BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20170007-EI

ENVIRONMENTAL COST RECOVERY
CLAUSE.
_____________________________/

VOLUME 1
PAGES 1 through 221

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN JULIE I. BROWN
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK

DATE: Wednesday, October 25, 2017

TIME: Commenced at 4:33 p.m.
Concluded at 5:35 p.m.

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

REPORTED BY: ANDREA KOMARIDIS
Court Reporter

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

APPEARANCES:

CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and STEPHANIE A. MORSE, ESQUIRE, 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.

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

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

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

GEORGE CAVROS, ESQUIRE, 120 East Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334, on behalf of Southern Alliance for Clean Energy.

APPEARANCES:

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

JOHN BUTLER, WADE LITCHFIELD, and JESSICA CANO, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, on behalf of Florida Power & Light Company.

CHARLIE MURPHY, STEPHANIE A. CUELLO, and MARGO A. DUVAL, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

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

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID	ADMITTED
1 - Comprehensive Exhibit List		192
25 through 43 - Stipulated testimony of parties		193
54 through 66 - (as identified on Comprehensive Exhibit List)		193

P R O C E E D I N G S

CHAIRMAN BROWN: Thank you so much.

And we are going to take appearances. There are five dockets and, staff, it's -- your suggestion that we take up the appearances all at once, correct?

MS. DUVAL: Yes, ma'am.

CHAIRMAN BROWN: Okay. So all parties, please, when I go through the list, can you please enter your appearances and declare which dockets you are entering an appearance for? Starting with Florida Power & Light.

MR. BUTLER: Thank you, Madam Chairman. John Butler and Wade Litchfield appearing in dockets 01, 02 and 07. Also appearing -- on behalf of Florida Power & Light Company.

Also appearing for Florida Power & Light Company in the 01 docket are Maria Moncada and Will Cox. In the 02 docket, Ken Rubin, and in the 07 docket, Jessica Cano.

CHAIRMAN BROWN: Okay.

MR. BUTLER: Thank you.

CHAIRMAN BROWN: Thank you.

Duke, Matt Bernier.

MR. BERNIER: Thank you, Madam Chairman.

Good afternoon, Commissioners. Matt Bernier for Duke Energy. I am entering an appearance in the 01, 02 and 07 dockets. And I would also like to enter an appearance for Dianne Triplett.

Thank you.

CHAIRMAN BROWN: Thank you.

Mr. Beasley.

MR. BEASLEY: Thank you, Madam Chair, Commissioners. James Beasley, appearing with Jeff Whalen for Tampa Electric Company in 01, 02 and 07 dockets.

CHAIRMAN BROWN: Thank you.

Gulf.

MR. BADDERS: Good afternoon. Russell Badders on behalf of Gulf Power, in the 01, 02 and 07 dockets. I would also like to enter an appearance for my partner, Steven Griffin, and for Gulf's General Counsel, Jeffery A. Stone.

CHAIRMAN BROWN: Thank you.

FIPUG.

MR. MOYLE: Thank you, Madam Chairman. Jon Moyle on behalf of the Florida Industrial Power Users Group. I would also like to enter an appearance for Karen Putnal, and those would be in the 01, 02 and 07 dockets.

CHAIRMAN BROWN: Thank you.

Ms. Keating.

MS. KEATING: Thank you, Madam Chairman, Commissioners. Beth Keating with the Gunster Law Firm here this afternoon for FPUC in the 01, 02, 03 and 04 dockets for Indiantown and Chesapeake in the 04 docket, and for Florida City Gas in the 03 and 04 dockets.

CHAIRMAN BROWN: Okay. Thank you.

Mr. Cavros.

MR. CAVROS: Good afternoon, Madam Chair, Commissioners. George Cavros on behalf of Southern Alliance for Clean Energy, entering an appearance in the 07 docket.

CHAIRMAN BROWN: Thank you.

Mr. Wright.

MR. WRIGHT: Robert Scheffel Wright and John T. Lavia, III, Gardner Law Firm, appearing on behalf of the Florida Retail Federation in the 01 docket, the fuel docket.

Thank you.

CHAIRMAN BROWN: Thank you.

Public Counsel.

MR. SAYLER: Erik Sayler on behalf of the Public Counsel. I would like to do a notice of appearance for Mr. Kelly, Ms. Christensen and myself in all the dockets but the 07 docket, and Mr. Rehwinkel.

MR. REHWINKEL: Yes, Charles Rehwinkel for the 07 docket only today, as well as Stephanie Morse.

Thank you.

CHAIRMAN BROWN: Thank you.

Staff.

MS. DUVAL: Margo DuVal for the 02 and 07 dockets. And I would like to enter appearances for Wesley Taylor in the 03 docket, Stephanie Cuello in the 04 and 07 dockets. Suzanne Brownless and Danijela Janjic in the 01 docket, and Charles Murphy in the 07 docket.

MS. HELTON: Mary Anne Helton as your adviser. I would also like to enter an appearance for your General Counsel, Keith Hetrick.

CHAIRMAN BROWN: Thank you.

We are opening the 07 docket.

Staff.

MR. MURPHY: Chairman, FPL, Gulf, Duke, TECO, OPC, FIPUG, and SACE are participating in this hearing. PCS Phosphate has been excused.

All non-Turkey Point issues are stipulated. The parties have waived opening statements on those issues.

FPL has ten minutes for an opening statement addressing Turkey Point. OPC, FIPUG, and SACE will share 15 minutes for opening statements on Turkey Point. Staff recommends that -- taking opening statements when the contested issues are taken up.

The following issues are contested and will require a vote by Commission after briefs are filed: Issues 1A through 1E, inclusive, that all relate to -- 10A to 10E, inclusive -- sorry. Thank you -- all are related to FPL Turkey Point.

All other issues are Type 2 stipulations and can be voted on today.

CHAIRMAN BROWN: And we'll get to that in a -- in a moment.

MR. MURPHY: Sure. The prefiled testimony of Witnesses Menendez, Hill --

CHAIRMAN BROWN: If you could, just one -- I know you're -- you're motoring through. I just want to make sure that we don't have any preliminary matters to address before we get to the record.

Seeing none -- Mr. Moyle?

MR. MOYLE: I --

CHAIRMAN BROWN: You've rejuvenated?

MR. MOYLE: I have one -- I was just curious, for planning purposes, what -- what the evening might look like.

CHAIRMAN BROWN: So, I was going to get to that when we go over some, you know, preliminary matters, after the record.

MR. MOYLE: Okay.

CHAIRMAN BROWN: Now is time.

MR. MURPHY: Oh, okay. The prefiled testimony of Witnesses Menendez, Hill, Swartz, West, Rusk, Carpinone, if I'm saying that right, Markey, and Boyett has been stipulated by the parties. Staff asks that the prefiled testimony of these witnesses be inserted into the record as though read.

CHAIRMAN BROWN: So, we will go ahead and enter into the record as though read the prefiled testimony of those witnesses that you just identified.

(Prefiled direct testimony inserted into the record as though read.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

CHRISTOPHER MENENDEZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 170007-EI

April 3, 2017

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 2016 - December 2016.

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 2016 - December 2016.
- 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 2016 - December 2016?

A. DEF requests approval of an over-recovery amount of $7,872,922 for the year ending December 31, 2016. 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 2016 - December 2016 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 over-recovery of $1,266,492 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the period January 2016 - December 2016. This amount is the difference between an actual over-recovery amount of $7,872,922 and an actual/estimated over-recovery of $6,606,430 for the period January 2016 - December 2016, as approved in Order PSC-16-0535-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 2016 - December 2016 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 $2,019,715 lower than projected. Individual O&M project variances are on Form 42-4A. Explanations associated with variances are contained in the direct testimonies of Jeffrey Swartz, Timothy Hill, and Patricia Q. West.

Q. How did actual capital recoverable expenditures for January 2016 - December 2016 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 $69,207 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 Patricia West.

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 $368,070 higher than projected due to the purchase of Seasonal NOx ("SNOx") emissions allowances in Q2 and Q3 2016. The balance in DEF's SNOx emissions inventory was below the allowable threshold according to DEF policy. This resulted in DEF purchasing SNOx allowances to ensure DEF would meet the EPA's reductions to DEF's emissions allowance accounts when EPA compliance occurred in December 2016 for SNOx. The purchases increased the weighted average cost of the SNOx emissions allowance inventory and resulted in the increased emissions 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. 20170007-EI

August 4, 2017

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. 20170007-EI?

A. Yes, I provided direct testimony on April 3, 2017.

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 2017 through December 2017. I also explain the variance between 2017 actual/estimated cost projections versus original 2017 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 2017 through December 2017.

Q. What is the actual/estimated true-up amount for which DEF is requesting recovery for the period of January 2017 through December 2017?

A. The 2017 actual/estimated true-up is an over-recovery, including interest, of $1,751,015 as shown on Form 42-1E, line 4. This amount is added to the final 2016 true-up over-recovery of $1,266,492 as shown on Form 42-2E, Line 7a, resulting in a net over-recovery of $3,017,507 as shown on Form 42-2E, Line 11. The calculations supporting the 2017 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 2017 through December 2017?

A. The capital structure, components and cost rates relied on to calculate the revenue requirement rate of return for the period January 2017 through December 2017 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 2017 through December 2017 compare with original projections?

A. Form 42-4E shows that total O&M project costs are estimated to be approximately $987k 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, Jeffrey Swartz and Patricia Q. West.

Q. How do estimated/actual capital recoverable costs for January 2017 through December 2017 compare with DEF's original projections?

A. Form 42-6E shows that total recoverable capital costs are estimated to be approximately $949k or 4% lower than originally projected. This form also lists individual project variances. The return on investment, depreciation expense and property taxes for each project for the actual/estimated period are provided on Form 42-8E, pages 1 through 17. Explanations for these variances are included in the direct testimonies of Mr. Hill, Mr. Swartz and Ms. West.

Q. Is DEF retiring any ECRC projects?

A. Yes. As noted in my testimony under Docket 160007-EI and approved in Order No. PSC-16-0535-FOF-EI, DEF is in the process of retiring the Anclote-Bartow Pipeline and with this retirement, the Pipeline Leak Detection (Project 3.1b), Pipeline Controls Upgrade (Project 3.1c), and Control Room Management (Project 3.1d) were retired August 31, 2016. The Alderman Road Fence (Project 3.1a) needed to remain in-service to support ongoing activities, and DEF retired this project as of June 30, 2017.

Q. How does DEF propose to treat unrecovered ECRC costs of the Pipeline Integrity Management Alderman Road Fence Project (Project 3.1a)?

A. Consistent with the Commission's treatment of the other three sub-projects in the Pipeline Integrity Management Project, DEF proposes that the Commission approve treating the Alderman Road Fence Project costs as a regulatory asset. DEF retired the asset as of June 1, 2017, and DEF proposes to amortize the balance equally over 26 months until fully recovered in 2019. This will allow the final amortization to align with the other three sub-projects which were retired last year. 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 Pipeline Integrity Management assets will have no effect on 2017 rates. Any over/under-recovery will be part of the normal true-up process in the annual ECRC proceedings. Unrecovered Alderman Road Fence costs are projected to be approximately $24k as of June 2017.

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. 20170007-EI

September 1, 2017

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. 20170007-EI?

A. Yes. I provided direct testimony on April 3, 2017 and August 4, 2017.

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 2018 through December 2018. My testimony also addresses capital and O&M expenses for DEF's environmental compliance activities for the year 2018.

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. West will co-sponsor Forms 42-5P pages 1-4, 6 and 8-20.
- Mr. Swartz and Ms. West 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 0.155 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2018 through December 2018 of approximately $60.0 million associated with a total of 18 environmental projects, and a true-up over-recovery provision of approximately $3.0 million from prior periods. My testimony also supports that projected environmental expenditures for 2018 are appropriate for recovery through the ECRC.

Q. What is the total recoverable revenue requirement for the period January 2018 through December 2018?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $60.0 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 2018 through December 2018?

A. The total true-up applicable to this period is an over-recovery of approximately $3.0 million. This amount consists of the final true-up over-recovery of approximately $1.3 million for the period January 2016 through December 2016, and an estimated true-up over-recovery of approximately $1.7 million for the current period of January 2017 through December 2017. The detailed calculation supporting the 2017 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (CAM-3) filed with the Commission on August 4, 2017.

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.

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.

Q. What capital structure, components and cost rates did DEF rely on to calculate the revenue requirement rate of return for the period January 2018 through December 2018?

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 2017 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. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2018?

A. Yes. Form 42-2P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $35.3 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2018?

A. Yes. Form 42-3P of Exhibit No. __ (CAM-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $27.7 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 2018?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are approximately $62.9 million. The costs are calculated on Form 42-1P line 1c of Exhibit No. __ (CAM-5).

Q. For the Crystal River 316(b) Compliance Project, how will compliance costs be allocated to rate classes?

A. Consistent with the allocation of previously approved Phase II Cooling Water Intake 316(b) costs, DEF proposes that capital and O&M costs associated with the Crystal River 316(b) Compliance Project be allocated to rate classes on a demand basis.

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 2015. 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 2018 customer billings is shown on Form 42-7P in Exhibit No. __(CAM-5) as follows:

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.158 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.154 cents/kWh
@ Primary Voltage	0.152 cents/kWh
@ Transmission Voltage	0.151 cents/kWh
General Service 100% Load Factor	0.151 cents/kWh
General Service Demand	
@ Secondary Voltage	0.153 cents/kWh
@ Primary Voltage	0.151 cents/kWh
@ Transmission Voltage	0.150 cents/kWh
Curtailable	
@ Secondary Voltage	0.151 cents/kWh
@ Primary Voltage	0.149 cents/kWh
@ Transmission Voltage	0.148 cents/kWh

Interruptible	
@ Secondary Voltage	0.147 cents/kWh
@ Primary Voltage	0.146 cents/kWh
@ Transmission Voltage	0.144 cents/kWh
Lighting	0.146 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 2018 and continue through the last bill group for December 2018.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>TIMOTHY HILL</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 170007-EI

April 3, 2017

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 14 years of experience in the power generation industry including positons 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 2016 Coal Combustion Residual ("CCR") Rule compliance activities and associated 2016 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 2016 – December 2016 compare to actual/estimated Capital projections for the CCR Rule (Project 18)?

A. The CCR Rule capital variance is $54,811 or 16% lower than projected due to lower than forecasted costs associated with groundwater assessment. This was partially offset by the installation of additional asphalt under the gypsum radial stacker to comply with Court Appointed Monitor audit findings.

Q. How did actual O&M project expenditures for the period January 2016 – December 2016 compare to actual/estimated O&M projections for the CCR Rule (Project 18)?

A. The CCR O&M variance is $1,177,325 or 50% lower than projected. This is primarily due to lower than expected costs for the Flue Gas Desulfurization (“FGD”) pond dredging.

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. 20170007-EI

August 4, 2017

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. 20170007-EI?

A. Yes, I provided direct testimony on April 3, 2017.

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 2017 actual/estimated cost projections and original 2017 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 2017 through December 2017.

A. O&M expenditures for CCR are expected to be $59k or 14% higher than projected. This is due to higher than anticipated costs associated with FGD blowdown pond closure.

Q. Please explain the variance between actual/estimated project expenditures and original projections for CCR (Project 18) capital for the period January 2017 through December 2017.

A. Capital expenditures for CCR are expected to be $141k or 69% lower than originally planned. This is due to fewer CCR wells being required than initially forecasted.

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. 20170007-EI

September 1, 2017

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. 20170007-EI?

A. Yes. I provided direct testimony on April 3, 2017 and August 4, 2017.

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 2018 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 2018?

A. <u>Ash Landfill and Flue Gas Desulfurization Ponds O&M Costs</u>

Various maintenance and repair work is required for the CR ash landfill and FGD ponds to comply with the rule. These include fixing ruts and animal burrows, vegetation management, erosion repairs, fugitive dust mitigation, Emergency Action Plan exercises and updates, and routine weekly inspections. Additionally the rule requires annual inspections of the landfill and FGD ponds by qualified engineers. DEF will also perform the required groundwater monitoring for ash management units, which includes engineering, sampling, analysis, and reporting. Total estimated O&M costs are approximately $501k.

Flue Gas Desulfurization ("FGD") Blowdown Ponds

DEF estimates approximately $114k of capital expenditures in 2018. DEF anticipates installing five groundwater monitoring wells to comply with the rule's groundwater assessment requirements.

Q. Are there any other CCR rule compliance activities and costs for which DEF expects to seek recovery in 2018?

A. DEF continues to evaluate the CCR rule to determine operating and cost impacts, and expects to incur costs in 2018 and beyond. However, the full extent of compliance activities and associated costs cannot be determined until further analysis and assessment, including CCR well data analysis, is complete. 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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 170007-EI

April 3, 2017

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 16 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 2016 - December 2016.

Q. **How do actual O&M expenditures for January 2016 - December 2016 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 $1,068,409 or 3% lower than projected. This variance is primarily attributable to $247,498 lower than expected CAIR Crystal River Project 7.4 – Base costs, and $817,092 lower than expected CAIR-Crystal River Project 7.4 – Energy Costs.

Q: **Please explain the variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Base for January 2016 - December 2016?**

A: O&M costs for CAIR Crystal River Project – Base were $247,498 or 1% lower than projected primarily due to lower than anticipated costs for the Unit 4 SCR Catalyst maintenance.

Q. Please explain the variance between actual project expenditures and the actual/estimated projections for CAIR Crystal River Project – Energy for the period January 2016 - December 2016?

A. O&M costs for CAIR Crystal River Project - Energy were $817,092 or 5% lower than forecasted primarily due to variations in the reagent costs. Ammonia expense was $519,752 favorable due the urea markets declining since the previous filing. Gypsum expense was $107,261favorable due to production volumes being approximately 9% lower than projected. Hydrated Lime and Caustic expenses were $547,478 and $133,894 favorable, respectively, due to market price fluctuations. These were partially offset by an unfavorable variance in Limestone expense of $557,293, due to increased product costs.

Q: Please explain the variance between actual project expenditures and actual/estimated projections for the CAIR Crystal River Project – Conditions of Certification (Project 7.4q) for January 2016 - December 2016?

A: Capital costs for CAIR Crystal River Project – Conditions of Certification were $192,951 or 27% higher than projected due to engineering and equipment procurement being ahead of schedule and costs resulting from previously unidentified underground obstacles identified during Ground Penetrating Radar investigations.

Q. How did actual Capital expenditures for January 2016 – December 2016 compare to actual/estimated projections for the Anclote Gas Conversion Project (Project 17.1)?

A. The Anclote Gas Conversion Capital variance is $212,739 or 153% lower than projected due to final adjustment charges for the two Forced Draft Fan Projects on Units 1 and 2.

Q. How did actual O&M expenditures for January 2016 - December 2016 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 $354,659 or 20% higher than projected. The O&M variance is due to the installation of necessary equipment to improve coal flow between the storage hoppers and the coal mills. These modifications were required to mitigate buildup and plugging in the piping caused by specific characteristics of the Western coal burned for MATS compliance.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>JEFFREY SWARTZ</u>

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170007-EI

August 4, 2017

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. 20170007-EI?

A. Yes, I provided direct testimony on April 3, 2017.

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 2017 actual/estimated cost projections and original 2017 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 Crystal River (CR) Program (Project 7.4) for the period January 2017 through December 2017?

A. O&M expenditures are expected to be approximately $967k or 3% lower than originally projected due to lower than anticipated limestone expense, and temporary staffing vacancies which are expected to be filled later in the year.

Q. How do actual/estimated capital project expenditures compare with original projections for the CAIR/CAMR Crystal River (CR) Conditions of Certification Program (Project 7.4) for the period January 2017 through December 2017?

A. Capital expenditures are expected to be approximately $8.4M or 25% lower than originally projected. This is due to finalizing the Waste Water Treatment design and engineering later than originally projected. As a result, some capital expenditures originally projected in 2017 are now expected to occur in 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. 20170007-EI

September 1, 2017

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. 20170007-EI?

A. Yes. I provided direct testimony on April 3, 2017 and August 4, 2017.

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 2018 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 2018 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 $33.7M 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 $8.2M based on current staffing levels, including labor for the CRN FGD Wastewater project discussed below.
- Contractor expenses are estimated at $4.3M for various services.

- Parts and materials are estimated at $2.3M.
- Other costs are estimated at $168k.
- Project expenses for absorber stack inspections are estimated at $104k.
- CR4 outage costs are estimated at $1M.
- Reagent and bi-product costs (ammonia, limestone, hydrated lime, caustic, dibasic acid and net gypsum sales/disposal) are estimated to total $17.6M.

Q. **Please provide an update on the CR 4&5 FGD Wastewater Treatment Project (Project 7.4q).**

A. CR4&5 coal-fired units generate blowdown wastewater that is discharged to a series of lined ponds for equalization and settling, then further discharged to unlined percolation ponds. In the Conditions of Certification dated August 1, 2012, the Florida Department of Environmental Protection ("FDEP") required DEF to evaluate an alternative disposal method based on results of groundwater monitoring near the percolation ponds. As explained in my August 31, 2015 testimony filed in Docket No. 20150007-EI, DEF has evaluated several treatment options to comply with the FDEP permit requirements and selected a strategy that uses a physical/chemical treatment system with a bioreactor treatment system to treat FGD blowdown wastewater with discharge to surface water or percolation ponds. As explained in my September 1, 2016 testimony filed in Docket No. 20160007-EI, DEF completed the final design in 2017. After a review of existing FGD WWT systems across the Duke Energy fleet consisting of physical/chemical and biological technologies, and after several comprehensive design reviews of vendor equipment and balance of plant components, DEF has developed preliminary estimated costs to operate and maintain the CR 4&5 FGD WWT system.

Q. **What 2018 O&M costs does DEF expect to incur for the CR 4&5 FGD Blowdown Wastewater Treatment project (Project 7.4q).**

A. Once the project is placed in-service in Q4 2018, DEF expects to incur 2018 O&M costs of approximately $495k, which includes FGD WWT Operators that will be required 24 hours per day to operate the system, provide basic maintenance, and conduct analytics required to run the system appropriately. On a full year basis, DEF's preliminary O&M estimate is approximately $1.96 million.

Q. What capital expenditures does DEF expect to incur in 2018 for the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?

A. DEF estimates 2018 capital expenditures of approximately $42M for the CR 4&5 FGD Blowdown wastewater project. This includes completion of the plant equipment construction and the WestTech/Frontier Bioreactor equipment.

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 51 employees that report to the Crystal River North Station Manager and 1 employee who reports to the Director-Florida Fossil-Hydro-Finance. There are 7 managers and 44 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. 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. What O&M costs does DEF expect to incur in 2018 for the MATS Program – Anclote Gas Conversion (Project 17.1)?

A. DEF does not expect any O&M costs.

Q. What O&M costs does DEF expect to incur in 2018 for the MATS Program – CR1&2 (Project 17.2)?

A. DEF estimates O&M costs of approximately $1.5 million for CR1&2 MATS compliance. This estimate includes support for reagent injection systems, fuel handling and equipment impacts from burning alternate fuels, and emissions monitoring and testing.

Q. What capital expenditures does DEF expect to incur in 2018 for the MATS Program – CR1&2 (Project 17.2)?

A. DEF does not anticipate any capital expenditures in 2018.

Q. Does this conclude your testimony?

A.	Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 170007-EI

April 3, 2017

Q. Please state your name and business address.

A. My name is Patricia Q. West. 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 Director Environmental Field Support – Florida.

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 Arts degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department between 1983 and 1986 and by the Florida Department of Environmental Protection (FDEP) from 1986 - 1990. At the FDEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. I joined Florida Power Corporation in 1990 as an Environmental Project Manager and then held progressively more responsible positions through the merger with Carolina Power and Light, and more recently through the merger with Duke Energy in my role as the Director Environmental Field Support – FL.

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 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) 4&5 (Project 17) for the period January 2016 through December 2016.

Q. How did actual O&M expenditures for January 2016 - December 2016 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 $187,182 or 24% higher than projected. This variance is primarily due remediation activities at Central Florida, UCF, and Wekiva substations which were higher than projected. Central Florida's substation is slated for a Deed Restricted Covenant ("DRC") with FDEP. We are currently compiling information in order to submit a formalized report to FDEP to support a proposal that this site be considered for a DRC with engineering and institutional controls. Work at UCF is now complete, a remediation report was sent to FDEP in July 2016 and approved in August 2016. Wekiva groundwater monitoring is still underway.

Q. How did actual O&M expenditures for January 2016 - December 2016 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 $10,605 or 10% lower than projected due to a project at 7100 Sunset Way, St. Pete Beach, requiring less engineered fill, equipment and associated disposal cost than originally estimated.

Q. How did actual O&M expenditures for January 2016 - December 2016 compare with DEF's actual/estimated projections for the PIM Project (Project 3)?

A. The PIM O&M variance is $327,980 or 47% lower than projected. This variance is attributed to monitoring and reporting charges being minimized as steps are being taken to remove the pipeline from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations.

Q. How did actual O&M expenditures for January 2016 - December 2016 compare with DEF's actual/estimated projections for the Cooling Water Intake - 316(b) Project (Project 6 & 6a)?

A. The Cooling Water Intake - 316(b) (Projects 6 & 6a) variance is $95,185 or 22% lower than projected, driven primarily by Cooling Water Intake 316(b) – Intermediate (Project 6a), which had a $111,894 or 59% lower than projected variance due to lower programmatic fees being assessed for Anclote and Suwannee Stations. No compliance monitoring was performed at Anclote station due to pending FDEP approval of a proposal for a non-monitoring program strategy and retirement of the Suwannee Steam Station, which eliminates the monitoring program requirement.

Q. How did actual O&M expenditures for January 2016 - December 2016 compare with DEF's actual/estimated projections for the CAIR/CAMR - Peaking Project (Project 7.2)?

A. The CAIR/CAMR - Peaking variance is $30,659 or 30% lower than projected primarily attributed to the retirement of Turner CT site, resulting in the cancellation of predictive emissions monitoring requirement.

Q. How did actual O&M expenditures for January 2016 - December 2016 compare with DEF's actual/estimated projections for the Arsenic Groundwater Standard Project (Project 8)?

A. The Arsenic Groundwater Monitoring variance is $16,857 or 13% lower than projected primarily due to the contractor completing Phase 1 of the work scope at a lower cost than originally estimated.

Q. How did actual Capital expenditures for January 2016 - December 2016 compare with DEF's actual/estimated projections for the Effluent Limitations Guideline Project (Project 15.1)?

A. The ELG Capital variance is $92,991 or 41% lower than projected primarily due to scheduled work scope shifting into 2017; the project is still in the initial Engineering & Development phase. The water balance study for the site has been completed and the design conception is complete and under Engineering review. The sample analysis was completed in late December, thereby shifting the completion of the Engineering Design and Review process into 2017.

Q. How did actual O&M expenditures for January 2016 - December 2016 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 $211,114 or 42% lower than projected due to lower than anticipated chemical usage required to control mercury re-emission from the FGDs.

Q. In Order No. PSC-10-0683-FOF-EI issued in Docket No. 100007-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. __ (PQW-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 history and status of the Cross State Air Pollution Rule ("CSAPR")?

A. The EPA adopted the CSAPR to replace the CAIR by publication in the Federal Register in August 2011. The CSAPR establishes state-level annual and seasonal SO_2 and NO_x emissions allowance requirements that were effective January 1, 2012. Under CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only ozone seasonal limits. In Order No. PSC-11-0553-FOF-EI, the Commission established a regulatory asset to allow DEF to recover the costs of its remaining CAIR NO_x allowance inventory over a three (3) year amortization period. However, on December 30, 2011, the D.C. Circuit Court of Appeals stayed the CSAPR leaving the CAIR in effect until it completed its review of CSAPR. Consequently, DEF continued to maintain its NO_x allowance inventory in order to comply with the CAIR. In August 2012, the D.C. Circuit Court of Appeals vacated the CSAPR and directed the EPA to continue administrating the CAIR program. The EPA subsequently appealed this decision to the U.S. Supreme Court. In April 2014, the U.S. Supreme Court overturned the D.C. Circuit Court's ruling and remanded the case back to the lower court for further action. In June 2014, the EPA requested that the court lift the CSAPR stay and allow it to be implemented under a revised schedule. This request was granted in October 2014 and the CSAPR went into effect on January 1, 2015, replacing the CAIR program. On July 28, 2015, the D.C. Circuit determined that EPA failed to cost justify a number of Phase 2 emission allowance budgets for certain states, including Florida, citing they were more stringent than necessary to achieve air compliance in downwind states, and held the Phase 2 NO_x allowance allocations invalid. Finally, 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. This means that Duke Energy sources in Florida are not subject to any CSAPR ozone season NOx emission limitations beginning in 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 must be incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023. 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 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 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 Supreme Court case will not be scheduled until October 2017, at the earliest, following the Court's return from summer recess. 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 Army Corps of Engineers to initiate a rulemaking to either rescind or revise the 2015 Clean Water Rule developed by the Obama administration. Subsequently, the new EPA administrator, Scott Pruitt, signed a pre-publication notice reflecting the intent to move forward with rulemaking in response to this directive. In addition, the executive order also seeks to have the Department of Justice determine the path forward on the Clean Water Rule litigation in light of the new policy direction. During this interim period, it is expected that the 2015 Clean Water Rule will remain in a nationwide stay and any new WOTUS jurisdictional determinations will be made by the Corps using the previous WOTUS definition.

Q. What is the status of the FDEP's Underground Storage Tank (UST) Rule (Project 10)?

A. The FDEP's UST Rule became effective on January 11, 2017. A detailed analysis of the rule is underway to determine the full extent of compliance activities and associated expenditure s for DEF's operations.

Q. What is the status of FDEP's Aboveground Storage Tank (AST) Rule (Project 4)?

A. The FDEP's AST rule became effective January 11, 2017. A detailed analysis of the Rule is underway to determine the full extent of compliance activities and associated expenditures for DEF's operations.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170007-EI

August 4, 2017

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20170007-EI?

A. Yes, I provided direct testimony on April 3, 2017.

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 2017 actual/estimated cost projections and original 2017 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 2017 through December 2017.

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 2017 through December 2017.

A. O&M expenditures for the substation system program are estimated to be $207k or 21% higher than originally projected. The variance is due to additional work at the Holder Substation, and several distribution projects completed in 2017 that were originally anticipated to continue into 2018.

Q. Please explain the variance between actual/estimated project expenditures and original projections for Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2) for the period January 2017 through December 2017.

A. O&M expenditures for the distribution system program are estimated to be $36k or 100% higher than originally forecasted. DEF conducted four groundwater quality monitoring events and installed one recovery well point at the 7100 Sunset Way, St. Petersburg Beach location.

Q. Please explain the variance between actual/estimated project expenditures and original projections for the Pipeline Integrity Program (Project 3) for the period January 2017 through December 2017.

A. O&M expenditures for the pipeline integrity management program are estimated to be $246k or 100% less than originally projected. This is due to the pipeline being retired and deregulated; no expenditures are expected for 2017.

Q. Please explain the variance between actual/estimated project expenditures and original projections for CAIR/CAMR - Peaking (Project 7.2) for the period January 2017 through December 2017.

A. O&M expenditures for CAIR/CAMR - Peaking are projected to be $92k or 100% lower than originally projected due to rule changes in late 2016, which eliminated both the requirement for CT units to report emissions data to the Environmental Protection Agency ("EPA") and the performance of Appendix E testing.

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 2017 through December 2017.

A. O&M expenditures for Sea Turtle – Coastal Street Lighting are expected to be $450 or 100% lower than forecasted. Capital is expected to be $500 or 100% lower than forecasted. Turtle nesting season has recently begun and DEF has not received any requests from Gulf County or Pinellas County Code Enforcement of any issues regarding new lighting fixtures.

Q. Please provide an update on Effluent Limitation Guidelines ("ELG") and DEF's Effluent Limitation Guidelines Program (Project 15.1).

A. On November 23, 2015, 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 must be incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023. On April 25, 2017, EPA issued an administrative stay postponing the compliance dates in the rule. On June 6, 2017, EPA published in the Federal Register its proposal to postpone certain compliance dates in the rule. On August 12, 2017, EPA will inform the Fifth Circuit Court of Appeals of the portions of the rule, if any, it intends to reconsider.

Pending the August 12, 2017, EPA decision, the ELG Project has been temporarily placed on hold awaiting further clarification of the rule. The original forecast was $4.1M for 2017; DEF expects 2017 expenditures to be approximately $111k.

Q. Please provide an update of DEF's National Pollution Discharge Elimination System ("NPDES") Program (Project 16).

A. The NPDES Project is expected to be $10k or 13% lower than originally forecasted due to the retirement of the Suwannee Steam Units. The effluent discharge was eliminated with the units' retirement; therefore, the Whole Effluent Toxicity ("WET") testing requirement was removed in the NPDES permit revision issued in May 2017.

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 impingement options. Entrainment compliance is site specific (mesh screen or closed-cycle cooling). Litigation of the 316(b) rule continues.

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.

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 established state-specific emission goals; for Florida, the goals included a phased approach beginning in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state could adopt a mass emissions approach culminating in a 2030 target of 105,094,704 tons (existing units) or 106,641,595 tons (existing plus new units). 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 9, 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 granted a 60-day abeyance of the CPP litigation. 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 29, 2017, the U.S. Department of Justice provided a status report on EPA's regulatory review of the CPP to the D.C. Circuit. In the report, DOJ requested that the litigation remain in abeyance pending the conclusion of EPA's anticipated rulemaking.

DEF does not expect to incur ECRC costs in 2017 related to carbon regulations.

Q. Please provide an update on the Coal Combustion Residual (CCR) Rule.

A. The CCR rule was published in the Federal Register on April 17, 2015, and became effective on October 17, 2015. The rule has specific compliance impacts on the ash landfill, gypsum storage pad and FGD lined blowdown ponds at the Crystal River site. DEF's planned 2017 compliance activities and their associated cost projections are provided by Mr. Timothy Hill.

Q. Please provide an update on the Mercury and Air Toxics Standards (MATS) Rule.

A. On June 29, 2015, the U. S. Supreme Court ruled that it was unreasonable for EPA to refuse to consider costs in determining that regulation of electric generating units was "appropriate and necessary" under Clean Air Act section 112. The Court remanded the case back to the D.C. Circuit Court of Appeals for further proceedings consistent with its opinion. In turn, on December 15, 2015 the D.C. Circuit Court of Appeals remanded the MATS rule to EPA without vacatur. On April 15, 2016 EPA issued the final “Supplemental Findings that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units.” Petitions have been filed with the D.C. Circuit Court challenging EPA’s findings. In the interim, the MATS rule will remain in effect pending any additional action by the D.C. Circuit.

Q. Please provide an update on the National Ambient Air Quality Standards (NAAQS).

A. The EPA set new 1-hour health-based NO2 and SO2 standards in 2010. In mid-2013, the EPA finalized SO2 non-attainment designations for two small areas in Florida outside DEF’s service territory. The EPA deferred making any other designations until late 2017. On August 21, 2015, the EPA published a final “data requirements” rule that establishes requirements for additional ambient air quality monitoring and/or modeling that will be used for future area designations. FDEP modeled the area surrounding the Crystal River facility and determined that future operation will not cause a nonattainment issue. This finding was provided to EPA on January 13, 2017, as part of the FDEP's Data Requirements Rule package submittal. On July 3, 2017, EPA published a final rule approving attainment plans for the two non-attainment areas outside of DEF’s service territory.

On October 26, 2015, the EPA published a revised ozone NAAQS, making the standard more stringent by changing it from 75 parts per billion (ppb) to 70 ppb. Currently the entire state of Florida is in compliance with this new standard.

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 is being contested, and the timeframe for resolution is unknown at this time. On June 27, 2017, the EPA and the Corps released a pre-publication version of a proposed rule to repeal the 2015 WOTUS rule and re-codify the definition of WOTUS which is currently in place. The official version was published in the Federal Register on July 27, 2017; the comment period expires on August 28, 2017. Until the new rule goes into effect, new WOTUS jurisdictional determinations will be made by the Corps using the previous WOTUS definition.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20170007-EI

September 1, 2017

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 1st Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20170007-EI?

A. Yes. I provided direct testimony on April 3, 2017 and August 4, 2017.

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 2018 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 2018 for the Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates approximately $683k of O&M costs at 8 sites for the Substation Environmental Investigation, Remediation and Pollution Prevention Program. The substation sites include Central Florida, Dunedin, East Clearwater, Holder, Kenneth City, Tarpon Springs, Wekiva, and Windermere. These costs also include institutional controls and report writing activities for various substations in the program.

Q. What costs does DEF expect to incur in 2018 for the Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. DEF is projecting approximately $15k in O&M for the Distribution System Investigation, Remediation, and Pollution Prevention Program (Project 2) for groundwater monitoring at the 7100 Sunset Way, St. Petersburg Beach location.

Q. What costs does DEF expect to incur in 2018 for the PIM Program (Project 3)?

A. The final project in the PIM Program retired June 2017 and Pipeline & Hazardous Materials Safety Administration regulations are no longer applicable. As approved in Order No. PSC-2016-0535-FOF-EI, DEF is amortizing the net book value of the PIM Program assets over three years. For 2018, DEF is projecting approximately $668k of amortization expense.

Q. What costs does DEF expect to incur in 2018 for the Aboveground Storage Tank ("AST") Program (Project 4)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2018.

Q. Please provide an update on the status of Cooling Water Intake – 316(b).

A. In Order Number PSC-2004-0990-PAA-EI issued in Docket 20040472-EI, the Commission approved for recovery through the Environmental Cost Recovery Clause ("ECRC") DEF's Comprehensive Design Study costs required by Section 316(b) of the Clean Water Act ("316(b) regulations"). These costs have been reflected under Project 6 in DEF's annual ECRC filings. As referenced in my testimony filed August 4, 2017 in the instant docket and consistent with my testimony in prior ECRC dockets, the final 316(b) rule became effective October 15, 2014.

The rule established requirements for reducing impingement and entrainment mortality of fish and other aquatic organisms associated with the operation of cooling water intake structures ("CWIS") at regulated facilities. The rule applies to existing power generating facilities that withdraw more than two million gallons per day ("MGD") from waters of the U.S. and use at least 25% of the water exclusively for cooling purposes. Requirements will be implemented through the National Pollutant Discharge Elimination System ("NPDES") permitting process. DEF's Crystal River Units 1, 2, 4, and 5, Anclote Units 1 and 2, and Bartow combined cycle are subject to 316(b) regulations.

Q. Please describe DEF's Crystal River 316(b) Compliance Plan.

A. The long-term compliance plan for Crystal River Units 1 and 2 ("CR South") is the retirement of those units. DEF is not seeking recovery of CR South 316(b) compliance costs through the Environmental Cost Recovery Clause. The 316(b) compliance plan for Crystal River Units 4 and 5 ("Crystal River North", "CR North", or "CRN") involves interconnection to the new Citrus County combined cycle ("Citrus CC") cooling tower blowdown system to supply makeup water to the CR North cooling towers. The existing CR North cooling water intake structure will be modified to serve as a backup system for operational conditions in which the required cooling tower makeup flow could not be supplied from Citrus CC. Based on preliminary engineering, project scope includes the installation of new piping and valves to extend the Citrus CC discharge pipe to the CR North intake channel, the addition of dedicated blowdown pumps for the Citrus CC cooling towers and a new traveling screen system for the CR North intake structure. DEF's selected compliance plan offers the following benefits. First, DEF's preliminary economic analysis identified this project as the least cost option for customers. Second, the selected option reduces the potential for biological impacts by re-using the cooling water discharge from Citrus CC. Third, the selected option has less system components and complexity than other considered alternatives, which is expected to reduce general environmental and human performance risks. Finally, this solution addresses potential NPDES permit limits on temperature and salinity due to tidal fluctuations in the discharge canal.

DEF's preliminary project cost estimate, based on preliminary engineering, is a capital cost of approximately $20.8 million. DEF expects to begin project spending in 2017; DEF expects capital expenditures to be approximately $1.7 million in 2017 and approximately $1.7 million in 2018. DEF will begin design engineering in 2017 and expects to complete final engineering in mid-2019. DEF expects the project to be placed in-service at the end of 2020. Once placed in-service, DEF expects ongoing O&M costs of approximately $0.2 million annually, which would be included in DEF's annual ECRC filings for Commission review and approval.

Q. Please provide an update on the 316(b) compliance plan for the Bartow and Anclote plants.

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 $245k in O&M costs in 2018 for this work. DEF will submit study results to FDEP in mid-2020; DEF will have five years from that submittal to complete the 316(b) compliance for Anclote and Bartow.

Q. What costs does DEF expect to incur in 2018 for the CAIR/CAMR Program (Project 7.2)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the BART Program (Project 7.5)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Arsenic Groundwater Standard Program (Project 8)?

A. DEF estimates approximately $150k in O&M costs for the Arsenic Groundwater Standard Program. In accordance to FDEP Consent Order No. 09-3463D executed on March 22, 2016 DEF continues its investigation to evaluate the potential source of arsenic groundwater exceedances. A summary report of findings will be submitted to the FDEP no later than December 31, 2017, and the Station must be in compliance with the arsenic groundwater limit by December 31, 2019 in accordance with 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.

Q. What costs does DEF expect to incur in 2018 for the Sea Turtle – Coastal Street Lighting Program (Project 9)?

A. DEF estimates $350 and $400 in O&M and capital costs, respectively, 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 2018 for the Underground Storage Tanks ("UST") Program (Project 10)?

A. DEF does not expect to incur any capital expenditures or O&M costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Modular Cooling Tower (Project 11)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Greenhouse Gas Inventory and Reporting Program (Project 12)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Mercury TMDL Program (Project 13)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 in for the HAPs ICR Program (Project No. 14)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect to incur any costs in 2018.

Q. What costs does DEF expect to incur in 2018 for the Effluent Limitation Guidelines CRN Program (Project No. 15.1)?

A. DEF is not projecting any 2018 capital costs for the ELG Crystal River North project. On November 23, 2015, 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 must be incorporated into affected stations' NPDES permits with a compliance timeframe between November 1, 2018 and December 31, 2023. On April 25, 2017, EPA issued an administrative stay postponing the compliance dates in the rule. On June 6, 2017, EPA published in the Federal Register its proposal to postpone certain compliance dates in the rule.

On August 14, 2017, the Department of Justice ("DOJ") filed a "Motion to Govern Further Proceedings" in the pending 5th Circuit litigation over the power plant ELG rules. In this motion, EPA announced its plans to "conduct a rulemaking to potentially revise the new more stringent Best Available Technology Economically Achievable ("BAT") effluent limitations and Pretreatment Standards for Existing Sources ("PSES") in the 2015 Rule that apply to two of the six relevant waste streams… (1) bottom ash transport water and (2) flue gas desulfurization (FGD) wastewater." On August 22, 2017 the Fifth Court of Appeals granted the DOJ's Motion and stayed the litigation related to the issues discussed above pending the resolution of EPA's rulemaking. DEF's ELG Project will remain on hold until these matters are addressed through EPA's rulemaking activities.

Q. What costs does DEF expect to incur in 2018 for the NPDES Program (Project No. 16)?

A. DEF estimates approximately $32k of O&M costs for Whole Effluent Toxicity ("WET") testing at DEF stations with NPDES permits.

Q. What O&M costs does DEF expect to incur in 2018 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $598k for CR4&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 2018 for the MATS Program – CR4&5 (Project No. 17)?

A. DEF does not expect capital expenditures in 2018.

Q. Does this conclude your testimony?

A. Yes.

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, where I have assumed positions of increasing responsibility during my 20 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for 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 2016 through December 2016 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 2016 through December 2016 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 26, illustrates the calculation of depreciation expenses 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 2016 through December 2016?

A. The final true-up amount for the Environmental Clause for the period January 2016 through December 2016 is an under-recovery of $658,080. The actual environmental cost over-recovery, including interest, is $5,097,893 for the period January 2016 through December 2016, as identified in Form 42-1A. This amount, less the $5,755,973 over-recovery approved in Commission Order No. PSC-16-0535-FOF-EI, issued November 22, 2016, in Docket No. 160007-EI, results in a final under-recovery of $658,080, as shown on Form 42-1A. This under-recovery amount will be applied in the calculation of the environmental cost recovery factors for the period January 2018 through December 2018.

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. Did Tampa Electric include costs in its 2016 final Environmental Clause true-up filing for any environmental projects that were not anticipated and included in its 2016 factors?

A. Yes, Tampa Electric included costs associated with Tampa Electric's Effluent Limitation Guidelines ("ELG") project. These costs are outlined on Form 42-4A. This project was approved for cost recovery by Commission Order No. PSC-16-0248-PAA-EI, issued June 28, 2016.

Q. How do actual expenditures for the January 2016 through December 2016 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 $1,665,457, or 7.4 percent greater than the actual/estimated projection costs. Form 42-6A shows the total capital investment costs are $51,472, or 0. 1 percent greater than the actual/estimated projection costs. Additional information regarding material 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 compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is $4,620 or 106.7 percent less than projected. The variance is due to less cogeneration purchases than projected and the application of a lower SO_2 emissions allowance rate than projected.
- **Polk NO_x Emission Reduction:** The Polk NO_x Emission Reduction project variance is a credit of $291,627, or 2,340.4 percent less than projected. This variance is due to sale of NO_x emission allowances that took place in the latter half of 2016.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project

variance is $21,040, or 138 percent greater than projected. During scheduled maintenance, the company discovered there was a need to replace additional parts. These replacements increased the actual costs of this project.

- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is $19,225, or 33.5 percent less than projected. The costs associated with this project are less than projected because less maintenance work was needed than originally projected.
- **Bid Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is $1,990, or 129.2 percent greater than projected. The costs associated with this project are greater than projected because more maintenance work was needed than originally projected.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) project variance is $306,440, or 80.8 percent less than projected. This variance is due to uncertainty associated with the compliance strategy due to the stay and potential repeal of the Clean Power Plan. The Clean Power Plan could impact the statewide operations of electric utilities as well as future operations of specific units that may or may not require additional impingement or entrainment reduction measures to comply with the Clean Water Act, Section 316(b). Despite the delay in planning, Tampa Electric remains in compliance with the Clean Water

Act, Section 316(b) since compliance measures are due to be submitted in conjunction with National Pollutant Discharge Elimination System ("NPDES") permit renewal.

- **Arsenic Groundwater Study Program:** The Arsenic Groundwater project variance is $5,380, or 36.5 percent less than projected. This variance is due to the timing of an invoice for the geo-chemical study that was expected to be paid by year-end; however, the invoice was not received until January 2017.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $274,440, or 20.4 percent greater than projected. The SCR ran more than projected and therefore the amount of consumables was greater than projected.
- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $606,306, or 53.6 percent more than projected. The SCR ran more than projected and therefore the amount of consumables was greater than projected.
- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $812,817, or 73.7 percent greater than projected. This variance is due to increased maintenance costs associated with the draft fans and damper fans.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $212,226, or 17.5 percent less than projected. The costs associated with this project are less than projected because less maintenance work was needed than

originally projected.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards ("MATS") project variance is $93,629, or 72.3 percent less than originally projected. The projected costs included contractor labor expenses; however, the company utilized internal labor rather than contractor labor. Internal labor costs are not recovered through the environmental clause.
- **Greenhouse Gas Reduction Program:** The Greenhouse Gas Reduction program project variance is $34,837, or 38.7 percent greater than projected. This variance is due to the receipt of an Enviance invoice that was expected to be paid in January 2017; however, the invoice was paid upon receipt in December 2016. Enviance is the environmental information management system that the company utilizes to report greenhouse gas emissions.
- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $277,818, or 28.9 percent greater than projected due to increased tons of gypsum transported to the storage area.
- **Big Bend Coal Combustion Residual Rule:** The Big Bend Coal Combustion Residual ("CCR") Rule project variance is $314,437, or 70.7 percent less than projected. The Slag Fines Pond Closure and Lining and Economizer Ash System Closure Plan cost estimates were high level estimates. As

a detailed scope for these studies was developed, the costs were less than projected. This decrease in costs accounts for approximately half of the variance. The second main driver for the variance is that approximately half the variance is due to CCR project work that was deferred until 2017.

- **Big Bend Effluent Limitations Guidelines:** The Big Bend Effluent Limitations Guidelines ("ELG") project variance is $60,558, or 20 percent less than projected. The ELG study cost estimates were high level estimates. Once the work on the study began, some contractor work included in the scope was determined not to be needed.

Capital Investment Project Variances

- **Big Bend Coal Combustion Residuals:** The Big Bend CCR Rule project variance is $1,535, or 56.4 percent less than projected. This variance is due to the in-service date for Economizer Ash System Closure Plan equipment being moved from 2016 into 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170007-EI
FILED: 08/04/2017

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 Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20170007-EI?

A. Yes, I submitted direct testimony on April 3, 2017.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 2017 through December 2017 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2018 through December 2018. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2017, 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 2018 through December 2018.

Q. Have you prepared an exhibit that shows the recoverable environmental costs for the actual/estimated period of January 2017 through December 2017?

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 2018 through December 2018.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied.

A. The actual/estimated true-up applicable for the current period, January 2017 through December 2017, is an over-recovery of $6,759,424. A detailed calculation supporting the calculation of the true-up 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 2017 ECRC factors?

A. Yes, Tampa Electric included costs for the second phase of its compliance with the Coal Combustion Residual ("CCR") Rule, which were not included in its 2017 ECRC factors. The company submitted its petition for approval of the expected costs of the second phase of CCR Rule compliance on July 28, 2017.

Q. What depreciation rates were utilized for the capital projects contained in the 2017 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-12-0175-PAA-EI, issued on April 3, 2012, in Docket No. 110131-EI.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2017 through December 2017?

A. Tampa Electric’s revenue requirement rate of return for January 2017 through December 2017 is calculated based on the capital structure, components and cost rates approved in Order No. PSC-12-0425-PAA-EU, issued on August 16, 2012 in docket No. 120007-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 2017 through December 2017 period compare with the company’s original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $6,032,620 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $228,166 less than originally projected. Significant variances for O&M and capital investments are explained below.

O&M Project Variances

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

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $4,569,690 or 50.2 percent less than projected. The recent historically low prices of natural gas caused the company to dispatch natural gas-fired units as baseload units, displacing coal-fired generation for base load. This variance is due to Big Bend Units 1 and 2 burning more natural gas and less coal than projected, which resulted in a reduction in the amount of consumables and maintenance needed.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring project variance is estimated to be $308,735 or 50.5 percent greater than projected. This variance is due to an increase in maintenance associated with insulator repairs and cleaning or replacement of insulation and lagging.

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is $316,153 or 316.2 percent greater than projected. This variance is due to an increase in maintenance costs associated with the repair of air dampers.

- **Bayside SCR Consumables:** The Bayside SCR consumables Project variance is estimated to be $111,712 or 54.8 percent less than projected. This variance is due to the Bayside units' re-projected run time being less than originally projected, resulting in less ammonia consumption.

- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is $31,200 or 83.9 percent less than projected. The actual/estimated maintenance cost associated with this project is less than what was originally projected because less maintenance work was needed than projected.

- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is $15,467 or 41.6 percent less than projected. The actual/estimated maintenance cost associated with this project is less than what was originally projected because less maintenance work was needed than projected.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is $29,660 or 79.7 percent less than projected. The actual/estimated maintenance cost associated with this project is less than what was originally projected because less maintenance work was needed than projected.

- **Clean Water Act Section 316(b) Phase II Study Program:** The Clean Water Act Section 316(b) Phase II Study Program project variance is $492,562 or 52.0 percent less than projected. The National Pollutant Discharge Elimination System ("NPDES") permit renewal for Big Bend Station has not yet been finalized, so a portion of the variance is related to uncertainty regarding the timing of the final requirements and associated monitoring data and reporting that must be submitted once the permit is finalized. The remainder of the variance is driven by the scope of the studies at Bayside Station being refined as Tampa Electric was able to reuse other biological studies for compliance with this requirement.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Study Project variance is $32,227 or 128.9 percent greater than projected. The Big Bend Station Arsenic Plan of Study is nearly complete and was submitted to FDEP for their review; however, the scope of needed remediation activities is still uncertain. The variance is due to costs associated with implementation of the Plan of Study, evaluation of the results, and preparation of the final report. These additional costs were not originally anticipated to occur in 2017.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $800,621 or 45.2 percent less than originally projected. This variance is due to greater use of natural gas and reduced use of coal, 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 $326,504 or 15.7 percent less than originally projected. This variance is due to greater use of natural gas and reduced use of coal, reducing 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 $643,576 or 34.5 percent less than projected. This variance is due to greater use of natural gas and reduced use of coal, reducing the amount of consumables and maintenance work needed, compared to the original projection.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $251,477 or 23.1 percent less than projected. This variance is due to the greater use of natural gas and reduced use of coal, reducing the need for consumables and maintenance work, compared to the original projection.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards project variance is $162,541 or 70.4 percent less than projected. Tampa Electric had planned on replacing the sorbent traps and mercury probes in 2017;

however, it was not necessary to replace these items in 2017.

- **Big Bend Gypsum Storage Facility:** The Big Bend Gypsum Storage Facility project variance is $1,109,206 or 92.4 percent greater than projected. This variance is due to an increase in costs for pile maintenance at the east yard, for tasks such as material segregation, gypsum pile grooming, yard arrangement, and truck loading, since the yard is being utilized more than originally projected.

- **Big Bend Effluent Limitation Guidelines:** The Big Bend Effluent Limitation Guidelines ("ELG") project variance is $147,012 or 294.0 percent greater than projected. This variance is due to greater than projected costs for the ongoing study to determine which technology will enable Tampa Electric to comply with the ELG Rule.

Capital Project Variances

- **Coal Combustion Residuals:** The Coal Combustion Residual project variance is estimated to be $210,872 or 77.9 percent less than projected. This variance is due to a timing change to refine the scope of planned work; the compliance deadlines allow for the work to be completed in 2018 instead of in 2017 as originally planned.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170007-EI
FILED: 09/01/2017

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 Manager, Rates in the Regulatory Affairs Department.

Q. Have you previously filed testimony in Docket No. 20170007-EI?

A. Yes, I submitted direct testimony on April 3, 2017 and August 4, 2017.

Q. Has your job description, education, or professional experience changed since then?

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 2018 through December 2018. 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 2018.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2018 through December 2018?

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 2018.

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

A. Yes. The ECRC factors, prepared under my direction and supervision, are provided in Exhibit No. PAR-3, Document No. 7, on Form 42-7P. These annualized factors will apply for the period January 2018 through December 2018.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2018 to December 2018?

A. The net true-up applicable for this period is an over-recovery of $6,101,344. This consists of a final true up under-recovery of $658,080 for the period of January 2016 through December 2016 and an estimated true-up over-recovery of $6,759,424 for the current period of January 2017 through December 2017. 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 August 4, 2017.

Q. Did Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2018 through December 2018?

A. Yes, Tampa Electric included costs for the second phase of its compliance with the Coal Combustion Residual ("CCR") Rule, which were not included in its 2017 ECRC factors. The company submitted its petition for approval of the expected costs of the second phase of CCR Rule compliance on July 28, 2017.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2018?

A. Tampa Electric proposes to include for ECRC recovery the 26 previously approved capital projects and their projected costs in the calculation of the 2018 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

Some of these projects are described in more detail in the direct testimony of Paul L. Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2018?

A. Yes. Form 42-3P contained in Exhibit No. PAR-3 summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which results in recoverable jurisdictional capital costs of $50,713,229.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2018?

A. Tampa Electric proposes to include for ECRC recovery the 25 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2018. 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 Coal Combustion Residuals
25) Big Bend Effluent Limitations Guidelines ("ELG")

Some of these projects are described in more detail in the direct testimony of Tampa Electric witness Paul L. Carpinone.

Q. Have you prepared a schedule showing the calculation of the recoverable O&M project costs for 2018?

A. Yes. Form 42-2P contained in Exhibit No. PAR-3 summarizes the recoverable jurisdictional O&M costs for these projects which total $22,107,997 for 2018.

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, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 33.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2018?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $72,821,226.

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 allocation factors were determined by calculating the percentage that each rate class contributes to the total MWH sales and then adjusted for line losses for each rate class. This information was based on applying historical rate class load research to the 2018 projected forecast of 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 2018 through December 2018 which Tampa Electric is seeking approval?

A. The computation of 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	0.343
GS, CS Secondary	0.343
GSD, SBF	
Secondary	0.342
Primary	0.338
Transmission	0.335
IS	
Secondary	0.337
Primary	0.333
Transmission	0.330
LS1	0.339
Average Factor	0.342

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 2018.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2018 through December 2018?

A. Tampa Electric used the weighted average cost of capital methodology approved by the Commission in Order No. PSC-2012-0425-PAA-EU to calculate the revenue requirement rate of return found on Form 42-8P.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2018 through December 2018 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 0.342 cents per kWh. This includes the projected capital and O&M revenue requirements of $72,821,226 associated with the company's 33 ECRC projects and a net true-up over-recovery provision of $6,101,344. My testimony also explains that the projected environmental expenditures for 2018 are appropriate for recovery through the ECRC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170007-EI
FILED: 09/01/2017

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 Health and Safety in the Environmental Health and Safety 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 Health and Safety. My responsibilities include the development and administration of the company's environmental, health and safety policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental, health and safety 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 2018 through December 2018 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 (0570039-083-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 2018 through December 2018.

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 2018; 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 $611,283.

Q. Please describe the Bid Bend NO_x Emission Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2018 through December 2018.

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 2018; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $138,956 of O&M expenses during 2018.

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 2018 through December 2018.

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 2018 through December 2018, 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 $37,200 for Big Bend Unit 1 Pre-SCR, $37,200 for Big Bend Unit 2 Pre-SCR, and $37,200 for Big Bend Unit 3 Pre-SCR for equipment maintenance. There are not any anticipated capital expenditures for Big Bend Units 2, 3 and 4 SCRs; however, the capital expenditures for Big Bend Unit 1 SCR are projected to be $900,000 for a catalyst replacement. Additionally, the O&M expenses are projected to be $1,498,585 for Big Bend Unit 1 SCR,

$1,629,977 for Big Bend Unit 2 SCR, $1,694,774 for Big Bend Unit 3 SCR and $1,061,162 for Big Bend Unit 4 SCR. These expenses are primarily associated with ammonia purchases.

Q. Please identify and describe the other Commission-approved programs 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")
12) Effluent Limitations Guidelines ("ELG")

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 2018 through December 2018.

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 2018 through December 2018 for the Big Bend Unit 3 FGD Integration project; however, O&M expenses are projected to be $4,423,789 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 2018 through December 2018; however, the O&M expenses are projected to be $2,200,000 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 2018 through December 2018.

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 2018 through December 2018, 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 will apply for renewal of the National Pollutant Discharge Elimination System (NPDES) Permit in 2018, and 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 2018 through December 2018.

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 2018 through December 2018, Tampa Electric projects O&M expenses associated with the consumable goods (primarily anhydrous ammonia) to be approximately $203,882.

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 2018 through December 2018.

A. The Clean Water Act 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. Tampa Electric is currently finalizing its compliance strategy for the CWIS Rule at Big Bend 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. The biological, financial, and technical study elements are underway for Bayside Power Station and will be submitted with the NPDES permit renewal application in February 2018. Retrofits could include the installation of cooling towers or screening facilities. Tampa Electric projects O&M expenditures to be $321,000 for the period of January 2018 through December 2018 for engineering studies.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenses for the period of January 2018 through December 2018.

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 2018 through December

2018, 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 2018 through December 2018.

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 2018 through December 2018, there are no anticipated O&M expenses at Bayside or Polk Power Stations. Although no O&M expenses are currently anticipated for Big Bend Power Station in 2018, a detailed plan of study is currently underway, which may refine the program's scope of work and require future expenditures.

Q. Please describe the MATS program activities.

A. The MATS program was approved by the Commission in Docket 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 cost recovery approval for 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 2018 through December 2018.

A. For 2018, Tampa Electric anticipates capital expenditures of $390,000 under the MATS program for monitoring equipment. O&M expenditures are projected to be $231,000 for testing requirements and maintenance of equipment.

Q. Please describe the GHG Reduction program activities and provide the estimated capital and O&M expenditures for the period of January 2018 through December 2018.

A. Tampa Electric's GHG Reduction program 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 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 Greenhouse Gas Mandatory Reporting rule will continue in 2018. For 2018, this activity is projected to result in approximately $93,149 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 2018 through December 2018.

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 in 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 2018, Tampa Electric does not anticipate any capital expenditures; however, the projected O&M expenses for this program during 2018 are $1,663,000.

Q. Please describe the EPA Coal Combustion Residuals ("CCR") Rule compliance activities and provide the estimated capital and O&M expenditures for the period of January 2018 through December 2018.

A. On April 17, 2015, the EPA issued a final rule to regulate coal combustion residuals ("CCRs") 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 CCRs and liquids. The Big Bend Unit 4 Economizer Ash Ponds and the East Coalfield Stormwater Pond (converted former slag fines pond), will be 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 on February 9, 2016. In that Order, the Commission found that the program meets the requirements for recovery through the ECRC. Incremental O&M expenses resulting from the groundwater monitoring program, ongoing inspections and general maintenance of regulated units will continue until final closure of these units is complete. In order to determine the best option to comply with the new rule, the company evaluated whether to continue operation of the regulated impoundments or to close them.

The impoundments for which closure will commence in 2018 are the North and South Economizer Ash impoundments and the slag pond. Work in these areas was originally expected to begin in 2017 and was rescheduled to 2018. This closure project and the closure of the slag pond will begin concurrently in 2018 for efficiency in engineering and construction of these projects. Also in 2018, additional work will be done at the North Gypsum Stackout area, another area where CCRs are managed at the station. The supplemental work includes drainage improvements and secondary containment in the main storage area, as well as additional remediation and improvements to line the adjacent unlined ditches and ponds. This work is needed to make the FGD operations fully compliant with the CCR Rule requirements.

On July 28, 2017, in Docket No. 20170168-EI, Tampa Electric requested approval for recovery of costs to close the Big Bend Economizer Ash & Pyrites Ponds ("EAPP"). The engineering and scope studies for the EAPP closure were previously approved by the Commission and have now been completed. The cost estimates provided for the EAPP closure are based on the clean closure option, including disposal of CCRs excavated from these impoundments. After the disposal activities are completed, the company will incur restoration and post-closure monitoring costs, which will be included in future year projected costs.

Tampa Electric anticipates $2,200,000 for capital expenditures and $6,125,000 for O&M expenses for the CCR projects described above. However, project engineering will include more detailed cost evaluations, and these projections will continue to be refined.

Q. Please describe Tampa Electric's Effluent Limitations Guidelines activities and provide the estimated O&M expenditures for the period of January 2018 through December 2018.

A. On November 3, 2015, the EPA published the final Steam Electric Power Generating Effluent Limitations Guidelines ("ELG"), 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, 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.

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 their petitions to 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. Compliance deadlines for these waste streams remain stayed at this time.

The ELG program was approved by the Commission in Docket No. 20160027-EI, Order No. PSC-2016-0248-PAA-EI, issued on June 28, 2016. In that Order, the Commission found that the program meets the requirements for recovery through the ECRC. However, due to the temporary stay and the intent by EPA to initiate rulemaking, Tampa Electric does not anticipate any O&M expenditures for the period January 2018 through December 2018.

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 (0570039-083-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 2018. Additionally, my testimony identified other projects that are required for Tampa Electric to meet environmental requirements, and I provided the associated 2018 activities and projected expenditures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard M. Markey
Docket No. 170007-EI
April 3, 2017

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. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

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 Affairs.

Q. What are your responsibilities with Gulf Power Company?
A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs 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 through December 2016.

Q. Mr. Markey, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2016 through December 2016 with the approved estimated true-up amounts.
A. As reflected in Mr. Boyett's Schedule 6A, the actual recoverable capital costs were $165,868,136 as compared to $163,602,598 included in the Estimated True-up filing. This resulted in a net variance of $2,265,538 over the estimated true-up. I will address two capital programs that contribute to the majority of this variance: Daniel Ash Management Project and Air Quality Compliance Program.

Q. Please explain the capital variance of ($63,186) or (4.5%) in the Daniel Ash Management Project (Line item 1.16).

A. This variance is a result in a change in millage rates used to calculate property taxes for assets in the State of Mississippi. Property taxes were actualized in December.

Q Please explain the capital variance of $2,306,646 or 1.7% in the Air Quality Compliance Program (Line item 1.26).

A. This variance is primarily the result of a change in assessed value and millage rates used to calculate property taxes for Plant Daniel scrubbers in the State of Mississippi. The change in assessed value and millage rate contributed $1,800,000 to the variance. Property taxes were actualized in December.

Q. How do the actual O&M expenses for the period January 2016 to December 2016 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 $33,624,145**,** as compared to the estimated true-up of $30,673,042. This resulted in a variance of $2,951,103 or 9.6% over the estimated true-up. I will address seven O&M projects and/or programs that contribute to this variance: General Water Quality, Groundwater Contamination Investigation, Above Ground Storage Tanks, FDEP NOx Reduction Agreement, Air Quality Compliance

Program, Crist Water Conservation, and Coal Combustion Residual (CCR).

Q. Please explain the variance of $745,008 or 37.3% in (Line item 1.6), General Water Quality.

A. This line item includes expenses related to Plant Crist's dam safety, ground water monitoring and treatment chemicals. This variance is primarily due to a groundwater study at Plant Crist in the amount of $480,000 and studies required to support Plant Crist's NPDES industrial wastewater permit renewal in the amount of approximately $223,000.

Q. Please explain the variance of $139,087 or 4.1% in (Line item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is also due to additional work being required by the FDEP to complete soil and groundwater assessment studies necessary to comply with the Florida Department of Environmental Protection (FDEP) established Consent Order and to comply with FDEP's established deadline. The cost increase is also from higher than expected excavation volumes of contaminated soil and its related disposal costs.

Q. Please explain the variance of ($81,782) or (63.9%) in (Line item 1.12), Above Ground Storage Tanks.

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities 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 Plant Crist and the Corporate Office tank maintenance expenses being less than projected. It was recommended that Gulf replace the Corporate Office emergency generator fuel tank rather than moving forward with the maintenance activities that were included in the 2016 estimated actual filing.

Q Please explain the variance of ($148,552) or (12%) in FDEP NOx Reduction Agreement (Line item 1.19).

A. The FDEP NOx Reduction Agreement includes O&M costs associated with the Plant Crist Unit 7 SCR and the Plant Crist Units 4 and 5 SNCR systems that were included as part of the 2002 agreement with FDEP. More specifically, this line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the agreement. This variance is primarily due to some scheduled SCR maintenance activities postponed until 2017 and to Crist Unit 7 operating less than expected.

Q. Please explain the O&M variance $1,517,681 or 7.7% 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 SCR and Plant Scherer Unit 3 SCR and baghouse. More specifically, this line item includes the cost of urea, anhydrous ammonia, limestone, and the general operation and maintenance activities associated with Gulf's Air Quality Compliance Program. This variance is primarily due to additional maintenance, inspection costs and repairs associated with the Plant Crist gypsum pond systems.

Q. Please explain the O&M variance ($422,040) or (79.9%) in the Crist Water Conservation (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, valve maintenance and pump replacements. This variance is primarily due to only one ash sluice pump being rebuilt during an outage instead of the three pumps that were projected. The other two pumps are scheduled to be rebuilt in 2017.

Q. Please explain the O&M variance $1,250,339 or 87.1% 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 FDEP. More specifically, the CCR program includes requirements to close the existing on-site ash pond at Plant Scholz, and regulates CCR units at Plants Crist, Scherer, Smith and Daniel. The variance is primarily due to activities related to the Plant Smith and Plant Scholz ash pond closure projects. Approximately $1,588,000 has been spent on the design and preliminary work for the Plant Smith ash pond closure project which was not included in the estimated actual projection filing. The Plant Smith variance was partially offset by the Plant Scholz pond closure project. Due to unexpected delays in the permitting process $339,279 was not spent on the Plant Scholz ash pond closure project as projected in the estimated actual filing.

Q. Mr. Markey, 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. 20170007-EI
Date of Filing: August 4, 2017

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. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

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 and 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 Affairs.

Q. What are your responsibilities with Gulf Power Company?
A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs area to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e. both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsible 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) estimated true-up for the period January through December 2017. This true-up is based on six months of actual data and six 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 2017 through December 2017 with the approved projected amounts.
A. As reflected in Mr. Boyett's Schedule 6E, the recoverable capital costs approved in the original projection total $163,184,721, as compared to the estimated true-up amount of $166,467,793. This difference results in a variance of $3,283,072 or 2.0%.

Q. Are there any factors that impact multiple capital projects?
A. Yes. The implementation of the Stipulation and Settlement Agreement, approved by order of the Commission in consolidated Docket Nos.

20160186-EI and 20160170-EI, impacts all components of Gulf's recoverable capital costs. Mr. Boyett discusses the details concerning these changes in his estimated true-up testimony. After taking the Stipulation and Settlement Agreement changes totaling $2,170,823 into consideration, there is a variance of approximately $1,112,249 that is largely attributed to four capital projects: 1) Air Quality Compliance Program $1,230,843; 2) Crist 6 & 7 Low NOx Burners, $291,634; 3) Effluent Limitations Guidelines ($353,313); and 4) Crist FDEP Agreement ($55,618). The variances attributed to these programs will be discussed below.

Q. Please explain the capital variance of $291,634 or 17.5% reflected in Low NOx Burners, Crist 6 & 7 (Line item 1.4).

A. The line item variance is due to the replacement of Unit 7's band gas canes on the Low NOx burners with new retractable gas gun burning technology. The original gas canes have become technologically obsolete.

Q. Please explain the capital variance of ($55,618) or (0.5%) reflected in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is primarily due to lower expenditures for Plant Crist's Unit 7 Selective Catalytic Reduction (SCR) catalyst replacement than budgeted.

Q. Please explain the capital variance of $1,230,843 or 0.9% reflected in the Air Quality Compliance Program (Line Item 1.26).

A. The line item variance is due to a change in assessed value and millage rates used to calculate property taxes for Plant Daniel scrubbers in the State of Mississippi and the repairs to Plant Crist's gypsum pond. The change in assessed value and millage rate contributes approximately $1,001,000 to the variance. The remainder of the variance is primarily due to a repair of the liner in Plant Crist's gypsum pond.

Q. Please explain the capital variance of ($353,313) or (48.2%) reflected in the Effluent Limitations Guidelines (ELG) (Line Item 1.29).

A. In April 2017, the Environmental Protection Agency (EPA) published a notice in the Federal Register that stayed the compliance dates for meeting the ELG for bottom ash transport water, as well as for fly ash transport water, flue gas desulfurization wastewater, flue gas mercury control wastewater and gasification wastewater. In April 2017, the Department of Justice also filed a motion with the 5th Circuit to hold the ELG litigation in abeyance for 120 days while the Agency undertakes reconsideration of the rule. At the conclusion of the 120-day period, EPA is expected to announce which portions of the rule, if any, that it seeks to have remanded to the Agency for further rulemaking.

Gulf's 2017 ELG compliance projects are associated with the new Plant Crist bottom ash handling and wastewater treatment systems. Both projects were placed on hold after EPA announced reconsideration of the rule. Gulf was in the process of completing construction of two underground injection wells at Crist that will be used for ELG compliance. Gulf has completed drilling of the wells and will complete the necessary site stabilization associated with this activity. Gulf will cease project related activities until after ELG is resolved. Gulf was in the preliminary engineering and design phase of the Plant Crist bottom ash handling system at the time the reconsideration was announced. The bottom ash project has been placed on hold until EPA provides clarification on future regulatory requirements. These project delays have resulted in the variance shown for Line Item 1.29.

Q. How do the estimated/actual 2017 O&M expenses compare to the original 2017 projections?

A. Mr. Boyett's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $39,672,854 as compared to $61,760,900, which was the amount projected in the 2017 Projection Filing, creating a variance of ($22,088,046) or (35.8%). I will address three O&M projects and programs that contribute to a significant portion of this variance: FDEP NOx Reduction Agreement, Air Quality Compliance Program, and Coal Combustion Residual.

Q. Please explain the O&M variance of $333,205 or 37.1% in FDEP NOx Reduction Agreement (Line Item 1.19).

A. The FDEP NOx Reduction Agreement includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses for activities undertaken in connection with the Plant Crist FDEP Agreement related to Ozone Attainment. This variance is primarily due to Plant Crist's Unit 7 SCR running at a higher utilization than projected.

Q. Please explain the O&M variance ($869,768) or (3.6%) 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 line item variance is primarily due to scrubber expenses, which vary with utilization of Gulf's coal units, being lower than projected.

Q. Please explain the variance of ($21,315,243) or (77.7%) 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 Florida Department of Environmental Protection (FDEP). For Gulf's generating plants, these regulatory compliance obligations are pursuant either to the CCR rule adopted last year 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. Approximately $23.4 million of the variance is attributable to delays in the Plant Scholz pond closure. The closure schedule shifted due to permitting delays. Gulf received the substantial revision to the NPDES permit on May 18, 2017, and it is now moving forward with the initial phases of the pond closure activities. Partially offsetting the delay in the Plant Scholz pond closure is approximately $2.5 million of expenses associated with the Plant Smith pond closure.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard M. Markey
Docket No. 20170007-EI
Date of Filing: September 1, 2017

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. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

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 Affairs.

Q. What are your responsibilities with Gulf Power Company?
A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs 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 projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2018 through December 2018.

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 schedule 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 described in Schedules 3P and 4P of Gulf Witness Boyett's Exhibit CSB-4 and my 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 are eight programs that were previously approved by the Commission with activities that have projected capital expenditures during 2018. These programs include: Continuous Emission Monitoring Systems (CEMS), Smith Waste Water Treatment Facility, Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, Crist Water Conservation, Air Quality Compliance Program, General Water Quality, and Coal Combustion Residuals.

Q. Mr. Markey, please describe the projected 2018 capital expenditures for Continuous Emission Monitoring Systems (CEMS) (Line Item 1.5).

A. Gulf plans to replace the existing Plant Crist CEMS monitors that are located in the scrubber stack and in the bypass stack during 2018. The existing monitors are at the end of the normal life cycle and need to be replaced. Expenditures associated with these activities reflected in the 2018 projection filing are $510,000.

Q. Mr. Markey, please describe the projected 2018 capital expenditures for Smith Waste Water Treatment Facility (Line Item 1.15).

A. Gulf plans to replace the existing treatment facility during 2018. The existing facility, installed in 2004, needs to be relocated as part of the ash pond closure project since the area will be used for future dry ash stacking. Expenditures associated with this line item in the 2018 projection filing total $150,000.

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

A. Gulf was granted approval for recovery of the Plant Smith Reclaimed Water project in FPSC Order No. PSC-09-0759-FOF-EI. Gulf has installed three deep injection wells, piping, and initial equipment needed for the pump station. During the remainder of 2017 and 2018, Gulf plans to continue to obtain additional operational data required to design the final pump station, additional piping and associated storage capacity. Gulf also plans to begin construction of the final pump station and wastewater equipment during 2018. Expenditures associated with these activities reflected in the 2018 projection filing are $9,989,000.

Q. Mr. Markey, please describe the projects included in the 2018 projection for the Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Gulf plans to replace catalyst in the Plant Crist Unit 7 SCR during 2018. This project also includes replacing the flue gas fans used for sampling. The flue gas fans and the catalyst have reached the end of their useful life and will be replaced in the 2018 outage. The projected 2018 expenditures for this line item are $1,461,250.

Q. Please describe the projected capital expenditures for the Crist Water Conservation program (Line Item 1.24).

A. The Crist Water Conservation program is part of Gulf's water conservation and consumptive use efficiency program required by the Plant Crist consumptive water use permit. Plant Crist's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. The 2018 projected expenditures for the Crist Water Conservation program are for upgrading two header pumps, due to corrosion from brackish water, that were installed when Plant Crist began receiving reclaimed water. The projected 2018 expenditures for this line item total $500,000.

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

A. The 2018 projected expenditures for the Air Quality Compliance program include costs associated with the following: Plant Crist and Plant Daniel scrubbers, Plant Crist Unit 6 SCR, as well as the Scherer 3 baghouse and SCR. More specifically, this line item includes expenditures for the Plant Crist gypsum storage area, gas cooling nozzles, scrubber agitator gear box, Unit 6 SCR catalyst layer, elevator, and air compressors. Gulf plans to complete final design and to move forward with the expansion of the gypsum storage area during 2018. Approximately $7.8 million is projected for expansion of the gypsum storage area, lining portions of the existing storage area, and installation of associated piping and pump structures. Plant Daniel projected costs include upgrading the scrubber ovation control system during 2018 as part of a plant-wide system upgrade. In 2018, Plant Scherer plans to purchase a layer of catalyst for the Scherer 3 SCR for installation during the 2019 outage. The projected 2018 expenditures for this program totals $11,639,715.

Q. Mr. Markey, please describe the projects included in Gulf's 2018 projection for the General Water Quality capital program (Line Item 1.27).

A. For 2018, Line Item 1.27 includes expenditures related to the groundwater monitoring requirements of the Plant Crist NPDES industrial wastewater permit. During a recent evaluation of the site geology, Gulf identified the need for additional monitoring wells to ensure compliance, which was agreed to by FDEP. Gulf expects to install the additional monitoring wells in 2018. The projected 2018 expenditures for this line item total $200,000.

Q. Mr. Markey, please describe the projects included in Gulf's 2018 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 National Pollutant

Discharge Elimination System (NPDES) 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 subject to Georgia's CCR Rule, which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2018. The projected 2018 expenditures for this line item total $41,024,551 which includes costs for Plants Scholz, Smith and Scherer as discussed below.

Construction activities for the closure of the ash pond at Plant Scholz have begun. In 2017, Gulf began construction of slurry wall. During 2018, the Scholz ash pond closure includes 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 2018 expenditures for the Plant Scholz CCR closure are projected to be $14,519,294.

Recently, Gulf began construction of the Plant Smith pond closure by relocating CCR material within the footprint of the pond. In 2018, Gulf will proceed with construction and associated activities to close a portion of the pond. The Smith pond closure includes construction of industrial wastewater ponds and a slurry wall as well as 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 2018 expenditures for the Plant Smith CCR closure are projected to be $13,343,945.

The Plant Scherer ash pond is scheduled to cease operations and stop receiving coal ash in 2019. Construction and related closure activities will be required for several years to accommodate closure. Design and construction of the Scherer dry bottom ash conversion and wastewater management system will occur in 2018 and 2019. In 2018, work will be performed to utilize cell 3 of the onsite landfill for ash storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill. The 2018 expenditures for the Plant Scherer CCR projects are projected to be $13,161,312.

Q. Mr. Markey, are you including the purchase of allowances in your 2018 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2018.

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 2018.

A. There are five O&M activities included in the air quality category that have projected expenses in 2018. 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 2018 estimated expenses for the Air Emission Fees are $278,972.

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 2018 estimated expenses for the Title V Program are $267,229.

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 2018 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 Continuous Emission Monitoring 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 2018 estimated expenses for the Emissions Monitoring are $740,920.

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, urea, 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. 020943-EI. The total 2018 estimated expenses for the FDEP NOx Reduction Agreement are $1,001,268.

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 Soil Contamination Studies, NPDES permit compliance, Dechlorination, Groundwater Monitoring and Assessment, Surface Water Studies, the Cooling Water Intake Program, the Impoundment Integrity Program, and Stormwater Maintenance. The total 2018 estimated expenses for the General Water Quality are $2,486,269.

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 Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Gulf has projected $3,300,916 of incremental expenses for this line item during the 2018 recovery period.

Line Item 1.8, State National Pollutant Discharge Elimination System (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 $34,500 during the projected recovery period.

Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical, and chemical costs related to the lead and copper drinking water quality standards. These expenses are expected to total $8,000 during the 2018 projection period.

Line Item 1.23, is the Coal Combustion Residuals (CCR) program that includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP). During 2018, 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 2018 expenses projected for the CCR line item total $12,041,680, which include pond closure activities for Plant Scholz and Plant Smith.

Construction activities to close the pond at Plant Scholz have begun. In 2017, Gulf commenced construction of an industrial wastewater pond and supporting activities to facilitate closure. The Scholz ash pond closure includes removing CCR material from portions of the existing pond, transferring CCR material upland to a dry stack area primarily within the footprint of the pond, and leasing a wastewater treatment system. The 2018 expenses for the Plant Scholz CCR closure are projected to be $7,977,139.

Recently, Gulf began construction of the Plant Smith pond closure and will continue with construction and associated activities in 2018 to close the pond. The Smith pond closure includes transferring CCR material upland to a dry stack area primarily within the footprint of the pond, and leasing a wastewater treatment system. The 2018 expenses associated with the Plant Smith CCR closure are projected to be $3,421,823.

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 2018 estimated expenses for the Environmental Audit/Assessment are $9,000.

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 2018 estimated expenses for the General Solid and Hazardous Waste are $1,065,139.

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

A. There are six other O&M activities that have been approved in past proceedings which have projected expenses during 2018. They are the Above Ground Storage Tanks program, the Sodium Injection System, the Air Quality Compliance Program, Crist Water Conservation, Emission Allowances, and Smith Water Conservation.

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 $223,390 are projected to be incurred during 2018.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at Plant Crist. Expenses totaling $10,000 are projected to be incurred during 2018 for this line item.

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, urea, limestone and general O&M expenses are included in the Air Quality Compliance Program line item. The projected cost for limestone costs associated with operation of the Plant Crist, Plant Daniel, and Plant Scherer 3 scrubbers is approximately $7.9 million. The projected 2018 expenses for this line item total $22,096,267.

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 $416,374 are projected to be incurred during 2018 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 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-FOF-EI. Expenses totaling $180,000 are projected to be incurred during 2018 for this line item.

Q. Please describe the emission allowance expense line items.

A. These line items include projected allowance expenses for Gulf's generation. Line Item 1.26 includes $8,926 of projected expenses for Annual NOx allowances, Line Item 1.27 includes $19,817 of projected expenses for Seasonal NOx allowances, and Line Item 1.28 includes $18,392 of projected expenses for SO_2 allowances during 2018.

Q. Do each of the capital projects and O&M activities that have projected costs in 2018 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2018 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.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 170007-EI
Date of Filing: April 3, 2017

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Regulatory and Cost Recovery Supervisor for Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida, in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration degree from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist. I worked in Forecasting for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Regulatory and Cost Recovery Supervisor. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, 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 2016 through December 2016 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 have.

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

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2016 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.

Q. What is the final ECRC true-up amount for the period ending December 31, 2016, to be addressed in the recovery period beginning January 2018?
A. An under-recovery in the amount of $3,262,290 was calculated and is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $3,262,290 under-recovery was calculated by taking the difference between the estimated January 2016 through December 2016 over-recovery of $7,840,455 as approved in FPSC Order No. PSC-16-0535-FOF-EI, dated November 22, 2016, and the actual over-recovery of $4,578,165, which is the sum of lines 5, 6 and 9 on Schedule 2A of my exhibit. The actual over-recovery includes the jurisdictional revenue requirements associated with the rededication of the portion of Scherer Unit 3 available to serve retail customers during the period.

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 2016 through December 2016. 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 2016 through December 2016 with the estimated/actual O&M expenses approved in conjunction with the November 2016 hearing. Schedule 5A shows the monthly O&M expenses by activity, 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 Mr. Markey's final true-up testimony.

Q. Please describe Schedules 6A and 7A of your exhibit.

A. Schedule 6A for the period January 2016 through December 2016 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2016 hearing. 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.160039-EI dated August 29, 2016. Schedule 7A provides the monthly recoverable costs associated with each project, along with the calculation of the jurisdictional recoverable costs. Any material variances in recoverable costs related to 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. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes for January 2016 through June 2016 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2015 Earnings Surveillance Report. For July 2016 through December 2016 the rate of return used is the WACC presented in Gulf's May 2016 Earnings Surveillance Report. The WACC for both periods includes a return on equity of 10.25%

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

A. Yes

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20170007-EI
Date of Filing: August 4, 2017

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 and Cost Recovery Manager for Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist and have held several positions with increasing responsibility prior to my current position of Regulatory and Cost Recovery Manager. My responsibilities include supervision of tariff administration, calculation of cost recovery factors, 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 estimated true-up amount for the period January 2017 through December 2017 for the Environmental Cost Recovery Clause (ECRC). I will also discuss the impact of implementing the Stipulation and Settlement Agreement (Settlement Agreement) approved by the Commission in Order No. PSC-2017-0178-S-EI in consolidated Docket Nos. 20160186-EI and 20160170-EI dated May 16, 2017.

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 nine schedules which are Gulf's environmental cost recovery estimated true-up schedules. My second exhibit contains the calculation of the Scherer/Flint credit, as defined later in my testimony, in accordance with provisions of the Settlement Agreement. Both exhibits were prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-2) and Exhibit No. _____(CSB-3).

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.

Q. What has Gulf calculated as the estimated true-up for the January 2017 through December 2017 period to be addressed in 2018 ECRC factors?

A. The estimated true-up for the current period is an over-recovery of $11,475,260 as shown on Schedule 1E of Exhibit CSB-2. This amount is based on six months of actual data and six months of estimated data. It will be added to the 2016 final true-up under-recovery amount of $3,262,290.

The total net true-up over-recovery of $8,212,969 will be addressed in Gulf's proposed 2018 ECRC factors. The detailed calculations supporting the estimated true-up for 2017 are contained in Schedules 2E through 8E 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 2017 through December 2017. 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 2017 through December 2017 to the projected O&M expenses approved by the Commission in Docket No. 20160007-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 2017 through December 2017 compares the estimated/actual investment-related recoverable costs to the projected amount approved in Docket No. 20160007-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-2016-0361-PAA-EI in Docket No. 20160039-EI dated August 29, 2016. Mr. Markey discusses variances in recoverable capital costs related to environmental project activities in his estimated/actual testimony. The difference between the total recoverable capital costs variance of $3,283,072 as shown on my Schedule 6E and the total variance of $1,112,249 discussed by Mr. Markey in his testimony is $2,170,823. The resulting difference is explained by an increase in the weighted average cost of capital (WACC), partially offset by a reduction in dismantlement expense for the period. 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 34 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 29 of Schedule 8E show the investment and associated costs related to capital projects, while pages 30 through 33 show the investment and return related to emission allowances, and page 34 shows the costs related to the regulatory asset for retired Plant Smith Units 1 and 2.

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

A. Consistent with Commission Order No. PSC-2012-0425-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 January 2017 through March 2017 is based on the WACC presented in Gulf's May 2016 Earnings Surveillance Report. For April 2017 through December 2017, the rate of return used is the WACC established by specific terms in the Settlement Agreement. The WACC for both periods includes a return on equity of 10.25 percent.

Q. Have you appropriately integrated the provision of the Settlement Agreement related to Plant Scherer Unit 3?

A. Yes. Gulf has integrated 100 percent of the environmental-related investment and expenses related to the Company's ownership in Plant

Scherer Unit 3 (Scherer 3) into ECRC. As reflected in Exhibit CSB-3, I have calculated the incremental revenue requirements related to the portion of Scherer 3 that continues to be committed to a wholesale customer through a long-term contract, which will expire in December 2019. This adjustment (Scherer/Flint credit) is calculated in accordance with the provisions in the Settlement Agreement, resulting in ECRC being revenue-neutral regarding the incremental inclusion 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 and Exhibit of
C. Shane Boyett
Docket No. 20170007-EI
Date of Filing: September 1, 2017

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 and Cost Recovery Manager for Gulf Power Company.

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 both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period of January 2018 through December 2018. I will also discuss the changes Gulf implemented as a result of the Stipulation and Settlement Agreement (Settlement Agreement), approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI dated May 16, 2017.

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's environmental cost recovery projection schedules. My second exhibit contains the calculation of the Scherer/Flint credit, in accordance with provisions of the Settlement Agreement. Both exhibits were prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-4) and Exhibit No. ______(CSB-5).

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 operating 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 with 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 2018 through December 2018. Schedule 2P of Exhibit CSB-4 shows the calculation of the recoverable O&M expenses broken down between demand-related and energy-related expenses. Schedule 2P also provides the appropriate jurisdictional factors and amounts related to these 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-4.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment project for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment project. 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 return on equity were used to develop the rate of return used to calculate the revenue requirements as shown on 8P?

A. Consistent with Commission Order No. PSC-12-0425-PAA-EU dated August 16, 2012, in Docket No. 120007-EI, the capital structure used in calculating the rate of return for recovery clause purposes is based on the weighted average cost of capital (WACC) established from the Settlement Agreement. This rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent for the period January 1, 2018, through December 31, 2018.

Q. Have you appropriately integrated the provision of the Settlement Agreement related to depreciation, amortization and dismantlement?

A. Yes. Beginning January 1, 2018, Gulf will implement new depreciation rates pursuant to the approved Settlement Agreement. Amortization of the regulatory asset resulting from the unrecovered plant balance associated with the retirement of Smith Units 1 and 2 will begin January 1, 2018. The amortization period is 15 years. As indicated in my Estimated True-up testimony previously filed in this docket, Gulf implemented reduced dismantlement accruals beginning July 1, 2017. The only remaining accruals are related to Coal Combustion Residuals at Plants Crist, Daniel and Scherer.

Q. Is the supporting data presented in accordance with the Uniform System of Accounts as prescribed by this Commission?

A. Yes.

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 were broken down within the retail jurisdiction based on the 12-MCP and 1/13th energy allocator. The use of this allocator is consistent with cost-of-service studies approved in Gulf's prior base rate cases. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2018 through December 2018?

A. The total projected jurisdictional recoverable costs for the period January 2018 through December 2018 is $211,656,376 as shown on line 1c of Schedule 1P of Exhibit CSB-4. This amount includes costs related to O&M activities of $42,515,980 and costs related to capital projects of $169,140,396, as shown on lines 1a and 1b of Schedule 1P. The adjustment (Scherer/Flint credit) as reflected on Lines 1.29 and 1.30 of Schedule 2P and Lines 1.35 and 1.36 of Schedule 3P calculates the incremental revenue requirement related to the portion of Scherer Unit 3 (Scherer 3) that continues to be committed to a wholesale customer through a long-term contact. The Scherer/Flint credit is calculated in accordance with the provisions in the Settlement Agreement, resulting in ECRC being revenue-neutral regarding the incremental inclusion of Scherer 3 investment and expenses.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2018 through December 2018, and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $203,589,886 for the period January 2018 through December 2018, as shown on line 5 of Schedule 1P of Exhibit CSB-4. This amount includes the recoverable costs related to the projection period offset by the total over-recovery true-up amount of $8,212,970. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. These amounts are allocated by rate class using the appropriate energy and demand allocators as shown on Schedule 6P and 7P of Exhibit CSB-4.

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 2015 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 I on Schedule 6P of Exhibit CSB-4.

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-4 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $34,758,056 for the period January 2018 through December 2018 was allocated using the energy allocator, as shown in column C on Schedule 7P of Exhibit CSB-4. The demand-related recoverable revenue requirement of $168,831,830 for the period January 2018 through December 2018 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 $21.24 monthly for the period January 2018 through December 2018.

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 2018 and will continue through the last billing cycle of December 2018.

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

A. Yes.

CHAIRMAN BROWN: Now on to the exhibits.

MR. MURPHY: Staff has compiled a stipulated comprehensive exhibit list, which includes the prefiled exhibits attached to witnesses' testimony and a number of staff exhibits. The list has been provided to the parties, the Commissioners, and the court reporter. This list is marked as the first hearing exhibit. And the other exhibits should be marked as set forth in the chart.

At this time, staff asks that the comprehensive exhibit list, marked as Exhibit 1, be entered into the record.

CHAIRMAN BROWN: Seeing no objection, we will go ahead and enter into the record Exhibit 1.

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

MR. MURPHY: Exhibits 25 through 43 were attached to the stipulated testimony of the parties. Exhibits 54 through 66 are staff's exhibits and have been stipulated by the parties.

Staff asks that Exhibits 25 through 43 and 54 through 66 be included in the record.

CHAIRMAN BROWN: Does anybody have any objection to entering those into the record? Seeing none, we will go ahead and move in

Exhibits 25 through 43 as well as 54 through 60 -- 66.

(Whereupon, Exhibits 25 through 43 and 54 through 66 were admitted into the record.)

CHAIRMAN BROWN: All right. Let us talk about the posture of the stipulated issues.

MR. MURPHY: If the Commission decides that a Bench decision is appropriate, staff recommends that the proposed stipulations for Issues 1 through 9, 10F, 10G, 11, 12A, 12B, 12C, and 13 should be approved by the Commission. All parties either support or do not oppose the proposed stipulations.

The stipulated numbers for several of the generic issues for FPL may need be to adjusted depending on the Commission's decision on the contested issues. These are Issues 2, 3, 4, and 7.

Staff asks that the Commission's approval of the stipulation also authorizes staff to adjust these fallout numbers consistent with the Commission's decision on the contested issues.

CHAIRMAN BROWN: Okay. So, Commissioners, this is the appropriate time to ask questions of staff on any of the stipulated issues. Any questions, Commissioners? If not, we are ripe for a motion on the proposed stipulation of Issues 1 through 9, 10F, 10G, 11, 12A, 12B, 12C, and 13.

Thank you, Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Madam Chair. I move that we approve the stipulations for Issues 1 through 9, 10F, 10G, 11, 12A, 12B, 12C, and 13, and allow for the fallout -- or future decisions to address the fallout issues in 2, 3, 4, and 7.

CHAIRMAN BROWN: Excellent.

COMMISSIONER CLARK: Second.

CHAIRMAN BROWN: Is there any further discussion? Seeing none, all those in favor of the motion, signify by saying aye.

(Chorus of ayes.)

CHAIRMAN BROWN: Opposed?

Passes unanimously. Thank you.

Now, staff on to the contested issues.

MR. MURPHY: The only thing we have is that FPL and OPC have indicated that they're going to have demonstrative exhibits.

CHAIRMAN BROWN: Great. We see them. Looking forward to it. Can't really see them, but they provide color over -- nice color.

(Laughter.)

CHAIRMAN BROWN: All right. So, are there any other things that we need to discuss before we get to opening statements?

Yes, that -- you want to know now.

MR. REHWINKEL: Well, Madam Chairman, I -- I -- before we started, I -- I asked if you had an idea about the schedule. And then I said I would wait to hear from everyone, but I thought -- I've thought about it. It's -- we've been here at it all day. It's nearly five.

The case that we are bringing here today is one that deals with a great deal of scientific testimony on an issue that the Commission has really not seen in -- in generations, if -- if at all. I say generations because I've been around for 30-something years now and -- and I've never seen it.

This issue was put off from last year. And we appreciate the company and the Commission working with us. The Public Counsel engaged an expert. The company has an expert. We've spent a lot of time and effort getting prepared for this hearing.

Ordinarily, attorneys -- I think they teach a course in it in law school, is you -- you kind of doing a lot at the last minute. We've had a lot of late nights getting ready for this hearing; spent a lot of time stipulating and streamlining the process.

CHAIRMAN BROWN: Thank you for that.

MR. REHWINKEL: And it -- I've never started a major hearing at the end of the day. And it's just something that it -- I want to voice some level of concern about it. It -- it seems to me that it would make sense to hear opening statements and take care of all the preliminaries associated with the -- the cooling-canal-system case and start fresh in the morning with cross-examination.

I -- the first witness up is Mr. Sole. And the -- the cross for him, at least from our side, is extensive. No attorney likes to start a cross and then have overnight, and then start again. It just seems to mess with the flow. And I'll just be frank about that.

CHAIRMAN BROWN: So, your proposal is to take up opening statements and then conclude for the day.

MR. REHWINKEL: That would be my recommendation. And I would also couple that with a commitment to make tomorrow work to conclude the hearing. I think we can do it. It may be a little bit of a long day, but I would rather be fresh --

CHAIRMAN BROWN: Well, that's from your perspective and your perspective only.

MR. REHWINKEL: No, I understand.

CHAIRMAN BROWN: There are other parties here.

MR. REHWINKEL: Yes, oh, that's -- that's my two- -- two-cents-worth on that.

CHAIRMAN BROWN: I appreciate that. And I do respect that. So, my goal was to start with the opening statements and at least get started on the first witness, acknowledging that we have seven total -- and that includes direct and rebuttal -- witnesses to take up, you know, given the time that we have.

I do acknowledge your concerns about starting fresh. We have been going all day. Some of us are a little tired, but some of us are fresh here and haven't been participating in some of the matters.

So, I would like to hear from the other parties before we make a decision on this. Starting with the FPL.

MS. CANO: Thank you, Madam Chairman.

FPL isn't going to object to what OPC is requesting here, but I do have, perhaps, a friendly amendment, if we want to get a little bit further than opening statements.

Ms. Deaton is not a technical or scientific witness. She only has direct. She was nearly stipulated. It's my belief that folks only have a few questions for her.

So, perhaps we could do opening statements and take Ms. Deaton out of order. She doesn't have rebuttal, so she would be done for the remainder of the hearing.

CHAIRMAN BROWN: I like it.

Are you amenable to that?

MR. REHWINKEL: Yes, Madam Chairman, I -- I am.

I have an exhibit that -- I would offer a friendly amendment to the friendly amendment, is that, if we could, do opening statements and I could have a brief --

CHAIRMAN BROWN: Yes.

MR. REHWINKEL: -- recess with the company and see if I can work something out. All of my te- -- my cross could be -- could be addressed if we could work that out. So, I would be happy to -- at least it could be limited and we could get that witness out of the way.

CHAIRMAN BROWN: Okay. Parties -- I -- wait -- if you don't mind, Mr. Moyle, I'm just going to go down the line.

FPL first.

MS. CANO: That would be fine with FPL. Thank you.

CHAIRMAN BROWN: Duke.

MR. BERNIER: Madam Chairman, given your vote on the stipulated issues, I would just ask to be excused.

CHAIRMAN BROWN: Yeah, I was waiting for that. Like, today. Like, right now.

MR. BERNIER: All these -- all these other ideas sound great, but --

(Laughter.)

MR. BEASLEY: We're --

CHAIRMAN BROWN: You may be excused.

MR. BERNIER: Thank you. Thank y'all.

MR. BEASLEY: We're in the same posture.

CHAIRMAN BROWN: You may be excused.

MR. BEASLEY: Thank you.

CHAIRMAN BROWN: All right.

Gulf.

MR. BADDERS: Same posture.

CHAIRMAN BROWN: Same -- you don't want to stay around?

COMMISSIONER POLMANN: Oh, come on.

MR. BADDERS: I promise to listen. How about that?

CHAIRMAN BROWN: You may be excused.

MR. BADDERS: Thank you.

CHAIRMAN BROWN: All right. So, FIPUG.

MR. MOYLE: Well, you -- you've heard a lot of me already today, and I -- I would support Mr. Rehwinkel in his request. I mean, putting on a big case, he's taking the labor majeure on this -- on this environmental docket and --

CHAIRMAN BROWN: Yeah.

MR. MOYLE: It seems -- seems reasonable.

CHAIRMAN BROWN: Okay. Mr. Cavros?

MR. CAVROS: Yes, I support Mr. Rehwinkel's request and Ms. Cano's amendment.

CHAIRMAN BROWN: Okay.

MR. CAVROS: We're good with that. Thank you.

CHAIRMAN BROWN: Commissioners, any thoughts?

All right. That's what we'll do. So, we will start with opening statements. And then we will go to Ms. Deaton. And then we will adjourn for the day. Sound good? We will take a break, but -- okay.

Moving on to opening statements -- is there anything else before we get to that? Seeing nothing else -- okay. Opening statements -- FPL will have ten minutes and intervenors have 15 minutes to share among themselves. Please feel free to utilize that however you see fit.

All right. Ms. Cano?

MS. CANO: Thank you.

Good afternoon, Chairman Brown and Commissioners. The disputed issues in FPL's environmental cost recovery case are related to Project 42, the Turkey Point Cooling Canal Monitoring Plan Project, which I will refer to as the Cooling Canal Project.

The Cooling Canal Project was approved by the Commission for environmental cost recovery purposes in 2009. The initial focus of that project was to implement an expanded monitoring program to identify potential impacts of the Turkey Point cooling canal system, or CCS, on groundwater in the vicinity of the CCS, as mandated by conditions of certification for the Turkey Point uprate project.

At the time, FPL explained that the conditions of certification provided that the project may need to progress from monitoring to implementation of taking required corrective actions, if warranted by the results of the monitoring.

The incremental movement of this project from monitoring to implementation of required corrective actions has been reported each year in the annual ECRC docket.

As will be discussed by FPL's witness, Mr. Sole, FPL has operated the CCS in full compliance with all applicable regulations, permits, and agreements; but nonetheless, and as a result of the information obtained in the expanded monitoring program, the Florida Water Management District directed FPL in 2013 to consult with it and other environmental agencies to identify corrective actions to address the movement of hypersaline groundwater associated with the CCS.

This consultation resulted in a number of administrative proceedings and actions by various agencies charged with environmental oversight over the CCS, including the Water Management District, the Florida Department of Environmental Protection, or FDEP, and the Miami-Dade County Department of Environmental Resources Management, or MDC-DERM. The MDC-DERM and FDEP issued notices of water-quality violations in 2015 and 2016, respectively.

In order to resolve those violations, FPL ultimately entered into a consent agreement with

MDC-DERM in 2015, which was amended in 2016, and agreed to a consent order, issued by the FDEP in 2016.

In compliance with the regulatory requirements set forth in the consent agreement and consent order, FPL is undertaking a number of actions to address impacts resulting from the hypersalinity of the CCS.

For example, FPL is freshening the cooling canals with supplemental water sources and constructing a recovery well system to retract and ultimately contain a hypersaline plume to the boundaries of the CCS.

FPL also was directed to complete an analysis that seeks to allocate the relative contribution of other entities and factors to the movement of the saltwater interface in the area because much is still not known about the CCS's relative role in the movement of that saltwater interface. Over the next ten years, FPL estimates it will spend $176 million to fulfill its obligations under the consent agreement and the consent order.

OPC is the only party presenting a witness challenging FPL's Cooling Canal Project costs. OPC's witness reviews historical pieces of data through the lens of current circumstances to conclude that FPL should have known there was a problem earlier and should have done something about it.

But the fundamental flaw in this position is the belief that the existence of increased salinity, or a tritium, in regional monitoring wells in an already-saltwater-intruded environment indicated the need to take action.

As will be discussed by Mr. Sole, the District has exercised a unique level of oversight over the CCS since 1972; and only after the expanded monitoring program in 2009 through 2013 did FPL and the relevant agencies assess the corrective action was, in fact, warranted.

Ironically, this means that OPC must be claiming that, in the 1980s or 1990s, FPL should have done something and spent some amount of money without an environmental directive to do so; an act that OPC surely would have challenged at the time as imprudent.

Now that FPL is required to take corrective actions, those actions are being challenged by OPC. Specifically, OPC's witness challenges whether the recovery well system, or RWS, will be effective, and challenges FPL's allocation of the costs of the RWS between capital and O & M.

With respect to the effectiveness of the RWS, FPL Witness Anderson explains that OPC's witness relies on flawed assumptions and a misplaced focus on the saltwater interface as opposed to the hypersaline plume that FPL is actually obligated to retract. In fact, one of OPC's own exhibits demonstrates that the RWS is projected to be quite effective in the goal of retracting the hypersaline plume.

With respect to the allocation of RWS costs between capital and O & M, FPL's proposed allocation is both conservative, based on what it allocates to capital, in light of the supporting technical study, and consistent with generally-accepted accounting principles, something that cannot be said for OPC's witness' proposed approach.

In sum, Commissioners, what FPL has presented for your review and approval are prudently-incurred costs to comply with environmental requirements of the South Florida Water Management District, the FDEP, and the MDC-DERM.

These costs are incurred as a direct result of the expanded monitoring program, which was imposed under the Turkey Point uprate conditions of certification, which formed the basis for this Commission's approval of the cost recovery project.

From its inception, that project has explicitly contemplated that the expanded monitoring may result in the need to take corrective actions and, in 2013, FPL specifically reported that this project was headed in that direction.

At all times, FPL has worked closely and collaboratively with the environmental regulatory agencies charged with the environmental oversight of the CCS, and continues to do so to this day.

We ask that you approve, as filed, the costs that FPL has presented to comply with the requirements of those agencies.

Thank you.

CHAIRMAN BROWN: All right. Thank you.

Who would like to go -- start out the opening statements? Public Counsel?

MS. MORSE: Yes, thank you.

CHAIRMAN BROWN: All right.

MS. MORSE: Good morning, Madam Chair and Commissioners.

CHAIRMAN BROWN: Good morning?

MS. MORSE: Good afternoon.

(Laughter.)

CHAIRMAN BROWN: You do need a break.

MS. MORSE: I do need a break.

At issue today is an expensive remediation project designed to fix a massive saline-contamination plume that leaked from FPL's property.

The evidence will show that the contamination was the direct result of FPL's repeated decades-long failures to prudently manage its nuclear facility's cooling canal water.

In the demonstrative at your far right, you can see the size and extent of the hypersaline portion of this plume outside of FPL's property on Demonstrative 14B, from our expert's testimony. This evidence comes from FPL. This doesn't even show the rest of the saline portion that extends further out than the pink hypersaline part that's depicted here.

FPL's failures, in turn, resulted in the pollution of the Biscayne Aquifer by FPL's cooling canal water. Needless to say, the Biscayne Aquifer is an important national -- natural resource in the region.

The protection of the state's natural resources is so important that the policy of the natural resource protection is enshrined in Florida's constitution. By precedent, FPL is prohibited from forcing customers to pay to fix problems which were caused by its imprudent management decision.

The contamination, which resulted in the need for remediation in this case, was preventable, and FPL had the data in its hands to show it happening in real time, but failed to act. As such, the cost to remedy the contamination must be borne by FPL's shareholders and not the customers.

Throughout the hearing, you may hear salinity and the related plume formation expressed in different ways. Examples of the terms are saline water, saltwater, hypersaline water or plume, but the basic fact is that the saline water is a contaminant to fresh water, whether it is referred to as hypersaline or simply saline.

The worst part of the contamination at issue is sometimes referred to as the hypersaline plume, but to be clear, hypersalinity is simply a subset in the worst-case scenario of the overall saline contamination, which has been seeping from FPL's cooling canal system, or CCS, for decades.

Eventually, so much of the salinity built up that it became a saline plume, and parts of that plume became so concentrated that it -- it's referred to as hypersaline.

Additionally, saline water tends to sink. So, you will hear evidence of different salinity measurements at different depth levels within the Biscayne Aquifer. There is no question that FPL was issued multiple notices of violation about the saline contamination coming out of the CCS.

There's no question that FPL admitted to violating the law regarding this saline contamination. FPL's admin- -- admissions appear in a final administrative order and in FPL's own testimony.

The evidence will show that the migration of saline water out of the CCS and the growth of the hypersaline plume are the direct result of management decisions FPL has made over its decades of operation and responsibility for maintaining the CCS. These management decisions include both actions and willful inaction by FPL, which resulted in the contamination at issue today.

Over the roughly four decades of its operation of the CCS, FPL made affirmative commitments via a number of written agreements with state and county regulatory agencies to take responsibility for making sure the saline water from the CCS did not contaminate the Biscayne Aquifer, and thus, vital public resources.

Rather than taking responsibility for its failures, FPL now seeks to mask the cost of its remediation project by proposing an allocation which would split the cost of its remediation project into remediation and so-called prevention or containment; thus, allocate the cost less to O & M and more to capital where they can earn at a robust profit for fixing their own misdeeds.

Additionally, FPL proposes to categorize some of this project as part of the groundwater monitoring program, which has previously come before this Commission. However, monitoring is clearly not the same as remediation or retraction of a plume of saline contamination.

The proposed evolution of the monitoring program -- which, in some years, costs in the low hundreds of thousands of dollars -- into a remediation project costing hundreds of millions of dollars defies logic and Commission policy.

The argument that these remediation costs have somehow already been approved by the Commission under the guise of the monitoring program should be a non-starter.

In addition, there are two major defects in FPL's current proposal. The first major defect is that the plan is simply not effective. The model FPL relies on shows that one major component of its plan will never fully retract the hypersaline plume out of the Biscayne Aquifer and back into FPL's property as required.

The components of FPL's remediation plan are a system of remediation wells and a separate process referred to as freshening or adding water to the CCS.

You will hear FPL refer to -- to the other wells as a recovery well system, or RWS. The evidence will show that the so-called recovery wells will likely only retract the hypersalinity from two out of the 11 layers of the Biscayne Aquifer.

The evidence shows that freshening -- the freshening component of FPL's remediation plan does more to retract the hypersalinity than the RWS does. The evidence projects that freshening will likely retract the hypersaline plume in Layers 4 to 6 of the Biscayne Aquifer.

While the RWS may achieve some retraction in Layers 7 and 8, even these two processes together will not retract the hypersalinity in the Layers 9 through 11 of the Biscayne Aquifer. So, the RWS will not achieve the regulatory requirements FPL must meet.

The second major defect in FPL's plan is that, even if given the benefit of the doubt that some of its remediation plan might work, FPL attempts to allocate too high a percentage of the project's cost into the so-called prevention or containment bucket and, thereby, shift too much of the costs onto the backs of ratepayers.

FPL made affirmative decisions to ignore the evidence and the data that it was obligated to gather over the past four decades. This evidence was in FPL's plain sight all along. FPL's decisions resulted in the massive contamination at issue today.

The bottom line is that, not only are ratepayers being asked to pay over a hundred million dollars to fix this problem, which was caused by the FPL's failure to manage the facility prudently, but on top of that hundred-plus-million-dollar cost, ratepayers would actually be saddled with having to additionally pay shareholders of FPL millions of dollars in profit on the remediation costs.

That's because FPL is now attempting to improperly categorize its remediation work as preventive work and, thus, a capital expense for which customers pay and on which FPL earns a profit. This is the very definition of adding insult to injury.

To make matters worse, you will hear evidence that FPL cannot assure you that the proposed remediation project will even work. In fact, FPL knows that they have multiple opportunities to change course and later burden customers with the costs of trying something new. Basically, they want to conduct remediation, research, and development at ratepayers' expense instead of shareholder expense.

In summary, the allocation of costs proposed by FPL is not supported by science or judicial precedent and, therefore, it should be denied or modified.

Thank you.

CHAIRMAN BROWN: Thank you.

You have six minutes and 44 seconds remaining.

MR. CAVROS: I'm going.

CHAIRMAN BROWN: All right.

MR. CAVROS: Good evening, Commissioners. George Cavros on behalf of the Southern Alliance for Clean Energy.

You know, this is a complex issue. It deals with ten square miles of online cooling canals. Hypersaline water has migrated underground now. It's formed a hypersaline plume. It's -- it's -- and it's spreading to the east and the west.

You're also going to, you know, be hearing about agreements that go back, some of them, 40 years. But one of the big questions that you will have to answer at the end of this hearing is did -- should have F- -- should -- did FPL know or should they have known that they had a groundwater contamination problem on their hands.

And the evidence will show is that -- that they did knew -- they did know. They had enough evidence to know, and that they did not act. And that is not prudent. And they can't recover.

Also, there's an -- you know, there's an old adage: An ounce of prevention is worth a pound of cure. You'll see that, over the whole timeline that we're discussing, that FP&L never took any preventive actions. And now they're coming back to the customers to pay for that pound of cure. The total project costs is going to be over $200 million. FPL customers should not have to pay for FPL's mistakes.

OPC is sponsoring a witness with 27 years of professional experience. He's looked at data and reports going back to 1978. He's concluded that FPL should have known, if not by 1978, certainly by 1992, that it had a growing contamination problem on its hands.

FPL, in fact, didn't act until 2013 when the South Florida Water Management District called them in for a consultation. FPL's defense is, well, no one told us to act. And that rings very hollow.

You heard about the consent agreement and the consent order. Those came forth or -- from the notice of violation that was filed by DEP and also Miami-Dade County. We're going to talk about those agreements at -- at length. And those compliance costs -- those requirements are imposing the compliance costs that FP&L is seeking to recover from customers now.

Commissioners, the Environmental Cost Recovery Clause docket is not an insurance policy. I don't believe it was ever intended for companies to come in and recover costs for violations of existing permits.

You've seen in the docket there's been about 400 letters from FP&L customers. And they all have the similar messaging: FPL, you created the mess. FPL, you clean up the mess. And FPL, you pay to clean it up. So, we ask this Commission, deny FPL's request.

Thank you.

CHAIRMAN BROWN: Thank you, Mr. Cavros.

Mr. Moyle, you've got four minutes left, roughly.

MR. MOYLE: Thank -- thank -- thank you.

And -- and to underscore a few key points, you will hear from a number of FPL witnesses -- I -- I think an important piece of evidence is the notice of violations that were issued by not only the Florida Department of Environmental Protection, but by -- by DERM.

And I think an issue that is before you is, well, how do you -- how do you read the environmental cost recovery statute, 366.8255, with respect to a matter that involves a regulator saying, you -- you violated.

That is, I think, something that doesn't happen regularly. And if you're a regulated entity, the notice of violation is not what you want, you know. You need to strive to be compliant with your laws and your -- and your permits.

And when you're not, it shouldn't be something that -- that is, then -- befalls the customers and the ratepayers, not only for the compliance costs, but -- but as OPC said, you know, a profit as well.

I mean, that -- that sends a real mixed message and, arguably, is not consistent with good public policy to -- to make a finding to say, well, you know, if you -- if you violate environmental regulations, you can get your -- your cost to fix it, plus you make a profit on your costs.

I mean, that's not the -- you know, the message that should -- should be sent with respect to notices of violation, which is really what -- what plays, I think, a significant role, in part, in this discussion.

The -- the statute talks about environmental compliance costs and -- and Paragraph 1D costs or expenses incurred by utility in complying with environmental laws or regulations.

You know, the statute doesn't address anything related to violations of permits. And I think that's a material factual distinction that -- that you all should -- should consider and, when making your decision, you know, not send the wrong message and not create any kind of wrong incentive with respect to allowing notices of violations to be issued, and then -- and then, as things unfold, allow the entity that's violated to -- to recover for fixing or attempting to fix the problem and then also earn a profit on that. And I don't think that is -- is the direction that you should head.

You know, there's concerns about -- about what the -- what the solution may be. You heard OPC say, well, we're not even thinking that what's being proposed is -- you know, is going to work. The ratepayers should not be -- be the ones, at the end of the day, who are picking up all the costs.

I mean, earlier today, you took action and -- and we closed out a very tough chapter in the ratepayers' life related to Duke and Crystal River and all of the, well, we'll try this, we'll try that, we'll try this.

And we think that there should be a -- a course of conduct where it's not the ratepayers acting kind of as the -- as the backstop for these types of things, and that there should be some shareholder risk and exposure with respect to addressing this problem, particularly when you have a regulator that is issuing a notice of violation.

So, we -- we support the comments of our colleagues and would ask that you not -- not grant FPL's petition as -- as filed.

CHAIRMAN BROWN: Okay. Thank you.

MR. MOYLE: Did I do okay on my time?

CHAIRMAN BROWN: You're done with your time.

MR. MOYLE: Okay.

CHAIRMAN BROWN: You went over your time. All right.

MR. MOYLE: Thank you.

CHAIRMAN BROWN: Thank you. Thank you, parties, for those opening comments.

Before we call the first witness to the stand, which is Ms. Deaton, I reiterate the same thoughts from the last proceeding regarding cross-examination. Irrelevant, immaterial, or unduly-repetitious evidence will be excluded. Please be advised accordingly.

Also, with regard to the exhibits, the -- again, the distribution process -- we have staff here able to assist you on providing those. And please have them collated -- I know how much you love it, OPC -- but it helps with the process, especially given the time that we have here today on such an important matter.

And witnesses are permitted up to five minutes each on direct and rebuttal to summarize the testimony. As I said, we have seven total witnesses. And the order of cross-examination, unless you see differently, shall be as follows: OPC followed by FIPUG, SACE, staff, and then Commissioners, and redirect. If you're amenable to that cross, that's how we will begin.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, ANDREA KOMARIDIS, 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 30th day of October, 2017.

ANDREA KOMARIDIS
NOTARY PUBLIC
COMMISSION #GG060963
EXPIRES February 9, 2021