BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20220007-EI

In re: Environmental cost recovery clause.
_________________________________/

VOLUME 1
PAGES 1 - 181

PROCEEDINGS: HEARING

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

DATE: Thursday, November 17, 2022

TIME: Commenced: 9:30 a.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

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

APPEARANCES:

MARIA JOSE MONCADA and JOEL BAKER, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-2863; appearing on behalf of Florida Power & Light Company (FPL).

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, LLC (DEF).

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

RICHARD GENTRY, PUBLIC COUNSEL; CHARLES J. REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE and MARY A. WESSLING, ESQUIRE, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400; appearing on behalf of the Citizens of the State of Florida (OPC).

APPEARANCES CONTINUED:

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

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

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

JACOB IMIG and ADRIA HARPER, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

APPEARANCES CONTINUED:

KEITH C. 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

P R O C E E D I N G S

CHAIRMAN FAY: Commissioners, we will now move next to the 07 docket, where Mr. Imig will present any preliminary matters that we have.

MR. IMIG: There are proposed stipulations of Issues 1 through 10, 12 and 14 through 17. FPL, Duke, TECO and Commission staff support the proposed stipulations. As discussed in more detail, OPC, FIPUG, PCS Phosphate and Nucor are willing to facilitate a Type 2 stipulation of these issues by taking no position.

Issues 11 and 13 are contested and will require a vote by the Commission after briefs are filed. All other issues will be voted on today.

All witnesses except for FPL Witness MacGregor has been -- have been excused with prefiled testimony and exhibits to be inserted into the record.

CHAIRMAN FAY: Okay. Great. Thank you, Mr. Imig.

Let's make sure we don't have any preliminary matters from the parties.

With that, we will move on to prefiled testimony.

MR. IMIG: The prefiled testimony of all

witnesses excepted FPL Witness MacGregor are the subject of a Type 2 stipulation. Staff asks that the prefiled testimony of all witnesses except FPL Witness MacGregor be entered into the record as though read.

CHAIRMAN FAY: Okay. Great. With that, we will show without objection that the testi -- prefiled testimony for all witnesses except for Ms. MacGregor will be entered into the record as though read.

(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. 20220007-EI

APRIL 1, 2022

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 pre-consolidated FPL's and pre-consolidated Gulf Power Company's ("Gulf") Environmental Cost Recovery Clause ("ECRC") final net true-up amounts associated with 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 am sponsoring Exhibits RBD-1 and RBD-2. RBD-1 provides the forms listed below for FPL and RBD-2 provides the same forms for Gulf.

- Forms contained in Exhibits RBD-1 and RBD-2:

- Form 42-1A reflects the final net true-up for the period January 2021 through December 2021.
- 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 71 through 74 of RBD-1 and pages 52 through 54 of RBD-2 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 and Gulf. The books and records are kept in the regular course of FPL's and Gulf'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.

FPL 2021 FINAL TRUE-UP CALCULATION

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

A. Form 42-1A shows the calculation of FPL's final net true-up for the period January 2021 through December 2021, an over-recovery of $6,314,841, which FPL is requesting be included in the calculation of the ECRC factors for the January 2023 through December 2023 period.

The actual end-of-period over-recovery for the period January 2021 through December 2021 of $9,063,219 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period over-recovery for the same period of $2,748,378 (shown on Form 42-1A, Line 6) results in the final net true-up over-recovery for the period January 2021 through December 2021 (shown on Form 42-1A, Line 7) of $6,314,841.

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

A. Yes. Form 42-2A shows the calculation of FPL's end-of-period true-up over-recovery amount of $9,063,219 for the period January 2021 through December 2021. The $7,688,023 over-recovery shown on line 5 plus the interest provision of $19,467 shown on line 6, which is calculated on Form 42-3A, and the adjustment of $1,355,729 shown on line 10 results in the final over-recovery of $9,063,219.

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 2021 through December 2021 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 $3,463,403 or 13.0% lower than projected. Form 42-6A shows a minor variance in total actual revenue requirements (depreciation, amortization, income taxes and return on capital investments) associated with the project capital investments of $674,734 or

0.4% lower 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 2021 through December 2021 are provided on Form 42-8A, pages 15 through 70 of RBD-1. Explanations for significant variances in project costs are addressed by FPL witness Katharine McGregor.

GULF 2021 FINAL TRUE-UP CALCULATION

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

A. Form 42-1A shows the calculation of Gulf's final net true-up for the period January 2021 through December 2021, an over-recovery of $4,571,970, which FPL is requesting be included in the calculation of the ECRC factors for the January 2023 through December 2023 period.

The actual end-of-period over-recovery for the period January 2021 through December 2021 of $8,388,638 (shown on Form 42-1A, Line 4) minus the actual/estimated end-of-period over-recovery for the same period of $3,816,668 (shown on Form 42-1A, Line 5) results in the final net true-up over-recovery for the period January 2021 through December 2021 (shown on Form 42-1A, Line 6) of $4,571,970.

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

A. Yes. Form 42-2A shows the calculation of Gulf's end-of-period true-up over-recovery amount of $8,388,638 for the period January 2021 through December 2021. The $7,196,445 over-recovery shown on line 5 plus the interest provision of $10,402 shown on line 6, which is calculated on Form 42-3A, plus the adjustment of $1,181,791 shown on line 10 results in the final over-recovery of $8,388,638 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 2021 through December 2021 compare with Gulf'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 $10,011,354 or 33.5% lower than projected. Form 42-6A shows a minor variance in total actual revenue requirements (depreciation, amortization, income taxes and return on capital investments) associated with the project capital investments of $1,744,271 or 1.3% lower 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 2021 through December 2021 are provided on Form 42-8A, pages 12 through 51 of RBD-2. Explanations for significant variances in project costs are addressed by FPL witness Katharine MacGregor.

Q. What is the 2021 final net true-up amount that will be included in FPL's 2023 ECRC factors?

A. FPL will include in the calculation of its 2023 ECRC factors a total 2021 final net true-up over-recovery of $10,886,811, which represents the 2021 final net over-recovery of $6,314,841 for FPL plus the 2021 final net true-up over-recovery of $4,571,970 for Gulf.

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. 20220007-EI

JULY 29, 2022

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 this 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 2022 through December 2022.

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-3 consists of nine forms, PSC Forms 42-1E through 42-9E.

- Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2022 through December 2022.
- 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 88) reflects return on capital investments and depreciation by project. Pages 89 through 94 provide the 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 2022 through December 2022.

Additionally, I am including Exhibit RBD-2, which is pre-consolidated Gulf Power Company's 2021 Final Net True-Up, which was incorrectly filed on April 1, 2022 as Exhibit RBD-1.

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 2022 through December 2022 is an under-recovery, including interest, of $3,465,963 (Exhibit RBD-3, page 1, line 3). The Actual/Estimated True-Up amount is calculated on Form 42-2E by comparing actual data for January 2022 through May 2022 and revised estimates for June 2022 through December 2022 to original projections for the same period. The under-recovery of $3,517,982 shown on line 1 plus the interest provision of $52,019 shown on line 2, which is calculated on Form 42-3E, results in the final under-recovery of $3,465,963 shown on line 3.

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 (1) the proposed new project - the Combustion Turbine National Emission Standards for Hazardous Air Pollutants Project ("CT NESHAP Project"), which is discussed in the testimony of FPL witness Katharine MacGregor filed on April 1, 2022 in this docket and (2) the modification to FPL's approved National Pollutant Discharge Elimination System Permit Renewal Requirements Project ("NPDES Permit Renewal Project"), which is discussed in the testimony of FPL witness MacGregor included in this filing.

Q. How do the actual/estimated project costs for January 2022 through December 2022 compare with original projections for the same period?

A. Individual project variances are provided on Forms 42-4E and 42-6E. Form 42-4E (Exhibit RBD-3, page 4) shows that total O&M project costs are $15,744,929 or 36.06% higher than projected, and Form 42-6E (Exhibit RBD-3, page 9) shows that total capital project revenue requirements are $6,516,677 or 1.94% lower than projected. Revenue requirements for each capital project for the 2022 actual/estimated period are provided on Form 42-8E (Exhibit RBD-3, pages 15 through 88). Explanations for significant variances in project costs are addressed by FPL witness MacGregor.

Q. FPL witnesses Valle and Bores address a request to establish a regulatory asset associated with the early retirement of the Martin Thermal Solar facility (Project 39). Is there a recoverable cost impact in 2022 associated with that request?

A. No. There is not an impact to the recoverable costs for the early retirement of Martin Thermal Solar in 2022. The retirement date is expected to be in January 2023. Any impact to the recoverable costs will be realized beginning February 1, 2023 and included in the 2023 projection filing that will be filed August 26, 2022.

Q. Have there been any other notable adjustments to the recoverable costs for the period January 2022 through May 2022?

A. Yes. As part of the combination of pre-consolidated Gulf Power's and pre-consolidated FPL's ECRC projects, accounting data was combined in several systems. During the process of validating the combination, FPL determined that certain accounting clean-up was required, which reduced the O&M expense in 15 projects listed in the table below. In March 2022, a true-up adjustment was made to correct all of the items discovered during the validation process.

PROJECT NO.	PROJECT NAME
5	Maintenance of Stationary Above Ground Fuel Tanks
8	Oil Spill Cleanup/Response Equipment
11	Air Quality Compliance
14	NPDES Permit Fees
19	Oil-Filled Equipment and Hazardous Substance Remediation
23	SPCC – Spill Prevention, Control and Countermeasures
27	Lowest Quality Water Source
28	CWA 316(b) Phase II Rule
37	DeSoto Next Generation Solar Energy Center
38	Space Coast Next Generation Solar Energy Center
39	Martin Next Generation Solar Energy Center
41	Manatee Temporary Heating System
42	Turkey Point Cooling Canal Monitoring Plan
54	Coal Combustion Residuals
427	General Water Quality

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Matthew Valle was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MATTHEW VALLE

DOCKET NO. 20220007-EI

JULY 29, 2022

Q. Please state your name and business address.

A. My name is Matthew Valle. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am the president of NextEra Energy Transmission, LLC.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science with Merit from the United States Naval Academy in Systems Engineering and a Master of Business Administration from Harvard Business School. Before entering the private sector, I served five years as a nuclear submarine officer in the United States Navy. From 2007 to 2011, I held the position of Principal with The Boston Consulting Group in its Dallas office where my responsibilities included running project teams for Fortune 500 clients in the energy and technology sectors. I joined the NextEra Energy, Inc. family in 2012 as the Vice President of NextEra Energy Transmission where I was responsible for the competitive development of transmission across the U.S. and Canada. From 2015 until earlier this year, I served as Vice President of Development at Florida Power & Light Company ("FPL" or "the Company").

Q. Please describe your duties and responsibilities during the seven years you served as Vice President of Development at FPL.

A. In that role, I was responsible for leading new generation development for the company across technologies including solar, batteries, electric vehicles, hydrogen and natural gas. Of pertinence to this matter, I was responsible for the development of 48 photovoltaic ("PV") solar sites totaling 3,576 MW. Those sites include solar recovered through rate base, the solar base rate adjustment mechanism and the SolarTogether program.

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's history and experience with the Martin Thermal Solar facility, and the recommendation to retire the facility.

Q. Please summarize your testimony.

A. Fourteen years ago the Florida legislature passed a law encouraging our State's utilities to explore the viability of renewable technologies. Heeding that call, FPL petitioned for approval to build three solar generation facilities applying the two types of technology used by the industry at that time: thermal solar at the Martin plant and PV solar at the DeSoto and Space Coast sites. Construction and operation of these solar facilities would provide FPL the opportunity to evaluate the suitability of integrating these technologies into the broader fleet, in terms of both performance and cost to customers. After twelve years of operations, PV solar is clearly the superior technology in Florida's environment. While thermal solar has worked well in other areas of the country, Florida's climate is not optimal. Florida's support for the exploration of renewable technologies provided the encouragement necessary to attain these learnings, not only for application to FPL's fleet but also for others in the state.

PV solar is the most efficient and economic way to integrate renewable technology in our State. In light of all of that has been learned regarding thermal solar's higher cost and lower output relative to FPL's PV sites, it is appropriate to retire the Martin Thermal Solar site early. As described by FPL witness Bores, doing so will save FPL customers $157.8 million.

Q. Please describe the history behind FPL's construction and operation of Martin Thermal Solar.

A. On June 25, 2008, Florida's then-governor signed into law an energy bill, codified at that time as Section 366.92(4), Florida Statutes ("Section 366.92(4)"), that called for the advancement of renewable energy by demonstrating the feasibility and viability of clean, zero greenhouse gas emitting energy systems in Florida. To encourage the exploration of renewable technologies, the statute also provided that "the commission shall provide for full cost recovery under the environmental cost-recovery clause [ECRC] of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of generation." Consistent with this renewable energy statute, on May 16, 2008 in Docket 080281-EI, FPL petitioned the Florida Public Service Commission

("Commission") for approval to construct three separate solar facilities totaling 110 MW of capacity – Martin Thermal Solar, DeSoto Solar and Space Coast Solar and recover their revenue requirements through FPL's ECRC.

Q. Did FPL anticipate that the Martin, DeSoto and Space Coast solar facilities would be cost-effective additions to the FPL fleet at the time it proposed those facilities as ECRC projects?

A. No, cost-effectiveness was not the rationale or intent of the law for developing these projects. At the time FPL filed its petition, solar energy projects were not yet cost-effective. It would take improvements in the technology as well as additional development of solar projects to realize the benefits FPL's solar projects provide now. Instead, the essential purpose behind Section 366.92(4) and the three solar facilities proposed by FPL was to take significant steps to understand how solar could become a more prevalent energy source in Florida. These three solar facilities would not only generate clean, renewable energy, but also would provide significant information and experience regarding key aspects of siting, constructing, and operating different solar technologies at various locations in Florida. At that time, thermal solar technology had a nearly three-decade history of successful development and operation in other parts of the country. More than five gigawatts of thermal solar capacity was already installed or in development around the world. Martin Thermal Solar was unique in that the blending of solar generated steam into a combined cycle power plant had never been done. Comparing the prevalence of the thermal and PV solar technologies as they existed in 2010, the Solar Energy Generating Systems

("SEGS") thermal solar plants in the Mojave Desert totaled 354 MW of capacity and had been in service since the 1980s, while the Desoto PV Solar project proposed by FPL would become the largest in the United States at just 25 MW in 2010. Because Solar thermal technology was more mature and proven, and because PV solar was becoming more cost effective and efficient at that time, further investigating the benefits and challenges of each technology would advance the objectives reflected in Section 366.92(4).

Q. Was FPL's proposal regarding the three solar facilities approved?

A. Yes, by Order No. PSC-08-0491-PAA-EI dated August 4, 2008, the Commission approved the Martin Thermal Solar, DeSoto Solar and Space Coast Solar projects as eligible for recovery through the ECRC pursuant to Section 366.92(4), and FPL proceeded with construction accordingly. As described in FPL's 2008 petition, Martin was constructed using thermal solar technology while DeSoto and Space Coast Solar were constructed using PV solar technology.

Q. When was Martin Thermal Solar placed into service and at what cost?

A. Martin Thermal Solar was placed into service in December 2010. Section 366.92(4), required that FPL use "reasonable and customary industry practices in the design, procurement, and construction of the project in a cost-effective manner appropriate to the location of the facility." In other words, the facility was not required to be a cost-effective addition to FPL's fleet, but rather that FPL's construction of the facility be undertaken in a cost-efficient manner. The total construction cost for Martin Thermal Solar at the time it was placed into service was \$391 million or \$5,213/kW_{ac}.

Q. Please describe in more detail the technology implemented at the Martin facility.

A. Martin Thermal Solar involved the installation of thermal solar technology that was integrated into the existing steam cycle for the Martin Unit 8 ("Unit 8") natural gas-fired combined cycle plant. This required the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors track the sun to maintain the optimum angle to collect solar radiation. The collectors concentrate the sun's energy on heat collection elements located in the focal line of parabolic reflectors. These heat collection elements contain a heat transfer fluid ("HTF") that reaches approximately 750 degrees Fahrenheit ("750 °F") when heated by the concentrated solar radiation. The HTF is then circulated to heat exchangers that produce the steam that is routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Q. Does Martin Thermal Solar provide incremental capacity to FPL's fleet?

A. No, the steam supplied by Martin Thermal Solar supplements the steam currently generated by the heat recovery steam generators. In other words, Martin Thermal Solar is a fuel displacement source; it does not create incremental capacity.

Q. How does thermal solar technology differ from PV solar technology?

A. Thermal solar technology differs from PV solar in that the parabolic mirrors themselves are not used to capture solar irradiance, but rather to focus the solar irradiance in a manner that heats the HTF to 750 °F. This requires immense heat and long periods of uninterrupted solar irradiance.

Q. Based on FPL's 12 years of experience, how compatible is thermal solar technology with the climate we experience in Florida?

A. Over Martin Thermal Solar's operating life, it has become apparent that Florida's climate is not optimal for thermal solar technology due to the near constant intermittent cloud cover. These swings in irradiance cause the temperature of the HTF to rapidly rise and fall throughout the day, creating excessive wear and failure on certain critical components of the system.

Q. Has thermal solar technology been used outside of Florida with more success?

A. Yes. Conditions such as those in more arid, desert-like climates, which differ significantly from Florida's climate, are suitable for thermal solar installations as intermittent cloud cover is less prevalent. Thermal solar technology has been used successfully in these climates for nearly 30 years. In fact, one of FPL's affiliates owned and operated the SEGS plants in Mojave California for nearly 30 years before they were retired at end of life between 2014 and 2020.

Q. Has FPL experienced challenges at Martin Thermal Solar other than incompatible climate?

A. Yes. Major components of the Martin Thermal Solar plant failed more often and at higher levels than anticipated. From the parabolic mirrors to components such as valves, ball joints and tubes, many components have required repairs or replacements.

Q. Has FPL investigated the cause of these component failures?

A. Yes. Based on analyses, FPL determined that most failures resulted from many factors occurring in parallel. For example, HTF tubing failures had cascading effects causing parabolic mirrors to break downstream. Not uncommon during major component failures are releases of HTF which become costly events to manage as well. Because of the intermittent cloud cover I previously described, the integrity of the HTF becomes compromised if the control system is unable to respond quickly. As a result, the control system is constantly working to manage the HTF temperature, which caused excessive wear and tear on the ball joints and valves and can lead to the presence of particulates in the HTF, which is also problematic as it requires more frequent cleaning of the filters to prevent clogging of the system.

Q. Please address FPL's experience regarding the cost to operate Martin Thermal Solar.

A. Simply put, operating Martin Thermal Solar has come at a relatively high cost. Martin Thermal Solar was expected to generate approximately 137,000 MWh annually, but, due to the challenges I mentioned earlier, it operated at 80% below that expectation for the period 2019 through 2021. In addition, Martin Thermal Solar was originally expected to cost approximately $1.7 million per year to operate and maintain, but the average cost for 2019 through 2021 was more than double. The eroding production and rising operating costs have caused Martin Thermal Solar to become uneconomic for FPL customers. The best way to demonstrate this is to compare the operations and maintenance cost of Martin Thermal Solar to that of FPL's PV solar on a unitized production basis. In 2021, Martin Thermal Solar cost approximately $139.00 per MWh to operate, while the FPL PV solar fleet cost an average of $1.70 per MWh to operate.

Q. Based on your overall experience, do you believe Martin Thermal Solar has served its intended purpose?

A. Yes. Florida has become a national leader in solar and the passage of Section 366.92(4) and this Commission's approval of FPL's three solar projects – including Martin Thermal Solar – was a fundamental steppingstone. By constructing and operating Martin Thermal Solar, FPL was able to test "the feasibility and viability" of thermal solar technology as a "clean energy system" in the state. Over the 12 years of its operation, the Commission has received information from FPL regarding construction costs, in-service costs, operating and maintenance costs, and hourly energy production. Without having undertaken the Martin Thermal Solar project, neither FPL nor the state could have gained knowledge regarding its suitability in Florida, or the performance and cost information necessary to assess its potential for broader-scale use.

Q. Based on what FPL has learned about solar technology since 2010, what have you concluded regarding whether the Company should continue to operate Martin Thermal Solar?

A. As I mentioned, Martin Thermal Solar has served its purpose, and the Company is well-served by the project and the knowledge it has gained. However, the benefits of operating the Martin Thermal Solar plant have reached their end. It is now clear that solar PV is a cost-effective renewable solution for FPL's customers, while thermal solar technology is not. As I've discussed, FPL's cost to operate solar PV is about one-eightieth the cost to operate Martin Thermal Solar. And, looking ahead to FPL's clean energy future, solar PV technology has advanced to the point that FPL's average construction cost of PV solar facilities has fallen significantly since 2010.

Q. Does the early retirement of Martin Thermal Solar benefit customers?

A. Absolutely. Retiring the facility is the right decision for FPL's customers. As described by FPL witness Bores, retiring the plant early and authorizing the Company to establish and recover a regulatory asset for the unrecovered early retired investment is projected to save customers $157.8 million when compared to the cost of continuing to operate Martin Thermal Solar.

Q. Is FPL adhering to its commitment to solar energy notwithstanding the early retirement of Martin Thermal Solar?

A. The answer is a resounding yes. With the learnings from FPL's early solar projects in hand, FPL has been adding cost-effective PV solar to FPL's fleet since 2016. Retiring Martin Thermal Solar and recovering the unrecovered early retired investment over 20 years is projected to save FPL customers $157.8 million and will allow FPL to further focus on the solar technology that has proven to be cost-effective and the superior solar performer in the Florida climate, PV solar.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Scott Bores was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF SCOTT R. BORES

DOCKET NO. 20220007-EI

JULY 29, 2022

Q. Please state your name and business address.

A. My name is Scott R. Bores. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

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

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

A. I am responsible for FPL's financial forecast, analysis of financial results, corporate budgeting, accounting, resource assessment and planning, and load forecast activities.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Connecticut in 2003 with a Bachelor of Science degree in Accounting. I received a Master of Business Administration from Emory University in 2011. I joined FPL in 2011 and have held several positions of increasing responsibility, including Manager of Property Accounting, Director of Property Accounting, Senior Director of Financial Planning & Analysis, and my current position as the Vice President of Finance. Prior to FPL, I held various accounting roles with Mirant Corporation, which was an independent power producer in Atlanta, Georgia, as well as worked for PricewaterhouseCoopers, LLP. I am a Certified Public Accountant ("CPA") licensed in the State of Georgia and a member of the American Institute of CPAs. I have previously filed testimony before the Florida Public Service Commission ("FPSC" or the "Commission") numerous times.

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

A. Yes. I am sponsoring the following exhibit:

- SRB-1 – CPVRR Benefit of Martin Thermal Solar Retirement

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

A. The purpose of my testimony is to present the results of the economic analysis which demonstrates retiring the Martin Thermal Solar Facility ("Martin Thermal Solar") in January 2023 creates significant economic value for FPL's customers. My testimony describes the key assumptions used in the economic analysis, the Company's proposal to establish a regulatory asset for the unrecovered early retired investment for Martin Thermal Solar, and the recovery of the regulatory asset, including a return on the unamortized balance, through FPL's Environmental Cost Recovery Clause ("ECRC").

Q. Please summarize your testimony.

A. As described by FPL witness Valle, Martin Thermal Solar was constructed as a result of legislation enacted in 2008 that enabled cost recovery of new solar technology. Martin Thermal Solar entered service at the end of 2010 and has served customers since that time by utilizing the sun to heat transfer fluid and ultimately displace the amount of natural gas needed to operate the Martin Unit 8 combined cycle unit (“Unit 8”). Over that time, we have learned that the cost to maintain and operate thermal solar facilities outweigh the benefits, and that photovoltaic solar is the more cost-effective choice for customers. As a result, FPL is seeking approval to retire Martin Thermal Solar and establish a regulatory asset for the unrecovered early retired investment to be recovered over 20 years through FPL’s ECRC, which results in a projected CPVRR benefit of approximately $157.8 million when compared to the base case scenario.

Q. Please describe the economic analysis performed for this proposal.

A. The economic analysis for this transaction compared two plans: 1) the base case scenario (“base case”) in which Martin Thermal Solar would continue to operate through the end of its estimated useful life in 2050; and 2) the scenario contemplated under this proposal in which FPL retires the facility in January 2023 (“early retirement”). When the two scenarios are compared, it is clear there is an immediate and ongoing benefit to FPL’s customers to retire Martin Thermal Solar in January 2023 and recover the unrecovered early retired investment over a 20-year period. As shown in Exhibit SRB-1, the CPVRR benefit to FPL customers is projected to be approximately $157.8 million.

Q. What are the major assumptions used in the base case scenario?

A. The base case scenario utilizes the actual production and operating costs from 2011-2021 to develop a projection of expected production and operating costs through the end of the estimated useful life in 2050. The amount of production was then run through FPL's resource planning model, Aurora, to determine the system impacts on an annual basis. The system impacts consist of fuel and variable operations and maintenance ("VOM") savings as a result of Martin Thermal Solar displacing the amount of natural gas needed to operate Unit 8.

Q. What projection of natural gas prices did FPL utilize in calculating the system impacts?

A. FPL utilized the October 2021 fuel forecast consistent with what was utilized in FPL's 2022 Ten Year Site Plan.

Q. FPL's Actual/Estimated Fuel Cost Recovery Petition filed July 27, 2022 in Docket No. 20220001-EI recognized the current extraordinary conditions impacting the natural gas market. In light of these unique circumstances, did FPL consider utilizing a more recent fuel projection?

A. As FPL only prepares the official Company fuel forecast once a year, it does not have a more recent fuel forecast to utilize. However, FPL did prepare a sensitivity utilizing the June 21, 2022 fuel curve, which is the same fuel curve utilized to develop its 2022 Actual/Estimated Fuel Cost Recovery calculation. It is also important to note that while there has been volatility in near-term natural gas prices, the long-term outlook beyond the next three years has not been subject to much fluctuation. Utilizing the sensitivity from the June 21, 2022 fuel curve still results in a significant CPVRR benefit of $150.2 million for customers.

Q. Did FPL assess how the CPVRR might change under both a high and low gas price environment?

A. Yes. As shown in the chart below, FPL performed a sensitivity analysis utilizing both a low and high gas price scenario. In the low gas price scenario, in which prices were assumed to be 12.1% lower than the base case mid-fuel, the CPVRR benefit increased by $0.35 million, for a total CPVRR benefit of $158.2 million. In the high gas price scenario, in which prices were assumed to be 12.1% higher than the base case mid-fuel, the CPVRR benefit decreased by approximately $2.0 million, for a total CPVRR benefit of $155.9 million.

Fuel Sensitivity CPVRR Savings vs. Status Quo $ millions	**Retire w/ 20 Yr Recovery**
TYSP LOW Fuel Curve	($158.2)
TYSP MID Fuel Curve	**($157.8)**
TYSP HIGH Fuel Curve	($155.9)
6-21-22 LOW Fuel Curve	($156.1)
6-21-22 MID Fuel Curve	**($150.2)**
6-21-22 HIGH Fuel Curve	($153.3)

Q. What level of annual production did FPL assume from the Martin Thermal Solar facility?

A. FPL assumed approximately 30,000 megawatt hours ("MWh") of annual production, which is roughly the average annual total production for the last five years of operation.

Q. How does FPL propose to account for the remaining net book value associated with the early retirement of Martin Thermal Solar on its books and records?

A. FPL proposes to establish a regulatory asset for the unrecovered early retired investment associated with Martin Thermal Solar of approximately $285 million in

Account 182.2 – Unrecovered Plant and Regulatory Study Costs. In addition, FPL proposes to amortize the regulatory asset to Account 407 – Amortization for Property Losses, Unrecovered Plant and Regulatory Study Costs on a straight-line basis over a 20-year period beginning in February 2023.

Q. Why does FPL believe recovering the investment over a 20-year period is reasonable?

A. FPL believes that a 20-year recovery is reasonable for two main reasons. First, the 20-year recovery period strikes a reasonable balance for customers between the current approved life and a shorter recovery period. Second, the 20-year period is consistent with the unrecovered early retired investment associated with various assets approved for capital recovery in FPL's 2021 Rate Settlement Agreement approved in Order No. PSC-2021-0446-S-EI, amended by Order No. 2021-0446A-S-EI.

Q. How has FPL accounted for dismantlement costs in the early retirement scenario?

A. FPL has included the costs of dismantlement from FPL's most recent dismantlement study filed in Docket No. 20210015-EI. The study provides for total dismantlement costs of $9.5 million in 2021 dollars, or $9.8 million when escalated to 2022 dollars. The $9.8 million in total costs was then reduced by approximately $0.55 million accrued for in 2022, leaving a net incremental dismantlement cost of $9.3 million in 2023 that is included as part of the economic analysis in the early retirement scenario.

Q. How is the remaining unamortized investment tax credit ("ITC") balance accounted for in the early retirement scenario?

A. Upon an early retirement of the facility, FPL is required to align amortization of the remaining unamortized ITC with the recovery of the unrecovered early retired investment in order to maintain compliance with IRS normalization requirements.[1] Given that FPL is requesting a 20-year capital recovery schedule, FPL is amortizing the remaining unamortized ITC balance over a 20-year period beginning in February 2023 as part of the economic analysis.

Q. What rate of return did FPL utilize in its economic analysis?

A. FPL utilized an incremental cost of capital from investor sources in its economic analysis of the transaction, which includes a 59.6% equity ratio and a mid-point return on equity of 10.6% as approved in FPL's 2021 Stipulation and Settlement Agreement in Docket No. 20210015-EI.

Q. What is the appropriate rate of return to be applied to the proposed regulatory asset requested for recovery through FPL's ECRC?

A. FPL has been recovering the cost of Martin Thermal Solar, including a return on the undepreciated balance utilizing the Company's weighted average cost of capital ("WACC"), since the facility was placed into service in December 2010. FPL is proposing to use the same rate of return for the proposed regulatory asset for the unrecovered early retired plant as would be used if the facility were not retired, and which is used for all other investments that are recovered through the cost recovery clauses. The existing investments recovered through a clause are and will continue

[1] I.R.C. § 46(f) and Treas. Reg. § 1.46-6(g)

to be funded with a mixture of long term debt and common equity, collectively, FPL's investor-provided sources of capital. It is important that these investments be funded in line with the Company's current capital structure, which matches the capital structure last reviewed and approved by the FPSC, so that it remains credit neutral. The expected net economic benefits to customers take full account of, and fully reflect, this overall cost of capital.

Q. Could some different capital structure or other cost of capital be considered appropriate for a transaction of this nature?

A. No. FPL's proposed rate of return is consistent with the return used for all other investments recovered through the Company's cost recovery clauses. As previously stated, it also is consistent with the Company's plans to finance the investment to remain credit neutral. Therefore, a return that does not reflect the cost of both equity and debt capital consistent with the Company's overall capital structure will not fully compensate the Company for this transaction.

Q. Is there a Commission standard or precedent regarding the use of FPL's WACC for clause investments?

A. Yes. The Commission has issued Order Nos. PSC-12-0425-PAA-EU and PSC-2020-0165-PAA-EU which specify the methodology for calculating the WACC applicable to clause-recoverable investments. A specific example of the application of WACC on regulatory assets recovered through FPL's ECRC is the Commission's approval of this treatment in Order No. PSC-12-0613-FOF-EI, Docket No. 12007-EI. In that order, it approved FPL's request to recover the remaining net book value of retired electrostatic precipitators at Port Everglades over a four-year capital recovery schedule and earn a return at FPL’s WACC until fully recovered. In addition, the Commission approved similar regulatory asset and return treatment for the Cedar Bay Transaction, Order No. PSC-15-0401-AS-EI, the SJRPP Transaction, Order No. PSC-2017-0415-AS-EI, and the Indiantown Transaction, Order No. PSC-2016-0506-FOF-EI. In so doing, the Commission’s orders provided that FPL should be permitted to earn their current, approved WACC on clause-recoverable investments.

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. 20220007-EI

April 1, 2022

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. 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 present for Commission review and approval DEF's actual true-up costs associated with environmental compliance activities for the period January 2021 - December 2021.

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 2021 - December 2021;
- 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 1-18: 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 2-6);

- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs) (CPD, pages 7-9); and
- CAIR-Crystal River Units 4 & 5 (CPD, pages 10-11).

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. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of 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 2021 - December 2021?

A. DEF requests approval of an actual over-recovery amount of $2,043,903 for the year ending December 31, 2021. 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 2021 - December 2021 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 $447,153 for the period January 2021 - December 2021 reflected on Line 3 of Form 42-1A. This amount is the difference between an actual over-recovery amount of $2,043,903 and an actual/estimated over-recovery of $1,596,750 for the period January 2021 - December 2021, as approved in Order PSC-2021-0426-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 2021 - December 2021 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 $40,611 or 0.2% higher than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimonies of Reginald Anderson, Kim McDaniel, and Eric Szkolnyj.

Q. How did actual capital recoverable expenditures for January 2021 - December 2021 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 $94,045 or 0.4% 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 1-18. Explanations associated with variances are contained in the direct testimonies of Reginald Anderson, Kim McDaniel, and Eric Szkolnyj.

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 \$3,557 or 29% lower than projected. This is primarily due to lower than expected SO_2 Allowance expense.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>GARY P. DEAN</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220007-EI

July 29, 2022

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. Have you previously filed testimony before this Commission in Docket No. 20220007-EI?

A. Yes, I provided direct testimony on April 1, 2022.

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 2022 through December 2022. I also explain the variance between 2022 actual/estimated cost projections versus original 2022 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 exhibit:

1. Exhibit No. __(GPD-3), which consists of PSC Forms 42-1E through 42-9E.

This exhibit provides detail on DEF's actual/estimated true-up capital and O&M environmental costs and revenue requirements for the period January 2022 through December 2022.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2022 through December 2022?

A. The 2022 actual/estimated true-up is an over-recovery, including interest, of $1,250,853 as shown on Form 42-1E, line 4. The final 2021 true-up over-recovery of $447,153 as shown on Form 42-2E, Line 7a, is added to this total, resulting in a net over-recovery of $1,698,006 as shown on Form 42-2E, Line 11. The calculations supporting the 2022 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 2022 through December 2022?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2022 through December 2022 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 2022 through December 2022 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $7,993,851. This is $500k, 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, Kim Spence McDaniel, and Eric Szkolnyj.

Q. How do estimated/actual capital recoverable costs for January 2022 through December 2022 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be $4,404,485. This is $45k 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, Ms. McDaniel, and Mr. Szkolnyj.

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 $10,383, or 73% lower than projected, due to lower-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. 20220007-EI

August 26, 2022

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. 20220007-EI?

A. Yes. I provided direct testimony on April 1, 2022, and July 29, 2022.

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 "Company") calculation of revenue requirements and Environmental Cost Recovery Clause ("ECRC") factors for customer billings for the period January 2023 through December 2023. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2023.

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-4), which consists of PSC Forms 42-1P through 42-8P

The individuals listed below are co-sponsors of Forms 42-5P pages 1-4 and 6-23 as indicated in their direct testimony. I am sponsoring Form 42-5P page 5.

- Ms. McDaniel will co-sponsor Forms 42-5P pages 1-4, 6 and 8-19.
- Mr. Anderson and Ms. McDaniel will co-sponsor Form 42-5P page 7.
- Mr. Anderson will co-sponsor Form 42-5P pages 20-22.
- Mr. Szkolnyj will co-sponsor Form 42-5P page 23.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average ECRC billing factor of 0.021 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2023 through December 2023 of approximately $10.0 million, and a true-up over-recovery provision of approximately $1.7 million from prior periods. My testimony also supports that projected environmental expenditures for 2023 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2023 through December 2023?

A. The total recoverable revenue requirement including true-up amounts is approximately $8.3 million as shown on Form 42-1P line 4 of Exhibit No. __(GPD-4).

Q. What is the total true-up to be applied for the period January 2023 through December 2023?

A. The total true-up applicable to this period is an over-recovery of approximately $1.7 million. This amount consists of the final true-up over-recovery of approximately $447 thousand for the period January 2021 through December 2021, and an estimated true-up over-recovery of approximately $1.3 million for the current period of January 2022 through December 2022. The detailed calculation supporting the 2022 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (GPD-3) filed with the Commission on July 29, 2022.

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, with the exception of Project 7.6, National Emission Standards for Hazardous Air Pollutants ("NESHAP"), which was submitted for approval with the April 1, 2022 Petition in this Docket. All other costs listed on Forms 42-1P through 42-7P were previously approved by the Commission and are listed below:

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 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. How will the NESHAP – Base (Project 7.6) be allocated to rate classes?

A. DEF proposes that capital and O&M costs associated with NESHAP be allocated to rate classes on a demand-base basis.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2023?

A. Yes. Form 42-2P of Exhibit No. __ (GPD-4) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $5.6 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2023?

A. Yes. Form 42-3P of Exhibit No. __ (GPD-4) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $4.4 million. Form 42-4P pages 1 through 10 show detailed calculations of these costs.

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

A. Yes. Form 42-5P pages 1 through 23 of Exhibit No. __ (GPD-4) 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 2023?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $10.0 million. The costs are calculated on Form 42-1P line 1c of Exhibit No. __ (GPD-4).

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-4). 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 are DEF's proposed 2023 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2023 customer billings is shown on Form 42-7P in Exhibit No. __(GPD-4) as follows:

RATE CLASS	ECRC FACTORS
Residential	0.022 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.021 cents/kWh
@ Primary Voltage	0.021 cents/kWh
@ Transmission Voltage	0.021 cents/kWh
General Service 100% Load Factor	0.018 cents/kWh
General Service Demand	
@ Secondary Voltage	0.020 cents/kWh
@ Primary Voltage	0.020 cents/kWh
@ Transmission Voltage	0.020 cents/kWh
Curtailable	
@ Secondary Voltage	0.016 cents/kWh
@ Primary Voltage	0.016 cents/kWh
@ Transmission Voltage	0.016 cents/kWh
Interruptible	
@ Secondary Voltage	0.018 cents/kWh
@ Primary Voltage	0.018 cents/kWh
@ Transmission Voltage	0.018 cents/kWh
Lighting	0.014 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 2023 and continue through the last billing cycle of December 2023.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Eric Szkolnyj was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

ERIC SZKOLNYJ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20220007-EI

April 1, 2022

Q. Please state your name and business address.

A. My name is Eric Szkolnyj. 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 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 the majority of CCP facilities in the 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 Mechanical Engineering from North Carolina State University. I have 17 years of experience in the power generation industry including positions as a Nuclear Control Room Supervisor, Lead Engineer, and Nuclear Oversight Lead Assessor within Duke Energy's Nuclear fleet at Harris Nuclear Plant, and as the Director of Operational Excellence Assessments & Oversight for Duke Energy's Enterprise. Prior to joining Duke Energy, I was employed by the Department of Defense as a civilian Shift Test Engineer for the U.S. Navy. In June of 2021, 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 explain material variances between actual and actual/estimated project expenditures for environmental compliance costs associated with DEF's Coal Combustion Residual ("CCR") Rule for the period January 2021 - December 2021. DEF did not have any material variances for the period January 2021 – December 2021.

Q. How did actual O&M project expenditures for the period January 2021 – December 2021 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR Rule O&M variance is $4,770 or 1% lower than projected.

Q. How did actual capital project expenditures for the period January 2021 – December 2021 compare to actual/estimated capital projections for the CCR Rule (Project 18)?

A. The CCR Rule capital variance is $1,175 or 0.1% higher than projected.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

ERIC SZKOLNYJ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220007-EI

August 26, 2022

Q. Please state your name and business address.

A. My name is Eric Szkolnyj. My business address is 526 South Church Street, Charlotte, NC 28202.

Q. Have you previously filed testimony before this Commission in Docket No. 20220007-EI?

A. Yes. I provided direct testimony on April 1, 2022 and July 29, 2022.

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 "Company") proposed compliance activities and related 2023 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-4) to Gary P. Dean's direct testimony:

- 42-5P page 23 – Coal Combustion Residual Rule

Q. What O&M costs does DEF expect to incur in 2023 for the Coal Combustion Residual Rule Program (Project No. 18)?

A. DEF is forecasting $399k in O&M costs for 2023.

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 2023 for the Coal Combustion Residual Rule Program (Project No. 18)?

A. DEF does not expect capital expenditures in 2023.

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. 20220007-EI

April 1, 2022

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 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 2021 - December 2021.

Q. How do actual O&M expenditures for January 2021 - December 2021 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 $209,537 or 1% higher than projected. This variance is primarily attributable to $1.46M higher than expected CAIR Crystal River – Energy (Reagents), which is mostly offset by $992k lower than expected CAIR Crystal River – Base and $261k lower than expected CAIR/Conditions of Certification - Energy.

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 2021 - December 2021?

A: O&M costs for CAIR Crystal River Project – Energy (Reagents) were $1,462,960 or 29% higher than projected. Variance for the reagents were $187k (9%) higher for Ammonia Expense, $62k (2%) higher for Limestone Expense, $7k (100%) lower for Dibasic Acid Expense, $541k (16%) less favorable for Gypsum Disposal/Sale (credit), $524k (23%) higher for Hydrated Lime Expense, and $155k (186%) higher Caustic Expense.

Q. Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2021 - December 2021?

A. O&M costs for CAIR Crystal River Project – Base were $992,359 or 7% lower than projected. This was primarily due to delays in material deliveries, which resulted in DEF being unable to complete certain repairs during the scheduled outage conducted in Fall 2021. This is a timing issue and the remaining work will be included in the 2022 outage scope.

Q. Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Conditions of Certification - Energy for January 2021 - December 2021?

A. O&M costs for CAIR Crystal River Project – Conditions of Certification – Energy, were $261,472 or 22% lower than projected. This was primarily due to actual maintenance and repair work completed during the Fall Outage coming in less than originally projected.

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. 20220007-EI

July 29, 2022

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. Have you previously filed testimony before this Commission in Docket No. 20220007-EI?

A. Yes, I provided direct testimony on April 1, 2022.

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 2022 actual/estimated cost projections and original 2022 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), and Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2).

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 2022 through December 2022?

A. O&M expenditures for the CAIR/CAMR CR-Energy (Reagents) Program are forecasted to be $630,601, or 8% lower than originally forecasted.

This variance is attributable to a forecasted $901k decrease in Ammonia expense, a $2.52M decrease in Limestone expense, a $38k decrease in Dibasic Acid expense, and a $671k decrease in Hydrated Lime expense. These were partially offset by a $3M decrease in the projected credit for Gypsum Sales and a $492k increase in Caustic expense.

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. 20220007-EI

August 26, 2022

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. 20220007-EI?

A. Yes. I provided direct testimony on April 1, 2022, and July 29, 2022.

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 2023 for Duke Energy Florida, LLC's ("DEF" or "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:

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

Q. What O&M costs does DEF expect to incur in 2023 for the CAIR/CAMR Crystal River – Energy Program (Project 7.4)?

A. DEF estimates O&M costs of approximately $4.4M 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 2023 for the MATS Program – CR 4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $194k 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.

(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. 20220007-EI

April 1, 2022

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 for the period January 2021 through December 2021, and Mercury & Air Toxic Standards (MATS) CR4 & CR5 – Energy (Project 17).

Q. How did actual O&M expenditures for January 2021 - December 2021 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 100%, or $30,000 lower than projected.

This variance is primarily due to a delay in permit issuance from the Florida Department of Environmental Protection ("FDEP"). DEF expected to begin development of a Plan of Study for the Anclote station in late 2021, but FDEP has not yet issued the permit.

Q. How did actual Capital expenditures for January 2021 - December 2021 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 18% or $393,629 higher than projected. This is primarily due to additional labor requirements and increased material costs related to work at the Crystal River Energy Complex. Delays at the port and a backlog of unloaded ships created a delay in DEF receiving the traveling screens and caused the construction to be extended seven weeks. This extension resulted in additional labor, site support, and equipment rentals.

Additionally, the cleaning of the intake pit walls where the new screens were to be installed required more work than originally planned. When the cleaning began, an area of the intake pit wall was found to have approximately 3-feet thick of calcified growth, which required additional labor and a crane rental.

Q. How did actual O&M expenditures for January 2021 - December 2021 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 $125,641 or 51% lower than forecasted. This is primarily due to the deferral of an outage on one of the units resulting in testing and repairs for that unit not being conducted as anticipated and lower than expected labor costs due to reduced contractor labor expenses.

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. What is the status of the Clean Water Rule?

A. On June 29, 2015 the Environmental Protection Agency ("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 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." (NWPR Rule)*. 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.

On January 20, 2021, through Executive Order 13990, the Biden Administration directed EPA and the Corps to review the NWPR Rule. The US District Court for the District of Arizona vacated and remanded the NWPR Rule on August 30, 2021, which vacated and remanded the rule nationwide. The EPA and Corps announced on September 3, 2021 that efforts to implement the NWPR Rule had ceased and on December 7, 2021, EPA published a proposed rule to officially repeal the NWPR Rule and replace it with the 1986 WOTUS rule. The public comment period for this proposed rule closed on February 7, 2022. EPA is currently engaged in drafting a rule to replace the 1986 WOTUS rule now in effect. 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. Please explain the NESHAPS for stationary combustion turbines ("CTs") rule and its impact to DEF.

A. In March of 2004, the EPA promulgated National Emission Standards for Hazardous Air Pollutants ("NESHAP") for stationary combustion turbines ("CTs") that are located at major sources of hazardous air pollutants ("HAPs") and are constructed after January 14, 2003. The NESHAP, subpart YYYY, implements section 112(d) of the Clean Air Act ("CAA") by requiring all major combustion turbine sources to meet HAP emission standards reflecting the application of the maximum achievable control technology ("MACT"). In August 2004, EPA stayed the effectiveness of the rule for the lean premix and diffusion flame gas-fired sub-categories of stationary combustion turbines. EPA concluded that a stay was necessary to avoid unnecessary expenditures on compliance as they evaluated a delisting petition for these two sub-categories of turbines.

On March 9, 2022, the EPA published in the *Federal Register*, at 87 Fed. Reg.13,183, a final rule to remove the stay for natural gas-fired stationary CTs. As a result of the final rule, lean premix and diffusion flame gas-fired turbines that were constructed or reconstructed at major sources of HAP emissions after January 14, 2003, must comply with emission and operating limitations beginning March 9, 2022, or upon startup of future affected units. Owners/operators will then have 180 days to demonstrate compliance with the formaldehyde standard, i.e., September 5, 2022. *See* 40 C.F.R. §63.6110(a).

Q. Which DEF generating units are impacted by the NESHAP Rule?

A. The Final Rule establishes emission and operating limitations applicable to stationary CTs located at major sources of HAP emissions and requires units to demonstrate initial and continuous compliance with these limitations. Under the EPA's definition of major source, DEF's Citrus County Combined Cycle (Units 1A, 1B, 2A, 2B), Bartow Combined Cycle (Units 4A, 4B, 4C, 4D), and Hines Energy Complex (Units 3A, 3B, 4A, 4B) are subject to the rule and associated compliance requirements. The rule establishes operations and emissions limitations that limit the emissions concentration of formaldehyde to 91 parts per billion by volume.

<u>Citrus Combined Cycle ("CCC")</u>

With the removal of the stay, DEF is required to demonstrate compliance with the operating and formaldehyde emissions limitation at its CCC units. Initial compliance testing to demonstrate compliance with the formaldehyde limitation is tentatively scheduled for the week of May 24, 2022. As required by the rule [40 CFR §63.6120(e)], DEF is developing an Alternate Monitoring Plan (AMP) that identifies the operating limitation(s) that will be used to ensure continuous compliance with the formaldehyde emissions limitation. Initial compliance testing costs are projected to be approximately $40,000-$90,000 for all units at CCC depending on the chosen AMP strategy. DEF will be required to conduct annual compliance tests to demonstrate continued compliance with the formaldehyde limit. Annual costs associated with compliance testing at CCC are projected to be approximately $40,000-$60,000 thereafter.

Preliminary data suggests that CCC can comply with the formaldehyde emissions limit and therefore DEF does not anticipate incurring capital costs to comply with this rule.

<u>Bartow Combined Cycle Station (“BCC”) and Hines Energy Complex (“HEC”)</u>

BCC and HEC are currently identified as major sources of HAPs. However, per 40 C.F.R. §63.1(c)(6), a source can seek reclassification to an Area Source if it demonstrates that its potential to emit HAPs is below the major source thresholds (10 tons per year of a single HAP or 25 tons of combined HAPs). Site specific test data demonstrates that BCC and HEC emit HAPs below major source thresholds and can be reclassified as an Area Source. Applications requesting reclassification of HEC and BCC as an Area Source were sent to FDEP for review on March 15, 2022 and March 23, 2022, respectively. Sites meeting the definition of an Area Source are not subject to the requirements of this rule. However, no later than 180 days after the effective date of the rule, i.e., September 5, 2022, DEF must either have received an air permit from FDEP stating the site is classified an Area Source or have completed initial tests to demonstrate compliance with the formaldehyde standard.

If DEF is successful in reclassifying BCC and HEC as Area Sources, the only anticipated costs associated with the rule are the reclassification costs, estimated to be $7,000 and $6,500 respectively, to cover permit application preparation and public notice of the revised Title V air permits. No further costs are anticipated once BCC and HEC are reclassified. However, it is possible FDEP could require periodic compliance tests to demonstrate BCC and HEC remain Area Sources. It is unknown at this time if that will be required, or if so, at what frequency compliance testing would be required.

DEF is tentatively scheduling initial compliance tests at the BCC and HEC to ensure testing can be completed by September 5, 2022, in the event DEF is unable to successfully reclassify the sites as Area Sources. As with CCC, BCC and HEC would be required to develop an AMP that identifies the operating limitation(s) that will be used to ensure continuous compliance with the formaldehyde emissions limitation. DEF is still exploring available options for making this demonstration. Initial compliance testing costs are projected to be approximately $40,000-$90,000 for each site, depending on the chosen AMP strategy. DEF would be required to conduct annual compliance tests to demonstrate continued compliance with the formaldehyde standard. Annual costs associated with compliance testing are projected to be approximately $40,000–$60,000 for each site thereafter.

In the event compliance tests reveal DEF will be unable to comply with the formaldehyde standard at CCC, BCC, or HEC, installation of an oxidation catalyst will be required. This will require the expenditure of an estimated $1.4 million per unit in capital costs, long-term O&M costs of maintaining the catalyst, as well as annual compliance testing costs of approximately $40,000-$60,000 per site. Because initial data indicates the units will either comply with the formaldehyde standard (CCC) or can be reclassified as an Area Source (BCC, HEC), DEF has not begun the process of assessing site-specific catalyst installation costs. As a result, the cost estimates provided are preliminary drafts and are subject to change.

Q. Do DEF's expected NESHAP compliance activity costs meet the recovery criteria established by Order No. 94-044-FOF-EI?

A. Yes. The proposed formaldehyde emission limitation compliance activities associated with the formaldehyde standard merit ECRC cost recovery under Order No. PSC-94-0044-FOF-EI. All costs associated with the project will be prudently incurred after April 13, 1993. This activity is legally required to comply with the requirements of the CAA, NESHAP Subpart YYYY. The need to engage in such activities has been triggered after the company's last rate case and are not recovered through base rates or through any other mechanism.

Q. When does DEF expect to begin incurring costs to comply with the MACT rule?

A. DEF expects to begin incurring Section CAA, NESHAP Subpart YYYY compliance costs associated with the proposed formaldehyde emission limitation activities in 2022, as early as the second quarter. Project costs will be subject to audit by the Commission.

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. 20220007-EI

July 29, 2022

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. Have you previously filed testimony before this Commission in Docket No. 20220007-EI?

A. Yes, I provided direct testimony on April 1, 2022.

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 2022 actual/estimated cost projections and original 2022 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), National Pollutant Discharge Elimination System (NPDES) (Project 16), and Mercury and Air Toxics Standards (MATS) – Crystal River (CR) 4&5 (Project 17), for the period January 2022 through December 2022.

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 2022 through December 2022.

A. O&M expenditures for Phase II Cooling Water Intake 316(b) are expected to be $93,941 (34%) lower than originally forecasted.

Project 6, 316(b) – Base, is forecasted to be $124k higher than forecasted. This variance is due to the fact that O&M expenditures for the Crystal River 316(b) compliant screens were not included in previous projections. These O&M expenditures are required for the periodic removal and cleaning of the screens to ensure they continue functioning properly as designed.

Project 6a, 316(b) – Intermediate, is forecasted to be $218k, or 84% lower than originally forecasted. This variance is primarily due to the continued delay in permit issuance from the Florida Department of Environmental Protection ("FDEP"). While it is unclear when the FDEP will issue the National Pollutant Discharge Elimination System ("NPDES") permit renewal, permit issuance could occur during the fourth quarter of 2022, in which case DEF currently proposes to initiate development of a study plan to verify that impingement meets the mortality standard in the 316(b) rule with a 24-month field monitoring effort to begin during 2023 after FDEP approval of the study plan.

Q. Please explain the variance between actual/estimated Capital project expenditures and original projections for Phase II Cooling Water Intake 316(b) – Base (Project 6) for the period January 2022 through December 2022.

A. Capital expenditures for Phase II Cooling Water Intake 316(b) Base are expected to be $425,824. This updated forecast is due to expenses associated with constructing a steel structure to properly hold and store the newly installed 316(b) compliant screens during cleaning. Unlike prior screens, the materials from which these screens are constructed require construction of a steel structure to hold the screens in the upright position to prevent damage to the screens during cleaning.

Q. Please explain the variance between actual/estimated Capital project expenditures and original projections for Phase II Cooling Water Intake 316(b) – Base, (Project 6.1) for the period January 2022 through December 2022.

A. Capital expenditures for Phase II Cooling Water Intake 316(b) Base – Bartow, are expected to be $920,901 or 86% lower than originally forecasted. This variance is primarily due to the continued delay in permit issuance from the FDEP. While it is unclear when the FDEP will issue the NPDES permit renewal, permit issuance could occur during the fourth quarter of 2022 in which case replacement of travelling screens could commence by the end of 2022.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for National Emission Standards for Hazardous Air Pollutants ("NESHAP") - Base (Project 7.6) for the period January 2022 through December 2022.

A. O&M expenditures for NESHAP are expected to be $170,448. This project was not originally forecasted for 2022.

Q. Please provide an update on National Emission Standards for Hazardous Air Pollutants ("NESHAP") project (Project 7.6).

As referenced in the April 1, 2022 testimony of Kim McDaniel, Docket No. 20220007-EI, DEF's Bartow Combined Cycle, Hines Energy Complex, and Citrus Combined Cycle, units are subject to NESHAP for stationary combustion turbines ("CTs") that are located at major sources of hazardous air pollutants ("HAPs").

<u>Bartow Combined Cycle Station ("BCC") and Hines Energy Complex ("HEC")</u>

As previously stated in Ms. McDaniel's April 1, 2022 testimony, applications requesting reclassification of HEC and BCC as an Area Source were sent to FDEP for review on March 15, 2022 and March 23, 2022, respectively. Title V permit revisions reclassifying HEC and BCC as Area Sources were issued May 4th and June 8th respectively. HEC and BCC are no longer subject to NESHAPS for stationary combustion turbines ("CTs") subpart YYYY.

Citrus Combined Cycle Station ("CCC")

During the week of May 16th, engineering testing was initiated at the CCC units to collect data that is supporting the development of an Alternate Monitoring Plan (AMP) that identifies the operating limitation(s) that will be used to ensure continuous compliance with the formaldehyde emissions limitation. DEF will also be exploring, through emissions testing of the Crystal River North coal units, the potential for reclassifying the Citrus Combined Cycle/Crystal River Site as an Area Source. Since the Crystal River North coal units and the Citrus Combined

Cycle units are contiguous and therefore share a Title V permit, emissions from both sites factor into the Area Source determination. Should DEF be successful in reclassifying the Citrus Combined Cycle/Crystal River site as an Area Source, the site will no longer be subject to the NESHAP for stationary CTs, subpart YYYY, and the AMP will not be necessary. DEF will provide the Commission an update on the status of the NESHAP strategy in the next available ECRC filing.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for Arsenic Groundwater Standard - Base (Project 8) for the period January 2022 through December 2022.

A. O&M expenditures for Arsenic Groundwater Standard - Base are expected to be $27,031 or 36% lower than forecasted, due to the timing of the final site rehabilitation report moving to 2023. The FDEP is requiring additional groundwater monitoring and assessment before a final site rehabilitation report and a No Further Action ("NFA") request can be developed and submitted. This will now occur in 2023.

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 2022 through December 2022.

A. O&M expenditures for NPDES are expected to be $6,207 (20%) higher than forecasted. This is primarily due to two supply chain related price increases from contract laboratories that occurred in January and in June 2022.

Q. Please explain the variance between actual/estimated O&M project expenditures and original projections for Mercury & Air Toxic Standards ("MATS") CR4 & CR5 - Energy (Project 17) for the period January 2022 through December 2022.

A. O&M expenditures for NPDES are expected to be $24,641 (13%) higher than forecasted. The original budget was for one unit only, however, Crystal River performed outages on both units, allowing for MATS testing to be completed on both units during the first half of this year.

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 Environmental Protection Agency ("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 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 2022 if the final NPDES renewal is issued by FDEP by early fourth quarter 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 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 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 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 the 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, the 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, the EPA and Corps released a pre-publication version of *The Navigable Waters Protection Rule: Definition of "Waters of the United States." (NWPR Rule)*. 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.

On January 20, 2021, through Executive Order 13990, the Biden Administration directed the EPA and the Corps to review the NWPR Rule. The US District Court for the District of Arizona vacated and remanded the NWPR Rule on August 30, 2021, which vacated and remanded the rule nationwide. The EPA and Corps announced on September 3, 2021 that efforts to implement the NWPR Rule had ceased and on December 7, 2021, the EPA published a proposed rule to officially repeal the NWPR Rule and replace it with the 1986 WOTUS rule. The public comment period for this proposed rule closed on February 7, 2022. The EPA currently plans to publish a final rule in August 2022.

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. 20220007-EI

August 26, 2022

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. 20220007-EI?

A. Yes. I provided direct testimony on April 1, 2022 and July 29, 2022.

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 2023 for Duke Energy Florida, LLC's ("DEF" or "Company") Substation Environmental Investigation, Remediation and Pollution Prevention

Program (Projects 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), National Emission Standards for Hazardous Air Pollutants (NESHAP – Base (Project 7.6, 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-4) to Gary P. Dean's direct testimony:

- 42-5P page 1 of 23 – Substation Environmental Investigation, Remediation and Pollution Prevention Program

- 42-5P page 2 of 23 - Distribution System Environmental Investigation, Remediation and Pollution Prevention Program
- 42-5P page 3 of 23 – PIM
- 42-5P page 4 of 23 - AST
- 42-5P page 6 of 23 - Phase II Cooling Water Intake
- 42-5P page 7 of 23 – Clean Air Interstate Rule ("CAIR")
- 42-5P page 8 of 23 – BART
- 42-5P page 9 of 23 - Arsenic Groundwater Standard
- 42-5P page 10 of 23 – Sea Turtle – Coastal Street Lighting Program
- 42-5P page 11 of 23 - UST
- 42-5P page 12 of 23 - Modular Cooling Towers
- 42-5P page 13 of 23 - Thermal Discharge Permanent Cooling Tower
- 42-5P page 14 of 23 - Greenhouse Gas Inventory and Reporting
- 42-5P page 15 of 23 - Mercury TMDL
- 42-5P page 16 of 23 - HAPs ICR
- 42-5P page 17 of 23 - Effluent Limitation Guidelines ICR Program
- 42-5P page 18 of 23 - Effluent Limitation Guidelines CRN Program
- 42-5P page 19 of 23 - NPDES

Q. What O&M costs does DEF expect to incur in 2023 for the Phase II Cooling Water Intake 316(b) Program (Projects 6 and 6a)?

A. DEF is forecasting a total of $589k in O&M costs for the Phase II Cooling Water Intake Program 316(b) projects in 2023.

DEF estimates approximately \$319k of O&M for Crystal River North, Project 6 - Base, for the routine inspection and cleaning of the 316(b) compliant screens.

DEF estimates approximately \$270k of O&M costs for the Anclote Station, Project 6a – Intermediate, to develop and begin implementation of a Plan of Study ("Study"). As indicated in my Actual-Estimate testimony filed on July 29, 2022, final NPDES permit renewal from the Florida Department of Environmental Protection ("FDEP") could occur during the fourth quarter of 2022. 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 up to 24 months, 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.

Q. What Capital costs does DEF expect to incur in 2023 for the Phase II Cooling Water Intake 316(b) Program for Bartow CC station (Project 6.1)?

A. DEF estimates the potential for \$690k of capital costs in 2023 for Bartow station 316(b) (Project 6.1).

These costs are for the 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 the full extent of compliance activities and associated expenditures could change depending on the conditions of the final NPDES permit when issued. As indicated in my Actual-Estimate testimony filed on July 29, 2022, permit issuance could occur during the fourth quarter of 2022.

Q. What costs does DEF expect to incur in 2023 for the National Emission Standards for Hazardous Air Pollutants ("NESHAP") – Base (Project 7.6)?

A. DEF is forecasting $60k in O&M costs for the NESHAP project in 2023 for annual compliance testing at Citrus Combined Cycle Station ("CCC"). As indicated in my testimony and Petition filed April 1, 2022 in this Docket, DEF is required to conduct annual compliance tests to demonstrate continued compliance with the formaldehyde limit.

On July 21, 2022, DEF submitted to EPA for approval a proposed Alternate Monitoring Plan ("AMP"), which is required for affected units that do not have an oxidation catalyst installed. DEF is exploring whether the installation of oxidation catalysts will be necessary and will update the Commission in a future filing.

As indicated in my testimony and Petition filed April 1, 2022 in this Docket, DEF's expected NESHAP compliance activity costs meet the recovery criteria established by Order No. 94-0044-FOF-EI.

Q. What costs does DEF expect to incur in 2023 for the Arsenic Groundwater Standard Program (Project 8)?

A. DEF forecasts 2023 O&M expenditures to be $44k. Anticipated costs are associated with post remediation groundwater monitoring, and preparation of a site rehabilitation completion report / No Further Action ("NFA") proposal and documentation necessary to submit the draft declaration of restrictive covenant to FDEP.

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 document all assessment work done under the Consent Order to identify the nature and extent of arsenic in groundwater. On October 15, 2019, FDEP notified DEF that sediment and soil assessment was complete, and that additional ground water delineation was

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

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 installation of the soil cap 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. DEF continues to conduct quarterly groundwater monitoring in accordance with the approved NAM. On August 27, 2021, DEF and FDEP amended 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 2023 for the NPDES Program (Project No. 16)?

A. DEF estimates $39k 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

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220007-EI

IN RE: ENVIRONMENTAL COST RECOVERY FACTORS

2021 FINAL TRUE-UP

TESTIMONY AND EXHIBIT

M. ASHLEY SIZEMORE

FILED: APRIL 1, 2022

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 2021 through December 2021 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 2021 through December 2021 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 30, 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 2021 through December 2021?

A. The final true-up amount for the Environmental Clause for the period January 2021 through December 2021 is an over-recovery of $1,187,656. The actual environmental cost under-recovery, including interest, is $3,101,967 for the period January 2021 through December 2021, as identified in Form 42-1A. This amount, less the $4,289,623 under-recovery approved in Commission Order No. PSC-2021-0426-FOF-EI, issued November 17, 2021, in Docket No. 20210007-EI, results in a final over-recovery of $1,187,656, 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 2023 through December 2023.

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. Did Tampa Electric include costs in its 2021 final Environmental Clause true-up filing for any environmental projects that were not anticipated and included in its 2021 factors?

A. Yes, Tampa Electric included costs associated with Tampa Electric's Bayside Station Section 316(b) Compliance project. These costs are outlined on Form 42-6A. This project was approved for cost recovery by Commission Order No. PSC-2021-0356-PAA-EI, issued September 15, 2021.

Q. How do actual expenditures for the January 2021 through December 2021 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 $47,178, or 0.5 percent less than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $570,985, or 1.3 percent less than the actual/estimated projection costs. Additional information regarding substantial variances is provided below.

O&M Project Variances

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.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowance variance is $54 or 132.2 percent less than projected. The variance in the SO_2 Emissions Allowance project is due to less cogeneration purchases. Also, included in the current estimate is a gain on SO_2 auction allowance proceeds that was not originally projected. The re-projection incorporated 6 months of actuals and 6 months of estimated amounts based on the same methodology with the averages based on updated historical amounts.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is $11,588, or 129.3 percent greater than projected. The variance is due to more stack safety maintenance costs being incurred than expected.

- **Big Bend PM Minimization and Monitoring:** The Big Bend Minimization and Monitoring project variance is $61,291, or 28 percent less than projected. The variance is due to precipitator improvements that led to less maintenance costs.

- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is $73,268, or 52.6 percent greater than projected. The variance is due to valve replacement cost incurred that were not expected.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is $5,245, or 87.1 percent less than projected. The variance is due to the delay in receiving final the NPDES Permit leading to fewer expenditures.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $58,800, or 55.3 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 $157,991, or 29.1 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 $1,029,389, or 115.2 percent greater than projected. The variance is due largely to an accounting error, the duplicate accrual of SCR deep catalyst layer cleaning and motor reconditioning costs, the correction of which was made in January 2022.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $462,424, or 74.3 percent less than projected. The variance is due to less facility yard maintenance being required as generation by coal was less than projected.

- **Big Bend Coal Combustion Residuals Rule:** The Big Bend Coal Combustion Residuals ("CCR") Rule project variance is $260,973, or 34.2 percent greater than projected. This variance is due to the removal of more material than originally anticipated.

- **Big Bend Coal Combustion Residuals Rule Phase II:** The Big Bend Coal Combustion Residuals ("CCR") Rule Phase II project variance is $676,745, or 11.6 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 Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is $58,892, or 1.1 percent less than projected. The variance is due portions of the asset being transferred to the Clean Energy Transition Mechanism (CETM) on December 31, 2021 in accordance with the company's 2021 Settlement Agreement in Docket No. 20210034-EI, Order No. PSC-2021-0423-S-EI issued on November 10, 2021.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $130,892, or 1.8 percent less than projected. The variance is due to the asset being transferred to the CETM on December 31, 2021 in accordance with the company’s 2021 Settlement Agreement in Docket No. 20210034-EI, Order No. PSC-2021-0423-S-EI issued on November 10, 2021.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $158,152, or 2 percent less than projected. The variance is due to the asset being transferred to the CETM on December 31, 2021 in accordance with the company’s 2021 Settlement Agreement in Docket No. 20210034-EI, Order No. PSC-2021-0423-S-EI issued on November 10, 2021.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $129,993, or 2 percent less than projected. The variance is due to the asset being transferred to the CETM on December 31, 2021 in accordance with the company’s 2021 Settlement Agreement in Docket No. 20210034-EI, Order No. PSC-2021-0423-S-EI issued on November 10, 2021.

- **Big Bend Unit CCR Rule Phase II:** The Big Bend CCR Rule

Phase II project variance is $33,498, or 26.1 percent greater than projected. This variance is due to timing differences in the project schedule when compared to the original projection.

- **Big Bend ELG Compliance:** The Big Bend ELG Compliance Project variance is $126,384, or 28.7 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.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220007-EI
IN RE: TAMPA ELECTRIC'S ENVIRONMENTAL
COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY AND EXHIBIT

OF

M. ASHLEY SIZEMORE

FILED: JULY 29, 2022

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 following three years as a Program Manager in Customer Experience, I managed billing and payment customer solutions, products, and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have over ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel 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 2022 through December 2022 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2023 through December 2023. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2022, 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 2023 through December 2023.

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

A. Yes, Exhibit No. MAS-2, containing two documents, was prepared under my direction and supervision. Document No. 1 contains nine schedules, 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 2023 through December 2023. Document No. 2 shows the calculations of the adjustments for the Big Bend Units 1, 2 and 3 projects that are being removed from ECRC.

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 2022 through December 2022, is an over-recovery of $5,382,902. 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 2022 ECRC factors?

A. Yes, Tampa Electric is including costs for a new environmental project that was not included in its 2022 factors. The new project is Tampa Electric's Clean Air Act("CAA"), National Emission Standards Hazardous Air Pollutants ("NESHAP") Subpart YYYY Compliance Project that was approved by the Commission in Order No. PSC-2022-0286-PAA-EI issued on July 22, 2022, in Docket No. 20220055-EI.[1] The project is required to comply with the Environmental Protection Agency's ("EPA") formaldehyde emission standard set for stationary, gas-fired combustion turbines.

Q. Is Tampa Electric including any other adjustments in this 2022 actual/estimated true-up?

A. Yes. Tampa Electric identified certain assets related to

[1] The protest period for this Proposed Agency Action order ends on August 12, 2022.

Big Bend Units 1, 2, and 3 that were moved to the company's Clean Energy Transition Mechanism ("CETM") in accordance with Tampa Electric's 2021 base rate settlement agreement approved in Order No. PSC-2021-0423-S-EI and issued on November 10, 2021, in Docket No. 2021-0034-EI ("2021 Agreement"). However, these project costs were not removed from the ECRC 2022 projections submitted in the Fall of 2021 as the company intended. Therefore, Tampa Electric removed the costs from its ECRC retroactive to January 1, 2022, when the Settlement Agreement and CETM took effect, as shown in my exhibit.

Q. Please describe the adjustment in greater detail.

A. Costs related to the following projects have been removed from the 2022 actual/estimated filing, retroactive to the time they should have been removed, January 2022.

List of projects:

No.	Description
1.	Big Bend Units 1 and 2 Flue Gas Conditioning
2.	Big Bend Unit 1 Classifier Replacement
3.	Big Bend Unit 2 Classifier Replacement
4.	Big Bend FGD Optimization and Utilization
5.	Big Bend NOx Emissions Reduction

6. Big Bend PM Minimization and Monitoring
7. Big Bend Unit 1 Pre-SCR
8. Big Bend Unit 2 Pre-SCR
9. Big Bend Unit 3 Pre-SCR
10. Mercury Air Toxics Standards

This adjustment reduces Big Bend Units 1, 2, and 3 ECRC net book value balances by $20.7 million, and reduces the ECRC revenue requirement for 2022 by $3.1 million as shown in Exhibit MAS-2, Document No. 2.

Q. What depreciation rates were utilized for the capital projects contained in the 2022 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-2021-0423-S-EI, issued on November 10, 2021, in Docket No. 20200264-EI.

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. Tampa Electric's midpoint Return on Equity "ROE" is expected to change from 9.95 percent to 10.20 percent as a result of the company's petition filed in Docket No.

20220122-EI. The Commission scheduled a hearing for this docket on August 16, 2022, and the Commission may render a bench decision at the end of that hearing or at a subsequent agenda conference. In the event the Commission does not approve this change in the midpoint ROE, Tampa Electric will submit revised schedules and factors after the decision so that the annual cost recovery clause hearing will include a request for approval of revised ECRC amounts.

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 2022 through December 2022 period compare with the company’s original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $272,431 less than originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $4,572,617 less than originally projected. Significant variances for O&M costs and capital project amounts are explained below.

O&M Project Variances

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.

- **SO2 Emissions Allowances:** The SO_2 Emissions Allowances project variance is estimated to be $110 or 269.3 percent less than projected. The variance is due to less cogeneration purchases than projected, the application of a lower SO_2 emission allowance rate than originally projected, and an SO_2 emission allowance gain of $58.70 that was not anticipated.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring project variance is estimated to be $42,716 or 16.5 percent less than originally projected. This variance is due to a timing change since a maintenance contract was entered later than expected, resulting in less cost being incurred during the period.

- **Big Bend NOx Emissions Reduction:** The Big Bend NOx Emission Reduction project variance is $303 or 14.5 percent less than originally projected. This variance is due to less maintenance required on a secondary damper than originally projected.

- **Bayside SCR and Ammonia:** The Bayside Selective Catalytic Reduction ("SCR") and Ammonia project variance is $147,559 or 97.7 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 $10,150 or 100 percent less than originally projected. This variance is due to the delay in receiving the NPDES permit. Once the permit is received, and a determination is made regarding the requirement for entrainment reductions, the costs will be incurred.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program project variance is $37,080 or 100 percent less than originally projected. This variance is due to the costs associated with actions required for Florida Department of Environmental Protection ("FDEP") approval of the company's plan being less than expected.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $26,002 or 7 percent less than originally projected. Less maintenance is required for Big Bend Unit 3 as it is running on natural gas and operating less than originally projected.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $89,197 or 6.4 percent less than originally projected. Less maintenance is required for Big Bend Unit 4 as it is running on natural gas and operating less than originally projected.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards ("MATS") project variance is $2,000 or 100 percent lower than originally projected. The Sorbent trap replenishment associated with mercury stack testing on Big Bend Unit 4 has not yet occurred. Once stack testing is complete, the costs will be incurred.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $78,922 or 6.5 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 – Phase I:** The Big Bend Coal Combustion Residual ("CCR") Rule – Phase I project variance is $132,857, or 14.3 percent less than originally projected. The variance is due to timing differences in project schedules when compared to original projections. The costs are expected to be incurred in the future.

- **Big Bend ELG Compliance:** The Big Bend Effluent Limitation Guidelines ("ELG") Compliance project variance is $706 or 14.3 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.

<u>Capital Project Variances</u>

As discussed earlier in my testimony, Tampa Electric is proposing to remove the remainder of certain retiring Big Bend Units 1, 2, and 3 asset balances from the ECRC. The amount of the revenue requirement variance associated with the net book value for these assets, are as follows:

No.	Description	Amount
1.	Big Bend Units 1 and 2 Flue Gas Conditioning	$(79,390)
2.	Big Bend Unit 1 Classifier Replacement	(80,286)
3.	Big Bend Unit 2 Classifier Replacement	(53,351)
4.	Big Bend FGD Optimization and Utilization	(185)
5.	Big Bend NOx Emissions Reduction	(505,339)
6.	Big Bend PM Minimization and Monitoring	(1,709,129)
7.	Big Bend Unit 1 Pre-SCR	(139,318)
8.	Big Bend Unit 2 Pre-SCR	(124,963)
9.	Big Bend Unit 3 Pre-SCR	(209,670)
10.	Mercury Air Toxics Standards	(156,714)
	Total Variance	$(3,058,345)

Other capital variances include the following:

- **Big Bend CCR Rule – Phases I & II:** The Big Bend CCR Rule Phase I project variance is $155,909, or 25.8 percent less than originally projected. The variance is due to a lower cost capital alternative, to avoid groundwater seepage issues, being identified and applied. The Big Bend

CCR Rule Phase II project variance is $10,913, or 4.9 percent greater than originally projected. This variance is due to capital activities related to finalizing the project that have come in slightly higher than originally anticipated.

- **Big Bend ELG Compliance:** The Big Bend ELG Compliance project variance is $1,296,150 or 56.9 percent less than originally projected. This variance is due to timing differences in the project schedule when compared to the original projection. While drilling the first injection well, the underground rock formation was more dense than anticipated and caused the drilling effort to move more slowly than expected. 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 $187,587 or 16.6 percent less than originally projected. Substantially all of the work is complete, and the project is expected to go into service shortly. The cost to finalize installation were less than expected.

- **Bayside 316(b)Compliance:** The Bayside 316(b) Compliance project variance is $117,098 or 67.4 percent greater than originally projected as engineering and material sourcing activities are ahead of schedule.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220007-EI

IN RE: TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

PROJECTION

JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT

OF

M. ASHLEY SIZEMORE

FILED: AUGUST 26, 2022

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. 20220007-EI?

A. Yes, I submitted direct testimony on April 1, 2022, and July 29, 2022.

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 2023 through December 2023. 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 2023.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2023 through December 2023?

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 2023.

Q. Are you requesting Commission approval of the projected environmental cost recovery factors for the company's various rate schedules?

A. Yes. The company requests approval of the ECRC factors provided in Exhibit No. MAS-3, Document No. 7, on Form 42-7P. The factors were prepared under my direction and supervision. These annualized factors will apply for the period January 2023 through December 2023.

Q. How were the environmental cost recovery clause factors calculated?

A. The environmental cost recovery factors were calculated based on the current approved cost allocation methodology and equity ratio as set out in the 2021 Stipulation and Settlement Agreement ("2021 Agreement"), approved in Order No. PSC-2021-0423-S-EI and issued on November 10, 2021, in Docket No. 2021-0034-E.

On August 16, 2022, the Commission approved the company's petition to increase its mid-point return on equity from 9.95 percent to 10.20 percent based on provisions in its 2021 Agreement. As a result, the cost recovery factors were calculated using the revised authorized return on equity.

Q. What is the 2021 baseline amount that Tampa Electric is using to compare its 2023 total revenue requirement?

A. Tampa Electric's baseline, as filed in its October 1, 2021 filing for the proposed 2022 ECRC cost recovery factors, is $27,891,196.

Q. What did Tampa Electric calculate as its 2023 revenue requirement and how does that compare against the 2021 baseline amount?

A. Tampa Electric 2023 revenue requirement is $17,417,925. This amount was compared to the 2021 baseline amount of $27,891,196, resulting in an incremental amount of ($10,473,271). In accordance with the 2021 Agreement, since the increment is negative, no changes to the allocation methodology need to be made in allocating revenues by class for the 2023 projected period.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2023 to December 2023?

A. The net true-up applicable for this period is an over-recovery of $6,570,558. This consists of a final true-up over-recovery of $1,187,656 for the period of January 2021 through December 2021 and an estimated true-up over-recovery of $5,382,902 for the current period of January 2022 through December 2022. 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 29, 2022.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2023 through December 2023?

A. No, Tampa Electric did not include costs for any new environmental projects in the factors presented in this testimony.

Q. What are the capital projects included in the calculation of the ECRC factors for 2023?

A. Tampa Electric proposes to include for ECRC recovery, costs for 19 previously approved capital projects in the calculation of the 2023 ECRC factors. These projects are listed below.

1) Big Bend Unit 3 Flue Gas Desulfurization (“FGD”) Integration
2) Big Bend Unit 4 Continuous Emissions Monitors

3) Big Bend Section 114 Mercury Testing Platform
4) Big Bend Units 1 and 2 FGD
5) Big Bend FGD Optimization and Utilization
6) Big Bend Particulate Matter ("PM") Minimization and Monitoring
7) Polk NO_x Emissions Reduction
8) Big Bend Unit 4 SOFA
9) Big Bend Unit 4 SCR
10) Big Bend FGD System Reliability
11) Mercury Air Toxics Standards ("MATS")
12) SO_2 Emission Allowances
13) Big Bend Gypsum Storage Facility
14) Big Bend Coal Combustion Residuals ("CCR") Rule – Phase I
15) Big Bend CCR Rule - Phase II
16) Big Bend Unit 1 Section 316(b)Impingement Mortality
17) Big Bend Effluent Limitations Guidelines ("ELG") Rule Compliance
18) Bayside 316(b) Compliance
19) Big Bend NESHAP Subpart YYYY Compliance

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2023?

A. Yes. Form 42-3P contained in Exhibit No. MAS-3 summarizes the cost estimates for these projects. Form 42-4P, pages 1 through 19, provides the calculations resulting in recoverable jurisdictional capital costs of $20,404,771.

Q. What O&M projects are included in the calculation of the ECRC factors for 2023?

A. Tampa Electric proposes to include for ECRC recovery O&M costs for 22 approved O&M projects in the calculation of the ECRC factors for 2023. These projects are listed below.

1) Big Bend Unit 3 FGD Integration
2) SO_2 Emission Allowances
3) Big Bend Units 1 and 2 FGD
4) Big Bend PM Minimization and Monitoring
5) National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees
6) Gannon Thermal Discharge Study
7) Polk NO_x Emissions Reduction
8) Bayside SCR Consumables
9) Big Bend Unit 4 Separated Overfired Air ("SOFA")
10) Clean Water Act Section 316(b) Phase II Study
11) Arsenic Groundwater Standard Program
12) Big Bend Unit 3 SCR
13) Big Bend Unit 4 SCR

14) Mercury Air Toxics Standards
15) Greenhouse Gas Reduction Program
16) Big Bend Gypsum Storage Facility
17) Big Bend CCR Rule - Phase I
18) Big Bend CCR Rule - Phase II
19) Big Bend Unit 1 Section 316(b) Impingement Mortality
20) Big Bend ELG Rule Compliance
21) Bayside 316(b) Compliance
22) Big Bend NESHAP Subpart YYYY Compliance

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2023?

A. Yes. Form 42-2P contained in Exhibit No. MAS-3 presents the recoverable jurisdictional O&M costs for these projects, which total $3,571,180 for 2023.

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 25.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2023?

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 $17,417,925.

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 2023 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 for the period January 2023 through December 2023 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	0.092
GS, CS Secondary	0.090
GSD, SBD	
Secondary	0.084
Primary	0.083
Transmission	0.082
GSLDPR	0.076
GSLDSU	0.075
LS1, LS2	0.066
Average Factor	0.087

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 2023.

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

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 2023 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 of an average ECRC billing factor of 0.087 cents per kWh. This includes the projected capital and O&M revenue requirements of $17,417,925 associated with the company’s 25 ECRC projects and a net true-up over-recovery provision of $6,570,558. My testimony also explains that the projected environmental expenditure for 2023 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.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220007-EI

ENVIRONMENTAL COST RECOVERY FACTORS

PROJECTIONS

JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY
OF
BYRON T. BURROWS

FILED: AUGUST 26, 2022

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 2023 through December 2023 projection period are activities related to programs previously approved by the Commission for recovery through the ECRC and also consistent with Tampa Electric's 2021 base rate settlement agreement approved in Order No. PSC-2021-0423-S-EI and issued on November 10, 2021, in Docket No. 2021-0034-EI ("2021 Agreement").

Q. Please provide an overview of the environmental compliance requirements of the Clean Air Act, Title V Operating Permit for the Big Bend Station that are recoverable through the ECRC.

A. The Big Bend plant is required to obtain and operate in accordance with a comprehensive air permit that incorporates all applicable air quality requirements including federal, state, and local regulations. This permit is known as a "Title V Operating Permit." Environmental Compliance Requirements of the Clean Air Act, Title V Operating permit (0570039-132-AV) for the Big Bend Station provide for reductions of sulfur dioxide ("SO_2"), particulate matter ("PM") and nitrogen oxides ("NO_x") emissions at the Station. The projects that are required under the current operating permit and are currently being recovered through the ECRC are listed below.

- Big Bend Particulate Matter ("PM") Minimization Program
- Big Bend Unit 3 SCR Project (O&M only)
- Big Bend Unit 4 SCR Project

In accordance with the 2021 Agreement, Tampa Electric removed certain assets related to Big Bend Units 1, 2, and 3 from the ECRC and transferred to the company's Clean

Energy Transition Mechanism ("CETM"), effective January 1, 2022. The Title V projects associated with those assets include the following: Big Bend Units 1-3 Pre-SCRs, Big Bend 1-3 SCRs, Big Bend NO_x Emission Reduction, and a portion of Big Bend PM Minimization Program. O&M expenditures for Big Bend SCR Unit 3 will continue to be incurred to ensure compliance with emission reduction standards until the unit's retirement in 2023.

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 2023 through December 2023.

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 2023; however, the O&M expenditures associated with Best Operating Practice ("BOP") and Best Available

Control Technology ("BACT") equipment and BOP procedures are expected to be $240,000.

Q. Please describe the Big Bend Unit 3 SCR project and provide estimated O&M expenditures for the period of January 2023 through December 2023.

A. The Big Bend Unit 3 SCR project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-PAA-EI, issued May 9, 2005. The SCR for Big Bend Unit 3 was placed in service in July 2008.

For the period of January 2023 through December 2023, the O&M expenditures are projected to be $355,095 for Big Bend Unit 3 SCR. These expenses are primarily associated with ammonia purchases and maintenance.

Q. Please describe the Big Bend Unit 4 SCR project and provide estimated capital and O&M expenditures for the period of January 2023 through December 2023.

A. The Big Bend Unit 4 SCR project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-PAA-EI, issued October 11, 2004. The SCR project at Big Bend Unit 4 encompasses the design, procurement, installation, and annual O&M expenditures associated with an SCR system for the generating unit. The SCR for Big Bend Unit 4 was placed in service in May 2007.

For the period of January 2023 through December 2023, capital expenditures are expected to be $4,000,000 and the O&M expenditures are projected to be $1,408,774 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases and maintenance.

Q. Are there other retiring Big Bend projects that will no longer be recovered through the ECRC; but through the CETM (consistent with the 2021 Settlement Agreement), and have they been removed from consideration in this filing?

A. Yes. In accordance with the 2021 Settlement, the retiring Big Bend Units 1-3 assets have been removed and recovery of expenditures related thereto have not been included in this ECRC filing, nor will they be included in any future ECRC filing. Other retiring Big Bend 1-3 assets include the following projects: Big Bend Units 1 and 2 Flue Gas Conditioning, Big Bend Units 1 and 2 Classifier Replacements, and certain assets of both Big Bend FGD Optimization and Utilization and Mercury Air Toxics Standards.

Q. Please identify and describe the other Commission-approved programs that you will discuss.

A. The programs previously approved by the Commission and included for expenditure recovery in this filing, 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
15) Big Bend NESHAP Subpart YYYY Compliance

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 2023 through December 2023.

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.

The company does not anticipate any capital or O&M expenditures during the period of January 2023 through December 2023 for the Big Bend Unit 3 FGD Integration project or the Big Bend Units 1 & 2 FGD project remaining assets.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M

expenditures for the period of January 2023 through December 2023.

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 2023 through December 2023, 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 expenditures 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 2023 through December 2023.

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 2023 through December 2023, Tampa Electric projects O&M expenditures associated with the consumable goods, primarily anhydrous ammonia, to be approximately $294,600.

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 2023 through December 2023.

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 has initiated the installation of measures that are necessary for compliance with the impingement mortality reduction part of the rule for Big Bend Unit 1 and Bayside

Units 1 & 2. Tampa Electric is working with the regulatory authority to determine if any entrainment reduction measures are required for Bayside Units 1 & 2. For Big Bend Units 1 & 4, Tampa Electric will complete the biological, financial, and technical study elements necessary to comply with the rule and submit with the next NPDES permit renewal. These elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend Unit 1 for entrainment reduction and Big Bend Unit 4 for impingement and entrainment reduction. Big Bend Unit 3 is anticipated to be retired prior to the determination of the final compliance measures.

The estimated Clean Water Act Section 316(b) Phase II Study related O&M expenditures for Big Bend Station and Bayside Power Station for the period January 2023 through December 2023 are $10,150.

For Big Bend Unit 1, which is in the final stages of being repowered to a clean, natural gas-fired combined cycle unit, Tampa Electric is in the process of installing the impingement mortality controls as required by the FDEP operating permit. The Commission approved cost recovery for the Big Bend Unit 1 Section 316(b) Impingement Mortality project in Order No. PSC-2018-0594-FOF-EI, issued on December 20, 2018.

Bayside Power Station will install traveling screens to reduce impingement mortality to comply with Section 316(b). Tampa Electric's petition filed with the Commission in Docket No. 20210087-EI, was approved by Commission Order No. PSC-2021-0356-PAA-EI, issued on September 15, 2021.

The estimated O&M expenditures for NPDES Annual Surveillance Fees for Big Bend, Bayside, and Polk generating plants for the period January 2023 through December 2023 are $34,500.

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 2023 through December 2023.

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 2023 through December 2023, Tampa Electric does not anticipate any capital expenditures for the Big Bend Unit 1 Section 316(b) Impingement Mortality Project and the O&M expenditures are estimated to be $300,000.

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 2023 through December 2023.

A. The Bayside Section 316(b) Compliance project was approved by the Commission in Docket No. 20210087-EI, Order No. PSC-2018-0356-PAA-EI, issued September 15, 2021. 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 2023 through December 2023, Tampa Electric does not anticipate any O&M expenditures for the Bayside Section 316(b)project. Tampa Electric anticipates the capital expenditures for the Bayside Section 316(b) Compliance Project to be $8,837,600. This increase is due to rising prices caused by inflation, additional costs due to delays associated with supply chain issues, and additional structural costs for the intake structure not anticipated in the original estimate.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenditures for the period of January 2023 through December 2023.

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 2023 through December 2023, 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 2023 through December 2023.

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 expenditures may be incurred if additional monitoring and assessment are required. For the period of January 2023 through December 2023, there are no anticipated O&M expenditures associated with the program.

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 2023 through December 2023.

A. For the period January 2023 through December 2023, Tampa Electric anticipates $100,000 in capital expenditures under the MATS program. O&M expenditures are projected to be approximately $1,000 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 2023 through December 2023.

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 2023. For the period January 2023 through December 2023, O&M expenditures are projected to be approximately $19,140.

Q. Please describe the Big Bend Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2023 through December 2023.

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 2023, Tampa Electric does not anticipate capital expenditures; however, the projected O&M expenditures for this program are expected to be $282,927.

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 2023 through December 2023.

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 expenditures 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 continued until completion 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 allow for finalization of the engineering and construction scope details, but the final phase of the project is currently underway, with completion expected in 2022.

Tampa Electric does not expect to incur capital expenditures for CCR Rule Phase I or Phase II projects for the period January 2023 through December 2023. For the period January 2023 through December 2023, the company expects to incur O&M expenditures of $200,004 for the CCR Rule – Phase II project.

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 2023 through December 2023.

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-down stream 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 regulating authority requires compliance no later than December 31, 2023.

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.

For the period January 2023 through December 2023, Tampa

Electric projects capital expenditures to be $3,373,288 and projects $300,000 in O&M expenditures.

Q. Please describe Tampa Electric's National Emission Standards Hazardous Air Pollutants ("NESHAP") Subpart YYYY Compliance Project activities and provide the estimated capital and O&M expenditures for the period of January 2023 through December 2023.

A. Tampa Electric's Clean Air Act, NESHAP Subpart YYYY Compliance Project was approved by the Commission in Order No. PSC-2022-0286-PAA-EI issued on July 22, 2022, in Docket No. 20220055-EI. The project is required to comply with the Environmental Protection Agency's ("EPA") formaldehyde emission standard set for stationary, gas-fired combustion turbines. For the period January 2023 through December 2023, Tampa Electric does not anticipate any capital expenditures and projects O&M expenditures to be $75,000.

Q. Please summarize your testimony.

A. I described ongoing environmental compliance requirements of the Clean Air Act, Title V Operating permit (0570039-132-AV) for the Big Bend Station. I described the progress

Tampa Electric has made to achieve the more stringent environmental standards. I have removed retiring Big Bend 1-3 Assets, the balances of which have been transferred to the company’s CETM, from the company’s cost recovery request, in accordance with the company’s 2021 Settlement Agreement. For the other projects, I identified estimated costs, by project, which the company expects to incur in 2023. Additionally, my testimony identified additional projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2023 activities and projected expenditures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 7th day of December, 2022.

Debbie R. Krick

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