BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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In the Matter of:

DOCKET NO. 20190007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE.
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VOLUME 1
PAGES 1 through 236

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY

DATE: Tuesday, November 5, 2019

TIME: Commenced: 4:12 p.m.
Concluded: 4:15 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

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

APPEARANCES:

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

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

RUSSELL A. BADDERS, ASSOCIATE GENERAL COUNSEL, One Energy Place, Pensacola, Florida 32520-0100; and STEVEN R. GRIFFIN, ESQUIRE, Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

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

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

DIANA CSANK and BRADLEY MARSHALL, ESQUIRES, 50 F. Street, NW, Eight Floor, Washington, DC 20001, appearing on behalf of Sierra Club.

LAURA A. WYNN and JAMES W. BREW, ESQUIRES, Stone Matheis Xenopoulos & Brew PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE and THOMAS DAVID, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

ASHLEY WEISENFELD and CHARLES MURPHY, ESQUIRES, General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

KEITH HETRICK, GENERAL COUNSEL; LEE ENG TAN, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	233	233
2-54	As identified in the comprehensive exhibit list	233	234

P R O C E E D I N G S

CHAIRMAN GRAHAM: All right. Staff, 07 docket, preliminary matters.

MS. WEISENFELD: Yes, Mr. Chairman.

There are proposed stipulations on all issues for all companies. All parties either agree or take no position on the proposed stipulations that are before the Commission today.

Additionally, all prefiled testimony and exhibits have been stipulated, all witnesses have been excused and all parties have waived opening statements.

Lastly, Sierra Club has been excused from this hearing.

CHAIRMAN GRAHAM: Okay, staff, so let's address prefiled testimony.

MS. WEISENFELD: We ask that the prefiled testimony of witnesses Deaton, Sole, Markey, Boyett, Menendez, Hill, Swartz, McDaniel, Rusk and Carpinone be entered into the record as though read.

CHAIRMAN GRAHAM: If there is no objection to entering all of those witnesses into the record as though read, seeing none, we will enter those into the record as though read.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20190007-EI

APRIL 1, 2019

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 Director of Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

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. 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. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International

Training Programs on Utility Regulation and Strategy. 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.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery Clause ("ECRC") final true-up amount associated with FPL's environmental compliance activities for the period January 2018 through December 2018.

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

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

- Form 42-1A reflects the final true-up for the period January 2018 through December 2018.
- 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 expense and return on capital investment for each capital investment project. Pages 64 through 67 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital investment project for the period.
- Form 42-9A presents the capital structures, components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period.

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

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

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

A. Form 42-1A, entitled "Calculation of the Final True-up Amount" shows the calculation of the net true-up for the period January 2018 through December 2018, an over-recovery of $22,191,591, which FPL is requesting be included in the calculation of the ECRC factors for the January 2020 through December 2020 period.

The actual end-of-period over-recovery for the period January 2018 through December 2018 of $16,577,171 (shown on Form 42-1A, Line 3) minus the actual/estimated end-of-period under-recovery for the same period of $5,614,420 (shown on Form 42-1A, Line 6) results in the net true-up over-recovery for the period January 2018 through December 2018 (shown on Form 42-1A, Line 7) of $22,191,591.

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

A. Yes. Form 42-2A, entitled "Calculation of the Final True-up Amount," shows the calculation of the end-of-period true-up over-recovery amount of $16,577,171 for the period January 2018 through December 2018. The $15,281,286 over-recovery shown on line 5 plus the interest provision of $1,295,885 shown on line 6, which is calculated on Form 42-3A, results in the final over-recovery of $16,577,171 shown on line 11.

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

A. Yes, they are.

Q. How did actual project O&M and capital revenue requirements for January 2018 through December 2018 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 $18,506,716 or 35.8% lower than projected, and Form 42-6A shows that the variance in total actual revenue requirements (return on capital investments, depreciation and taxes) associated with the project capital investments were $1,268,223 or 0.8% 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 2018 through December 2018 are provided on Form 42-8A, pages 14 through 63.

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

A. The significant variances in FPL's 2018 actual O&M expenses and capital revenue requirements from actual/estimated amounts are associated with the following projects:

O&M Variance Explanations

Project 1. Air Operating Permit Fees

Project expenditures are $90,925, or 31.6% higher than previously projected. The variance is primarily due to higher than originally projected natural gas and fuel oil usage. The projected annual Title V fees and costs for the current year are calculated based on fuel consumption projections provided by FPL's Energy Marketing &

Trading group and on the Department of Environmental Protection's fee for pollutant tons emitted.

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

Project expenditures are $456,392, or 65.3% lower than previously projected. The variance is primarily due to an input error in the 2018 actual/estimated filing. The 2018 actual/estimated filing included $699,377 for this project, but the amount that should have been reflected in the actual/estimated filing for this project is $148,241 which is $94,744, or 63.9% lower than the actual costs of $242,985. This variance is primarily associated with an overrun of $122 thousand for tank painting at the Port Everglades Terminal. Tank painting was originally budgeted for touch-up coating work, but the actual job cost was higher because it required a complete shell coating instead. There was also a $9 thousand overrun due to high alarm gauges installed on above ground storage tanks at the Emergency Offsite Facility at Plant St. Lucie, which were not included in the original budget. These overruns were offset by an underrun of $38 thousand due to work originally planned for the removal of oily water separator at Plant Fort Myers GTs, which was no longer needed when the gas turbines were retired.

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

Project expenditures were $298,161 or 11.4% higher than previously projected. The variance is primarily due to FPL obtaining more equipment clearances (i.e., de-energize installed equipment) than expected, which are required for equipment repair. This resulted in a higher than projected number of transformers being repaired during 2018.

Project 19b. Substation Pollutant Discharge Prevention & Removal – Transmission

Project expenditures are $411,643 or 38.6% higher than previously projected. The variance is primarily due to FPL obtaining more equipment clearances than expected, which are required for equipment repair. This resulted in a higher than projected number of transformers being repaired during 2018.

Project 21. St. Lucie Turtle Nets

Project costs are $101,404 or 98.1% higher than previously projected. The variance is primarily due to more net cleaning activity than was estimated. Larger than expected volumes of aquatic organisms accumulated on the net, which required more frequent removal.

Project 22. Pipeline Integrity Management

Project expenditures are $116,850, or 145.2% lower than previously projected. The variance is due to the following issues at Martin Units 1 and 2 and Manatee Units 1 and 2.

- Martin Units 1 and 2: (1) The retirement of Martin Units 1 and 2 at the end of 2018 eliminated the need for approximately $20 thousand in project activities that were included in the original 2018 projections, and (2) an underrun of $46 thousand that was the result of sales tax credits applied in 2018.

- Manatee Units 1 and 2: (1) An underrun of approximately $11 thousand in sales tax credits that was applied in 2018, (2) an underrun of approximately $40 thousand due to the deferral of planned pipeline depth of cover work due to the determination by survey that the areas in question are wetlands.

Project 23. Spill Prevention, Control and Countermeasures

Project expenditures are $108,435 or 12.2% lower than previously projected. The variance is primarily due to reduced vendor availability, which resulted in a lower than projected number of projects completed during 2018. Additionally, the Turkey Point nuclear units had an underrun due to efficiency improvements associated with the installation of transformer containment berms.

Project 29. SCR Consumables

Project expenditures are $79,768 or 15.0% higher than previously projected. The variance is primarily associated with the Martin Unit 8 site ($165 thousand). A full evacuation of the anhydrous ammonia tank and system was required to repair corroded piping, which also required a full cleaning, recoating and relabeling of the tank, and touch up of other piping areas throughout the ammonia system. In addition, the anhydrous ammonia that was evacuated had to be properly disposed and the tank had to be refilled following completion of the repairs. This increase was partially offset by a Manatee Unit 3 ($85 thousand) underrun due to less maintenance required than originally anticipated and consolidation of required training classes.

Project 33. MATS Project

Project expenditures are $868,714 or 36.3% lower than previously projected. The variance is primarily due to lower than projected consumption of powder-activated carbon in the Scherer Unit 4 baghouse due to lower than projected generation output.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures are $63,461 or 11.0% higher than previously projected. The variance is primarily due to higher than projected maintenance costs that included replacement of certain combiner boxes, solar panels and connectors in order to maintain the reliability of the site.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures are $93,042 or 23.7% lower than previously projected. The variance is primarily due to lower than planned support costs. As FPL added new solar facilities, the costs that support the facilities have been reduced through optimized personnel assignments and employees' base locations that resulted in spreading costs across more facilities.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project costs are $17,780,211 or 62.9% lower than previously projected. FPL was able to complete installation of the recovery and cluster wells at a cost that was $8.8 million less than originally budgeted. Actual construction costs came in lower than estimated, despite the need to construct an additional cluster well after the Recovery Well System was complete. There was also an $8 million reduction due to the deferral of planned sediment removal activities, which were deferred due to adequate thermal efficiency of the cooling canal system in 2018.

Project 45. 800 MW Unit ESP

Project expenditures are $84,911 or 11.3% higher than previously projected. The variance is primarily due to an increased scope of work at Manatee Units 1&2 for items identified during the annual inspections of the ESPs. The identified items were related to three key areas: weather enclosure, penthouse, and ESP internals, all of which required additional maintenance to ensure reliability. In addition, both of the ash silos had all of the external metal flashing replaced due to corroded material. This resulted in the project expenses increasing $157 thousand over the original budget plan for this work. This was partially offset by a $74 thousand reduction at Martin Units 1&2 associated with their retirement on December 31, 2018. In anticipation of the retirement, less maintenance was performed on the ESPs throughout the year resulting in the $40 thousand underrun in payroll and $34 thousand underrun in outside services.

Project 47. NPDES Permit Renewal Requirements

Project expenditures are $164,728 or 33.8% lower than previously projected. The variance is primarily due to a delay in beginning the Florida Department of Environmental Protection-approved chlorine dioxide test. Additional evaluations of the chlorine dioxide injection system were required to ensure that the chlorine dioxide could be injected as safely and with as little impact to the environment as possible.

Project 50. Steam Electric Effluent Guidelines Revised Rules

Project expenditures are $100,144 or 33.9% lower than previously projected. The variance is primarily due to lower than projected expenditures by Southern Company Services associated with delays in the effective date of the Steam Electric Effluent Limitation Guidelines Rule, and potential changes to effluent limitations for flue gas desulfurization-related wastewater at Plant Scherer.

Capital Variance Explanations

Project 41. Manatee Temporary Heating System

Project costs are $100,235 or 20.9% lower than previously projected. The variance is related to delays in the project schedule that resulted from delays in equipment deliveries, including the pumps that are needed for the heating system. Temporary heaters were rented in order to maintain compliance during the delays.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project costs are $323,168 or 7.2% lower than previously projected. The variance is primarily due to a delay in the commencement of the Turning Basin and Turtle Point Backfill activities due to permitting delays. These activities were deferred to 2019.

Project 54. Coal Combustion Residuals

Project costs are $405,211 or 12.5% lower than previously projected. The variance is primarily due to changes in Southern Company Services' schedule for engineering evaluation and analysis of the ash pond project at Plant Scherer.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20190007-EI

JULY 26, 2019

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 Director of Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Actual/Estimated True-up associated with FPL's environmental compliance activities for the period January 2019 through December 2019.

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

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

- Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2019 through December 2019.
- 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 14 through 64) reflects return on capital investments and depreciation by project. Pages 65 through 67 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital investment project.
- Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investment amounts included for recovery for the period January 2019 through December 2019.

Q. Please explain the calculation of the Environmental Cost Recovery Clause ("ECRC") Actual/Estimated True-Up amount FPL is requesting this Commission to approve.

A. The Actual/Estimated True-Up amount for the period January 2019 through December 2019 is an over-recovery, including interest, of $7,117,811 (Appendix I, page 1, line 4). The Actual/Estimated True-Up amount is calculated on Form 42-2E by comparing actual data for January 2019 through May 2019 and revised estimates for June 2019 through December 2019 to original projections for the same period. The over-recovery of $6,177,306 shown on line 5 plus the interest provision of $940,505 shown on line 6, which is calculated on Form 42-3E, results in the final over-recovery of $7,117,811 shown on line 11.

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

A. Yes.

Q. How do the actual/estimated project costs for January 2019 through December 2019 compare with original projections for the same period?

A. Form 42-4E (Appendix I, page 4) shows that total O&M project costs are $2,802,536 higher than projected, while Form 42-6E (Appendix I, page 9) shows that total capital project revenue requirements are $6,790,910 lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Revenue requirements for each capital project for the 2019 actual/estimated period are provided on Form 42-8E (Appendix I, pages 14 through 64).

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

A. The significant variances in FPL's 2019 recoverable O&M expenses and capital revenue requirements from projection amounts are associated with the following projects:

O&M Variance Explanations

Project 3a. Continuous Emission Monitoring Systems ("CEMS")

Project expenditures are $125,253, or 23.0% higher than previously projected. The variance is primarily due to the deferral to 2019 of CEMS improvement projects that were originally scheduled for completion in 2018. Lack of component availability resulted in installation delays associated with CEMS equipment and new network security requirements resulted in installation delays associated with project-related IT hardware.

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

Project expenditures are $173,197, or 37.1% higher than previously projected. The variance is primarily due to an input error in the 2019 projections filing. The 2019 projections filing included $467,402 for this project, but the amount that should have been reflected in the projections filing for this project is $660,402.

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

Project expenditures are $101,871, or 35.8% lower than previously projected. The variance is primarily due to the unanticipated sale of surplus oil spill response equipment in 2019.

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

Project expenditures are $344,018 or 12.9% higher than previously projected. The variance is primarily due to FPL obtaining more equipment clearances (i.e., de-energize installed equipment) than expected, which are required for equipment repair. This resulted in a higher than projected number of transformers being repaired.

Project 19b. Substation Pollutant Discharge Prevention & Removal – Transmission

Project expenditures are $154,620 or 15.7% lower than previously projected. The variance is primarily due to FPL obtaining fewer equipment clearances than expected, which are required for equipment repair. This resulted in a lower than projected number of transformers being repaired during the first half of 2019.

Project 21. St. Lucie Turtle Nets

Project expenditures are $245,961 or 223.6% higher than previously projected. The variance is primarily due to larger than expected volumes of aquatic organisms accumulating on the net that required additional activities to ensure turtle safety. Activities included deploying aquatic organism removal equipment year round, rather than for only the historical six–month growth season, to address emergency responses to aquatic organism intrusion events. Additional samples and inspections were required to monitor and mitigate the aquatic organism buildup.

Project 22. Pipeline Integrity Management

Project expenditures are $101,883, or 56.2% lower than previously projected. The variance is due to the retirement of Martin Units 1 and 2 at the end of 2018, which eliminated the need for project activities associated with those units that were included in the original 2019 projections.

Project 24. Manatee Plant Reburn

Project expenditures are $59,310 or 37.1% higher than previously projected. The variance is primarily due to replacement of oil burner tips associated with increased oil burn resulting from higher than projected plant operation.

Project 28. CWA 316(b) Phase II Rule

Project expenditures are $274,804 or 19.5% lower than previously projected. The variance is primarily attributed to the Florida Fish and Wildlife Conservation Commission-approved ("FWC") reduction in horseshoe crab monitoring activities at the Cape Canaveral Energy Center. The approved reduction was a direct result of the success of the horseshoe crab barrier preventing horseshoe crabs from being impacted by plant activities. The variance was partially offset by increased CWA 316(b) study-related activities at the Lauderdale plant where portions of studies originally scheduled for 2018 were postponed until certain design aspects of the new Dania Beach Energy Center were finalized and then completed in 2019.

Project 33. MATS Project

Project expenditures are $596,496 or 22.1% lower than previously projected. The variance is primarily due to lower than projected consumption of powder-activated carbon in the Scherer Unit 4 baghouse due to lower than projected generation output.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures are $120,917 or 24.2% higher than previously projected. The variance is primarily due to higher than projected field maintenance, which resulted in increased payroll, relocation, and training expenses.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures are $50,974 or 16.0% lower than previously projected. The variance is primarily due to less than anticipated repair work being needed, resulting in lower payroll expenses.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures are $2,275,277 or 12.8% higher than previously projected. The variance is primarily due to deferral from 2018 to 2019 of additional planned monitoring, nutrient management, deep injection well testing, and well maintenance due to permitting delays. The variance was partially offset by a reduction in the sediment removal program, which was not required in 2019 due to adequate thermal efficiency of the cooling canals.

Project 47. NPDES Permit Renewal Requirements

Project expenditures are $566,024 or 1,254.3% higher than previously projected. The variance is primarily due to the Florida Department of Environmental Protection-approved chlorine dioxide pilot test being delayed from 2018 to 2019. In addition, testing is ongoing and has been extended until the next planned outage so that the condenser inlet boxes and tube sheet can be opened and inspected to ensure effective biocide treatment prior to full scale implementation of the project.

Project 50. Steam Electric Effluent Guidelines Revised Rules

Project expenditures are $188,100 versus an original estimate of $0. The variance is associated with study related costs, which were originally anticipated to be capitalized. Delays associated with the issuance of a final, revised Steam Electric Effluent Limitations Guidelines ("ELG") Rule delayed capitalization.

Project 54. Coal Combustion Residuals

Project expenditures are $72,828 or 21.8% lower than previously projected. The variance is primarily due to lower than projected expenditures by Southern Company associated with the Scherer Unit 4 dry bottom ash system.

Capital Variance Explanations

Project 3. Continuous Emission Monitoring Systems

Project revenue requirements are $105,680, or 17.9% lower than previously projected. The variance is primarily due to the retirements in December 2018 of Lauderdale Plant Units 4 and 5 and the Martin Plant Units 1 and 2.

Project 23. SPCC – Spill Prevention, Control and Countermeasures

Project revenue requirements are $342,652, or 13.5% lower than previously projected. The variance is primarily due to delays in the in-service dates for oil booms at the Martin plant from October 2019 to December 2019 and June 2019 to December 2019 at the Ft. Myers plant. Additionally, there was a change in the in-service date of an oil water separator at the Turkey Point Nuclear Plant from October 2018 to June 2019 due to extra time required to obtain a necessary permit revision from Miami-Dade County. Finally, $1.3 million for placing an oil boom into service at the Manatee Plant was moved to Project 8a, Oil Spill Cleanup/Response Equipment.

Project 34. St. Lucie Cooling Water System Inspection & Maintenance

Project revenue requirements are $109,878, or 23.7% lower than previously projected. The variance is primarily due to the suspension of all activity associated with the proposed turtle barrier pending receipt of a new or updated biological opinion from the National Marine Fisheries Service ("NMFS"). Testing in 2018 of the proposed barrier determined there was a potential for turtle injuries and therefore was suspended due to comments received from the NMFS and the FWC.

Project 41. Manatee Temporary Heating System ("MTHS")

Project revenue requirements are $1,432,105, or 52.9% lower than previously projected. The variance is primarily due to the delay of capital spend and in-service dates for the Ft. Myers Plant MTHS and the Dania Beach Energy Center ("DBEC") MTHS. The Ft. Myers Plant MTHS was placed into service in February 2019, rather than December 2018 as previously estimated. This in-service delay was due to delays in equipment deliveries. The cause for the delay of the in-service date for the DBEC

MTHS was that the MTHS installed in 2018 did not perform as designed and was returned to the manufacturer for repairs, therefore requiring the use of temporary heaters during the 2018-2019 manatee season. The DBEC MTHS is expected to be operational in September 2019 for testing and emergency use and placed into service in December 2019.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project revenue requirements are $1,384,722, or 21.2% lower than previously projected. The variance is primarily due to deferrals from 2018 to the fourth quarter of 2019 in capital spending for the Turning Basin and Turtle Point Backfill projects, resulting from delays in the permitting process.

Project 45. 800 MW Unit ESP

Project revenue requirements are $4,283,807, or 18.4% lower than previously projected. The variance is primarily due to the retirement of Martin Plant Units 1 and 2 in December of 2018.

Project 54. Coal Combustion Residuals

Project revenue requirements are $1,307,040, or 21.7% higher than previously projected. The variance is primarily due to higher than projected engineering and construction costs associated with required wastewater treatment, and higher than projected quantities of concrete, steel, piping, and installation labor hours associated with waste management activities at Plant Scherer. These increases were partially offset by lower than projected costs associated with deferral of the landfill construction.

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. 20190007-EI

AUGUST 30, 2019

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 Director of Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval FPL's Environmental Cost Recovery Clause ("ECRC") projections and factors for the January 2020 through December 2020 period.

Q. Is this filing in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

A. Yes. The costs being submitted for the 2020 projected period are consistent with that order.

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

A. Yes, I am sponsoring the following exhibits:

- Exhibit RBD-3 provides revised 2019 actual/estimated true-up capital schedules, which are explained later in my testimony.
- Exhibit RBD-4 provides the calculation of FPL's proposed ECRC factors for the period January 2020 through December 2020 and includes PSC Forms 42-1P through 42-8P, which are provided in Appendix I. Appendix II provides the calculation of the stratified separation factors.
    - FPL witness Michael W. Sole is co-sponsoring Form 42-5P (Project Progress Reports).

Q. Have you made any adjustments to the 2019 actual/estimated true-up schedules that were filed in this docket on July 26, 2019?

A. Yes. FPL has revised capital recovery unamortized balances and accumulated depreciation balances beginning January 2019 on five capital projects to correctly reflect retired ECRC recoverable assets associated with St. John's River Power Park ("SJRPP"), per the Settlement Agreement approved by the Commission in Order No. PSC-2017-0415-AS-EI, issued in Docket No. 20170123-EI on October 24, 2017. These corrections do not impact net investment amounts. The capital projects and amounts associated with these corrections are as follows:

- Project 3 – Continuous Emission Monitoring Systems (Base Strata) –The capital recovery unamortized balance (line 3b) and accumulated depreciation (line 3a) amounts were increased by $17,850.

- Project 5 – Maintenance of Stationary Above Ground Fuel Storage (Base Strata) –The capital recovery unamortized balance (line 3b) and accumulated depreciation (line 3a) amounts were decreased by $21,854.
- Project 31 – Clean Air Interstate Rule (CAIR) Compliance (Base Strata) –The capital recovery unamortized balance (line 3b) and accumulated depreciation (line 3a) amounts were decreased by $11,733,302.
- Project 33 – MATS Project (Base Strata) –The capital recovery unamortized balance (line 3b) and accumulated depreciation (line 3a) amounts were decreased by $4,095.
- Project 54 – Coal Combustion Residuals (Base Strata) –The capital recovery unamortized balance (line 3b) and accumulated depreciation (line 3a) amounts were decreased by $916.

Additionally, FPL has revised the accumulated depreciation balances on two capital projects to include reserve salvage and removal costs and retirements that were inadvertently excluded from accumulated depreciation amounts but were included in the calculation of net investment. The capital projects and amounts associated with these revisions are as follows:

- Project 3 – Continuous Emission Monitoring Systems (Intermediate Strata) – Reserve salvage and removal costs of $1,613 reported in January 2019 (line 1d) were inadvertently excluded from accumulated depreciation (line 3a), but were included in net investment (line 5).

- Project 8 – Oil Spill Clean-up/Response Equipment (Intermediate Strata) – Retirements of $8,858 reported in November 2019 (line 1c) were inadvertently excluded from accumulated depreciation (line 3a), but were included in net investment (line 5).

As stated above, these corrections do not impact net investment or total system recoverable costs of the impacted projects and therefore do not change the actual/estimated true-up over-recovery of $7,117,811 for the period January 2019 through December 2019 filed on July 26, 2019. FPL's revised 2019 actual/estimated true-up capital schedules are included in Exhibit RBD-3.

Q. Have you provided a schedule showing the calculation of projected environmental costs being requested for recovery for the period January 2020 through December 2020?

A. Yes. Form 42-1P (page 1) in Exhibit RBD-4 provides a summary of projected environmental costs being requested for recovery for the period January 2020 through December 2020. Total jurisdictional revenue requirements including true-up amounts and revenue taxes, are $161,954,048 (page 1, line 5). This amount includes the jurisdictional revenue requirements projected for the January 2020 through December 2020 period, which are $191,146,927 (page 1, line 1c), the actual/estimated true-up over-recovery of $7,117,811 for the January 2019 through December 2019 period (page 1, line 2) and the final true-up over-recovery of $22,191,591 for the January 2018 through December 2018 period (page 1, line 3).

The detailed calculations supporting the 2019 actual/estimated and 2018 final true-ups were provided in Exhibit RBD-1 and Exhibit RBD-2 filed in this docket on April 1, 2019 and July 26, 2019, respectively.

Q. Please describe the schedules that are provided in Appendix I of Exhibit RBD-4.

A. Forms 42-1P through 42-8P provide the calculation of ECRC factors for the period January 2020 through December 2020 that FPL is requesting this Commission to approve.

Form 42-1P (page 1) provides a summary of projected environmental costs being requested for recovery for the period January 2020 through December 2020.

Form 42-2P (pages 2 through 4) presents the O&M costs associated with FPL's environmental projects for the projected period along with the calculation of the total jurisdictional amount of $41,464,119 for these projects.

Form 42-3P (pages 5 through 7) presents the recoverable amounts associated with capital costs for FPL's environmental projects for the projected period, along with the calculation of the total jurisdictional recoverable amount of $149,682,808.

Form 42-4P (pages 8 through 59) presents the detailed calculation of the capital recoverable amounts by project for the projected period. Pages 60 through 62 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each capital project.

Form 42-5P (pages 63 through 123) provides the description and progress of approved environmental projects included in the projected period.

Form 42-6P (page 124) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the average of the twelve monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Form 42-7P (page 125) presents the calculation of the proposed 2020 ECRC factors by rate class.

Form 42-8P (page 126) presents the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments included for recovery through the ECRC for the period January 2020 through December 2020.

Q. Has FPL requested to modify the method used to calculate the weighted average cost of capital ("WACC") to be applied to recoverable investments in its cost recovery clauses?

A. Yes. FPL filed an Unopposed Joint Motion to Modify Order No. PSC-12-0425-PAA-EU ("2012 WACC Order") Regarding Weighted Average Cost of Capital Methodology ("Joint Motion") on August 21, 2019 in this docket to incorporate an adjustment to accumulated deferred federal income taxes, if needed, in order to comply with Internal Revenue Service Normalization Rules. As stated in the Joint Motion, a modified WACC methodology would apply only in instances when the Limitation Provision is not met, i.e., a forecasted test period is used to set rates and the depreciation-related Accumulated Deferred Federal Income Tax ("ADFIT") balance used for ratemaking purposes is less than or equal to the ADFIT projected for the period in which the new rates take effect.

Q. Is FPL proposing to apply a WACC calculation to its 2020 ECRC recoverable investments different than what is currently required under the 2012 WACC Order?

A. No. FPL has met the Limitation Provision, i.e., FPL's projected 2020 ADFIT is higher than the level included in FPL's WACC reflected in its May 2019 Earnings Surveillance Report, therefore no adjustment to its WACC methodology is required. As stated in the Joint Motion, the WACC methodology currently prescribed in the 2012 WACC Order should be applied to projected recoverable investments as long as FPL's Limitation Provision required under the Internal Revenue Code is met or exceeded.

Q. Are all costs listed in Forms 42-1P through 42-8P included in Exhibit RBD-4, Appendix I attributable to environmental compliance projects previously approved by the Commission?

A. Yes.

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

A. Yes. FPL has separated the production-related environmental costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of environmental costs between the retail and wholesale jurisdictions. The calculations of the stratified separation factors are provided in Exhibit RBD-4, Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL W. SOLE

DOCKET NO. 20190007-EI

AUGUST 30, 2019

Q. Please state your name and address.

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

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

A. I am employed by NextEra Energy, Inc. ("NEE") as Vice President of Environmental Services.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor's of Science degree in Marine Biology from the Florida Institute of Technology in 1986. I served as an Officer in the United States Marine Corps from 1985 through 1990 attaining the rank of Captain. I was employed by the Florida Department of Environmental Protection ("FDEP") in multiple roles from 1990 to 2010 and served as the Secretary of the FDEP from 2007-2010. I have been employed by Florida Power & Light Company ("FPL" or the "Company"), or its affiliate NextEra Energy Resources, in multiple roles since 2010. Since November 2016, I have held the position of Vice President of Environmental Services. In that role, I have overall responsibility for environmental, licensing, and compliance efforts for the Company. In May 2017, I was appointed by Governor Scott to the Florida Fish and Wildlife Conservation Commission.

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 FPL's 2019 Supplemental CAIR/MATS/CAVR Filing and to describe the progress of projects the Commission has approved for recovery through the Environmental Cost Recovery Clause ("ECRC").

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

A. Yes, I am sponsoring Exhibit MWS-1 – FPL Supplemental CAIR/ MATS/CAVR Filing. Together with FPL witness Renae B. Deaton, I am co-sponsoring FPL's Project Progress Report, which is included in Exhibit RBD-4 as Form 42-5P.

Q. Please briefly describe your Exhibit MWS-1.

A. My Exhibit MWS-1, which provides FPL's 2019 Supplemental CAIR/MATS/CAVR Filing was filed in this docket on April 1, 2019. Per Order No. PSC-07-0922-FOF-EI, issued in Docket No. 070007-EI on November 16, 2007, this filing provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule ("CAIR"), now the Cross State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), which was formerly the Clean Air Mercury Rule ("CAMR") and Clean Air Visibility Rule ("CAVR")/ Best Available Retrofit Technology ("BART") projects.

Q. Are you also sponsoring an exhibit that describes the progress of FPL's Commission-approved ECRC Projects?

A. Yes. Form 42-5P, which I co-sponsor, provides a brief and accurate description of each of FPL's ECRC projects and provides an update on the 2019 activity associated with each project.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard M. Markey
Docket No. 20190007-EI
Date of Filing: April 1, 2019

Q. Please state your name and business address.

A. My name is Richard M. Markey, and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. Mr. Markey, will you please describe your education and experience?

A. I graduated from Oklahoma State University, Stillwater, Oklahoma, in 1983 with a Bachelor of Science degree in Geology and a minor in Petroleum Engineering Technology. I also hold a Master's degree in Civil Engineering from Florida State University, Tallahassee, Florida. Prior to joining Gulf Power, I worked in the Oil & Gas industry, Environmental Consulting and Florida Department of Environmental Regulation. In October 1994, I joined Gulf Power Company as a Geologist and have since held various positions with increasing responsibilities such as Air Quality Engineer, Supervisor of Land & Water Programs, and Manager of Land and Water Programs. In 2016, I assumed my present position as Director of Environmental Services.

Q. What are your responsibilities with Gulf Power Company?
A. As Director of Environmental Services, my primary responsibility is overseeing the activities of the Environmental Services section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and laws and regulations that may be enacted or amended in the future. In performing this function, I have the responsibility for numerous environmental activities.

Q. Mr. Markey, what is the purpose of your testimony?
A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) final true-up for the period January 2018 through December 2018.

Q. Mr. Markey, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2018 through December 2018 with the approved estimated true-up amounts.
A. As reflected in Mr. Boyett's Schedule 6A, the actual recoverable capital costs were $155,403,921 as compared to $155,545,219 included in the Estimated True-up filing. This difference resulted in a net variance of ($141,298) under the estimated true-up projection. The variance was primarily due to the Coal Combustion Residual Program (Line item 1.28).

Q Please explain the capital variance of ($92,091) or (75.1%) in the Coal Combustion Residual Program (Line item 1.28)

A. This variance is primarily due to delays associated with the Plant Smith and Plant Scholz ash pond closure projects. Hurricane Michael and the following weeks of rainfall slowed progress on the pond closure projects and resulted in capital costs being less than projected. NOAA weather records for 2018 show that Plant Smith and Plant Scholz received over 20 inches of rain above their respective average rainfalls for the year.

Q. How do the actual O&M expenses for the period January 2018 to December 2018 compare to the amounts included in the Estimated True-up filing?

A. Mr. Boyett's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $38,535,091, as compared to the estimated true-up of $38,737,706. This difference resulted in a variance of $202,615 or 0.5% under the estimated true-up. I will address seven O&M projects and/or programs that, collectively, contribute to this variance: Emissions Monitoring, General Water Quality, Groundwater Contamination Investigation, General Solid & Hazardous Waste, Aboveground Storage Tanks, Air Quality Compliance Program, and Coal Combustion Residual (CCR).

Q. Please explain the variance of $159,361 or 21.7% in (Line item 1.5), Emissions Monitoring.

A. This line item includes expenses associated with the Environmental Protection Agency's (EPA) requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the Continuous Emissions Monitoring System (CEMS), including Relative Accuracy Test Audits (RATAs) and Linearity Tests. This variance is primarily due to unanticipated CEMs port repairs required for Crist Units 4 & 5.

Q. Please explain the variance of ($450,240) or (18.3%) in (Line item 1.6), General Water Quality.

A. This line item includes expenses related to National Pollutant Discharge Elimination System (NPDES) permit compliance, Dechlorination, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, the Impoundment Integrity Program, and Stormwater Maintenance. The line item variance is primarily due to two factors: (1) minimal maintenance expenses were required for the Plant Crist impoundment integrity program ($289,000); and (2) O&M costs for the Plant Crist industrial wastewater permit compliance and renewal were less than projected in the Estimated True-Up filing ($286,000).

Q. Please explain the variance of ($462,142) or (14%) in (Line item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is due to a reduction in the excavation costs required for the ECRC substation remediation program during 2018.

Q. Please explain the variance of ($161,629) or (15.7%) in (Line item 1.11), General Solid & Hazardous Waste.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This variance is primarily due to costs associated with transformer oil spills and associated disposal costs for Gulf's power delivery operations being less than projected.

Q. Please explain the variance of $68,046 or 38.2% in (Line item 1.12), Above Ground Storage Tanks.

A. The Above Ground Storage Tanks program includes maintenance activities, tank integrity inspections, and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. This variance is primarily due to the FDEP required Plant Crist petroleum storage tank integrity testing expenses being greater than originally projected.

Q. Please explain the O&M variance of $1,095,377 or 4.7% in the Air Quality Compliance Program, (Line item 1.20).

A. The Air Quality Compliance Program line item primarily includes O&M expenses associated with the Plant Daniel Units 1 and 2 scrubbers, Plant Crist Units 4 through 7 scrubber, Plant Scherer Unit 3 scrubber, Plant Crist Unit 6 Selective Catalytic Reduction (SCR) and Plant Scherer Unit 3 SCR and baghouse. More specifically, this line item includes the cost of ammonia, urea, limestone, and the general operation and maintenance activities associated with Gulf's Air Quality Compliance Program. The variance is primarily due to maintenance and limestone expenses associated with the Plant Crist scrubber being greater than originally projected. During the second half of 2018, Gulf completed maintenance work on the gypsum storage area required to place the sediment pond and associated piping back in-service. Costs associated with Crist Unit 7 MATS testing and tuning and the scrubber booster motor replacement were also greater than originally projected.

Q. Please explain the O&M variance of ($488,403) or (8.1%) in the Coal Combustion Residual, (Line item 1.23).

A. The CCR program includes O&M costs associated with the regulation of Coal Combustion Residuals by United States Environmental Protection Agency and the Florida Department of Environmental Protection. More specifically, the CCR program includes requirements to close the existing on-site ash ponds at Plant Scholz and Plant Smith, and to regulate CCR units at Gulf's Plants Crist, Scherer, Smith and Daniel. The CCR line item variance is primarily due to project delays related to Hurricane Michael and the following weeks of rainfall that slowed progress on the pond closure projects.

Q. Mr. Markey, does this conclude your testimony?
A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Environmental Cost Recovery Clause	Docket No.: 20190007-EI
	Filed: August 30, 2019

ERRATA SHEET

July 26, 2019 Testimony of Richard M. Markey

PAGE #	LINE #	
Page 1	Line 24	Change "155,146,676" to "155,178,694"
Page 2	Line 1	Change "(711,296) or (0.5%)" to "(679,278) or (0.4%)"
Page 2	Line 4	Change "(216,598)" to "(216,119)"
Page 2	Line 18	Change "234,674" to "234,844"
Page 3	Line 6	Change "(707,750)" to "(706,457)"

Reason for Change

On August 8, 2019, Gulf Power submitted a Revised May 2019 Earnings Surveillance Report. The revisions affect the weighted average cost of capital (WACC) used to calculate the recoverable capital related cost. The revised WACC is applicable to the period from July 2019 through December 2019.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard M. Markey
Docket No. 20190007-EI
Date of Filing: July 26, 2019

Q. Please state your name and business address.

A. My name is Richard M. Markey, and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. Mr. Markey, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) estimated true-up for the period January through December 2019. This true-up is based on five months of actual data and seven months of estimated data.

Q. Mr. Markey, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 2019 through December 2019 with the approved projected amounts.

A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $155,857,972, as compared to the estimated true-up amount of $155,146,676. This difference results in a variance of $(711,296) or (0.5%). I will address three projects that contribute to this variance.

Q. Please explain the capital variance of ($216,598) or (8.5%) reflected in the Smith Water Conservation Program (Line Item 1.17).

A. The variance is primarily due to postponing construction of the Plant Smith Underground Injection Control (UIC) wastewater treatment system and associated pump station from the Spring of 2019 to Fall 2019 due to additional time required for final design and permitting. The new treatment system and permanent pump station are required for Plant Smith to begin using reclaimed water for the Unit 3 cooling tower water supply. Gulf has completed installation of three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station and for current wastewater discharges. The reclaimed water project is anticipated to be a catalyst for other wastewater utilities in the area to promote the re-use of reclaimed water.

Q. Please explain the capital variance of $234,674 or 41.9% reflected in the Plant NPDES Permit Compliance Projects (Line Item 1.25).

A. This line item variance is primarily due to increased project cost and construction delays associated with the Plant Smith discharge canal project. During 2018, Plant Smith planned to replace its second discharge canal crossover; however, project completion was delayed to 2019 due to Hurricane Michael and design modifications. Design modifications were required to address dewatering as well as installation of a bypass for discharge canal flow around the work area. The second discharge canal crossover is utilized for safe access obtaining main plant discharge samples as required by the Plant Smith NPDES industrial wastewater permit.

Q. Please explain the capital variance of ($707,750) or (15.2%) reflected in the Coal Combustion Residual (CCR) (Line Item 1.28).

A. The CCR line item variance is primarily due to delays associated with the Plant Daniel CCR projects and the Plant Scholz ash pond closure project. During 2018, Gulf expected final design and construction of the Plant Daniel bottom ash handling and wastewater treatment systems to be completed in the 2019 timeframe; however, construction has been delayed to 2020 due to timing of vendor selection and equipment fabrication. In addition, completion of the Plant Scholz pond closure project has been delayed due to Hurricane Michael related rainfall and cleanup work necessary due to the extreme rainfall event.

Q. How do the estimated/actual 2019 O&M expenses compare to the original 2019 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are estimated at $30,651,813, as compared to the amount projected in the 2019 Projection filing of $33,564,237, which creates a variance of ($2,912,424) or (8.7%). I will address five O&M projects and programs that contribute to a significant portion of this variance: Air Emission Fees, Groundwater Contamination

Investigation, FDEP NOx Reduction Agreement, Air Quality Compliance Program, and Coal Combustion Residuals.

Q. Please explain the O&M variance of ($89,076) or (29.2%) in Air Emission Fees (Line Item 1.2).

A. The Air Emission Fees line item represents expenses projected for annual fees required by the Clean Air Act Amendments (CAAA) of 1990 that are payable to the FDEP and Mississippi Department of Environmental Quality. The fees are based on annual tons of emissions regulated under the Title V Air Program. The 2019 variance is primarily due to Plant Crist and Plant Daniel fees being less than projected due to the units running less than originally estimated.

Q. Please explain the O&M variance of ($554,487) or (19.6%) in Groundwater Contamination Investigation (Line Item 1.7).

A. The line item variance is due to lower O&M expenses for the Fort Walton Remediation groundwater remediation system due to installation of a new remediation system, the FDEP revising the schedule for several projects, and reducing cost of outsourcing remediation report preparation and performing more work in-house.

Q. Please explain the O&M variance of ($516,082) or (50.5%) in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement line item includes costs associated with the Plant Crist Unit 7 Selective Catalytic Reduction (SCR) and the

Plant Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the 2002 agreement with FDEP for ozone attainment. The line item variance is primarily due to the quantity of anhydrous ammonia and urea required being less than originally projected as well as reduced maintenance expenses for the Crist Unit 7 SCR and the SNCRs. Gulf is not operating the SNCRs as much as originally projected due to a reduction in coal-fired operations for Units 4 and 5.

Q. Please explain the O&M variance of ($2,668,356) or (12.2%) in the Air Quality Compliance Program (Line Item 1.20).

A. The Air Quality Compliance Program currently includes O&M expenses associated with the Plant Crist scrubber, the Crist Unit 6 SCR and the Plant Daniel scrubbers, as well as Plant Scherer's baghouse, MATS emissions monitoring equipment, SCR, and scrubber. More specifically, this line item includes the cost of limestone and ammonia, along with general operation and maintenance activities included in Gulf's Air Quality Compliance Program. The projected line item variance is primarily due to a reduction in the projected chemical and maintenance expenses associated with the Plant Crist scrubber. Long-term maintenance activities for the Plant Crist scrubber have been reduced due to plans to increase gas capabilities for Crist Units 6 and 7. In addition, the quantity of limestone, hydrated lime, and anhydrous ammonia required for Plant Crist are less than originally projected due to reduced generation.

Q. Please explain the variance of $974,628 or 30.2% in Coal Combustion Residual (Line Item 1.23).

A. The Coal Combustion Residual (CCR) line item includes O&M expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency (EPA) and the FDEP. For Gulf's generating plants, these regulatory compliance obligations are pursuant either to the CCR rule or to permit requirements added by the State through the National Pollutant Discharge Elimination System (NPDES) permits issued for each of Gulf's generating facilities. The majority of the line item variance is due to costs associated with the Plant Crist and Smith CCR compliance programs being greater than originally projected. Additional groundwater monitoring wells and site investigation activities were required for Gulf's assessment of corrective measures for CCR compliance at Plants Crist and Smith.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard M. Markey
Docket No. 20190007-EI
Date of Filing: August 30, 2019

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

A. My name is Richard M. Markey. My business address is One Energy Place, Pensacola, Florida, 32520. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. Mr. Markey, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2020 through December 2020.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have one exhibit (RMM-1) which includes Schedule 5P - Description and Progress Report of Environmental Compliance Activities and Projects.

Counsel: We ask that Mr. Markey's exhibit consisting of one document be marked as Exhibit No. _____ (RMM-1).

CAPITAL

Q. Mr. Markey, please identify the capital projects included in Gulf's ECRC projection filing.

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are listed in Schedules 3P and 4P of Gulf Witness Boyett's Exhibit CSB-3 and described in Schedule 5P included in my Exhibit RMM-1. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects. Mr. Boyett compiled these schedules and has calculated the associated revenue requirements for Gulf's requested recovery. Of the projects shown on Mr. Boyett's schedules, there is one new program that Gulf is proposing and seven programs that were previously approved by the Commission with activities that have projected capital expenditures during 2020. These programs include: Smith Water Conservation, Crist Florida Department of Environmental Protection (FDEP) Agreement for Ozone Compliance, Crist Water Conservation, Plant NPDES Permit Compliance Projects, Air Quality Compliance Program, Coal Combustion Residuals, and Steam Effluent Limitations Guidelines.

Q. Mr. Markey, please describe the new capital project Gulf seeks to recover through the ECRC.

A. Gulf is including one new project, the Crist Closed Ash Landfill (CAL), in addition to the programs previously approved by the Commission. Gulf has included costs for the CAL project under the General Water Quality line item.

Q. Mr. Markey, please describe the Crist Closed Ash Landfill (CAL) project that Gulf seeks to recover under the General Water Quality line item (Line Item 1.27).

A. During the Plant Crist industrial wastewater permit renewal process, the Florida Department of Environmental Protection (FDEP) inquired about the status of the Crist closed ash landfill and potential impacts to adjacent waters. In the fall of 2017, FDEP permitting staff conducted a site visit at the closed ash landfill and requested that Gulf collect water quality samples in the surface waters adjacent to the closed landfill, which is located between Governor's Bayou and the Escambia River. FDEP is the permitting agency that issues Gulf its wastewater facility discharge permit under FDEP's EPA approved Clean Water Act National Pollutant Discharge Elimination System (NPDES) permitting program. FDEP implements the permitting program as authorized by Florida Statutes Section 403.0885 and rules promulgated by the Department in Chapters 62-4 and 62-620 of the Florida Administrative Code (F.A.C.).

After reviewing the data resulting from analysis of the collected water samples, FDEP directed Gulf to submit a plan of study (Order 17-1224) identifying potential geological and engineering assessment methods that would allow Gulf to evaluate the integrity of the landfill and to identify "any seeps and discharges as well as the quantity and quality of those discharges to waters of the state" from the CAL. The plan of study was approved by FDEP on April 25, 2018.

Gulf began implementing field work portions of the plan of study in June 2018 and completed work in the April 2019 timeframe. An engineering report summarizing findings from the study and rehabilitation options evaluated for the closed landfill was submitted to FDEP on July 23, 2019. The report recommends regrading the surface of the CAL and then capping the CAL with a low permeability, synthetic material. These actions are needed to reduce water infiltration, to provide separation of ash and stormwater, and to provide stability improvements. On August 28, 2019, FDEP approved the proposed action plan and implementation schedule. FDEP Order 17-1224 requires Gulf to complete FDEP approved rehabilitation actions by July 23, 2023. The projected 2020 expenditures for this line item total $10,153,027.

Q. Mr. Markey, please provide an update on the Smith Water Conservation program (Line Item 1.17).

A. Gulf was granted approval for ECRC recovery of the Plant Smith Reclaimed Water project in Florida Public Service Commission (FPSC) Order No. PSC-09-0759-FOF-EI. Gulf has completed installation of three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station and for current wastewater discharges. Gulf plans to complete design and begin construction of the system needed for reclaimed water and continued permitted wastewater disposal in the fall of 2019. The new wastewater treatment system and permanent pump station are required for Plant Smith to begin using reclaimed water for the Unit 3 cooling tower water supply and continue permitted wastewater disposal. Expenditures associated with these activities reflected in the 2020 projection filing are $12,816,779.

While Gulf is in the process of completing design and construction of the reclaimed water system, the Smith UIC system is also integral for injection of wastewater from the Plant Smith ash pond closure project.

Q. Mr. Markey, please describe the projects included in the 2020 projection for the Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Gulf plans to replace the existing Plant Crist Unit 7 low NOx burner and simulator controls during 2020. The supplier will be discontinuing support and updates for the existing controls in 2020. To maintain cyber security, the control systems need to be up to date with supported operating systems to prevent and address cyber vulnerabilities. The projected 2020 expenditures for this line item total $107,574.

Q. Mr. Markey, please describe the projected 2020 capital expenditures for Plant NPDES Permit Compliance Projects (Line Item 1.25).

A. The water quality based copper effluent limitation included in Chapter 62 Part 302, F.A.C. is included by reference in the Plant Crist NPDES industrial wastewater permit. Since the more stringent hardness based standard was implemented in 2002, Gulf Power has continued to evaluate and reduce the sources of copper at Plant Crist. Plant Crist completed several projects to reduce copper, including installation of stainless steel condenser tubes on Unit 6 and dredging of the former ash pond, as well as adding pH control and aeration systems to the pond. While these projects significantly reduced copper concentrations, Plant Crist reported an exceedance of the copper standard in second quarter 2017 that resulted in FDEP requiring Gulf to implement a plan of study to further reduce copper concentrations in the discharge.

Gulf Power submitted results of the copper plan of study in June 2019. The plan of study recommends retubing the Unit 6C service water cooler and Units 4 and 5 condensers with stainless steel tubes to eliminate these copper sources. On July 5, 2019, FDEP approved the proposed corrective actions and implementation schedule. FDEP Order 17-1224 requires Gulf to complete the corrective actions to address copper by January 25, 2021. Gulf is currently in the process of procuring material for retubing the Unit 6C service water cooler in order to complete the project during the fall 2019 outage. The Units 4 and 5 condenser project is expected to be completed in the 2020 timeframe. Expenditures associated with these activities reflected in the 2020 projection filing are $3,131,598.

Q. Please describe the projected capital expenditures for the Air Quality Compliance program (Line Item 1.26).

A. The 2020 projected expenditures for the Air Quality Compliance program include costs associated with the following: scrubbers at Plant Crist, Plant Daniel, and Plant Scherer, Plant Crist Unit 6 SCR, as well as the Plant Daniel Low NOx burners. More specifically, this includes approximately $4 million of expenditures for the expansion of the Plant Crist Underground

Injection Control (UIC) pump station. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage area and associated groundwater remediation system. Additionally, this line item includes $3,022,922 of expenditures to upgrade the Plant Crist Unit 6 SCR and scrubber controls to meet cyber security requirements. The projected capital cost for Gulf's ownership portion of the Scherer Unit 3 scrubber is $292,112 to replace scrubber system pumps and valves and to conduct roadway improvements for work around the gypsum landfill. Plant Daniel will also be replacing the low NOx burners on Unit 1, which have reached the end of their useful life. The cost of the new low NOx burners is $510,000. The projected 2020 expenditures for this program total $7,825,035.

Q. Mr. Markey, please describe the projects included in Gulf's 2020 projection for the Coal Combustion Residuals capital program (Line Item 1.28).

A. Line Item 1.28 is related to the regulation of Coal Combustion Residuals (CCR) by the United States Environmental Protection Agency (EPA) and FDEP. For Gulf's generating plants, these regulatory compliance obligations are pursuant to either the CCR rule adopted in April of 2015 or through new requirements added by FDEP to the NPDES industrial wastewater permits issued for each of Gulf's Florida generating facilities pursuant to authority granted under the Clean Water Act. The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule (391-3-4-.10), which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019. The projected 2020 expenditures for this line item total $49,278,428 and includes costs for Scholz, Smith, Scherer, Daniel and Crist as discussed below.

Construction activities for closure of the ash pond at Plant Scholz will continue through the Fall of 2020. During 2020, the Scholz ash pond closure project will include construction of a new stormwater management system, transferring CCR material to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2020 expenditures for the Plant Scholz CCR closure are projected to be $6,850,985 million.

In 2018, Plant Smith began construction of a new lined industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. Gulf plans to complete construction of the first pond and associated pump station and piping in 2020 and then to proceed with construction of two additional industrial wastewater ponds and a slurry wall. During pond construction, CCR material will be excavated and transported to a new dry stack area within the footprint of the pond. The 2020 expenditures for the Plant Smith CCR closure are projected to be $16,586,152.

During 2020, construction of the Scherer CCR wastewater management system will continue, which includes installing wastewater treatment systems for wastewater streams that have been routed to the ash pond such as coal pile runoff, equipment wash water, and precipitator sumps. In addition, construction will begin on Cell 3 of the onsite landfill for CCR storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill. The 2020 expenditures for Gulf's ownership portion of the Plant Scherer CCR projects are projected to be $2,456,800.

Plant Daniel must cease placing CCR and non-CCR waste streams into the ash pond no later than October 31, 2020, in accordance with the CCR rule. New wastewater treatment and ash handling systems are required for the waste streams currently being routed to the pond (bottom ash and low volume wastewater) prior to the October 31, 2020, deadline. The Unit 1 and Unit 2 dry bottom ash conversion projects are scheduled to be placed in-service during 2020. Plant Daniel also plans to begin work on a temporary wastewater treatment system that will provide treatment for low volume wastewater streams while the plant closes and repurposes the bottom ash pond to serve as a low volume wastewater treatment pond. The 2020 expenditures for Gulf's ownership portion of the Plant Daniel CCR projects are projected to be $23,234,491.

Plant Crist has projected $150,000 of capital expenditures in 2020 for additional CCR groundwater monitoring wells.

Q. Mr. Markey, please describe the projects included in Gulf's 2020 projection for the Steam Effluent Limitations Guideline capital program (Line Item 1.29).

A. In 2015, the EPA finalized revisions to the steam electric effluent limitations guidelines (ELG) rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization (FGD) scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance applicability dates in the 2015 rule ranged from November 1, 2018, to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest ELG applicability date for FGD wastewater and bottom ash transport water from the original (2015 rule) "as soon as possible date" of November 1, 2018, to a new "as soon as possible" date of November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest applicability date or "no later than" date of December 31, 2023.

State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA plans to propose ELG rule revisions in the second half of 2019 and to finalize the rulemaking by December 2020. Gulf has projected costs in 2020 for engineering and design of Gulf's ownership portion of the Scherer scrubber wastewater treatment system. The 2020 expenditures for this line item total $871,250.

Q. Mr. Markey, are you including the purchase of allowances in your 2020 projection filing?

A. Yes, Gulf has projected the need to purchase seasonal NOx allowances for Plant Daniel in 2020. Gulf has projected $85,000 of expenditures for Line item 1.33 during 2020.

Operation and Maintenance (O&M)

Q. How do the projected Environmental O&M activities listed on Schedule 2P of Mr. Boyett's Exhibit CSB-4 compare to the O&M activities approved for cost recovery in past ECRC proceedings?

A. All of the O&M programs listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings.

Q. Please describe the O&M activities included in the air quality category for 2020.

A. There are five O&M activities included in the air quality category that have projected expenses in 2020. The five activities are: Air Emission Fees, Title V, Asbestos Fee, Emissions Monitoring, and the FDEP NOx Reduction Agreement.

On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990, also known as Title V fees, that are payable to the FDEP, the Mississippi Department of Environmental Quality, and the Georgia Environmental Protection Division. The total 2020 estimated expenses for the Air Emission Fees are $285,269.

Included in the air quality category, Title V (Line Item 1.3) represents projected ongoing expenses associated with implementation of the Title V permits. The total 2020 estimated expenses for the Title V program are $231,465.

On Schedule 2P, Asbestos Fees (Line Item 1.4) consists of the fees required to be paid to the FDEP for asbestos abatement projects. The total 2020 estimated expenses for the Asbestos Fees are $1,000.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the CEMS equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMS, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. The total 2020 estimated expenses for the Emissions Monitoring are $736,399.

The FDEP NOx Reduction Agreement (Line Item 1.19) is comprised of O&M costs associated with the Plant Crist Unit 7 SCR and the Plant Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the 2002 agreement with FDEP for ozone attainment. This line item includes the cost of anhydrous ammonia, air monitoring, and general O&M expenses related to activities undertaken in connection with the agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-EI in Docket No. 20020943-EI. The total 2020 estimated expenses for the FDEP NOx Reduction Agreement are $560,731.

Q. What O&M activities are included in the water quality category?

A. General Water Quality (Line Item 1.6), identified in Schedule 2P, includes costs associated with NPDES industrial wastewater permit compliance, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, Dechlorination, the Impoundment Integrity Program, and Stormwater Maintenance. The total 2020 estimated expenses for General Water Quality are $1,542,559.

Q. What other O&M activities are included in the water quality category?

A. Groundwater Contamination Investigation (Line Item 1.7) was previously approved for environmental cost recovery in FPSC Docket No. 19930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $2,241,964 of incremental expenses for this line item during the 2020 recovery period.

Line Item 1.8, State NPDES Administration, was previously approved for recovery in the ECRC and reflects expenses associated with NPDES annual fees and permit renewal fees for Gulf's three generating facilities in Florida. These expenses are expected to be $35,000 during the projected recovery period.

Line Item 1.23 is the CCR program that includes expenses related to the regulation of Coal Combustion Residuals by the EPA, FDEP, and the Georgia Environmental Protection Division. During 2020, the Plant Scholz and Plant Smith CCR closure projects will be under construction, and Gulf will continue its ongoing CCR groundwater monitoring and engineering inspections. The 2020 expenses projected for the CCR line item total $6,866,072, which encompasses Plant Scholz and Plant Smith pond closure activities.

As mentioned previously, construction activities for closure of the ash pond at Plant Scholz are ongoing. During 2020, the Scholz ash pond closure project will include construction of a new stormwater management system, transferring CCR material upland to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. The 2020 expenses for the Plant Scholz CCR closure are projected to be $1.0 million.

In 2018, Plant Smith, began construction of a new industrial wastewater treatment pond by relocating CCR material within the ash pond footprint. In

2020, Gulf will proceed with construction of the new pond and associated activities to close a portion of the pond. The 2020 pond closure activities will include construction of additional industrial wastewater ponds and a slurry wall, as well as transferring CCR material upland to a dry stack area within the northern footprint of the pond. The 2020 expenses associated with the Plant Smith CCR closure are projected to be $4.1 million

Q. What activities are included in the environmental affairs administration category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Mr. Boyett's Exhibit CSB-4. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. The total 2020 estimated expenses for the Environmental Audit/Assessment are $15,000.

Q. What O&M activities are included in the General Solid and Hazardous Waste category?

A. The General Solid and Hazardous Waste activity (Line Item 1.11) involves the proper identification, handling, storage, transportation, and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. The total 2020 estimated expenses for the General Solid and Hazardous Waste activity is approximately $1 million.

Q. Are there any other O&M activities that have been approved for recovery that have projected expenses?

A. There are five other O&M activities that have been approved in past proceedings which have projected expenses during 2020. They are the Above Ground Storage Tanks program, the Air Quality Compliance Program, Crist Water Conservation, Smith Water Conservation, and Emission Allowances.

Q. What O&M activities are included in the Above Ground Storage Tanks line item?

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities, tank integrity inspections, and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $183,659 are projected to be incurred.

Q. What activities are included in the Air Quality Compliance Program (Line Item 1.20)?

A. This line item encompasses O&M expenses associated with the capital projects approved for ECRC recovery under the Air Quality Compliance Program and expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber as well as associated equipment. Anhydrous ammonia, hydrated lime, limestone and general O&M expenses are included in the Air Quality Compliance Program line item. The projected 2020 expenses for this line item total $18,287,138.

Q. What activities are included in the Crist Water Conservation line item (Line Item 1.22)?

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water systems, such as piping and valve maintenance. Expenses totaling $45,978 are projected to be incurred during 2020 for this line item.

Q. What activities are included in the Smith Water Conservation line item (Line Item 1.24)?

A. The Smith Water Conservation line item includes general O&M expenses associated with the Plant Smith deep injection well system that was placed in service during 2016 as part of the Plant Smith Reclaimed Water capital project. The injection well system is currently used for wastewater disposal as part of the CCR projects on site and will be used for reclaimed water in the future. The projected costs include sampling and analytical charges, chemicals, and mechanical integrity testing expenses required by the FDEP permit. Gulf was granted approval for recovery of the Plant Smith Reclaimed Water project in FPSC Order No. PSC-09-0759-FIF-EI. Expenses totaling $48,696 are projected to be incurred during 2020 for this line item.

Q. Please describe the emission allowance expense line items.
A. This line item includes projected allowance expenses for Gulf's generation. Line Item 1.26 includes $3,087 of projected expenses for annual NOx allowances, Line Item 1.27 includes $7,113 of projected expenses for seasonal NOx allowances, and Line Item 1.28 includes $9,834 of projected expenses for SO_2 allowances during 2020.

Q. Do each of the capital projects and O&M activities that have projected costs in 2020 meet the ECRC statutory guidelines?
A. Yes. The projects included in Gulf's 2019 ECRC projection filing meet the requirements of the ECRC statute and are consistent with the Commission's precedents regarding environmental cost recovery. Each of the capital projects and O&M activities set forth in Mr. Boyett's schedules include only prudent costs that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

Q. Mr. Markey, does this conclude your testimony?
A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20190007-EI
Date of Filing: April 1, 2019

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory Forecasting and Pricing Manager for Gulf Power Company (Gulf or the Company).

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

A. I graduated from the University of Florida in 2001 with a Bachelor of Science degree in Business Administration and earned a Master of Business Administration degree from the University of West Florida in 2005. I joined Gulf Power in 2002 and worked five years as a Forecasting Specialist until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. I transferred to Gulf Power's Financial Planning department in 2014 as a Financial Analyst until being promoted to lead the Regulatory and Cost Recovery department later that year. My current responsibilities include oversight of the Company's Regulatory, Pricing and Forecasting functions which include the calculation of clause revenue requirement and cost recovery factors, tariff administration, and the regulatory filing function of Gulf Power Company.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present the final true-up amount for the period January 2018 through December 2018 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I am sponsoring one exhibit. My exhibit consists of ten schedules, nine of which are environmental cost recovery final true-up schedules and one schedule containing the Scherer/Flint credit calculation, as described later in my testimony. This exhibit was prepared under my direction, supervision, and review.

Counsel: We ask that Mr. Boyett's exhibit consisting of ten schedules be marked as Exhibit No. _____ (CSB-1)

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2018 set forth in your exhibit?
A. Yes. These documents were prepared under my supervision.

Q. Have you verified that, to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in

accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission (FPSC or Commission).

Q. What is the final ECRC true-up amount for the period ending December 2018, to be addressed in the recovery period beginning January 2020?

A. An over-recovery in the amount of $1,896,136 was calculated and is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $1,896,136 over-recovery was calculated by taking the difference between the estimated January 2018 through December 2018 over-recovery of $9,436,937 as approved in FPSC Order No. PSC-2018-0594-FOF-EI, dated December 20, 2018, and the actual over-recovery of $11,333,073 which is the sum of lines 5, 6 and 9 on Schedule 2A of my exhibit.

Q. Please describe Schedules 2A and 3A of your exhibit.

A. Schedule 2A shows the calculation of the actual over-recovery of environmental costs for the period January 2018 through December 2018. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. This method is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4A and 5A of your exhibit.
A. Schedule 4A compares the actual O&M expenses for the period January 2018 through December 2018 with the estimated/actual O&M expenses as filed on July 25, 2018, in Docket No. 20180007-EI. Schedule 5A shows the monthly O&M expenses by activity, including the offsetting Scherer/Flint credit, along with the calculation of jurisdictional O&M expenses for the recovery period. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Any material variances in O&M expenses are discussed in Gulf Witness Markey's final true-up testimony.

Q. Please describe Schedules 6A and 7A of your exhibit.
A. Schedule 6A for the period January 2018 through December 2018 compares the actual recoverable costs related to investment with the estimated/actual amount as filed on July 25, 2018, in Docket No. 20180007-EI. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the recovery period. Recoverable costs also include a return on working capital associated with emission allowances and the regulatory asset associated with the retirement of Smith Units 1 and 2 established by Commission Order No. PSC-16-0361-PAA-EI in Docket No. 20160039-EI dated August 29, 2016. Schedule 7A provides the monthly recoverable costs associated with each project, including the offsetting Scherer/Flint credit, along with the calculation of the jurisdictional recoverable costs.

Any material variances in recoverable costs related to the environmental investment for this period are discussed in Mr. Markey's final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 34 pages that provide the monthly calculations of the recoverable costs associated with each approved capital project for the recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, cost of emission allowances and the regulatory asset. Pages 1 through 29 of Schedule 8A show the investment and associated costs related to capital projects, while pages 30 through 33 show the investment and costs related to emission allowances, and page 34 shows the costs related to the regulatory asset for retired Plant Smith Units 1 and 2.

Q. Mr. Boyett, what capital structure, components and cost rates did Gulf use to calculate the revenue requirement rate of return?

A. For January 2018 through June 2018, the rate of return used is the weighted average cost of capital (WACC) established by specific terms in the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated Dockets Nos. 20160186-EI and 20160170-EI dated May 16, 2017 (2017 Settlement Agreement). The 2017 Settlement Agreement WACC was adjusted for the implementation of Gulf's Stipulation and Settlement Agreement approved by the

Commission in Order No. PSC-2018-0180-FOF-EI dated April 12, 2018 (2018 Tax Reform Settlement) to reflect the lower federal income tax rate as a result of the Tax Cuts and Jobs Act. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 20120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes for July 2018 through December 2018 is based on the WACC presented in Gulf's May 2018 Earnings Surveillance Report, adjusted to achieve the 53.5 percent equity ratio as approved by 2018 Tax Reform Settlement. The WACC for both periods includes a return on equity of 10.25% as reflected on Schedule 9A.

Q. Please describe Schedule 10A.

A. Schedule 10A provides the monthly calculation of the total ECRC revenue requirements of Gulf's ownership in Scherer Unit 3 (Scherer 3) and quantifies the portion of Scherer 3 incremental revenue requirements that continues to be committed to a wholesale customer through a long-term contract (Scherer/Flint credit), which will expire December 2019. In accordance with the provisions of the 2017 Settlement Agreement, Gulf is including the Scherer/Flint credit as an offset to recoverable O&M and capital investment costs until Scherer 3 is no longer partially committed to the wholesale customer. The Scherer/Flint credits appear on Lines 1.29 and 1.30 of Schedules 4A and 5A and on Lines 1.35 and 1.36 of Schedules 6A and 7A of my Exhibit CSB-1. The inclusion of the Scherer/Flint credit, as calculated, results in ECRC being revenue-neutral regarding the incremental portion of Scherer 3 investment and expenses.

Q. Mr. Boyett, does this conclude your testimony?
A. Yes

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20190007-EI
Date of Filing: July 26, 2019

Q. Please state your name, business address and occupation.
A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory, Forecasting and Planning Manager for Gulf Power Company. (Gulf or the Company)

Q. Have you previously filed testimony in this docket?
A. Yes I have.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present the estimated true-up amount for the period January 2019 through December 2019 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?
A. Yes, I am sponsoring one exhibit. My exhibit consists of ten schedules, nine of which are environmental cost recovery estimated true-up schedules and one of which contains the Scherer/Flint credit calculation, as described later in my testimony. This exhibit was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of ten schedules be marked as Exhibit No. _____(CSB-2).

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

A. Yes, I have. The actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission (FPSC).

Q. What has Gulf calculated as the estimated true-up for the January 2019 through December 2019 period to be addressed in 2020 ECRC factors?

A. The estimated true-up for the current period is an over-recovery of $4,640,870 as shown on Schedule 1E of Exhibit CSB-2. This amount is based on five months of actual data and seven months of estimated data. The estimated true-up amount will be added to the 2018 final true-up over-recovery amount of $1,896,136. The resulting total true-up over-recovery of $6,537,006 will be addressed in Gulf's proposed 2020 ECRC factors. The detailed calculations supporting the estimated true-up for 2019 are contained in Schedules 2E through 10E of Exhibit CSB-2.

Q. Please describe Schedules 2E and 3E of your Exhibit CSB-2.
A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2019 through December 2019. Schedule 3E of this exhibit is the calculation of the interest provision on the average true-up balance. This same method of calculating interest is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4E and 5E of your Exhibit CSB-2.
A. Schedule 4E compares the estimated/actual O&M expenses for the period January 2019 through December 2019 to the projected O&M expenses approved by the Commission in Docket No. 20180007-EI. Schedule 5E shows the monthly O&M expenses by activity, along with the calculation of jurisdictional O&M expenses for the current recovery period. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Gulf Witness Markey describes the reasons for the expected variances in O&M expenses in his estimated/actual testimony.

Q. Please describe Schedules 6E and 7E of your Exhibit CSB-2.
A. Schedule 6E for the period January 2019 through December 2019 compares the estimated/actual investment-related recoverable costs to the projected amount approved in Docket No. 20180007-EI. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the current recovery period. Recoverable

costs also include a return on working capital associated with emission allowances and a return on the unamortized balance of the regulatory asset associated with the retirement of Smith Units 1 and 2 established by Commission Order No. PSC-16-0361-PAA-EI in Docket No. 160039-EI, dated August 29, 2016. Mr. Markey discusses variances in recoverable capital costs related to environmental project activities in his estimated/actual testimony. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements.

Q. Please describe Schedule 8E of your Exhibit CSB-2.

A. Schedule 8E includes 35 pages that provide the monthly calculations of recoverable costs associated with each capital project for the current recovery period. As stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, return on working capital associated with emission allowances and return on unamortized balance of the Smith 1 and 2 regulatory asset. Pages 1 through 30 of Schedule 8E show the investment and associated costs related to capital projects, while pages 31 through 34 show the inventory and associated costs related to emission allowances, and page 35 shows the costs related to the regulatory asset for retired Plant Smith Units 1 and 2.

Q. What capital structure and cost rates were used to develop the rate of return, applied to calculate revenue requirements, as shown on Schedule 9E of Exhibit CSB-2?

A. The capital structure and cost rates used for cost recovery clause purposes for the period January 2019 through June 2019 is based on Gulf's May 2018 Earnings Surveillance Report. The period July 2019 through December 2019 is based on the capital structure and cost rates in the May 2019 Earnings Surveillance Report. The capital structure for both periods has been adjusted to achieve a 53.5 percent equity ratio per the terms of the 2018 Tax Reform Stipulation and Settlement Agreement, approved by Commission Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI. The weighted average cost of capital (WACC) for both periods includes a 10.25 percent return on equity. The resulting revenue requirement rate of return as presented on Schedule 9E is consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 120007-EI.

Q. Please describe Schedule 10E of your exhibit.

A. Schedule 10E provides the monthly calculation of the total ECRC revenue requirements of Gulf's ownership in Plant Scherer Unit 3 (Scherer 3) and quantifies the incremental portion of Scherer 3 environmental revenue requirements that continues to be committed to a wholesale customer through a long-term contract (Scherer/Flint credit), which will expire December 2019. In accordance with the provisions of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2017-0178-S-EI in consolidated Docket Nos. 20160186-EI and 2016170-EI dated May 16, 2017, Gulf is including the Scherer/Flint credit as an offset to recoverable O&M and capital investment costs until Scherer 3 is no longer partially committed to the wholesale customer. The Scherer/Flint credits appear on Lines 1.29 and 1.30 of Schedules 4E and 5E, as well as on Lines 1.36 and 1.37 of Schedules 6E and 7E, of my Exhibit CSB-2. The inclusion of the Scherer/Flint credit, as calculated, results in ECRC being revenue-neutral regarding the incremental portion of Scherer 3 investment and expenses.

Q. Mr. Boyett, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20190007-EI
Date of Filing: August 30, 2019

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory, Forecasting and Planning Manager for Gulf Power Company. (Gulf or the Company).

Q. Have you previously filed testimony in this docket?

A. Yes I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present both the calculation of revenue requirements and the development of environmental cost recovery factors for the period January 2020 through December 2020. I will also present a correction of Gulf Power's weighted average cost of capital and resulting recalculation of the 2019 estimated true-up amount based upon the revised May 2019 Earnings Surveillance Report (Revised May ESR) that was submitted to the Florida Public Service Commission (FPSC or Commission) on August 8, 2019.

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

A. Yes, I am sponsoring two exhibits. My first exhibit consists of eight schedules, which are Gulf Power's environmental cost recovery projection schedules. My second exhibit contains five schedules that provide the recalculation of the estimated true-up amount for the period January 2019 through December 2019, which was filed with the FPSC in Docket No. 20190007-EI on July 26, 2019. Both exhibits were prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-3) and Exhibit No. _____(CSB-4)

Q. What environmental costs is Gulf requesting recovery of through the Environmental Cost Recovery Clause (ECRC)?

A. As discussed in the testimony of Gulf Witness Richard M. Markey, Gulf is requesting recovery for certain environmental compliance expenses and capital costs that are consistent with both the decision of the Commission in Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and past proceedings in this ongoing recovery docket. The costs identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

Q. How was the amount of projected Operations and Maintenance (O&M) expenses to be recovered through the ECRC calculated?

A. Mr. Markey has provided projected recoverable O&M expenses for January 2020 through December 2020. Schedule 2P of Exhibit CSB-3 shows the calculation of the recoverable O&M expenses broken down between demand-related and energy-related expenses. Schedule 2P also provides the jurisdictional recoverable O&M expenses. All O&M expenses associated with compliance with air quality environmental regulations were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. The remaining expenses were broken down between demand and energy, consistent with Gulf's last approved cost-of-service methodology.

Q. Please describe Schedules 3P and 4P of your Exhibit CSB-3.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment program for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment program. Schedules 3P and 4P also include the calculation of the jurisdictional amount of recoverable revenue requirements. To prepare these schedules, Mr. Markey provided the expenditures, clearings, retirements, salvage, and cost of removal related to each capital project, as well as the monthly costs for emission allowances. From that information, plant-in-service and construction work in progress (non-interest bearing) was calculated. Additionally, depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances, were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the test year on which present base rates were set.

Q. How was the amount of property taxes to be recovered through the ECRC derived?

A. Property taxes were calculated by applying the projected applicable millage rate to the ECRC apportioned assessed value.

Q. What capital structure and cost rates were used to develop the rate of return, applied to calculate the revenue requirements, as shown on 8P of Exhibit CSB-3?

A. The capital structure and cost rates used for cost recovery clause purposes is based on the weighted average cost of capital presented in Gulf's Revised May 2019 ESR, as adjusted per the terms of the 2018 Tax Settlement and Stipulation Agreement, approved by FPSC Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI, dated April 12, 2018.

Gulf is party to an Unopposed Joint Motion to Modify Order No. PSC-12-0425-PAA-EU Regarding Weighted Average Cost of Capital Methodology (Joint Motion), filed on August 21, 2019 in this docket. The Joint Motion proposes modifications to the existing methodology for calculating the weighted average cost of capital (WACC) applicable to clause-recoverable investments to enable compliance with Internal Revenue Service Normalization Rules. Gulf Power's depreciation-related accumulated deferred income taxes (ADIT) in its Revised May ESR filing is less than its projected ADITs; therefore, the Limitation Provision is met or exceeded, and no adjustments are necessary to the Revised May ESR capital structure. Under either methodology, the rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent and a federal income tax rate of 21 percent.

Q. How has the breakdown between demand-related and energy-related investment costs been determined?

A. Consistent with Commission Order No. PSC-13-0606-FOF-EI dated November 19, 2013, in Docket No. 130007-EI, investment costs recoverable through ECRC are allocated between demand and energy based on the 12-MCP and 1/13th energy allocator, respectively. The use of this allocation method is consistent with cost-of-service studies approved in Gulf's most recent base rate case. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What jurisdictional factors were used to calculate projected recoverable costs for the period January 2020 through December 2020?

A. The demand jurisdictional factors applied in the calculation of retail revenue requirements is 97.23427 percent, which is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. The energy jurisdictional factors for each month are based on historical 2018 retail kilowatt-hour sales expressed as a percentage of 2018 total territorial kilowatt-hour sales. The existing wholesale generation services agreement between Gulf Power Company and Florida Public Utilities Company (FPU) will expire on December 31, 2019; however, on August 12, 2019, Gulf Power and FPU executed a new stratified wholesale agreement that will commence on January 1, 2020, if approved. In order to implement a stratified allocation of costs between the retail and wholesale jurisdiction consistent with the new contract structure, considerable work by Gulf Power to stratify environmental costs and derive appropriate stratified jurisdictional factors must be completed. Gulf currently estimates this work will be completed before 2020 final true-up calculations are filed with the Commission. Subject to the foregoing determination of stratified jurisdictional factors, any eventual over or under recovery of costs due to changes in jurisdictional allocations will be handled through the normal true-up process.

Q. Have there been any other notable changes to the projected recoverable costs for the period January 2020 through December 2020?

A. Yes. The ratemaking adjustment I have referred to in previous testimony as the "Scherer/Flint credit" will cease at the end of December 2019 when the long-term wholesale contract with Flint EMC expires on December 31, 2019. As a result, the portion of Scherer Unit 3 ECRC costs which were previously excluded from Gulf's retail cost recovery will be included in the ECRC recoverable costs and revenue requirements beginning in 2020.

The end of this ratemaking treatment was contemplated by the Stipulation and Settlement Agreement approved by FPSC Order No. PSC-17-0178-S-EI.

Q. What is the total amount of projected recoverable costs related to the period January 2020 through December 2020?

A. The total projected jurisdictional recoverable costs for the period January 2020 through December 2020 is $189,722,598 as shown on line 1c of Schedule 1P of Exhibit CSB-3. This amount includes costs related to O&M activities of $31,239,013 and costs related to capital projects of $158,483,585, as shown on lines 1a and 1b of Schedule 1P.

Q. Please describe the revised schedules contained in your Exhibit CSB-4.

A. Gulf discovered miscalculations in the May 2019 Earnings Surveillance Report and subsequently submitted a Revised May 2019 Earnings Surveillance Report to the Commission on August 8, 2019. The revisions caused a slight change in the WACC used for cost recovery purposes as calculated based upon the Revised May ESR. The result was a change from 6.9752 to 6.9802 percent, an increase of one-half of one basis point on the annual pre-tax WACC.

Q. How does the revised WACC affect the estimated/actual true-up amount for the period ending 2019 that you previously filed in this docket filed on July 26, 2019?

A. When the revised WACC is applied to the ECRC average net investment from July 2019 through December 2019, the 2019 estimated true-up over-recovery amount changes from $4,640,870 to $4,609,567, a decrease of $31,303. Exhibit CSB-4 contains certain revised 2019 estimated true-up schedules. Schedule 1E of this exhibit shows the revised total true-up over-recovery of $4,609,567. The estimated true-up amount will be added to the 2018 final true-up of $1,896,136, which results in a total true-up over-recovery of $6,505,703 to be included in the proposed 2020 ECRC factors. Schedule 2E of this exhibit presents the revised calculation of the estimated true-up amount for the period January 2019 through December 2019. Schedule 3E of this exhibit presents the calculation of the revised interest provision. Schedule 6E of this exhibit compares recoverable costs from the revised 2019 estimated/actual to the original 2019 projection. Schedule 7E provides the revised monthly jurisdictional recoverable revenue requirements associated with each project.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2020 through December 2020, and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $183,348,811 for the period January 2020 through December 2020, as shown on line 5 of Schedule 1P of Exhibit CSB-3. This amount includes the recoverable costs related to the projection period offset by the revised total over-recovery true-up amount of $6,505,703. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. The total recoverable energy and demand amounts are allocated by rate class using the appropriate energy and demand allocators as shown on Schedule 6P and 7P of Exhibit CSB-3.

Q. How were the rate class allocation factors calculated for use in the Environmental Cost Recovery Clause?

A. The demand allocation factors used in the ECRC have been calculated using the 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. and adjusted for losses. The energy allocation factors were calculated based on projected kWh sales for the period adjusted for losses. The calculation of the allocation factors for the period is shown in columns A through G on Schedule 6P of Exhibit CSB-3.

Q. How were these factors applied to allocate the requested recovery amount properly to the rate classes?

A. As I described earlier in my testimony, Schedule 1P of Exhibit CSB-3 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $30,703,797 for the period January 2020 through December 2020 was allocated using the energy allocator, as shown in column C on Schedule 7P of Exhibit CSB-3. The demand-related recoverable revenue requirement of $152,645,014 for the period January

2020 through December 2020 was allocated using the demand allocator, as shown in column D on Schedule 7P. The energy-related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column E on Schedule 7P.

Q. What is the monthly amount related to environmental costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kWh will be $18.97 monthly for the period January 2020 through December 2020.

Q. When does Gulf propose to collect its environmental cost recovery charges?

A. The factors will be effective beginning with Cycle 1 billings in January 2020 and will continue through the last billing cycle of December 2020.

Q. Mr. Boyett, does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

March 29, 2019

Q. Please state your name and business address.

A. My name is Christopher Menendez. 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: regulatory financial reports and analysis of state, federal and local regulations and their impact on DEF. In this capacity, I am also responsible for DEF's True-up, Actual/Estimated and Projection filings in the Environmental Cost Recovery Clause docket ("ECRC").

Q. Please describe your educational background and professional experience.

A. I joined the Company on April 7, 2008 as a Senior Financial Specialist in the Florida Planning & Strategy group. In that capacity, I supported the development of long-term financial forecasts and the development of current-year monthly earnings and cash flow projections. In 2011, I accepted a position as a Senior Business Financial Analyst in the Power Generation Florida Finance organization. In that capacity, I provided accounting and financial analysis support to various generation facilities in DEF's Fossil fleet. In 2013, I accepted a position as a Senior Regulatory Specialist. In that capacity, I supported the preparation of testimony and exhibits for the Fuel Docket as well as other Commission Dockets. In October 2014, I was promoted to my current position. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. In this role, I was responsible for inventory-related accounting and inventory control functions for Cott-owned manufacturing plants in the United States and Canada. I received a Bachelor of Science degree in Accounting from the University of South Florida, and I am a Certified Public Accountant in the State of Florida.

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 2018 - December 2018.

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

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

Exhibit No.___ CAM-1 consists of the following:

- Form 42-1A: Final true-up for the period January 2018 - December 2018.
- 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.

- Form 42-9A: DEF's capital structure and cost rates.

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

- Pipeline Integrity Management (Capital Program Detail (CPD), pages 2-3)
- Above Ground Storage Tank Secondary Containment (CPD, pages 4-9)
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs)(CPD, pages 10-13)
- CAIR-Crystal River Units 4 & 5 (CPD, pages 14-15)

These exhibits were developed under my supervision and they are true and accurate.

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

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

Q. What is the final true-up amount DEF is requesting for the period January 2018 - December 2018?

A. DEF requests approval of an over-recovery amount of $6,433,136 for the year ending December 31, 2018. 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 2018 - December 2018 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 $1,988,942 for the period January 2018 - December 2018 reflected on Line 3 of Form 42-1A. This amount is the difference between an actual over-recovery amount of $6,433,136 and an actual/estimated over-recovery of $4,444,194 for the period January 2018 - December 2018, as approved in Order PSC-2018-0594-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 2018 - December 2018 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 $3,231,435 or 8% lower than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimonies of Timothy Hill, Jeffrey Swartz, and Kim McDaniel.

Q. How did actual capital recoverable expenditures for January 2018 - December 2018 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 $41,943 or 0.2% 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 Timothy Hill, Jeffrey Swartz and Kim McDaniel.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER A. MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

July 26, 2019

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes, I provided direct testimony on March 29, 2019.

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's ("DEF") actual/estimated true-up costs associated with environmental compliance activities for the period January 2019 through December 2019. I also explain the variance between 2019 actual/estimated cost projections versus original 2019 cost projections for emission allowances (Project 5).

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

A. Yes. I am sponsoring the following exhibits:

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

These exhibits provide detail on DEF's actual/estimated true-up capital and O&M environmental costs and revenue requirements for the period January 2019 through December 2019.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2019 through December 2019?

A. The 2019 actual/estimated true-up is an over-recovery, including interest, of $16,666,006 as shown on Form 42-1E, line 4. This amount is added to the final 2018 true-up over-recovery of $1,988,942 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $18,654,948 as shown on Form 42-2E, Line 11. The calculations supporting the 2019 actual/estimated true-up are on Forms 42-1E through 42-8E.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2019 through December 2019?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2019 through December 2019 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 2019 through December 2019 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be $13,971,187 or 34% lower than originally projected. This form also lists individual O&M project variances. Explanations for these variances are included in the direct testimonies of Timothy Hill, Kim McDaniel, and Jeffrey Swartz.

Q. How do estimated/actual capital recoverable costs for January 2019 through December 2019 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be $256,226 or 1% higher 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. Hill, Ms. McDaniel, and Mr. Swartz.

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 $4,423 or 22% 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

CHRISTOPHER A. MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

August 30, 2019

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes. I provided direct testimony on March 29, 2019, and July 26, 2019.

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 2020 through December 2020. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2020.

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __(CAM-5), which consists of PSC Forms 42-1P through 42-8P; and
2. Exhibit No. __(CAM-6), which provides details of capital projects.

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 8-20.
- Mr. Swartz and Ms. McDaniel will co-sponsor Form 42-5P page 7.
- Mr. Swartz will co-sponsor Form 42-5P pages 21 and 22.
- Mr. Hill 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 0.078 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2020 through December 2020 of approximately $30.6 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $18.7 million from prior periods. My testimony also supports that projected environmental expenditures for 2020 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2020 through December 2020?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $30.6 million as shown on Form 42-1P line 5 of Exhibit No. __(CAM-5).

Q. What is the total true-up to be applied for the period January 2020 through December 2020?

A. The total true-up applicable to this period is an over-recovery of approximately $18.7 million. This amount consists of the final true-up over-recovery of approximately $2.0 million for the period January 2018 through December 2018, and an estimated true-up over-recovery of approximately $16.7 million for the current period of January 2019 through December 2019. The detailed calculation supporting the 2019 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (CAM-3) filed with the Commission on July 26, 2019.

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

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

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

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

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

CAIR was replaced by the Cross-State Air Pollution Rule on January 1, 2015. Consistent with Order No. PSC-2011-0553-FOF-EI, DEF treated the costs associated with unusable NOx emission allowances as a regulatory asset and amortized it over three (3) years, beginning January 1, 2015, until fully recovered 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 and PSC-2018-0014-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 Nos. 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 was previously approved in Order No. PSC-2015-0536-FOF-EI, and Order No. PSC-2018-0594-FOF-EI.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2020 through December 2020?

A. DEF used the capital structure, components and cost rates consistent with the language in Order No. PSC-2012-0425-PAA-EU. As such, DEF used the rates contained in its May 2019 Earnings Surveillance Report Weighted Average Cost of Capital. These rates are shown on Form 42-8P, Exhibit No. ___(CAM-5). Form 42-8P includes the derivation of debt and equity components used in the Return on Average Net Investment, Form 42-4P lines 7a and b.

Q. Does DEF's Weighted Average Cost of Capital ("WACC") comply with paragraph 19 of the 2017 Second Revised and Restated Stipulation and Settlement Agreement ("2017 Settlement")?

A. Yes. The WACC complies with paragraph 19 of the 2017 Settlement approved by the Commission in Order No. PSC-2017-0421-AS-EU.

Q. Is DEF retiring any ECRC projects?

A. Yes. DEF is forecasting to retire the Avon Park and Higgins combustion turbine plants in 2020. With this retirement, the Above Ground Tank Secondary Containment (Projects 4.1d and 4.1i) and CAIR CT (Projects 7.2a and 7.2e) assets will also be retired.

Q. How does DEF propose to treat unrecovered ECRC costs of the Above Ground Tank Secondary Containment and CAIR CT projects?

A. Similar to the Commission's treatment of the NOx Allowances, as approved in Commission Order No. PSC-2011-0553-FOF-EI, in Docket No. 20110007-EI, the Crystal River Thermal Discharge Compliance Project, as approved in Commission Order No. PSC-2013-0381-PAA-EI, in Docket No. 20130091-EI, and the Above Ground Tank Secondary Containment and CAIR CT (Turner), as approved in Order No. PSC-2016-0535-FOF-EI in Docket No. 20160007-EI, DEF proposes that the Commission approve treating these costs as a separate regulatory asset for each investment as of the month following the respective retirement for each asset. DEF currently expects a May 31, 2020 retirement for the Avon Park and Higgins stations; however, this date is subject to change and the establishment of the regulatory asset should occur in the month following the actual retirement date. DEF requests to amortize the regulatory assets equally over one year until fully recovered. The unamortized investment balance should earn a return at DEF's WACC until such time as the investment is fully recovered.

The proposed amortization of the Above Ground Secondary Containment and CAIR CT assets will have no effect on 2019 rates. Any over/under-recovery will be part of the normal true-up process in the annual ECRC proceedings. Avon Park and Higgins unrecovered Above Ground Secondary Containment costs are approximately $242k as of December 31, 2019; unrecovered CAIR CT costs are approximately $349k as of December 31, 2019.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2020?

A. Yes. Form 42-2P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $23.5 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2020?

A. Yes. Form 42-3P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $25.8 million. Form 42-4P pages 1 through 18 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. __ (CAM-5) provide a description, progress summary and recoverable cost estimates for each project.

Q. What are the total projected jurisdictional costs for environmental compliance projects for the year 2020?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $49.3 million. The costs are calculated on Form 42-1P line 1c of Exhibit No. __ (CAM-5).

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

A. The ECRC factors are calculated on Forms 42-6P and 42-7P of Exhibit No. __(CAM-5). The demand component of class allocation factors is calculated by determining the percentage each rate class contributes to monthly system peaks adjusted for losses for each rate class which is obtained from DEF's load research study filed with the Commission in July 2018. 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 2018 ECRC billing factors by the various rate classes and delivery voltages?

A. The calculation of DEF's proposed ECRC factors for 2020 customer billings is shown on Form 42-7P in Exhibit No. __(CAM-5) as follows:

RATE CLASS	ECRC FACTORS
Residential	0.079 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.079 cents/kWh
@ Primary Voltage	0.078 cents/kWh

@ Transmission Voltage	0.077 cents/kWh
General Service 100% Load Factor	0.075 cents/kWh
General Service Demand	
@ Secondary Voltage	0.076 cents/kWh
@ Primary Voltage	0.075 cents/kWh
@ Transmission Voltage	0.074 cents/kWh
Curtailable	
@ Secondary Voltage	0.072 cents/kWh
@ Primary Voltage	0.071 cents/kWh
@ Transmission Voltage	0.071 cents/kWh
Interruptible	
@ Secondary Voltage	0.073 cents/kWh
@ Primary Voltage	0.072 cents/kWh
@ Transmission Voltage	0.072 cents/kWh
Lighting	0.070 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 bill group for January 2020 and continue through the last bill group for December 2020.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20190007-EI

March 29, 2019

Q. Please state your name and business address.

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

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

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

Q: What are your responsibilities in that position?

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

Q: **Please describe your educational background and professional experience.**

A: I have a Bachelor of Science degree in Nuclear Engineering from the University of Florida and a Master of Science degree from the University of Central Florida. I have 16 years of experience in the power generation industry including positions as an Engineering Manager, a Maintenance Manager, and a Plant Manager within Duke Energy's fossil fleet, and as Fleet and Harris Station Maintenance Manager in Duke Energy's nuclear fleet. Prior to joining Duke Energy I was employed by Delta Air Lines as a General Manager in Engineering and Maintenance, and prior to that I served 21 years as a commissioned officer in the U.S. Navy, serving in the nuclear fleet. In November of 2014, I began my current role as CCP Regional General Manager.

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

A. The purpose of my testimony is to provide an update on DEF's 2018 Coal Combustion Residual ("CCR") Rule compliance activities and associated 2018 compliance costs for which the Company seeks recovery through the Environmental Cost Recovery Clause ("ECRC").

Q. **How did actual Capital project expenditures for the period January 2018 – December 2018 compare to actual/estimated Capital projections for the CCR Rule (Project 18)?**

A. The CCR Rule capital variance is $47,266 or 41% lower than projected due to actual prices obtained from drilling vendors that were less than estimated, and fewer new wells were required than originally forecasted.

Q. How did actual O&M project expenditures for the period January 2018 – December 2018 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR O&M variance is $181,133 or 20% lower than projected. This is primarily due to timing of expenses associated with flue gas desulfurization ("FGD") dewatering and solids removal originally projected to be incurred in 2018 but will be incurred in 2019.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

July 26, 2019

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes, I provided direct testimony on March 29, 2019.

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 2019 actual/estimated cost projections and original 2019 cost projections for environmental compliance costs associated with DEF's Coal Combustion Residual ("CCR") Rule compliance project.

Q. Please explain the variance between actual/estimated project expenditures and original projections for CCR (Project 18) O&M for the period January 2019 through December 2019.

A. O&M expenditures for CCR are expected to be $2,104,595 or 51% lower than projected. This is primarily due to updates in costs, implementation methods, and timing associated with the FGD settling pond closure. There has also been favorable pricing obtained through bid events.

Q. Please explain the variance between actual/estimated project expenditures and original projections for CCR (Project 18) Capital for the period January 2019 through December 2019.

A. Capital expenditures for CCR originally forecasted to occur in 2019 will be moved to 2020. DEF forecasted $168k of capital spending in 2019 for engineering for design and permitting associated with a potential new lined landfill unit as a possible corrective action measure to address groundwater quality impacts as required for compliance with the CCR Rule. This was consistent with the understanding and discussions about the rule requirements at the time. DEF continues to analyze the rule and expects to select the final corrective action measure(s) as early as fourth quarter of this year and will begin incurring charges in 2020.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

TIMOTHY HILL

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

August 30, 2019

Q. Please state your name and business address.

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

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes. I provided direct testimony on March 29, 2019 and July 26, 2019.

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 2020 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. __ (CAM-5) to Christopher A. Menendez's direct testimony:

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

Q. What are the CCR rule compliance activities and associated costs for which DEF is seeking recovery in 2020?

A. Landfill and Flue Gas Desulfurization Ponds O&M Costs

Various maintenance and repair work is required for the ash landfill to comply with the rule. These include fixing ruts and animal burrows, vegetation management, erosion repairs, fugitive dust mitigation, and routine weekly inspections.

DEF will also continue to perform the required groundwater monitoring for ash management units, which includes engineering, sampling, analysis, and reporting. Groundwater monitoring in 2020 will also include costs for activities related to evaluating and selecting corrective measures to address groundwater quality exceedances related to the ash landfill. DEF projects to incur approximately $50k in O&M costs related to completing the closure of the FGD Blowdown pond. Total O&M costs are forecasted to be approximately $241k.

Ash Landfill Capital Costs

DEF estimates approximately $42k of capital expenditures in 2020 for engineering for design and permitting associated with a potential new lined landfill unit as a possible corrective action measure to address groundwater quality impacts as required for compliance with the CCR Rule. DEF will update the Commission on the selected compliance option(s), including project timeline and initial cost projections, in Docket 20200007-EI.

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2020?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts and expects to incur costs in 2020 and beyond. However, the full extent of compliance activities, timing of these activities and associated costs cannot be determined until further analysis and assessment are complete, including the selection of corrective measures for groundwater quality exceedances. As these analyses and assessments are completed and additional compliance activities and costs become known, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

March 29, 2019

Q. Please state your name and business address.

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

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Vice President –Fossil/Hydro Operations Florida.

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 18 years of power plant and production experience at Duke Energy in various managerial and executive positions in fossil steam, combustion turbine and nuclear plant operations. I also managed new construction and O&M projects. I have extensive contract negotiation and management experience. My prior experience includes nuclear engineering and operations experience in the United States Navy, and project management, engineering, supervisory and management oversight experience with a pulp, paper and chemical manufacturing company.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between actual and actual/estimated project expenditures for environmental compliance costs associated with DEF's Integrated Clean Air Compliance Program (Project 7.4), Mercury and Air Toxics Standards ("MATS") - Anclote Gas Conversion Project

(Project 17.1), and Mercury & Air Toxics Standards (MATS) – CR 1&2 (Project 17.2) for the period January 2018 - December 2018.

Q. How do actual O&M expenditures for January 2018 - December 2018 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 $2,290,057 or 7% lower than projected. This variance is primarily attributable to $2M lower than expected CAIR Crystal River Project 7.4 – Energy costs, and a $455k lower than expected CAIR Crystal River Project 7.4 – Conditions of Certification Energy costs. This was partially offset by a $137k higher than forecasted CAIR Crystal River Project 7.4 – Base cost.

Q. Please explain the O&M variance between actual project expenditures and the actual/estimated projections for CAIR Crystal River Project – Energy for the period January 2018 - December 2018?

A. O&M costs for CAIR Crystal River Project - Energy were $1,945,295 or 11% lower than forecasted primarily due to lower than projected generation.

Q: Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Conditions of Certification (Project 7.4) for January 2018 - December 2018?

A: O&M costs for CAIR Crystal River Project – Conditions of Certification were $455,439 or 92% lower than projected. This was primarily due to the in-service timing of the project, which resulted in lower labor charges than originally forecasted.

Q. Please explain the O&M variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2018 - December 2018?

A. O&M costs for CAIR Crystal River Project – Base were $137,199 or 1% higher than projected due to higher than anticipated repairs on the units during the planned outage, and additional repairs on the hydrated lime system modifications.

Q: Please explain the capital variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Conditions of Certification (Project 7.4q) for January 2018 - December 2018?

A: Capital costs for CAIR Crystal River Project – Conditions of Certification were $1,602,441 or 3.6% higher than projected. This primarily due to weather-related impacts, which resulted in higher than expected labor costs.

Q. How did actual O&M expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the MATS – CR 1&2 Project (Project 17.2)?

A. The MATS – CR 1&2 O&M variance is $524,745 or 35% lower than projected. The O&M variance is primarily due to lower than projected generation.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

July 26, 2019

Q. Please state your name and business address.

A. My name is Jeffrey Swartz. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes, I provided direct testimony on March 29, 2019.

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 2019 actual/estimated cost projections and original 2019 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. How do actual/estimated O&M project expenditures compare with original projections for the CAIR/CAMR CR Program (Project 7.4) for the period January 2019 through December 2019?

A. O&M expenditures are expected to be $12,004,847 or 34% lower than originally projected. This projected variance is primarily due to $0.9M lower than originally projected CAIR-Base costs, $9.1M lower than originally projected CAIR-Energy (Reagents), $2M lower than originally projected CAIR-Conditions of Certification (Energy), and $37k lower than originally projected CAIR-A&G expense.

Q. Please explain the variance between actual/estimated O&M expenditures and the original projections for O&M expenditures for the CAIR/CAMR CR-Base Program (Project 7.4) for the period January 2019 through December 2019?

A. O&M expenditures the CAIR/CAMR CR-Base Program are expected to be $935,274 or 6% lower than originally forecasted. This is primarily due to generation run times at CR 4 and 5 forecasted to be lower than originally projected, and contractor and material costs coming in lower than originally budgeted.

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 2019 through December 2019?

A. O&M expenditures for the CAIR/CAMR CR-Energy (Reagents) Program are expected to be $9,056,687 or 53% lower than originally forecasted. This is primarily due to lower than projected generation at CR units 4 and 5, as well as a planned outage at unit 5 being longer than originally scheduled. Ammonia expense is forecasted to come in approximately $2.4M or 56% lower than originally forecasted, limestone expected is forecasted to come in approximately $2.7M or 36% lower than originally forecasted, gypsum expense is forecasted to come in approximately $2.6M or 114% lower than originally forecasted, and hydrated lime is forecasted to come in approximately $1.4M or 41% lower than originally forecasted.

Q. Please explain the variance between actual/estimated O&M expenditures and the original projections for O&M expenditures for the CAIR/CAMR CR-Energy (Conditions of Certification) Program (Project 7.4) for the period January 2019 through December 2019?

A. O&M expenditures for the CAIR/CAMR CR-Energy (Conditions of Certification) Program are expected to be $1,975,775 or 68% lower than originally forecasted. This is primarily due to less resources than originally budgeted and reduced contractor expense due to reduced unit run time.

Q. How do actual/estimated Capital project expenditures compare with original projections for the CAIR/CAMR CR (Conditions of Certification) Program (Project 7.4q) for the period January 2019 through December 2019?

A. Capital expenditures for the CAIR/CAMR CR (Conditions of Certification) Program are expected to be $1,912,081 or 49% higher than originally projected primarily due to construction work delays stemming from unforeseen underground conditions, weather delays, and changes in implementation work. This shifted some work that was originally planned for 2018 into 2019. This project was placed in-service on February 16, 2019.

Q. How do actual/estimated O&M expenditures compare with original projections for the Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program (Project 17.2) for the period January 2019 through December 2019?

A. Capital expenditures for the Mercury & Air Toxics Standards (MATS) – Crystal River 1&2 Program are expected to be $14,848 or 25% lower than originally projected. The invoice received in 2019 completes Units 1&2 project costs. Crystal River units 1 & 2 were retired December 2018.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

August 30, 2019

Q. Please state your name and business address.

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

Q. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes. I provided direct testimony on March 29, 2019 and July 26, 2019.

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 costs that will be incurred in 2020 for Duke Energy Florida LLC's ("DEF" or "Company") Integrated Clean Air Compliance Program (Project 7.4), Mercury and Air Toxics Standards

(MATS) Program – Anclote Gas Conversion (Project 17.1), and Mercury and Air Toxics Standards (MATS) Program – Crystal River Units 1 & 2 (CR1&2) (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 sponsoring Exhibit No.__ (JS-1), which is an organization chart for DEF's Crystal River Clean Air Projects. I am also co-sponsoring the following portions of Exhibit No. __ (CAM-5) to Christopher A. Menendez's direct testimony:

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

Q. What O&M costs does DEF expect to incur in 2020 for air emission controls at Crystal River Units 4 and 5 (CR4&5) as part of the Integrated Clean Air Compliance Program (Project 7.4)?

A. DEF estimates O&M costs of approximately $22.6M to support the operation and maintenance of air emissions controls that were installed at the CR Energy Complex ("CREC") as outlined in DEF's Integrated Clean Air Compliance Plan as follows:

- Labor costs are estimated at $7.3M based on current staffing levels, including labor for the CRN FGD Wastewater Treatment ("WWT") project.

- Contractor expenses are estimated at $6.1M for various services and include contractor costs associated with the WWT.
- Parts and materials are estimated at $1.9M.
- Other costs are estimated at $0.2M.
- CR5 outage costs are estimated at $1.4M.
- Reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) are estimated to total $5.7M.

Q. What steps does DEF take to ensure that the level of expenditures for the operation of CR4&5 controls is reasonable and prudent?

A. Plant management controls and monitors operations and costs using several methods. Work is scheduled and conducted proactively and efficiently. Costs are approved by the appropriate level of management per existing Company policies. All expenditures are monitored on a monthly basis, and budget variances are analyzed for accuracy and appropriateness.

Q. Please discuss the organization being used to operate and maintain the CAIR equipment?

A. The Company established a dedicated unit to manage, operate and maintain the CAIR equipment as shown by the organization chart on Exhibit__(JS-1). This unit consists of 61 employees that report to the Crystal River North Station Manager and 1 employee who reports to the Director-Florida Fossil-Hydro-Finance. There are 8 managers and 53 maintenance, operations and support employees. The operators work rotating shifts in order to staff the operations of CREC 24 hours per day. The maintenance employees primarily work days, but shift employees are available to work when needed. In an effort to keep regular staffing levels low, contractors are used for specialized or lower-skilled work which minimizes overall operation and maintenance costs.

Q. Please discuss the organization being used to operate and maintain the CAIR and WWT equipment?

A. The Company established a dedicated unit to manage, operate and maintain the CAIR equipment as shown by the effective organizational staffing chart on Exhibit__(JS-1). This exhibit illustrates the 44 equivalent positions that report to the Crystal River North Station Manager, 1 that reports to the Regional Services Outages & Projects Manager and 1 that reports to the Director-Florida Fossil-Hydro-Finance. There are 5 manager positions and 41 maintenance, operations and support positions, reflecting DEF's staffing efficiency improvements. The operators work rotating shifts in order to staff the operations of CREC 24 hours per day. The maintenance staff primarily work days, but shift positions are available to work when needed. In an effort to keep regular staffing levels low, contractors are used for specialized or lower-skilled work which minimizes overall operation and maintenance costs.

Q. Are there policies and procedures in place to efficiently operate and maintain the CAIR equipment?

A. Yes. There are several different policies and procedures used to efficiently operate and maintain the CAIR equipment. First and foremost, the plant adheres to all OSHA and Company safety-related policies and procedures. It also follows operations and maintenance procedures during startups, shut downs, steady state situations and transient scenarios. All employees are trained to respond effectively to many different operating scenarios as part of these procedures. The procedures were developed during construction and startup and continue to be revised as more experience and expertise is gained with the equipment.

The plant uses existing corporate-wide policies and procedures to efficiently conduct business such as human resources (hiring, compensation, and performance management), supply chain management (purchasing, contracting, and inventory) and information technology (NERC Critical Infrastructure Protection).

Q. Are personnel operating and maintaining this equipment trained in these policies and procedures?

A. Yes. Personnel selected to operate and maintain CAIR equipment have to meet job-related qualifications for specific positions. Some operation employees are hired from outside companies and have previous experience operating this type of equipment at other utilities. Other operation employees are selected to participate in an in-house apprentice program. These employees must complete a 2 to 4-year training program before they are fully qualified workers. This training includes a mix of classroom and hands-on training that helps employees progress through different levels of task proficiency. Maintenance employees are selected based on their skills and experience and are provided equipment specific training to optimize equipment maintenance.

Equipment-specific training was conducted during the construction and start-up phase of the project and continues as major equipment overhauls are performed. This training included equipment walk-downs, discussions with vendor representatives and hands-on operating and maintenance work performed under the supervision of qualified individuals.

From a business process standpoint, CAIR employees are trained on policies and procedures using several different methods that include required reading and review of the policies and procedures, small group discussions, one-on-one interaction with subject matter experts, computer-based training and on the job task training.

Q. Does the Company have controls in place to ensure these policies and procedures are followed?

A. DEF ensures compliance with policies and procedures through management controls, equipment round checklists, procedure sign-offs and internal audits. The level of controls is based on the particular policy or procedure.

Q. Are there any other mechanisms in place to ensure proper operation and maintenance of CAIR equipment?

A. Along with the above methods, prudent engineering judgment and industry standards are used to ensure proper operation and maintenance of CAIR equipment. The FGD Engineer (System Owner) works directly with operations and maintenance personnel to ensure that systems are working in accordance with design parameters.

Routine maintenance is performed on a regular and on-going basis. In addition, specialized inspection and maintenance work is conducted during scheduled unit and equipment outages. These specialized work activities are identified and refined as the Company gains more operational experience with the equipment.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>KIM SPENCE McDANIEL</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190007-EI

March 29, 2019

Q. Please state your name and business address.

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

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Manager of Environmental Services.

Q. What are your responsibilities in that position?

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

Q. Please describe your educational background and professional experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between actual and actual/estimated project expenditures for environmental compliance costs associated with FPSC-approved programs under my responsibility. These programs include the T&D Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") (Project 3), Above Ground Secondary Containment (Project 4), Phase II Cooling Water Intake – 316(b) (Projects 6 & 6a), CAIR/CAMR - Peaking (Project 7.2), Best Available Retrofit Technology ("BART") (Project 7.5), Arsenic Groundwater Standard (Project 8), Sea Turtle Coastal Street Lighting Program (Project 9), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge

Permanent Cooling Tower (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Daily Maximum Loads Monitoring (Project 13), Hazardous Air Pollutants Information Collection Request ("ICR") Program (Project 14), Effluent Limitation Guidelines Program (Project 15.1), National Pollutant Discharge Elimination System ("NPDES") (Project 16) and Mercury and Air Toxics Standards ("MATS") – Crystal River ("CR") Units 4&5 (Project 17) for the period January 2018 through December 2018.

Q. How did actual O&M expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the Transmission & Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention Projects (Projects 1 & 1a)?

A. The Substation System Program variance is $169,915 or 20% lower than projected. The Transmission portion (Project 1) is $153k or 32% lower than forecasted primarily due to some of the remediation work at the East Clearwater substation, which was projected to be completed in 2018, being re-scheduled into 2019. Repairs were made to several units at that location, however, repairs made to Bank #1 needed additional follow-up work, which will require an outage. Remediation activities will resume once repair has been completed. Holder substation was also projected to be completed in 2018, and most of the repairs were completed by December 2018. Additional repair work is still required on Bank #5. Remediation activities will resume once the repairs have been completed.

The Distribution portion (Project 1a) is $17k or 5% lower than forecasted primarily due to the lower than expected costs for potential groundwater monitoring and reporting charges.

Q. How did actual O&M expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Project (Project 2)?

A. The Distribution System Environmental Investigation, Remediation, and Pollution Prevention Project variance is $8,000 or 100% lower than projected. DEF did charge any costs to this project in 2018.

Q. How did actual O&M expenditures for January 2018 - December 2018 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 $324,183 or 122% higher than projected. This variance is driven primarily by Cooling Water Intake 316(b) – Base (Project 6), which had a $228k or 98% higher than projected variance primarily due to the cost of repairs to the existing intake structure at Crystal River North station that were necessary to prepare for the installation of new pumps to meet 316(b) compliance. Cooling Water Intake 316(b) – Intermediate (Project 6a) variance was $96k or 290% higher than forecasted, due to accelerating the schedule of studies for data analyses and modeling activities associated with the preparation of the 316(b) 122.21[r] report for Anclote. These studies were accelerated to maximize the efficient use of internal resources in conducting these analyses and reflect only a shift in timing of planned costs.

Q. How did actual O&M expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the Sea Turtle – Coastal Street Lighting Project (Project 9)?

A. The Sea Turtle – Coastal Street Lighting Project variance is $46,366 higher than forecasted. This is due to a lighting request for sea turtle protection involving the retrofit of 54 lights on Eldorado Avenue, Clearwater Beach, City of Clearwater, FL. DEF retrofitted 54 lights, that were part of an LED street light upgrade, to install turtle-sensitive lights to keep the turtles from gravitating toward the streets.

Q. How did actual O&M expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the Effluent Limitations Guideline Project (Project 15.1)?

A. The ELG O&M variance is $40,000 or 100% lower than projected due to timing of expenditures. Project implementation was shifted to 2019 to provide additional time for engineering design and for continued discussions with FDEP to address ELG requirements in the CR 4&5 NPDES permit renewal process. DEF now expects these costs to be incurred in 2019,

Q. How did actual Capital expenditures for January 2018 - December 2018 compare with DEF's actual/estimated projections for the Effluent Limitations Guideline Project (Project 15.1)?

A. The ELG Capital variance is $705,576 or 77% lower than projected due to timing of expenditures. Project implementation was shifted to 2019 to provide additional time for engineering design and for continued discussions with FDEP to address ELG requirements in the CR 4&5 NPDES permit renewal process. DEF now expects these costs to be incurred in 2019. The first phase of ELG compliance projects is scheduled to be completed in 2019. DEF plans to scope and schedule the second phase of compliance projects once the final ELG requirements are published by EPA.

Q. How did actual O&M expenditures for January 2018 - December 2018 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 $390,423 or 85% lower than forecasted, primarily due to lower reagent and maintenance costs, and less burner testing due to reduced unit generation.

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

expected changes in environmental regulations. Has DEF conducted such a review?

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

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

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

Q. What is the status of the Cross-State Air Pollution Rule ("CSAPR")?

A. On November 17, 2015, the EPA proposed a revised CSAPR. The EPA proposed to remove Florida from the CSAPR program, beginning with the 2017 ozone season; however, the EPA stated that it will perform additional modeling that could result in changing that proposal. On September 7, 2016, EPA finalized its CSAPR Update rule, lowering the current CSAPR state ozone season NOx emission budgets for 22 Eastern states. EPA eliminated Florida, South Carolina, and North Carolina from the CSAPR ozone season program based on modeling which shows that NOx emissions from these states do not significantly contribute to ozone nonattainment in any downwind state. Duke Energy sources in Florida are no longer subject to any CSAPR NOx emission limitations as of the beginning of 2017.

Q. What is the status of the ELG (Project 15.1)?

A. On November 23, 2015, the Environmental Protection Agency ("EPA") published the final revision to the ELG establishing technology-based national standards for effluent waste streams. The rule went into effect on January 4, 2016 and applies to all steam electric generating stations. The new limits were to have been incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023; however, on September 18, 2017, EPA issued a final rule postponing the compliance deadlines of FGD wastewater and bottom ash transport water for two years. DEF is currently working with the FDEP to address these ELG requirements in its Crystal River Units 4 and 5 NPDES permit that is now in the renewal process.

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

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

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

On February 14, 2019, EPA and Corps published in the Federal Register, the "Revised Definition of 'Waters of the United States,'" which proposes to narrow the extent of Clean Water Act jurisdiction as compared to the 2015 definition adopted by the Obama Administration (Proposed Rule). Comments on the Proposed Rule are due by April 15, 2019.

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. 20190007-EI

July 26, 2019

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. Have you previously filed testimony before this Commission in Docket No. 20190007-EI?

A. Yes, I provided direct testimony on March 29, 2019.

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 2019 actual/estimated cost projections and original 2019 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 2019 through December 2019.

Q. Please explain the variance between actual/estimated project expenditures and original projections for Substation Environmental Investigation, Remediation and Pollution Prevention Program (Projects 1 & 1a) for the period January 2019 through December 2019.

A. O&M expenditures for the substation system program are estimated to be $222,258 or 54% higher than originally projected. Project 1, Transmission Substation Remediation, is forecasted to be $210k, or 51% higher than originally projected. The variance is primarily due to remediation costs, originally forecasted to occur in 2018, shifting to 2019 when project resumed at the Central Florida and Clearwater Substations. Project 1a, Distribution Substation Remediation, is forecasted to be $12k, or 100% higher than originally projected. The distribution portion of this program is now complete, and the variance is primarily attributable to remediation activities associated with the completion of final remediation reports submitted to the Florida Department of Environmental Protection.

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 2019 through December 2019.

A. O&M expenditures for Phase II Cooling Water Intake 316(b) are expected to be $418,476 or 140% higher than originally forecasted. This is primarily due to additional work scope being required for the mandated 316(b) reports, and to provide further details for compliance options being evaluated. The additional work scope includes more detailed biological, engineering and economic evaluations, and modelling efforts.

Q. Please explain the variance between actual/estimated project expenditures and original projections for Sea Turtle – Coastal Street Lighting (Project 9) for the period January 2019 through December 2019.

A. O&M expenditures for Sea Turtle – Coastal Street Lighting are expected to be $48,324 lower than forecasted. Turtle nesting season has recently begun and DEF has not received any new requests from Gulf County or Pinellas County Code Enforcement of any issues regarding new lighting fixtures, therefore the $350 forecasted is not expected to be spent. There was an adjustment of $47,974 from the 2018 True-Up Filing, dated March 29, 2019 in this Docket. As referenced in DEF's response to Staff's Second Interrogatories, Question 8.c, DEF has credited the cost of the sea turtle lighting retrofit, including commercial paper interest, totaling $47,974. This adjustment can be seen on Exhibit CAM-3, Page 6 of 27, Line 1-9, Column Jul-19.

Q. Please explain the variance between actual/estimated project expenditures and original projections for the Effluent Limitation Guidelines CRN (Project 15.1) for the period January 2019 through December 2019.

A. Capital expenditures are forecasted to be $1,759,119 or 100% higher than originally forecasted. This is due to timing, no capital expenditures were originally projected for 2019. Work originally planned for 2018 was shifted to 2019 to provide additional time for engineering design and for continued discussions with FDEP to address ELG requirements in the CR 4&5 NPDES permit renewal process.

Q. Please explain the variance between actual/estimated project expenditures and original projections for MATS CR4&5 (Project 17) for the period January 2019 through December 2019.

A. O&M expenditures for MATS CR 4&5 are expected to be $435,159 or 73% lower than forecasted. This is primarily due to lower than originally forecasted run times on CR 4&5, resulting in more time the unit was in reserve.

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 Services' biological opinion, and the incidental take statement, concluding the each action was based on reasonable interpretations of the applicable statutes and sufficiently supported by the adequate record. The court also found that 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, will be 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 required information is being prepared for submittal with the renewal applications due July 2020 and August 2020, respectively. Retirement of Crystal River Units 1 & 2 in 2018 satified 316(b) requirements for those units. A 316(b) Complinace Plan for Crystal River Units 4 & 5 is being developed 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.

Q. Please provide an update on Carbon Regulations.

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

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

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

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

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of both the CPP and the CO_2 NSPS rules while each is reviewed by EPA. As a result, the D.C. Circuit has granted a number of 60-day extensions holding the CPP litigation in abeyance. The most recent extension was issued on June 20, 2019. Neither the EO nor the abeyance change the current status of the CPP which is under a legal hold by the U.S.

Supreme Court. With regard to the CO2 NSPS, that rule will remain in effect pending the outcome of EPA's review.

On June 19, 2019, EPA signed a final rule informally referred to as the Affordable Clean Energy ("ACE") Rule, which repeals and replaces the CPP. In the ACE Rule, EPA finalized revised guidelines to replace the CPP and inform the development of state plans to reduce GHG emissions from exisiting coal-fired electric generating units (EGUs). EPA has determined that heat rate improvement measures are the best system of emission reduction (BESR) for reduing GHG emissions fromexisting coal-fired EGUs. The rule requires states to develop their individual state plan within three years of the effective date of the ACE Rule.

DEF is currently evaluating the potential impacts from the final ACE Rule, but does not expect to incur ECRC costs in 2020 related to carbon regulations.

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

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

On June 27, 2017, the EPA and the Corps published a proposed rule to repeal the 2015 WOTUS rule and re-codify the definition of WOTUS which is currently in place. On January 31, 2018 the EPA and Corps announced a final rule adding an applicability date to the 2015 rule, thereby deferring implementation to early 2020. This rule has no immediate impact to Duke Energy. The agencies will continue to apply the pre-existing WOTUS definition that was in place prior to 2015 rule until 2020. EPA intends to publish the final rule in December 2019.

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. 20190007-EI

August 30, 2019

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. 20190007-EI?

A. Yes. I provided direct testimony on March 29, 2019 and July 26, 2019.

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 2020 for Duke Energy Florida LLC's ("DEF" or "Company") Substation Environmental Investigation, Remediation and Pollution Prevention

Program (Project 1 & 1a), Distribution Environmental Investigation, Remediation and Pollution Prevention Program (Project 2), Pipeline Integrity Management ("PIM") Program (Project 3), Above Ground Storage Tanks ("AST") Program (Project 4), Phase II Cooling Water Intake 316(b) Program (Project 6), CAIR/CAMR Continuous Mercury Monitoring System ("CMMS") Program (Projects 7.2 & 7.3), Best Available Retrofit Technology ("BART") Program (Project 7.5), Arsenic Groundwater Standard Program (Project 8), Sea Turtle – Coastal Street Lighting Program (Project 9), Underground Storage Tanks ("UST") Program (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Compliance (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury Total Maximum Loads Monitoring ("TMDL") (Project 13), Hazardous Air Pollutants ("HAPs") Information Collection Request ("ICR") (Project 14), Effluent Limitation Guidelines CRN (Project 15.1), National Pollutant Discharge Elimination System ("NPDES") Program (Project 16), and Mercury & Air Toxics Standards ("MATS") Program – Crystal River Units 4 & 5 ("CR4&5") (Project 17).

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. __(CAM-5) to Christopher A. Menendez'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
- 42-5P page 20 of 23 - MATS – CR4&5

Q. What costs does DEF expect to incur in 2020 for the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates approximately $25k in O&M costs for 2020. This is predominantly for work at the Central Florida substation. The transmission portion of this program (Project 1) is forecasted to be complete in 2020. The distribution portion of this program (Project 1a) is complete.

Q. What costs does DEF expect to incur in 2020 for the Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. The Distribution System Environmental Investigation, Remediation and Pollution Prevention Program is complete, DEF is not projecting any further costs. DEF does not expect to incur any O&M costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the PIM Program (Project 3)?

A. The PIM Program assets retired September 2016 and June 2017. As approved in Order Nos. PSC-2016-0535-FOF-EI and PSC 2018-0014-FOF-EI, DEF amortized the net book value of the PIM Program assets over three years, which was fully amortized as of August 2019. DEF does not expect to incur any capital expenditures or O&M costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Aboveground Storage Tank ("AST") Program (Project 4)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Phase II Cooling Water Intake Program (Project 6)?

A. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule. DEF expects to incur $136k in O&M costs in 2020, which includes 122.21(r) reports for Anclote and Bartow stations in order to assess 316(b) compliance, and programmatic costs for all stations with NPDES permits. DEF will submit study results to FDEP for Anclote July 2020 and Bartow August 2020.

DEF expects 2020 capital expenditures to be approximately $4.9 million for the Crystal River North 316(b) compliance project, which will be complete in 2020.

Q. What costs does DEF expect to incur in 2020 for the CAIR/CAMR Program (Project 7.2)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the BART Program (Project 7.5)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Arsenic Groundwater Standard Program (Project 8)?

A. 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 have identified the need for additional remedial compliance activities. To address these sources, DEF estimates approximately $1.2M in O&M costs for remediation activities, additional assessment and monitoring that may be required, and subsequent preparation and submittal of a remediation completion report to FDEP. This amount includes approximately $75k for cleanup of an area of Crystal River Units 4 & 5 stormwater basin located near Monitoring Well #32 that has been identified as a potential source of elevated arsenic, to be completed during the first half of 2020; approximately $1.0M for potential remediation activities at the former north ash pond area; and $150k for projected additional monitoring and assessment to support the two projects mentioned above. These costs and the timing of expenditure are preliminary and subject to change as they are contingent upon results and timing of the review and approval process with FDEP. 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. The SARA is currently under review by FDEP.

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

Once the SARA is approved by FDEP, DEF must submit a Remediation Action Plan to FDEP for review and approval which is expected to occur in late 2019, and will be implemented following approval from FDEP, anticipated in the second half of 2020.

Q. What costs does DEF expect to incur in 2020 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?

A. DEF estimates $300 in O&M and $300 in capital costs for the Sea Turtle – Coastal Street Lighting Program. The O&M costs are to install mitigation on any existing street lights during nesting season that may interfere with sea turtle nesting for Gulf County, Mexico Beach, and Pinellas County. Capital costs are projected to install new street lights if required in Gulf County, Mexico Beach, and Pinellas County and any lighting required for the Don Cesar project in Pinellas County.

Q. What costs does DEF expect to incur in 2020 for the Underground Storage Tanks ("UST") Program (Project 10)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Modular Cooling Tower (Project 11)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Greenhouse Gas Inventory and Reporting Program (Project 12)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Mercury TMDL Program (Project 13)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 in for the HAPs ICR Program (Project No. 14)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect to incur any costs in 2020.

Q. What costs does DEF expect to incur in 2020 for the Effluent Limitation Guidelines CRN Program (Project No. 15.1)?

A. DEF expects approximately $40K in O&M expenditures and $80K in Capital expenditures in 2020. DEF expects this project to be completed in 2020. DEF is continuing to monitor ELG requirements to determine if additional compliance activities are necessary.

Q. What costs does DEF expect to incur in 2020 for the NPDES Program (Project No. 16)?

A. DEF estimates approximately $25k of O&M costs for Whole Effluent Toxicity ("WET") testing as required at DEF stations with NPDES permits.

Q. What O&M costs does DEF expect to incur in 2020 for the MATS Program – CR 4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $598k for CR 4&5 MATS compliance. This estimate includes emissions testing, burner inspections, maintenance of emissions monitoring and control technologies, and reagent costs.

Q. What capital costs does DEF expect to incur in 2020 for the MATS Program – CR 4&5 (Project No. 17)?

A. DEF does not expect capital expenditures in 2020.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190007-EI
FILED: 4/1/2019

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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 hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, and during my tenure I assumed positions of increasing responsibility. I have over 20 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for cost recovery clauses and wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

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 2018 through December 2018 period.

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

A. Yes. Exhibit No. PAR-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 2018 through December 2018 period;
- Form 42-2A, Document No. 2, provides the detailed calculation of the actual true-up for the period;
- Form 42-3A, Document No. 3, shows the interest provision calculation for the period;

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

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

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What is the final true-up amount for the Environmental Clause for the period January 2018 through December 2018?

A. The final true-up amount for the Environmental Clause for the period January 2018 through December 2018 is an over-recovery of $2,396,214. The actual environmental cost over-recovery, including interest, is $15,868,697 for the period January 2018 through December 2018, as identified in Form 42-1A. This amount, less the $13,472,483 over-recovery approved in Commission Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018, in Docket No. 20180007-EI, results in a final over-recovery of $2,396,214, 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 2020 through December 2020.

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

A. All costs listed in Forms 42-4A through 42-8A for which

Tampa Electric is seeking recovery are incurred for environmental compliance projects approved by the Commission.

Q. How do actual expenditures for the January 2018 through December 2018 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 $1,291,726, or 10.2 percent less than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $78,838, or 0.2 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.

- **Big Bend Units 1 and 2 Flue Gas Desulfurization ("FGD"):** The Big Bend Units 1 and 2 FGD project variance is $73,827 or 12.9 percent lower than projected. The variance is due to greater use of natural gas instead of coal, so the cost for consumables for the Units 1 and 2 FGD was less than projected.

- **Big Bend PM Minimization and Monitoring**: The Big Bend PM Minimization and Monitoring project variance is $115,739 or 28.5 percent greater than projected. The variance is due to greater than expected cleaning and maintenance costs in 2018 for insulators, rappers, and other related equipment parts.

- **Big Bend Unit 1 SCR**: The Big Bend Unit 1 SCR project variance is $240,367, or 68.5 percent less than projected. The variance is due to greater use of natural gas instead of coal, so the cost for SCR consumables and maintenance was less than projected for the year.

- **Big Bend Unit 2 SCR**: The Big Bend Unit 2 SCR project variance is $182,149, or 50.4 percent less than projected. The variance is due to greater use of natural gas instead of coal, so the cost for SCR consumables and maintenance was less than projected.

- **Big Bend Unit 3 SCR**: The Big Bend Unit 3 SCR project variance is $576,296, or 37.1 percent less than projected. The variance is due to greater use of natural gas instead of coal, so the cost for SCR consumables and maintenance was less than projected.

- **Big Bend Unit 4 SCR**: The Big Bend Unit 4 SCR project variance is $259,519, or 39.9 percent more than projected. Unit 4 burned more coal than expected, and as a result, the cost of consumables and maintenance was higher than projected.

- **Big Bend Coal Combustion Residuals Rule Phase II**: The Big Bend Coal Combustion Residuals ("CCR") Rule Phase II project variance is $798,049, or 16.8 percent less than projected. Project disposal activity was suspended when the existing landfill stopped accepting CCR material. Subsequently, a new landfill was identified, approved for use, and is now accepting the material. As a result, these costs are expected to be incurred in the future.

There were no significant cost variances related to capital investment projects.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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 Director, Regulatory Affairs 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 Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I assumed positions of increasing responsibility over time. My current position is Director of Regulatory Affairs.

At Tampa Electric, I have accumulated over 20 years of electric utility experience in the areas of load forecasting; management of the fuel and purchased power, capacity, and environmental cost recovery clauses; rate setting and rate filings; and regulatory project management activities. I also oversee the coordination and filing of all Tampa Electric and Peoples Gas filings with federal and state regulatory agencies. I am a member of the Southeastern Electric Exchange Rates and Regulation Committee.

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 2019 through December 2019 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2020 through December 2020. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2019, 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 2020 through December 2020.

Q. Have you prepared an exhibit that shows the recoverable environmental costs for the actual/estimated period of January 2019 through December 2019?

A. Yes, Exhibit No. PAR-2, containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E, which show the current period actual/estimated true-up amount to be used in calculating the cost recovery factors for January 2020 through December 2020.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied during the period January 2020 through December 2020?

A. The actual/estimated true-up applicable for the current period, January 2019 through December 2019, is an over-recovery of $4,108,435. 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 2019 ECRC factors?

A. No. Tampa Electric is not including costs for any new environmental projects that were not anticipated or included in its 2019 ECRC factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2019 actual/estimated true-up?

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

Q. What capital structure components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2019 through December 2019?

A. Tampa Electric's revenue requirement rate of return for January 2019 through December 2019 is calculated based on the capital structure components and current period cost rates as approved in Order No. PSC-2012-0425-PAA-EU, issued on August 16, 2012 in Docket No. 20120007-EI. 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 2019 through December 2019 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $3,458,889 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $34,905 less than originally projected. Significant variances for O&M costs and capital project amounts are explained below.

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

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

- **Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration**: The Bend Unit 3 FGD Integration Project variance is estimated to be $228,005 or 32.1 percent less than projected. The variance is due to lower costs for consumables and maintenance than expected as the units burned natural gas.

- **Big Bend Units 1 & 2 FGD**: The Big Bend Units 1 & 2 FGD project variance is estimated to be $545,211 or 80.2 percent less than projected. The variance is due to lower costs for consumables and maintenance than expected as the units burned natural gas.

- **Big Bend PM Minimization & Monitoring**: The Big Bend PM Minimization & Monitoring Project variance is estimated to be $91,274 or 22.9 percent lower than projected. This variance is due to less maintenance being required than expected, after inspection.

- **Big Bend NO_x Emissions Reduction**: The Big Bend NO_x Emissions Reduction project variance is $50,694 or 84.5

percent less than projected. This variance is due to the operation of Big Bend Units 1 & 2 on natural gas.

- **Clean Water Act Section 316(b) Phase II Study Program:** The Clean Water Act Section 316(b) Phase II Study Program project variance is $59,714 or 66.3 percent less than projected. The National Pollutant Discharge Elimination System ("NPDES") permit renewal for Big Bend Station has not yet been finalized. The variance is related to permit delays and uncertainty regarding the timing of the final requirements and reporting that must be submitted once the permit is finalized.

- **Big Bend Unit 1 SCR**: The Big Bend Unit 1 SCR project variance is $73,421 or 43.9 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the unit's need for consumables and maintenance work, compared to the original projection.

- **Big Bend Unit 2 SCR**: The Big Bend Unit 2 SCR project variance is $95,745 or 36.7 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the use of consumables and need for maintenance work, compared to the original projection.

- **Big Bend Unit 3 SCR**: The Big Bend Unit 3 SCR project variance is $100,172 or 25.3 percent more than projected. This variance is due to greater maintenance costs related to the replacement of Unit 3 SCR power cells during the outage, compared to the original projection.

- **Big Bend Unit 4 SCR**: The Big Bend Unit 4 SCR project variance is $748,089 or 35.0 percent less than projected. This variance is due to less total run time estimated when compared to the original projection.

- **Mercury Air Toxics Standards**: The Mercury Air Toxics Standards project variance is $67,245 or 89.8 percent less than projected. Both Polk and Big Bend Power Stations achieved Low Emitting Electric Generating Unit status in 2017. As a result, monitoring is not required at this time, only periodic testing, and the costs were less than originally projected.

- **Big Bend Gypsum Storage Facility**: The Big Bend Gypsum Storage Facility project variance is $57,406 or 4.3 percent less than projected. The variance is due to a delay in the receipt of a vendor invoice, compared to the original projection.

- **Big Bend CCR Rule – Phase II**: The Big Bend Coal Combustion Residual ("CCR") Rule Phase II project variance is $1,598,319 or 26.6 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to delays in landfill availability. The project expenditures are still needed and will be incurred in the future.

Capital Project Variances

- **Big Bend Units 1 through 4 SCR**: Variances ranging from $54,042 to $62,263 for Big Bend Units 1 through 4 SCR, where amounts were greater than originally projected, are due to the change in the weighted average cost of capital applied for the July 2019 to December 2019 period, from 7.5190 percent to 7.7662 percent, as required by Order No. PSC-2012-0425-PAA-EI, issued on August 16, 2012.

- **Big Bend CCR Rule - Phase I**: The Big Bend CCR Rule Phase I project variance is $129,328 or 53.6 percent less than projected. The variance is due to timing differences in the project schedule when compared to the original projection. Project ground water monitoring activities have occurred more slowly than originally projected due to water sampling and analysis requiring more time than anticipated. 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 $286,972 or 96.0 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. The project expenditures are still needed and will be incurred in the future.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190007-EI
FILED: 08/30/2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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 Director, Regulatory Affairs in the Regulatory Affairs Department.

Q. Have you previously filed testimony in Docket No. 20190007-EI?

A. Yes, I submitted direct testimony on April 1, 2019 and July 26, 2019.

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 2020 through December 2020. 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 2020.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2020 through December 2020?

A. Yes. Exhibit No. PAR-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 2020.

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. PAR-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 2020 through December 2020.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2020 to December 2020?

A. The net true-up applicable for this period is an over-recovery of $6,504,649. This consists of a final true-up over-recovery of $2,396,214 for the period of January 2018 through December 2018 and an estimated true-up over-recovery of $4,108,435 for the current period of January 2019 through December 2019. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. PAR-2 filed with the Commission on July 26, 2019.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2020 through December 2020?

A. No, Tampa Electric is not including costs for any new environmental projects.

Q. What are the capital projects included in the calculation of the ECRC factors for 2020?

A. Tampa Electric proposes to include for ECRC recovery costs for the 29 approved capital projects in the calculation of the 2020 ECRC factors. These projects are listed below.

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

17) Big Bend Unit 3 Pre-SCR
18) Big Bend Unit 1 SCR
19) Big Bend Unit 2 SCR
20) Big Bend Unit 3 SCR
21) Big Bend Unit 4 SCR
22) Big Bend FGD System Reliability
23) Mercury Air Toxics Standards ("MATS")
24) SO_2 Emission Allowances
25) Big Bend Gypsum Storage Facility
26) Big Bend Coal Combustion Residuals ("CCR") Rule – Phase I
27) Big Bend CCR Rule - Phase II
28) Big Bend Unit 1 Section 316(b)Impingement Mortality
29) Big Bend Effluent Limitations Guidelines ("ELG") Rule Compliance

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2020?

A. Yes. Form 42-3P contained in Exhibit No. PAR-3 summarizes the cost estimates for these projects. Form 42-4P, pages 1 through 29, provides the calculations resulting in recoverable jurisdictional capital costs of $44,522,907.

Q. What O&M projects are included in the calculation of the

ECRC factors for 2020?

A. Tampa Electric proposes to include for ECRC recovery O&M costs for 27 approved O&M projects in the calculation of the ECRC factors for 2020. These projects are listed below.

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

19) Big Bend Unit 3 SCR
20) Big Bend Unit 4 SCR
21) Mercury Air Toxics Standards
22) Greenhouse Gas Reduction Program
23) Big Bend Gypsum Storage Facility
24) Big Bend CCR Rule - Phase I
25) Big Bend CCR Rule - Phase II
26) Big Bend Unit 1 Section 316(b) Impingement Mortality
27) Big Bend ELG Rule Compliance

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2020?

A. Yes. Form 42-2P contained in Exhibit No. PAR-3 presents the recoverable jurisdictional O&M costs for these projects, which total $9,440,821 for 2020.

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

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

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2020?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P of Exhibit No. PAR-3. These expenditures total $53,963,728.

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 2020 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 2020 through December 2020, for which Tampa Electric is seeking approval?

A. The computation of the billing factors is shown in Exhibit

No. PAR-3, Document No. 7, Form 42-7P. The proposed ECRC billing factors are summarized below.

Rate Class	**Factors by Voltage Level (¢/kWh)**
RS Secondary	0.244
GS, CS Secondary	0.244
GSD, SBF	
Secondary	0.243
Primary	0.241
Transmission	0.238
IS	
Secondary	0.239
Primary	0.237
Transmission	0.234
LS1	0.241
Average Factor	0.244

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 2020.

Q. What capital structure components and cost rates did Tampa

Electric rely on to calculate the revenue requirement rate of return for January 2020 through December 2020?

A. Tampa Electric used the weighted average cost of capital methodology approved by the Commission in Order Nos. PSC-2012-0425-PAA-EU and PSC-2017-0456-S-EI to calculate the revenue requirement rate of return found on Form 42-8P.

Q. Is Tampa Electric required to adjust its projected weighted average cost of capital calculations to avoid a tax normalization violation, which may occur in certain circumstances described in the utilities' unopposed joint motion to modify Order No. 2012-0425-PAA-EU, submitted in this docket on August 21, 2019?

A. No, an adjustment is not required for 2020. Tampa Electric expects to meet the limitation provision for the projected period. Therefore, the methodology used to calculate the revenue requirement rate of return shown on Form 42-8P is that described in Order No. 2012-0425-PAA-EU, and the use of the current methodology does not violate the tax normalization requirement.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2020 through

December 2020 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 a final average ECRC billing factor of 0.244 cents per kWh. This includes the projected capital and O&M revenue requirements of $53,963,728 associated with the company’s 36 ECRC projects and a net true-up over-recovery provision of $6,504,649. My testimony also explains that the projected environmental expenditures for 2020 are appropriate for recovery through the ECRC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190007-EI
FILED: 08/30/2019

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. CARPINONE

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

A. My name is Paul L. Carpinone. 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 in the 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 Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the states of Florida and Pennsylvania since 1984. Prior to joining Tampa Electric, I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the area of environmental, health and safety. In 2006, I became 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 meet or surpass compliance with applicable environmental requirements, and that rules and polices are in place and functioning appropriately and consistently 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 2020 through December 2020 projection period are activities related to programs previously approved by the Commission for recovery through the ECRC.

Q. Please provide an overview of the environmental compliance requirements that are the result of the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice ("the Orders").

A. The general requirements of the Orders provide for further reductions of sulfur dioxide ("SO_2"), particulate matter ("PM") and nitrogen oxides ("NO_x") emissions at Big Bend Station. Tampa Electric has implemented the requirements of the Orders, and now these agreements have been terminated by the corresponding court systems. The ongoing requirements of these projects, which are further described later in my testimony, are now part of the Big Bend Title V operating permit (0570039-110-AV). The projects that are now required under the operating permit are listed below.

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

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

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

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2020 through December 2020.

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 2020; however, the O&M expenses associated with existing and recently installed Best Operating Practice ("BOP") and best available control technology ("BACT") equipment and continued implementation of the BOP procedures are expected to be $398,500.

Q. Please describe the Big Bend NO_x Emission Reduction program activities and provide the estimated capital and

O&M expenses for the period of January 2020 through December 2020.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric does not anticipate any capital expenditures in 2020; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $12,000 of O&M expenses during 2020.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2020 through December 2020.

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

For the period of January 2020 through December 2020, there are not any capital expenditures anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. The O&M expenditures for Big Bend Pre-SCR projects are projected to be $10,800 for Big Bend Unit 1 Pre-SCR, $10,800 for Big Bend Unit 2 Pre-SCR, and $12,000 for Big Bend Unit 3 Pre-SCR for equipment maintenance. There are not any anticipated capital expenditures for Big Bend Units 1 through 4 SCRs. The O&M expenses are projected to be $164,668 for Big Bend Unit 1 SCR, $329,616 for Big Bend Unit 2 SCR, $716,027 for Big Bend Unit 3 SCR, and $968,634 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases.

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

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

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration.
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables
5) Clean Water Act Section 316(b) Phase II Study
6) Big Bend FGD System Reliability
7) Arsenic Groundwater Standard
8) Mercury and Air Toxics Standards ("MATS")
9) Greenhouse Gas ("GHG") Reduction Program
10) Big Bend Gypsum Storage Facility
11) Coal Combustion Residuals ("CCR") Rule
12) Big Bend Unit 1 Section 316(b) Impingement Mortality
13) Big Bend Effluent Limitations Guidelines ("ELG") Rule Compliance

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 2020 through December 2020.

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 expenditures during January 2020 through December 2020 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $390,754 for consumables, primarily anhydrous ammonia, and ongoing maintenance. There are not any anticipated capital expenditures for the Big Bend Units 1 & 2 FGD project during January 2020 through December 2020; however, the O&M expenses are projected to be $250,146 for consumables, primarily anhydrous ammonia, and ongoing maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M expenditures for the period of January 2020 through December 2020.

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 2020 through December 2020, 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 316(a) 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. At this time, the company anticipates that an additional thermal study will not be required. If a thermal study is required, Tampa Electric will incur O&M expenses and will include them in the true-up filing.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2020 through December 2020.

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 2020 through December 2020, Tampa Electric projects O&M expenses associated with the consumable goods, primarily anhydrous ammonia, to be approximately $119,000.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study Program activities and provide the estimated O&M expenditures for the period of January 2020 through December 2020.

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

Electric is currently finalizing its compliance strategy for the CWIS Rule at Big Bend Station and is working with the regulating authority to determine the need and scheduling for biological, financial, and technical study elements necessary to comply with the rule. These elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits. Estimated O&M expenses for the period January 2020 through December 2020 are $40,000.

However, for Big Bend Unit 1, which will be repowered to a clean, natural gas-fired combined cycle unit, the permit will require installation of impingement mortality controls as part of the Big Bend Unit 1 Modernization. Therefore, in Order No. PSC-2018-0594-FOF-EI, issued on December 20, 2018, the Commission approved cost recovery for the Big Bend Unit 1 Section 316(b) Impingement Mortality project.

The biological, financial, and technical study elements have been identified for Bayside Power Station and submitted with the station’s NPDES permit renewal application in February 2018. Retrofits could include the installation of cooling towers or screening facilities.

Estimated O&M expenses for the period January 2020 through

December 2020 are $40,000 for additional study-related information to be provided to the regulatory agencies.

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 2020 through December 2020.

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 2020 through December 2020, Tampa Electric projects capital expenditures for the Big Bend Unit 1 Section 316(b) Impingement Mortality Project to be $1,200,000. There are no O&M expenses anticipated during 2020.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenditures for the period of January 2020 through December 2020.

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 cost recovery approval for prudent costs associated with this project. The Big Bend FGD System Reliability project has been running concurrently with the installation of the SCR systems on the generating units. For the period of January 2020 through December 2020, 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 2020 through December 2020.

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. For the period of January 2020 through December 2020, there are no anticipated O&M expenses at Bayside or Polk

Power Stations. At the time the budget was prepared, no O&M expenses were anticipated for Big Bend Power Station in 2020. A detailed plan of study was submitted to the FDEP, and after reviewing the study, FDEP requested a site wide groundwater evaluation. Additional costs may be incurred for this evaluation and would be included for Commission review in future true-up filings.

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 2020 through December 2020.

A. For 2020, Tampa Electric does not anticipate capital expenditures under the MATS program in 2020. O&M expenditures are projected to be approximately $27,000 for testing requirements and maintenance of equipment.

Q. Please describe the GHG Reduction program activities and provide the estimated O&M expenditures for the period of January 2020 through December 2020.

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 2020. For 2020, this activity is projected to result in approximately $93,150 of O&M expenditures.

Q. Please describe the Big Bend Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2020 through December 2020.

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. The project was placed in service in November 2014. For 2020, Tampa Electric does not anticipate any capital expenditures; however, the projected O&M expenses for this program during 2020 are $947,064.

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 2020 through December 2020.

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-2016-00994-PAA-EI, issued February 9, 2016. In that Order, the Commission found that the CCR Rule – Phase I program met the requirements for recovery through the ECRC. Incremental ongoing O&M expenses resulting from the groundwater monitoring program, berm inspections, and general maintenance of regulated units were approved under the Order. In order to determine the best option to remain in compliance with the new rule, the company evaluated whether to continue operation of the regulated CCR units or close them. Tampa Electric, for Phase II of the project, 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-2016-00994-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 to original grade, 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 which will need to be dewatered and shipped to the landfill, this project is expected to continue through 2021. The East Coalfield Stormwater Runoff Pond (slag pond) closure and retrofit was originally scheduled to begin in 2019 but has been delayed due to unusually high rainfall amounts. The project is now scheduled to begin and be completed in 2020. The North Gypsum Stackout Area Drainage Improvements project began in 2019 and is expected to be completed in 2020.

Tampa Electric expects to incur $2,158,000 and $583,500 in 2020 capital expenditures for CCR Rule - Phase I and Phase II projects, respectively. The company expects to incur $4,916,092 for O&M expenses for the CCR Rule - Phase II program. There are no O&M expenses projected for the CCR Rule – Phase I program during 2020.

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 2020 through December 2020.

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 rule requires compliance after November 1, 2018, but no later than December 31, 2023. EPA issued a temporary stay of these compliance deadlines beginning April 25, 2017 for certain waste streams, including FGD wastewater.

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

Consummating Order No. PSC-2016-0290-CO-EI issued July 25, 2016 in the same docket.

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

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

On June 6, 2017, the EPA issued proposed rulemaking to postpone these deadlines until it has completed reconsideration of the 2015 rule. On August 11, 2017, EPA issued a letter to the Utility Water Act Group (“UWAG”) and the U.S. Small Business Association regarding petitions received by the EPA requesting reconsideration of the rule. In this letter, EPA stated that it would be appropriate to conduct rulemaking to “potentially revise” the limitations for bottom ash transport water and FGD wastewater. The compliance deadlines for these waste streams were revised to be as soon as possible after November 1, 2020, but no later than December 31, 2023. Tampa Electric expects that the selected compliance option will continue to be required as the best option for customers even if some changes are made to the rule. For the year January 2020 through December 2020, Tampa Electric projects capital expenditures to be $4,500,000. The company does not currently project any O&M expenditures for this project for the period.

Q. Please summarize your testimony.

A. The settlement agreements Tampa Electric had with FDEP and EPA required significant reductions in emissions from Big Bend and Gannon Power Stations. These settlement agreements have been terminated due to the company having satisfied all requirements as set forth by the CFJ and CD. Ongoing requirements for projects originating with the CFJ and CD have been incorporated into Big Bend's Title V Operating permit (0570039-110-AV) and are discussed throughout my testimony. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I identified estimated costs, by project, which the company expects to incur in 2020. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2020 activities and projected expenditures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CHAIRMAN GRAHAM: Okay. Exhibits.

MS. WEISENFELD: Staff has compiled a stipulated comprehensive exhibit list which includes the prefiled exhibits attached to the witnesses' testimony in this case and staff's exhibits. The list has been provided to the parties, the Commissioners and the court reporter.

We request that the list be marked as the first hearing exhibit, and the other exhibits be marked as set forth in the list.

(Whereupon, Exhibit No. 1 was marked for identification.)

(Whereupon, Exhibit Nos. 2-54 were marked for identification.)

CHAIRMAN GRAHAM: Okay.

MS. WEISENFELD: So at this time, we ask that the comprehensive exhibit list be marked as Exhibit 1 and be entered into the record.

CHAIRMAN GRAHAM: We will enter Exhibit 1, the comprehensive exhibit list, into the record.

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

MS. WEISENFELD: We also ask that all prefiled exhibits and staff's exhibits be included in the record as set forth in the comprehensive exhibit list numbered Exhibits 2 through 54.

CHAIRMAN GRAHAM: If there is no objection to entering Exhibits 2 through 54, we will enter that into the record as well.

(Whereupon, Exhibit Nos. 2-54 were received into evidence.)

CHAIRMAN GRAHAM: All right, decision time. Staff, what is the posture of the Commission for making a bench decision?

MS. WEISENFELD: If the Commission decides that a bench decision is appropriate, we recommend that the proposed stipulations of all issues be approved by the Commission. All parties either support or do not oppose the proposed stipulations.

CHAIRMAN GRAHAM: Parties, are there any comments? Seeing none, Commissioners.

COMMISSIONER CLARK: Mr. Chairman, move approval of all issues.

COMMISSIONER FAY: Second.

CHAIRMAN GRAHAM: It's been moved and seconded approval of all issues -- the proposed stipulation of all issues, is that what you meant to say?

COMMISSIONER CLARK: Yes, sir.

CHAIRMAN GRAHAM: Okay. It's been moved and seconded.

Any further decision -- further discussion?
Seeing none, all in favor say aye.
(Chorus of ayes.)
CHAIRMAN GRAHAM: Any opposed?
(No response.)
CHAIRMAN GRAHAM: By your action, you have approved that motion.
All right. Any other matters, staff?
MS. WEISENFELD: Only that since the Commission has made a bench decision, post-hearing filings are not necessary and the final order will be issued by November 25th, 2019.
CHAIRMAN GRAHAM: Do the parties have any other matters to be addressed in this one?
All right. You know, it kind of messes up my whole role when you guys change, like, the first three and then this one.
Okay. So then we adjourn this hearing and we will proceed to the 01 docket.
(Proceedings concluded at 4:15 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 15th day of November, 2019.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020