 2010, is a result of the EPA's GHG Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's GHG Mandatory Reporting Rule will continue in 2022. For 2022, there are no O&M expenditures anticipated.

Q. Please describe the Big Bend Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. The Big Bend Gypsum Storage Facility program was approved by the Commission in Docket No. 20110262-EI, Order No. PSC-2012-0493-PAA-EI, issued September 26, 2012. In that order, the Commission found that the program meets the requirements for recovery through the ECRC. For 2022, Tampa Electric does not anticipate capital expenditures;

however, the projected O&M expenses for this program are expected to be $1,213,236.

Q. Please describe the company's EPA CCR Rule compliance activities and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. On April 17, 2015, the EPA issued a final rule to regulate CCR as non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The rule, which became effective on October 19, 2015, covers all operational CCR disposal facilities, as well as inactive impoundments which contain CCR and liquids. The Big Bend Unit 4 Economizer Ash Ponds, the East Coalfield Stormwater Pond (converted former slag fines pond), and the North Gypsum Stackout Area are regulated under the rule.

The initial phase of the company's CCR compliance was approved by the Commission in Docket No. 20150223-EI, Order No. PSC-2016-0068-PAA-EI, issued February 9, 2016. In that order, the Commission found that the CCR Rule – Phase I program met the requirements for recovery through the ECRC. Incremental ongoing O&M expenses resulting from the groundwater monitoring program, berm inspections, and general maintenance of regulated units were approved under the Order. In order to determine the best option to remain in compliance with the new rule, the company evaluated whether to continue operation of the regulated CCR units or close them. Tampa Electric chose a combination of closure and retrofit projects to remain in compliance with the CCR Rule, as discussed later in this section.

Two CCR retrofit projects were also approved for Tampa Electric’s CCR Rule – Phase I program under Order No. PSC-2016-0068-PAA-EI. These included: 1) removal of remaining residual slag from the East Coalfield Stormwater Runoff Pond and lining the pond to continue operating it as part of the station’s stormwater system; and 2) installing secondary stormwater containment facilities and lining drainage ditches for the North Gypsum Stackout Area to make it fully compliant with the rule’s requirements.

Phase II of Tampa Electric’s CCR Rule program was approved by the Commission in Docket No. 20170168-EI, Order No. 2017-0483-PAA-EI, issued December 22, 2017. In that Order, the Commission found that the Phase II program met the requirements for recovery through the ECRC. Expenses for the Economizer Ash Pond System Closure project, which includes removal and offsite disposal of all CCR and restoration of the area, were approved by the Commission's Order.

The Economizer Ash Pond System Closure began in the fourth quarter of 2018 with initial dewatering and removal of CCR for disposal. Due to the large amount of CCR in the Economizer Ash Ponds that needed to be dewatered and shipped to the landfill, this project has continued and is expected to be completed in late 2021. The East Coalfield Stormwater Runoff Pond (slag pond) closure and retrofit project was originally scheduled to be completed in 2019 but was delayed due to unusually high rainfall amounts throughout that year. As a result, this project was initiated in 2020 and completed in early 2021, in accordance with state regulatory requirements. The North Gypsum Stackout Area Drainage Improvements Project was also delayed to finalize engineering and construction scope details, but is currently underway, with completion expected in 2022.

Tampa Electric expects to incur $1,500,000 in capital expenditures for the North Gypsum Stackout - Phase I project during 2022. The company expects to incur O&M expenses of $930,000 for this CCR Rule – Phase I project in 2022. There are no capital or O&M expenditures anticipated for the CCR Rule – Phase II (Economizer Ash Closure) project in 2022.

Q. Please describe Tampa Electric's ELG Rule activities, both study and compliance related and provide the estimated capital and O&M expenditures for the period of January 2022 through December 2022.

A. On November 3, 2015, the EPA published the final Steam Electric Power Generating ELG Rule, with an effective date of January 4, 2016. The ELG establish limits for wastewater discharges from FGD processes, fly ash, and bottom ash transport water, leachate from ponds and landfills containing CCR, gasification processes, and flue gas mercury controls. Big Bend Station's FGD system is affected by this rule. The blow-downstream from the FGD system is currently sent to a physical chemical treatment system to remove solids, some metals, and ammonia and adjust pH prior to discharge to Tampa Bay via the once through condenser cooling system water. This treatment system will need to be modified or replaced to achieve compliance with the new EPA regulations. The rule requires compliance after November 1, 2018, but no later than December 31, 2023. EPA issued a temporary stay of these compliance deadlines beginning April 25, 2017 for certain waste streams, including FGD wastewater.

The Big Bend ELG Study Program ("ELG Study") was approved by the Commission in Docket No. 20160027-EI, Order No. PSC-2016-0248-PAA-EI, issued June 28, 2016.

The ELG Study, which was completed in 2018, identified viable technologies to treat the Tampa Electric Big Bend Station combined effluent streams to bring the streams into compliance with the more stringent requirements under the ELG Rule and resulted in the selection of the deep well injection solution.

The Big Bend ELG Compliance project was approved by the Commission in Docket No. 20180007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018. In that order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery for prudently incurred costs.

On June 6, 2017, the EPA issued proposed rulemaking to postpone these deadlines until it has completed reconsideration of the 2015 rule. On August 11, 2017, EPA issued a letter to the Utility Water Act Group ("UWAG") and the U.S. Small Business Association regarding petitions received by the EPA requesting reconsideration of the rule. In this letter, EPA stated that it would be appropriate to conduct rulemaking to "potentially revise" the limitations for bottom ash transport water and FGD wastewater. The compliance deadlines for these waste streams were revised to be as soon as possible after November 1, 2021, but no later than December 31, 2023. Tampa Electric expects that the selected compliance option will continue to be required as the best option for customers even if some changes are made to the rule. For the year January 2022 through December 2022, Tampa Electric projects capital expenditures to be $13,510,436. The company projects $4,944 in O&M expenditures for this project for the period.

Q. Please summarize your testimony.

A. The settlement agreements Tampa Electric had with FDEP and EPA required significant reductions in emissions from Big Bend and Gannon Power Stations. These settlement agreements have been terminated due to the company having satisfied all requirements as set forth by the CFJ and

CD. Ongoing requirements for projects originating with the CFJ and CD have been incorporated into Big Bend’s Title V Operating permit (0570039-128-AV) and are discussed throughout my testimony. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I identified estimated costs, by project, which the company expects to incur in 2022. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2022 activities and projected expenditures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CHAIRMAN CLARK: Exhibits.

MR. IMIG: Staff has compiled a Stipulated Comprehensive Exhibit list, which includes the prefiled exhibits attached to the witnesses' testimony in this case and a number of staff exhibits. The list has been provided to the parties, the Commissioners and the court reporter.

Staff asks that the list be marked as the first hearing exhibit and the other exhibits marked as set forth in the chart.

CHAIRMAN CLARK: So ordered.

(Whereupon, Exhibit Nos. 1-49 were marked for identification.)

MR. IMIG: At this time, staff asks that the Comprehensive Exhibit List, marked as Exhibit No. 1, be entered into the record.

CHAIRMAN CLARK: Without objection, so ordered.

(Whereupon, Exhibit No. 1 was received into evidence.)

MR. IMIG: Staff asks is that Exhibits 2 through 49 be included in the record.

CHAIRMAN CLARK: Any objections? So ordered.

(Whereupon, Exhibit Nos. 2-49 were received into evidence.)

CHAIRMAN CLARK: All right. Moving on to opening statements.

Any of the parties wish to make an opening statement in this matter? I have none.

All right. Staff, is this docket in a posture for the Commission to make a bench decision?

MR. IMIG: Yes, Commissioner. Provided the parties are willing to waive briefing these issues, the Type 2 stipulations of all of the issues are in the posture for a bench decision by the Commission.

CHAIRMAN CLARK: Anyone want to brief? Seeing no briefs.

Commission, questions?

Motion?

COMMISSIONER FAY: Mr. Chairman, I would move the Commission approve stipulated Issues 1 through 13 as numbered in the prehearing.

COMMISSIONER GRAHAM: Second.

CHAIRMAN CLARK: Motion and a second to approve the stipulations as presented.

Any discussion?

On the motion, all in favor say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?

(No response.)

CHAIRMAN CLARK: Motion carries.

Staff, any other items that need to be addressed?

MR. IMIG: Since the Commission has made a bench decision, post-hearing filings are not necessary. The final order will be issued by November 22nd, 2021?

CHAIRMAN CLARK: All right. The 07 docket is closed and we will OPC open the 01 docket.

(Proceedings concluded.)

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 15th day of November, 2021.

Debbie R Krick

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