BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE.
______________________________/

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, November 4, 2013

TIME: Commenced at 9:47 a.m.
Concluded at 9:51 a.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

APPEARANCES:

ASHLEY M. DANIELS, JAMES D. BEASLEY, and J. JEFFRY WAHLEN, ESQUIRES, Ausley Law Firm, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JEFFREY A. STONE, ESQUIRE, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591, appearing on behalf of Gulf Power Company.

JOHN T. BURNETT and DIANE TRIPLETT, ESQUIRES, Post Office Box 14042, St. Petersburg, Florida 33733; GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf of Duke Energy Florida, Inc.

KAREN PUTNAL, ESQUIRE, c/o Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Florida Retail Federation, c/o Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Florida Retail Federation.

JOHN T. BUTLER and KENNETH M. RUBIN, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, appearing on behalf of Florida Power & Light Company.

APPEARANCES (Continued):

J.R. KELLY, PUBLIC COUNSEL, PATRICIA A. CHRISTENSEN and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32393-1400, appearing on behalf of the Citizens of Florida.

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, PCS Phosphate - White Springs, c/o Brickfield Law Firm, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

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

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, and CURT KISER, GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
1 - 61	256	256

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good morning. We'll go ahead and call this hearing to order. It's our annual clause hearings. And, Staff, would you read the notice, please.

MS. GILCHER: By notice issued September 27, 2013, this time and place is set for a hearing conference in the following dockets: 130001-EI, 130002-EG, 130003-GU, 130004-GU, and 130007-EI. The purpose of the hearing conference is set out in the notice.

CHAIRMAN BRISÉ: All right. Thank you. At this time we will take appearances. And, staff, do we have any specific instructions that we want to give with respect to that?

MS. GILCHER: Staff suggests that all parties give their appearances at the same time. There are five dockets to address this morning. All parties should enter their appearances and declare the dockets that they are entering their appearance for.

CHAIRMAN BRISÉ: Okay. Thank you. All right. At this time we'll take appearances.

MR. BUTLER: Good morning, Mr. Chairman. John Butler and Ken Rubin. We're appearing in the 01, the 02, and the 07 dockets.

MS. DANIELS: Good morning, Commissioners. I am Ashley Daniels appearing with Jim Beasley and Jeff Wahlen of Ausley McMullen on behalf of Tampa Electric in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Okay. Thank you.

MR. STONE: Good morning, Commissioners. I'm Jeffrey A. Stone of the law firm Beggs and Lane and I'm appearing on behalf of Gulf Power Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel and Patricia Christensen in all dockets; Joseph McGlothlin in 01 and 07. And J.R. Kelly, the Public Counsel, is here.

CHAIRMAN BRISÉ: Thank you.

MR. WRIGHT: Good morning, Mr. Chairman and Commissioners. Robert Scheffel Wright and John T. LaVia, III, appearing on behalf of the Florida Retail Federation in the fuel docket, 130001. The same attorneys also appearing on behalf of DeSoto County Generating Company in the ECRC docket, 130007.

Thank you.

CHAIRMAN BRISÉ: Thank you.

MR. KEATING: Good morning, Commissioners. Beth Keating with the Gunster law firm. I'm here today on behalf of FPUC in the 01 and 02 dockets; on behalf of FPUC and Florida City Gas in the 03 docket; and on behalf of FPUC, FPUC Indiantown, Chesapeake, and Florida City Gas in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MS. PUTNAL: Good morning. I am Karen Putnal with the Moyle Law Firm and appearing today on behalf of Florida Industrial Power Users Group in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. BREW: Good morning, Mr. Chairman. I'm James Brew. I'm appearing for White Springs Agricultural Chemicals, PCS Phosphate in the 01, 02, and 07 dockets. And I'd like to make an appearance for F. Alvin Taylor, as well.

CHAIRMAN BRISÉ: Thank you.

MR. HORTON: Mr. Chairman, Norman H. Horton, Jr., appearing on behalf of Sebring Gas System in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MS. TRIPLETT: Good morning. Diane Triplett, John Burnett, and Matt Bernier, appearing on behalf of Duke Energy Florida in the 01, 02, and 07 dockets. And also appearing in the 07 docket is Gary Perko. Thank you.

CHAIRMAN BRISÉ: Thank you.

MS. CORBARI: Kelly Corbari appearing in the 04 docket.

CHAIRMAN BRISÉ: Okay.

MS. GILCHER: Julia Gilcher appearing in the 02 and 01 docket. I'd also like to make an appearance in the 02 docket for Lee Eng Tan and in the 01 docket for Martha Barrera.

CHAIRMAN BRISÉ: Thank you.

MR. LAWSON: Michael Lawson for the 03 docket.

MR. MURPHY: Charles Murphy in the 07 docket.

MS. HELTON: And, Mary Anne Helton, advisor to the Commission in all of the dockets. And also here today is the General Counsel, Curt Kiser.

CHAIRMAN BRISÉ: Thank you.

Are we missing anyone? Okay.

Are there any parties that have been excused from the hearing?

MS. GILCHER: Yes, Chairman. There's been three parties excused from the hearing today; St. Joe Natural Gas Company, Peoples Gas System, and Southern Alliance for Clean Energy.

CHAIRMAN BRISÉ: Okay. And it's my understanding that St. Joe Natural Gas Company had an interest in Docket 03 and 04?

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: And Peoples Gas, 03 and 04, as well.

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: And Southern Alliance for Clean Energy in the 02 docket.

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: Okay. The order that we plan to take up the dockets today is 02, 03, 04, 07, and then 01.

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CHAIRMAN BRISÉ: We'll proceed with Docket 07.

MR. MURPHY: Commissioner, there are proposed stipulations for all issues except 10, 10A through D, and 11. Testimony on those issues will be heard in this docket on December 19th and 20th. All parties either agree or take no position on the proposed stipulations that are before the Commission today, and the parties have waived opening statements.

CHAIRMAN BRISÉ: Okay. Thank you. Let's address the prefiled testimony.

MR. MURPHY: Commissioners, at this time staff asks that the prefiled testimony of all witnesses identified in Section VI on Pages 4 and 5 of the prehearing order be inserted into the record as though read.

CHAIRMAN BRISÉ: Okay. We will enter the prefiled testimony identified in Section VI on Pages 4 and 5 of the prehearing order. We'll insert those into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

April 1, 2013

Q. Please state your name and business address.

A. My name is Thomas G. Foster. 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 Progress Energy Service Company, LLC as Manager, Retail Riders and Rate Cases.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Progress Energy Florida, Inc. ("PEF"). These responsibilities include: regulatory financial reports; and analysis of state, federal and local regulations and their impact on PEF. In this capacity, I am also responsible for PEF's True-up, Estimated/Actual, and Projection filings in the Environmental Cost Recovery Clause (ECRC).

Q. Please describe your educational background and professional experience.

A. I joined Progress Energy on October 31, 2005 as a Senior Financial Analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning and in 2012 I was again promoted to Manager of Retail Riders and Rate Cases. Prior to working at Progress Energy, I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was primarily responsible for ensuring proper accounting for all fixed assets in addition to various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear operator. I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance 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 Progress Energy Florida'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, PEF's Actual True-up costs associated with environmental compliance activities for the period January 2012 through December 2012.

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

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

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

- Form 42-1A is the final true-up for the period January 2012 through December 2012.
- Form 42-2A is the final true-up calculation for the period.
- Form 42-3A is the calculation of the interest provision for the period.
- Form 42-4A is the calculation of variances between actual and estimated/actual costs for O&M Activities.
- Form 42-5A is a summary of actual monthly costs for the period of O&M Activities.
- Form 42-6A is the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A is a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A, pages 1 through 18, is the calculation of return on capital investment, depreciation expense and property tax expense for each project recovered through the ECRC.
- Form 42-9A is PEF's capital structure and cost rates.

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

- Pipeline Integrity Management (Capital Program Detail (CPD), pages 2 through 3)
- Above Ground Storage Tank Secondary Containment (CPD, pages 4 through 9)
- Clean Air Interstate Rule (CAIR) Combustion Turbines (CTs)(CPD, pages 10 through 13)
- CAIR (CPD, pages 14 through 21)
- Thermal Discharge Permanent Cooling Tower (CPD, page 22)

These exhibits 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 PEF. The books and records are kept in the regular course of PEF's business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by Federal Energy Regulatory Commission (FERC) and any accounting rules and orders established by this Commission.

Q. What is the final true-up amount for which PEF is requesting for the period January 2012 through December 2012?

A. PEF is requesting approval of an over-recovery amount of $12,631,810 for the calendar period ending December 31, 2012. This amount is shown on Form 42-1A, Line 1.

Q. What is the net true-up amount PEF is requesting for the January 2012 through December 2012 period to be applied in the calculation of the environmental cost recovery factors to be refunded/recovered in the next projection period?

A. PEF requests approval of an under-recovery of $2,001,164 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the period January 2012 through December 2012. This amount is the difference between an actual over-recovery amount of $12,631,810 and an actual/estimated over-recovery of $14,632,974, as approved in Order PSC-12-0613-FOF-EI, for the period January 2012 through December 2012.

Q. Are all costs listed in 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 2012 through December 2012 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-4A shows a total O&M project variance of $7,955 lower than projected for an immaterial difference. Individual O&M project variances are also on Form 42-4A. Below are explanations for O&M projects with material variances.

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

1. **Substation Environmental Investigation, Remediation, and Pollution Prevention (Project No. 1):** The project expenditure variance is $1,472,647 or 28% lower than projected. This variance is due to the inability to perform scheduled remediation work at some substation sites as further discussed in Corey Zeigler's Direct Testimony.

2. **Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project No. 2):** The project expenditure variance is $146,745 or 28% lower than projected. This variance is attributed to the determination that no further action was necessary at 9 transformer sites due to clean deviation sampling lab results, and the delay of further action at 4 contaminated transformer sites until 2013 as discussed in Mr. Zeigler's Direct Testimony.

3. **Pipeline Integrity Management (Project No. 3):** The project expenditure variance is $1,124,385 or 81% lower than projected. This variance is primarily due to the cancellation of a substantial number of "5 year assessment" projects and postponement of two major "FDOT highway support projects" as explained

in Patricia West's Direct Testimony.

4. **CAIR Combustion Turbine Predictive Emissions Monitoring Systems (Project No. 7.2):** The project expenditure variance is $37,365 or 27% lower than projected. This variance is primarily attributed to the timing of payments for air emissions testing performed at Bartow and Higgins stations late in 2012 as discussed in Ms. West's Direct Testimony.

5. **CAIR Crystal River (Project 7.4):** The project expenditure variance is $2,747,465 or 11% higher than projected. This variance is primarily due to reagent pricing and usage variances, increased costs to facilitate gypsum removal from the site, reclassification of costs to fix a Vehicle Barrier System drainage issue, and costs necessary to remove clinkers in the interior of the absorber. This project is further discussed in Jeff Swartz' Direct Testimony.

6. **Best Available Retrofit Technology (Project No. 7.5):** The project expenditure variance was $50,468 or 187% higher than projected due to legal and environmental consulting services required to support negotiations with the Florida Department of Environmental Protection (FDEP) to obtain necessary permits for Crystal River Units 1 and 2 (CR1&2) as explained in Ms. West's Direct Testimony.

7. **Sea Turtle Coastal Street Lighting Program (Project No. 9):** The project expenditure variance is $2,304 or 92% lower than projected. The variance is

due to delay with the University of Florida and PEF performing additional testing of Florida Wildlife Commission's recommended LED as discussed in Mr. Zeigler's Direct Testimony.

8. **National Pollutant Discharge Elimination System (Project No.16):** The project was $50,229 or 22% lower than projected. This variance is attributable to FDEP changes to and approval of Section 316(a) plan of studies (POS) for the Suwannee, Anclote and Bartow power stations as further discussed in Ms. West's Direct Testimony.

Capital Investment Project Variances

Q. How did actual Capital recoverable expenditures for January 2012 through December 2012 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-6A shows that Total Capital Investment Activities - Recoverable Costs variance was $852,852 lower than projected for an immaterial difference. Actual costs and variances by individual project 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 through 18.

Capital Investment Project Variances

1. **National Pollutant Discharge Elimination System (Project No. 16):** The project recoverable cost variances is $24,166 or 45% lower than projected. This variance is the result of a delay in the project to allow for nitrogen Waste Load Allocation

approval from the Tampa Bay Nitrogen Consortium as further discussed in Ms. West's Direct Testimony.

2. **Mercury & Air Toxics Standards (Project 17):** The project recoverable cost variance is $33,121 or 87% lower than projected. This variance is primarily the result of a reduction in the level of mercury monitoring activities on Crystal River Units 4&5 as explained in Ms. West's Direct Testimony.

Q: Does the retirement of PEF's Crystal River 3 Nuclear Plant (CR3) impact any ECRC projects?

A: Yes, construction of the Thermal Discharge Permanent Cooling Tower is no longer necessary with the retirement of CR3.

Q: Please describe the Thermal Discharge Permanent Cooling Tower project.

A: The Commission approved recovery of capital and operating costs that PEF incurs to implement a permanent solution to ensure thermal discharge compliance through ECRC in Order PSC-08-0775-FOF-EI, Docket No. 080007-EI. A permanent cooling compliance solution was necessary to mitigate CR 1&2 environmental factors and the need for additional cooling brought about by conditions created by the implementation of the CR3 Extended Power Uprate (EPU) project. As discussed in the August 29, 2008 testimony of Daniel L. Roderick in Docket No. 080007, the permanent solution associated with the CR1&2 thermal discharge limit was undertaken in coordination with the CR3 Uprate project POD impacts as it made more sense to consider the project as a whole from an engineering perspective. Because the project had drivers with different recovery mechanisms, a portion of the project costs have been allocated to ECRC and the EPU driven costs have been allocated to the Nuclear Cost Recovery Clause (NCRC).

Q: How does PEF propose to treat unrecovered ECRC costs of the Thermal Discharge Permanent Cooling Tower?

A: Consistent with the Commission's treatment of NOx allowance costs in Docket No. 110007, PEF proposes that the Commission approve treating these costs, including any exit or wind-down costs, as a regulatory asset as of January 1, 2013 and allow PEF to amortize it equally over approximately three years until fully recovered by December 31, 2015. The unamortized investment balance should earn a return at PEF's WACC until such time as the investment is fully recovered. This is consistent with Order No. PSC-11-0553-FOF-EI, Docket No. 110007-EI, where the Commission established a regulatory asset to allow PEF to recover the costs of its remaining NOx allowance inventory over a three year period. The Commission held that PEF prudently incurred the costs for the NOx allowances but due to changing situations the allowances were no longer expected to have value. The proposed amortization of the unrecovered costs for the cooling tower will have no impact on 2013 rates. Any over/under-recovery will be part of the normal true-up process in the annual ECRC proceedings. Unrecovered ECRC Thermal Discharge Permanent Cooling Tower costs are approximately $18.1 million as of December 31, 2012.

Q: Are any of the alternative coal testing costs for which PEF seeks recovery included in the MFRs that PEF filed in its last ratemaking proceeding in Docket No. 090079-EI ?

A: No. These costs were not contemplated at the time of PEF's last base rate case and as such are not being recovered in PEF's base rates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 1, 2013

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A. Yes, I provided direct testimony on April 1, 2013.

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) estimated/actual true-up costs associated with environmental compliance activities for the period January 2013 through

COM 5
AFD 1
APA 1
ECO 1
ENG 5
GCL 1
IDM
TEL
CLK 1

December 2013. I also explain the variance between 2013 estimated/actual cost projections versus original 2013 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. __TGF-3, which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __TGF-4, which provides details of capital projects by site.

These exhibits provide detail on DEF's estimated/actual true-up capital and O&M environmental costs and revenue requirements for the period January 2013 through December 2013.

Q. What is the estimated/actual true-up amount for which DEF is requesting recovery for the period of January 2013 through December 2013?

A. The estimated/actual true-up amount for 2013 is an under-recovery, including interest, of $17,547,195 as shown in Exhibit No. __ (TGF-3), Form 42-1E, Line 4. This amount will be added to the final true-up under-recovery of $2,001,164 for 2012 shown on Form 42-2E, Line 7a, resulting in a net under-recovery of $19,548,359 as shown on Form 42-2E, Line 11. The calculations supporting the estimated true-up for 2013 are contained in Forms 42-1E through 42-8E.

Q. What capital structure, components and cost rates did DEF rely upon to calculate the revenue requirement rate of return for the period January 2013 through December 2013?

A. The capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return for the period January 2013 through December 2013 are shown on page 42-9E. Page 42-9E 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 included in Exhibit TGF-3. The schedule also cites all sources and includes the rationale for using the particular capital structure and cost rates.

Q. How do estimated/actual O&M expenditures for January 2013 through December 2013 compare with original projections?

A. Form 42-4E shows that total O&M project costs are projected to be approximately $10 million or 29% higher than originally projected. Significant O&M variances are discussed below.

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

1. Transmission and Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention (Project 1) - O&M

O&M expenditures for the substation system programs are estimated to be approximately $1.6 million or 66% higher than originally projected as discussed in the testimony of Mr. Corey Zeigler.

2. Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project 2) – O&M

O&M expenditures for the distribution system program are estimated to be approximately $79,000 or 42% lower than originally projected as discussed in the testimony of Mr. Zeigler.

3. Pipeline Integrity Management Program (Project 3) – O&M

O&M expenditures for the PIM program are expected to be approximately $221,000 or 37% lower than originally projected as dicusssed in the testimony of Ms. Patricia West.

4. Emissions Allowances (Project 5) – O&M

SO2 and NOx expenses are estimated to be approximately $630,000 or 22% higher than originally projected. This variance is primarily due to increased burns at Crystal River Units 1&2.

5. CAIR/CAMR – Peaking Program (Project 7.2) – O&M

O&M expenditures for the CAIR/CAMR – Peaking Program are estimated to be approximately $47,000 or 69% higher than originally projected as discussed in the testimony of Ms. West.

6. CAIR Crystal River - Energy (Project 7.4) – O&M

Total O&M expenditures are expected to be approximately $7.2 million or 26% higher than originally projected as discussed in the testimony of Mr. Swartz

7. Best Available Retrofit Technology Program (Project 7.5) – O&M

O&M costs for the BART Program are estimated to be approximately $12,000 or 74% lower than originally projected as discussed in the testimony of Ms. West.

8. Arsenic Groundwater Standard (Project 8) – O&M

O&M costs for the Arsenic Groundwater Standard are expected to be approximately $10,000 or 32% lower than originally projected as discussed in the testimony of Ms. West.

9. Sea Turtle – Coastal Street Lighting (Project 9) – O&M

O&M costs for the Sea Turtle Program are expected to be approximately $2,000 or 76% lower than originally projected as discussed in the testimony of Mr. Zeigler.

10. National Pollutant Discharge Elimination System - Energy (Project 16) – O&M

O&M costs for the NPDES Program are expected to be approximately $98,000 or 21% lower than originally projected as discussed in the testimony of Ms. West.

11. Mercury & Air Toxics Standards (MATS) Program – CR4&5 (Project 17) – O&M

O&M expenditures for the MATS – CR4&5 Program are expected to be approximately $198,000 higher than originally projected as discussed in the testimony of Ms. West.

12. Mercury & Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2) – O&M

O&M expenditures for the MATS – CR1&2 Program are expected to be approximately $786,000 as discussed in the testimony of Ms. West.

Q. How do estimated/actual capital recoverable costs for January 2013 through December 2013 compare with DEF's original projections?

A. Total recoverable capital costs itemized on Form 42-6E, are projected to be approximately $5.8 million or 3% higher than originally projected. Below are variance explanations for expenditures associated with capital investment projects with significant variances. The return on investment, depreciation and taxes for each project for the estimated/actual period are provided on Form 42-8E, pages 1 through 18.

Capital Investment Project Variances – Recoverable Costs

1. Pipeline Integrity Management Program (Project 3) - Capital

Capital expenditures for the PIM Program are expected to be approximately $1.1 million lower than originally projected. This decrease is due to the correction of prior year accounting adjustments. In February 2005, $0.59 million recorded in ECRC CWIP was reversed in the same month in a non-ECRC CWIP account. Consequently, this reversal was not reflected in ECRC as it was posted to non-ECRC CWIP. In April 2005, $0.51 million of PIM costs previously charged to ECRC CWIP in December 2003 were inadvertently charged again in January 2004 . DEF has reflected a $1.1 million credit to the PIM project in January 2013 and a total credit of $1.3 million to accumulated depreciation, return, and depreciation and property tax as shown on Exhibit TGF-4 page 2 of 24 Lines1b, 3, 7c and 8e, respectively. The January 2013 deferred ECRC under-recovered ECRC balance was offset by interest of approximately $52,000 associated with this credit as shown on Exhibit TGF-3 page 3 of 27 Line 6.

2. CAIR (Project 7.x) – Capital

Capital expenditures are estimated to be approximately $6.7 million or 145% higher for this program than originally projectedas discussed in the testimony of Mr. Swartz.

3. Sea Turtle – Coastal Street Lighting Program (Project 9)

Capital expenditures are estimated to be approximately $3,000 or 100% lower than originally projected as discussed in the testimony of Mr. Zeigler.

4. Thermal Discharge Permanent Cooling Tower (Project 11.1) – Capital

As explained in the petition filed in Docket No. 130007-EI and Docket 130091-EI, DEF announced on February 5, 2013 that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal loading resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary. For that reason, DEF is treating costs incurred of approximately $18.2 million for the project, including any future exit or wind-down costs, as a regulatory asset as of January 1, 2013, and amortizing it over three years until fully recovered by December 31, 2015, with a return on the unamortized balance.

5. National Pollutant Discharge Elimination System (NPDES) (Project 16) - Capital

Capital expenditures for the NPDES Program are expected to be approximately $9.3 million higher than originally projected as discussed in the testimony of Ms. West.

6. Mercury & Air Toxics Standards (MATS) Program – CR4&5 (Project 17) - Capital

Capital expenditures for MATS – CR4&5 are expected to be approximately $9.6 million or 96% lower than originally projected as discussed in the direct testimony of Ms. West.

7. Mercury & Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2) - Capital

Capital expenditures for MATS – CR1&2 Program are shown to be approximately $194,000 higher than originally projected as discussed in the testimony of Ms. West.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

AUGUST 30, 2013

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013 and August 1, 2013.

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's (DEF or Company) calculation of revenue requirements and Environmental Cost Recovery Clause (ECRC) factors for customer billings for the period January 2014 through December 2014. My testimony addresses capital and O&M expenses associated with DEF's environmental compliance activities for the year 2014.

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

The following individuals are co-sponsors of Forms 42-5P pages 1 through 21 as indicated in their testimony:

- Mr. Zeigler will co-sponsor Forms 42-5P pages 1, 2 and 10.
- Ms. West will co-sponsor Forms 42-5P pages 3, 4, 6, 8, 9, 11, 12, 13, 14, 15, 16, 17, 18, and 19.
- Mr. Swartz and Ms. West will co-sponsor Form 42-5P page 7.
- Mr. Hellstern will co-sponsor Form 42-5P page 20.
- Mr. Swartz will co-sponsor Form 42-5P page 21.

Q. What is the total recoverable revenue requirement relating to the projection period January 2014 through December 2014?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is approximately $87.1 million as shown on Form 42-1P, Line 5 of Exhibit No. __(TGF-5).

Q. What is the total true-up to be applied for period January 2014 through December 2014?

A. The total true-up applicable for this period is an under-recovery of approximately $19.5 million. This consists of the final true-up under-recovery of approximately $2 million for the period from January 2012 through December 2012 and an estimated true-up under-recovery of approximately $17.5 million for the current period of January 2013 through December 2013. The detailed calculation supporting the 2013 estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (TGF-3) filed with the Commission on August 1, 2013.

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

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

The Substation and Distribution System O&M programs (Project 1 & 2) were previously approved by the Commission in Order No. PSC-02-1735-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-03-1348-FOF-EI.

The recovery of sulfur dioxide (SO_2) Emission Allowances (Project 5) was previously approved in Order No. PSC-95-0450-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.

The Phase II Cooling Water Intake 316(b) Program (Project 6) was previously approved in Order No. PSC-04-0990-PAA-EI.

DEF's Integrated Clean Air Compliance Plan (Project 7) approved by the Commission as a prudent and reasonable means of complying with CAIR and related regulatory requirements in Order No. PSC-07-0922-FOF-EI.

The Arsenic Groundwater Standard Program (Project 8), the Sea Turtle Lighting Program (No. 9), and the Underground Storage Tanks Program (No. 10) were previously approved in Order No. PSC-05-1251-FOF-EI.

The Modular Cooling Tower Program (Project 11) was previously approved by the Commission in Order No. PSC-07-0722-FOF-EI.

The Crystal River Thermal Discharge Compliance Project (Project 11.1) and the Greenhouse Gas Inventory and Reporting Project (Project 12) were previously approved in Order No. PSC-08-0775-FOF-EI.

The Total Maximum Daily Loads for Mercury Project (Project 13) was previously approved in Order No. PSC-09-0759-FOF-EI.

The Hazardous Air Pollutants (HAPs) ICR Project (Project 14) was previously approved in Order No. PSC-10-0099-PAA-EI.

The Effluent Limitations Guidelines ICR Project (Project 15) was previously approved in Order No. PSC-10-0683-PAA-EI.

National Pollutant Discharge Elimination System (NPDES) (Project 16) was previously approved in Order No. 11-0553-FOF-EI.

Mercury & Air Toxic Standards (MATS) (Project 17) which replaces Maximum Achievable Control Technology (MACT) was previously approved in Order No. 11-0553-FOF-EI and Order No. PSC-12-0432-PAA-EI.

Q. Are costs that were incurred by DEF for the Thermal Discharge Permanent Cooling Tower (No. 11.1) being treated in accordance with Order No. PSC-13-0381-PAA-EI?

A. Yes. DEF announced on February 5, 2013 that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal load resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary. For that reason, DEF is treating costs of approximately $18.2 million incurred for the project, including any future exit or wind-down costs, as a regulatory asset as of January 1, 2013, and amortizing it over three years until fully recovered by December 31, 2015, with a return on the unamortized balance. The Commission approved this treatment in Order No. PSC-13-0381-PAA-EI.

Q. What capital structure, components and cost rates did DEF rely upon to calculate the revenue requirement rate of return for the period January 2014 through December 2014?

A. DEF used the capital structure, components, and cost rates consistent with the language in Order No. PSC-12-0425-PAA-EU. As such, DEF used the rates contained in its May 2013 Earnings Surveillance Report Weighted Average Cost of Capital. These rates are shown on Form 42-8P, Exhibit No. ___(TGF-5). Form 42-8P includes the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b).

Q. What effect does the Stipulation and Settlement Agreement in Order No. PSC-12-0104-FOF-EI and the 2013 Revised and Restated Stipulation and Settlement Agreement in Docket No. 130208, subject to approval by the Commission, have on the CAIR investments presented in this Docket?

A. As I described in my direct testimony dated August 30, 2012 in Docket No. 120007-EI, pursuant to the Stipulation and Settlement Agreements, DEF disaggregated Project 7.4 CAIR assets that were projected to be in service by year end 2013 from those that were not expected to be in-service. The provision of the Stipulation and Settlement Agreement that provided authority for this disaggregation has been carried forward into the Revised and Restated Stipulation and Settlement Agreement. Specifically, paragraph 14 of both the Settlement Agreement and Revised and Restated Stipulation and Settlement Agreement states that effective with the first billing cycle of January 2014, DEF is authorized to remove capital assets installed and in-service on the Crystal River Units 4 & 5 power plants to comply with the Federal Clean Air Interstate Rule (CAIR) from the ECRC and transfer those capital assets to base rates in an amount equal to the annual retail revenue requirements of the assets projected to be in-service as of December 31, 2013 (excluding O&M related costs) which was reflected in the Company's filing (Form 42-4P; Project 7.4, Page 8 of 17) in Docket 120007-EI in Exhibit__(TGF-3). The investments not projected to be in-service at year end 2013 continue to be recovered through the ECRC in future dockets and are included on Form 42-4P page 8 of 17 in Exhibit_(TGF-5).

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2014?

A. Yes. Form 42-2P contained in Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional O&M cost estimates for these projects of approximately $41.8 million.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2014?

A. Yes. Form 42-3P contained in Exhibit No. __ (TGF-5) summarizes recoverable jurisdictional capital cost estimates for these projects of approximately $25.7 million. Form 42-4P, pages 1 through 17, shows 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 21, contained in Exhibit No. __ (TGF-5) provide a description, progress, and recoverable cost estimates for each project.

Q. What is the total projected jurisdictional costs for environmental compliance projects for the year 2014?

A. Total jurisdictional capital and O&M costs of approximately $67.5 million to be recovered through the ECRC are calculated on Form 42-1P, Line 1c of Exhibit No. __ (TGF-5).

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

A. The ECRC factors are calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No. __(TGF-5). The demand component of class allocation factors are 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 July 2012. 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 2014 ECRC billing factors by the various rate classes and delivery voltages?

A. The computation of DEF's proposed ECRC factors for 2014 customer billings is shown on Form 42-7P in Exhibit No. __(TGF-5). These factors are as follows:

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.243 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.236 cents/kWh
@ Primary Voltage	0.234 cents/kWh
@ Transmission Voltage	0.231 cents/kWh
General Service 100% Load Factor	0.206 cents/kWh
General Service Demand	
@ Secondary Voltage	0.221 cents/kWh
@ Primary Voltage	0.219 cents/kWh
@ Transmission Voltage	0.217 cents/kWh
Curtailable	
@ Secondary Voltage	0.294 cents/kWh
@ Primary Voltage	0.291 cents/kWh
@ Transmission Voltage	0.288 cents/kWh
Interruptible	
@ Secondary Voltage	0.201 cents/kWh
@ Primary Voltage	0.199 cents/kWh
@ Transmission Voltage	0.197 cents/kWh
Lighting	0.183 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 2014 and continue through the last bill group for December 2014.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average ECRC billing factor of 0.232 cents per kWh which includes projected jurisdictional capital and O&M revenue requirements for the period January 2014 through December 2014 of approximately $67.5 million associated with a total of 17 environmental projects, and a true-up under-recovery provision of approximately $19.5 million from prior periods. My testimony also demonstrates that projected environmental expenditures for 2014 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS G. FOSTER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 1, 2013

(Revised OCTOBER 7, 2013)

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A. Yes, I provided direct testimony on April 1, 2013.

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) estimated/actual true-up costs associated with environmental compliance activities for the period January 2013 through December 2013. I also explain the variance between 2013 estimated/actual cost projections versus original 2013 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. __TGF-3R, which consists of PSC Forms 42-1E through 42-9E; and
2. Exhibit No. __TGF-4R, which provides details of capital projects by site.

These exhibits provide detail on DEF's estimated/actual true-up capital and O&M environmental costs and revenue requirements for the period January 2013 through December 2013.

Q. What is the estimated/actual true-up amount for which DEF is requesting recovery for the period of January 2013 through December 2013?

A. The estimated/actual true-up amount for 2013 is an under-recovery, including interest, of $17,567,172 as shown in Exhibit No. __ (TGF-3R), Form 42-1E, Line 4. This amount will be added to the final true-up under-recovery of $2,001,164 for 2012 shown on Form 42-2E, Line 7a, resulting in a net under-recovery of $19,568,337 as shown on Form 42-2E, Line 11. The calculations supporting the estimated true-up for 2013 are contained in Forms 42-1E through 42-8E.

Q. What capital structure, components and cost rates did DEF rely upon to calculate the revenue requirement rate of return for the period January 2013 through December 2013?

A. The capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return for the period January 2013 through December 2013 are shown on page 42-9E. Page 42-9E 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 included in Exhibit TGF-3R. The schedule also cites all sources and includes the rationale for using the particular capital structure and cost rates.

Q. How do estimated/actual O&M expenditures for January 2013 through December 2013 compare with original projections?

A. Form 42-4E shows that total O&M project costs are projected to be approximately $10 million or 29% higher than originally projected. Significant O&M variances are below.

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

1. Transmission and Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention (Project 1) - O&M

O&M expenditures for the substation system programs are estimated to be approximately $1.6 million or 66% higher than originally projected as discussed in the testimony of Mr. Corey Zeigler.

2. Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project 2) – O&M

O&M expenditures for the distribution system program are estimated to be approximately $79k or 42% lower than originally projected as discussed in the testimony of Mr. Zeigler.

3. Pipeline Integrity Management Program (Project 3) – O&M

O&M expenditures for the PIM program are expected to be approximately $221k or 37% lower than originally projected as dicusssed in the testimony of Ms. Patricia West.

4. Emissions Allowances (Project 5) – O&M

SO2 and NOx expenses are estimated to be approximately $633k million or 22% higher than originally projected. This variance is primarily due to increased burns at Crystal River Units 1&2.

5. CAIR/CAMR – Peaking Program (Project 7.2) – O&M

O&M expenditures for the CAIR/CAMR – Peaking Program are estimated to be approximately $47k or 69% higher than originally projected as discussed in the testimony of Ms. West.

6. CAIR Crystal River - Energy (Project 7.4) – O&M

Total O&M expenditures are expected to be approximately $7.2 million or 26% higher than originally projected as discussed in the testimony of Mr. Swartz

7. Best Available Retrofit Technology Program (Project 7.5) – O&M

O&M costs for the BART Program are estimated to be approximately $12k or 74% lower than originally projected as discussed in the testimony of Ms. West.

8. Arsenic Groundwater Standard (Project 8) – O&M

O&M costs for the Arsenic Groundwater Standard are expected to be approximately $10k or 32% lower than originally projected as discussed in the testimony of Ms. West.

9. Sea Turtle – Coastal Street Lighting (Project 9) – O&M

O&M costs for the Sea Turtle Program are expected to be approximately $2k or 76% lower than originally projected as discussed in the testimony of Mr. Zeigler.

10. National Pollutant Discharge Elimination System - Energy (Project 16) – O&M

O&M costs for the NPDES Program are expected to be approximately $98k or 21% lower than originally projected as discussed in the testimony of Ms. West.

11. Mercury & Air Toxics Standards (MATS) Program – CR4&5 (Project 17) – O&M

O&M expenditures for the MATS – CR4&5 Program are expected to be approximately $198k higher than originally projected as discussed in the testimony of Ms. West.

12. Mercury & Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2) – O&M

O&M expenditures for the MATS – CR1&2 Program are expected to be approximately $786k as discussed in the testimony of Ms. West.

Q. How do estimated/actual capital recoverable costs for January 2013 through December 2013 compare with DEF's original projections?

A. Total recoverable capital costs itemized on Form 42-6E, are projected to be approximately $5.8 million or 3% higher than originally projected. Below are variance explanations for expenditures associated with capital investment projects with significant variances. The return on investment, depreciation and taxes for each project for the estimated/actual period are provided on Form 42-8E, pages 1 through 18.

Capital Investment Project Variances – Recoverable Costs

1. Pipeline Integrity Management Program (Project 3) - Capital

Capital expenditures for the PIM Program are expected to be approximately $1.1 million lower than originally projected. This decrease is due to the correction of prior year accounting adjustments. In February 2005, $0.59 million recorded in ECRC CWIP was reversed in the same month in a non-ECRC CWIP account. Consequently, this reversal was not reflected in ECRC as it was posted to non-ECRC CWIP. In April 2005, $0.51 million of PIM costs previously charged to ECRC CWIP in December 2003 were inadvertently charged again in January 2004 . DEF has reflected a $1.1 million credit to the PIM project in January 2013 and a total credit of $1.3 million to accumulated depreciation, return, and depreciation and property tax as shown on Exhibit TGF-4R page 2 of 23 Lines1b, 3, 7c and 8e, respectively. The January 2013 deferred ECRC under-recovered ECRC balance was offset by interest of approximately $52k associated with this credit as shown on Exhibit TGF-3R page 3 of 27 Line 6.

2. CAIR (Project 7.x) – Capital

Capital expenditures are estimated to be approximately $9.0 million or 194% higher for this program than originally projected as discussed in the testimony of Mr. Swartz.

3. Sea Turtle – Coastal Street Lighting Program (Project 9)

Capital expenditures are estimated to be approximately $3k or 100% lower than originally projected as discussed in the testimony of Mr. Zeigler.

4. Thermal Discharge Permanent Cooling Tower (Project 11.1) – Capital

As explained in the petition filed in Docket No. 130007-EI and Docket 130091-EI, DEF announced on February 5, 2013 that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal loading resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary. For that reason, DEF is treating costs incurred of approximately $18.2 million for the project, including any future exit or wind-down costs, as a regulatory asset as of January 1, 2013, and amortizing it over three years until fully recovered by December 31, 2015, with a return on the unamortized balance.

5. National Pollutant Discharge Elimination System (NPDES) (Project 16) - Capital

Capital expenditures for the NPDES Program are expected to be approximately $9.3 million higher than originally projected as discussed in the testimony of Ms. West.

6. Mercury & Air Toxics Standards (MATS) Program – CR4&5 (Project 17) - Capital

Capital expenditures for MATS – CR4&5 are expected to be approximately $9.6 million or 96% lower than originally projected as discussed in the direct testimony of Ms. West.

7. Mercury & Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2) - Capital

Capital expenditures for MATS – CR1&2 Program are shown to be approximately $194k higher than originally projected as discussed in the testimony of Ms. West.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>COREY ZEIGLER</u>

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

April 1, 2013

Q. Please state your name and business address.

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Progress Energy Florida (PEF) as the Environmental Health and Safety Manager for Transmission and Distribution.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include providing oversight and subject matter expert resources to the Transmission and Distribution Business Units for managing Environmental Health and Safety (EH&S) compliance.

Q. Please describe your educational background and professional experience.

COM 5
AFD 1
APA 1
ECO 1
ENG 4
GCL 1
IDM
TEL
CLK 1-Ct Rep

A. I received a Bachelors of Science degree in General Business Administration and Management from the University of South Florida. Prior to my current EH&S Manager role, I was the Environmental Permitting and Compliance Manager for Energy Delivery. I have 22 years experience in the utility industry holding various operational, supervisor and managerial roles at PEF.

Q. **Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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 estimated/actual project expenditures for environmental compliance costs associated with PEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) and Sea Turtle Coastal Street Lighting Program (Project 9) for the period January 2012 through December 2012.

Q. **How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits for the Substation System Program?**

A. The project expenditure variance for the Substation System Program is $1,472,647 or 28% lower than projected. This variance is attributable to the inability to conduct scheduled remediation at some substation sites during the course of 2012 for one of three reasons: (1) inability to take an outage for load/reliability reasons; (2) need to purchase/obtain additional parts to complete the repairs; and (3) unusually high rain events which precluded returning to several substation sites for further remediation. The substation primarily responsible for this variance is Windermere, where remediation work was ceased for an entire month during 2012 due to high water tables.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits for the Distribution System Program?

A. The project expenditure variance for the Distribution System Program is $146,745 or 28% lower than projected. A total of 13 transformer sites were scheduled for abatement work in 2012. The variance is attributable to the determination that no further action was necessary at 9 sites due to clean deviation sampling lab results, and the delay of further action at 4 contaminated sites until 2013. The 4 sites will be re-sampled or monitored quarterly throughout 2013 to determine if additional remediation is required.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's estimated/actual projections as presented in

previous testimony and exhibits for the Sea Turtle Coastal Street Lighting Program?

A. The project expenditure variance for the Sea Turtle Coastal Street Lighting Program is $2,304 or 92% lower than projected. This variance is due to delay with the University of Florida and PEF performing additional testing of Florida Wildlife Commission's recommended LED technology for new installations which is considered turtle compliant.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

<u>COREY ZEIGLER</u>

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 1, 2013

Q. Please state your name and business address.

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013.

COM 5
AFD 1
APA 1
ECO 1
ENG 5
GCL 1
IDM
TEL
CLK 1

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 2013 estimated/actual cost projections versus original 2013 cost projections for environmental compliance costs associated with the FPSC-approved environmental programs under my responsibility. These programs include the Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Projects 1 & 1a), Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2) and Sea Turtle – Coastal Street Lighting (Project 9).

Q. **Please explain the variance between the estimated/actual project expenditures and original projections for the Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a) for the period January 2013 to December 2013.**

A. O&M expenditures for the substation system programs are estimated to be $1.6 million or 66% higher than originally projected. This increase is primarily attributable to ongoing remediation work at Windermere substation and contaminated soil at Turner Plant substation which was not evident during initial environmental inspections. Because contamination is below ground, it is difficult to determine remediation costs at substation sites until the remediation process is underway. Although visible inspections provide some indication of the potential amount of contamination, the areal extent and depth of subsurface contamination can only be determined when the site is excavated. Also, the amount of soil that needs to be removed to achieve FDEP clean-up target levels depends on the results of tests conducted in the field as remediation is performed.

Q. Please explain the variance between estimated/actual project expenditures and original projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) for the period January 2013 to December 2013.

A. O&M expenditures for the distribution system program are estimated to be $79,000 or 42% lower than originally projected. This decrease is primarily due to a reduction in remaining transformer sites planned for abatement work in 2013 from nine (9) to five (5).

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Sea Turtle – Coastal Street Lighting Program (Project 9) for the period January 2013 to December 2013.

A: O&M project expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $2,000 or 76% lower than originally projected. The University of Florida and DEF expected to perform additional testing of Florida Wildlife Commission's recommended LED technology for new installations that was not necessary because the LED technology is considered turtle compliant.

Capital expenditures for the Sea Turtle – Coastal Street Lighting Program are estimated to be $3,000 or 100% lower than originally projected due to a delay in installing or retrofitting several streetlight fixtures in Pinellas County and Mexico Beach.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 30, 2013

Q. Please state your name and business address.

A. My name is Corey Zeigler. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013 and August 1, 2013.

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 the year 2014 for Duke Energy Florida's (DEF or Company)

Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) and the Sea Turtle Coastal Street Lighting Program (Project 9).

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 the schedule Exhibit No._ (TGF-5) to Thomas G. Foster's direct testimony:

- 42-5P page 1 of 21 - Substation Environmental Investigation, Remediation, and Pollution Prevention.
- 42-5P page 2 of 21 - Distribution System Environmental Investigation, Remediation, and Pollution Prevention.
- 42-5P page 10 of 20 - Sea Turtle - Coastal Street Lighting.

Q. What costs does DEF expect to incur in 2014 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. DEF estimates O&M costs of approximately $1.9 million at 38 sites for the Substation System Investigation, Remediation and Pollution Prevention Program.

Q. What steps is the Company taking to ensure that the level of expenditures for the Substation System Program is reasonable and prudent?

A. DEF works annually with the Florida Department of Environmental Protection (FDEP) to determine specific substation sites to remediate to ensure compliance with FDEP criteria. To ensure the level of expenditures is reasonable and prudent, DEF closely monitors remediation work and provides quarterly reports to the FDEP on progress made remediating sites.

Q. What costs does DEF expect to incur in 2014 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. DEF estimates O&M costs of approximately $16,000 to perform remediation at 1 site and monitoring at 5 sites for the Distribution System Investigation, Remediation and Pollution Prevention Program. This estimate assumes 1 single-phase transformer site at an average cost of $10,800 per site and deviation sampling costs of $1,000 per site at 5 sites. The average cost per site was based upon DEF's analysis of the prior two years of invoices associated with the remediation of transformer sites.

Q. What steps is the Company taking to ensure that the level of expenditures for the Distribution System program is reasonable and prudent?

A. To ensure the level of expenditures is reasonable and prudent, DEF closely monitors remediation work and provides quarterly reports to the FDEP on progress made remediating sites.

Q. What costs does DEF expect to incur in 2014 in connection with the Sea Turtle/Street Lighting Program (Project 9)?

A. DEF estimates capital and O&M expenses of approximately $2,100 and $500, respectively, for the Sea Turtle/Street Lighting Program to ensure compliance with sea turtle ordinances in Franklin, Gulf, and Pinellas Counties and the City of Mexico Beach.

Q. What steps is the Company taking to ensure that the level of expenditures for the Sea Turtle/Street Lighting Program is reasonable and prudent?

A. DEF cooperates with local governments and regulatory agencies to develop compliance plans that allow flexibility to make only those modifications necessary to achieve compliance. DEF ensures that evaluation of each streetlight requiring modification occurs so that only those activities necessary to achieve compliance are performed in a reasonable and prudent manner. In addition, DEF evaluates emerging technologies and incorporates their use where reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MARK HELLSTERN

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

August 1, 2013

Q. Please state your name and business address.

A. My name is Mark Hellstern. My business address is 1729 Bailles Bluff Rd., Holiday, FL 34691.

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

A. I am employed by Duke Energy Florida, Inc. ("DEF" or the "Company") as the Project Director for the Anclote Gas Conversion Project.

Q. What are your responsibilities in that position?

A. My responsibilities entail major project planning and execution, including oversight, construction, commissioning and start up. My primary duties involve managing engineering activities to ensure project scope is accurate and complete, providing input to estimate development, assisting in the development of project execution and contracting strategies, and providing input to the overall project schedules and oversight of construction execution. These duties are relevant to projects that emerge from system planning and environmental planning activities where specific projects are identified as viable projects that will move forward into funding, contracting, design, construction and startup phases. Our group generally accommodates projects in excess of $50 million in value.

Q. Please describe your educational background and professional experience.

A. I started with Duke Energy in December 2011 as the Major Project Manager for the Crystal River 3 Containment Repair Project, and was responsible for managing engineering activities, estimate development, scope certainty, project staffing and management, options analysis, and contract negotiations and selection of vendors to repair the containment structure. In late 2012, I assumed a rotational assignment as Manager, Project Governance in support of building project management governance and processes for the newly merged company. I assumed the position as Project Director for the Anclote Gas Conversion Project in late June 2013 due to George Hixon's retirement. Previously, from 2009-2011, I was employed by Tennessee Valley Authority as General Manager, Nuclear Generation Development and Construction (NGDC) for Quality and Construction Oversight. In this capacity, I was responsible for the development and implementation of nuclear construction quality programs, construction oversight, and project management processes. I had oversight of the Watts Bar II Completion Project, Bellefonte Completion Project, and Major Nuclear Outages over $100 million. In a rotational leadership assignment, I was also the Senior Manager, Project Support and Infrastructure, for the Bellefonte Nuclear Plant Construction Completion Project. In 2009, I retired as a Captain in the US Navy after 26 years of service. In my last assignment, from 2006-2009, I was the Senior Advisor to the Director, Naval Reactors, for Aircraft Carrier Operations and Fleet Training Initiatives and was the Senior Naval Officer charged with oversight of the Navy's 11 nuclear aircraft carriers for safe operations, maintenance, construction, and refueling including the training programs for over 1500 nuclear operators. I served in 8 ships through 11 combat deployments and commanded the USS HAYLER (DD 997). I have led or had leadership roles in shipbuilding and commercial projects ranging from $3 million to $5 billion. I served in the Pentagon as the Secretary of Defense Deputy Director for Asian and Pacific Affairs and as the Executive Assistant to the Principle Deputy Secretary of Defense for Policy. I hold a BS in Marine Engineering from the US Naval Academy and an MS in Physics with Distinction from the US Naval Postgraduate School. I am a distinguished graduate of the Air Command and Staff College and was the Senior Military Fellow at MIT in Security Studies.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an update on the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1).

Q. What has been your role in the Anclote Gas Conversion Project?

A. I transitioned into the role as Project Manager for the Anclote Gas Conversion Project in late June 2013. I worked with Mr. George Hixon, the previous Project Manager, to ensure efficient transition. Like Mr. Hixon, I am responsible for overall construction management and review of engineering studies, schedules and estimates to ensure the project is accurately defined, and an adequate timeline for the project is executed. . In addition, I work with others in the organization to lead internal contract planning and strategy efforts, and work with supply change to contract boiler modification work and balance of plant (BOP) engineering services.

Q: Did you review the Direct Testimony of Mr. George Hixon filed in this docket on April 1, 2013?

A: Yes, and I will be adopting that testimony on behalf of the Company. I have personal knowledge of the facts that Mr. Hixon discussed in his testimony due to my previous oversight role as Manager, Project Governance and participation in monthly review meetings with Mr. Hixon's project team. Mr. Hixon and I had a thorough transition, and I have a full understanding of the scope and execution of the project.

Q. What costs do you expect to incur in 2013 in connection with the MATS – Anclote Gas Conversion Project (Project 17.1)?

A. We currently expect to incur approximately $64.7 million of costs for the project in 2013. Such costs include contractor mobilization; some permitting activities;

BOP detailed engineering services and equipment procurement; boiler controls engineering; procurement of boiler equipment, associated engineering, materials, and components needed to complete conversion of Unit 1 and Unit 2; actual field engineering and contractor construction execution costs for Unit 1 and BOP scope; construction execution for Unit 2 gas conversion; and detailed engineering and procurement of components needed to modify and upgrade the natural gas metering and regulating station and Force Draft (FD) Fan modification.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the MATS – Anclote Gas Conversion Program (Project 17.1) for the period January 2013 to December 2013.

A. We currently expect to incur $16.8 million more for 2013 than originally projected in DEF's 2013 Projection Filing. This variance is primarily attributable to scope changes in the boiler and electrical commodities for Unit 1 and BOP due to unexpected "as found" conditions which required engineering and field modifications to complete the additional scope of work for Unit 1 and BOP. Additionally, as engineering matured for the Fan Modification Scope, procurement costs and estimated installation costs increased. The Unit 1 Gas Conversion was completed and placed into commercial service on July 13, 2013. The Unit 2 Gas Conversion is expected to be completed and placed into service in December 2013.

Q. Does the Anclote Gas Conversion Project remain on schedule to meet its targeted in-service date?

A. Yes, consistent with the schedule set forth in Mr. Hixon's April 1, 2013 testimony, the Unit 1 Gas Conversion was completed on July 13, and DEF continues to expect that Unit 2 will be fully converted to natural gas by mid-December 2013. DEF also anticipates that it will complete installation of the FD fans in early second quarter 2014.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MARK HELLSTERN

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

August 30, 2013

Q. Please state your name and business address.

A. My name is Mark Hellstern. My business address is 1729 Bailles Bluff Rd., Holiday, Florida, 34691.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A. Yes, I provided direct testimony on August 1, 2013.

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 the Mercury and Air Toxics Standards (MATS) - Anclote Gas Conversion Project (Project 17.1), specifically the projected costs that the Company will incur on this project in 2014.

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. __ (TGF-5) to Thomas G Foster's testimony:

- 42-5P page 20 - Mercury & Air Toxic Standards (MATS) - Anclote Gas Conversion.

Q. What are the estimated total project costs for the MATS – Anclote Gas Conversion Project (Project 17.1)?

A. The Company's current project estimate to complete is approximately $126.5 million. This estimate is higher than the $94.3 million estimate provided in the April 1, 2013 testimony of Mr. Hixon, which I am adopting due to Mr. Hixon's retirement. The increased costs are primarily attributable to the need for new FD fans discussed in Mr. Hixon's testimony, as well as the additional scope changes necessary to address "as found" boiler conditions and other scope increases for the gas conversion as discussed in my testimony of August 1, 2013.

Q. What costs do you expect to incur in 2014 in connection with the MATS – Anclote Gas Conversion Project (Project 17.1)?

A. We currently expect to incur approximately $33.4 million of costs for the project in 2014. Such costs will be incurred for: contractor mobilization; some permitting activities; FD Fan Modification detailed engineering services; BOP engineered equipment procurement for the FD Fan Modification scope; some construction completion costs for Unit 2 gas conversion; field engineering, contractor construction execution, and remaining procurement of components for the FD Fan Modification.

Q. Does the Anclote Gas Conversion Project remain on schedule to meet its targeted in-service date?

A. Yes, as indicated in my August 1, 2013 testimony, most of the Unit 1 work was completed on July 13, 2013 and DEF continues to expect that most of the Unit 2 work will be completed by mid-December 2013. As described above, there is still work that needs to be done in 2014 primarily related to FD fan modifications.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

April 1, 2013

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 the Environmental Services and Strategy Department of Progress Energy Florida (PEF) as Manager of Generation Environmental Field Support Services.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include ensuring that environmental technical and regulatory support is provided during the development and implementation of environmental compliance strategies for power generation 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 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 when I assumed my current position as Manager of Generation Field Support Services.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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 the actual project expenditures and estimated/actual cost projections for environmental compliance costs associated with PEF's Pipeline Integrity Management (PIM) Program (Project 3), aspects of PEF's Integrated Clean Air Compliance Program within my area of responsibility (Project 7.2), Best Available Retrofit Technology (BART) (Project 7.5), National Pollutant Discharge Elimination System (NPDES) (Project 16) and Mercury & Air Toxics Standards (MATS) –

CR 4&5 (Project 17) for the period January 2012 through December 2012. In addition, I am co-sponsoring Exhibit No. __ (PQW-1), PEF's review of the efficacy of its Integrated Clean Air Compliance Plan and retrofit options in relation to expected environmental regulations, as outlined in sections I, II, III, IV (parts A and B.3), V and VI. Mr. Ben Borsch is sponsoring section IV (parts B, 1 and 2, C and D). These sections of the exhibits are true and accurate.

Q. Please explain the variance between actual project expenditures and estimated/actual projections for Pipeline Integrity Management (PIM) for the period January 2012 to December 2012.

A. Pipeline Integrity Management operation and maintenance (O&M) costs were $1,124,385 or 81% lower than the Estimated/Actual Filing. This variance is primarily due to the cancellation of a substantial number of "5 year assessment" projects and postponement of two major "Florida Department of Transportation (FDOT) highway support" projects. The "5 year assessment" projects were cancelled given the planned Anclote Gas Conversion and limited need to operate the pipeline. PEF decided to reduce the Maximum Operating Pressure (MOP) of the pipeline from 960 psig to 450 psig to decrease O&M costs and preserve pipeline safety in conjunction with operating restrictions. Reducing the MOP allows PEF to still use the pipeline during any period of time when there may be a need to transfer oil to the Anclote station. PEF discussed the regulatory implications of this decision with the U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) auditor during the May 2012 audit of the Pipeline Programs. The "FDOT highway support" projects planned for later 2012 were subsequently postponed by FDOT until 2013.

Q. Please explain the variance between actual project expenditures and estimated/actual projections for the CAIR Combustion Turbine Predictive Emissions Monitoring Systems for the period January 2012 to December 2012.

A. The CAIR Combustion Turbine Predictive Emissions Monitoring Systems O&M costs were $37,365 or 27% lower than the Estimated/Actual Filing. This variance is primarily attributed to the payments for air emissions testing performed at Bartow and Higgins stations in accordance with 40 CFR Part 75, Appendix E being made in 2013 instead of 2012 as originally projected in the Estimated/Actual Filing.

Q. Please explain the variance between actual project expenditures and estimated/actual projections for Best Available Retrofit Technology (BART) for the period January 2012 to December 2012.

A. BART O&M costs were $50,468 or 187% higher than the Estimated/Actual Filing. This variance is attributed to legal and environmental consulting services required to support negotiations with the FDEP to obtain necessary permits for Crystal River Units 1 and 2. The need to perform sulfur dioxide (SO_2) emissions modeling is in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the Environmental Protection Agency. The need for this type of effort was referenced in the May 14, 2012 update of PEF's

Integrated Clean Air Compliance Plan, and my August 1, 2012 Direct Testimony and Exhibit No. PQW-1 (page 9) in Docket 120007-EI.

Q. Please explain the variance between actual project expenditures and estimated/actual projections for the NPDES project for the period January 2012 to December 2012.

A. NPDES O&M costs were $50,229 or 22% lower than the Estimated/Actual Filing. This variance is attributable to FDEP changes to and approval of a plan of studies (POS) for cooling water intake investigations being conducted at the Suwannee, Anclote and Bartow power stations in accordance with Section 316(a) of the Clean Water Act. Suwannee's POS sampling schedule was reorganized to incorporate 2012 winter sampling events. Anclote's POS has not been approved by FDEP. Bartow's POS was approved during the third quarter of 2012 and implemented during the fourth quarter of 2012.

NPDES recoverable capital costs were $24,166 or 45% lower than the Estimated/Actual Filing. This variance is the result of a delay in the project to allow for nitrogen Waste Load Allocation (WLA) approval from the Tampa Bay Nitrogen Consortium. This approval was necessary for FDEP to approve the substantial NPDES permit modification for the installation of an internal surface water outfall for discharge of process wastewater at the Bartow power station. PEF submitted a permit modification application to FDEP in September 2012, and the WLA was issued in October 2012. FDEP issued a draft permit modification to PEF in January 2013 with a final permit expected early in the second quarter of 2013.

Q. Please explain the variance between actual project expenditures and estimated/actual projections for MATS for the period January 2012 to December 2012.

A. MATS recoverable capital costs were $33,121 or 87% lower than the Estimated/Actual Filing. This variance is primarily the result of a reduction in the level of mercury monitoring activities on Crystal River Units 4 and 5 from what was included in the Estimated/Actual Filing. Monitoring of mercury emission levels via the use of carbon traps was determined to be acceptable for the purpose of initial data acquisition to assess the units' emissions so that compliance options could be evaluated. Therefore, no additional monitoring system equipment was installed in 2012. Assessment of mercury and other pollutants regulated by MATS is ongoing and PEF will continue to apprise the Commission on the progress of these assessments and any compliance actions that may be required. This will include the evaluation of any additional monitoring system equipment that may be necessary to monitor, report and/or comply with MATS.

Q. In Order No. PSC 10-0683 -FOF-EI issued in Docket 100007-EI on November 15, 2010, the Commission directed PEF 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 PEF's retrofit options for each generating unit in

relation to expected changes in environmental regulations." Has PEF conducted such a review?

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

Q: Is PEF evaluating any options to extend the operation of Crystal River Units 1 and 2 beyond the MATS compliance dates?

A: Yes. PEF is evaluating alternative fuel options that would allow Crystal River Units 1 and 2 to continue operating in compliance with MATS for a limited period of time. PEF plans to schedule and obtain permits for operational tests in 2013 to determine how the units perform with alternative coals. If these tests are successful, it may be possible for PEF to extend Crystal River Units 1 and 2 operations to the 2018-2020 timeframe in compliance with MATS.

Q: What is the estimated cost of alternative coals testing?

A: The preliminary cost estimate to perform alternative coal trials on Crystal River Units1 and 2 is about $1 million. A refined cost estimate will be provided to the Commission as part of the 2013 ECRC Estimated/Actual filing.

Q: When would alternative coals testing costs be incurred?

A: PEF expects to incur all costs for the alternative coal trials in 2013.

Q: How would these costs be recovered?

A: Consistent with the Petition filed simultaneously with this testimony, PEF proposes to recover costs for alternative coal testing on Crystal River Units 1 and 2 through the ECRC consistent with other MATS activities.

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

A: PEF installed emission controls contemplated in its CAIR Plan on time and within budget. The Flue Gas Desulfurization (FGD) and Selective Catalytic Reduction (SCR) system have enabled PEF to comply with CAIR requirements and will continue to be the cornerstone of PEF's integrated air quality compliance strategy. PEF is confident that the approved Plan, along with compliance strategies under development, will enable it to achieve and maintain compliance with all applicable regulations, including MATS, in a cost effective manner. PEF is evaluating additional compliance options in light of MATS and other regulatory developments affecting fossil fuel-fired electric generating units. The results of the analyses performed to date are discussed in Exhibit No. __ (PQW-1), as well as the testimony of Benjamin Borsch.

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

DOCKET NO. 130007-EI

AUGUST 1, 2013

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. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013.

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 2013 estimated/actual cost projections versus original 2013 cost projections for environmental compliance costs associated with FPSC–approved environmental programs under my responsibility. These programs include Pipeline Integrity Management (PIM) Program (Project 3), Above Ground Storage Tank Program (Project 4), Phase II Cooling Water Intake (Project 6), CAIR/CAMR Continuous Mercury Monitoring System (CMMS) (Projects 7.2 & 7.3), Best Available Retrofit Technology (BART) Program (Project 7.5), Arsenic Groundwater Standard (Project 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower Project (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury TMDL (Project 13), Hazardous Air Pollutants (HAPs) ICR Program (Project 14), Effluent Limitation Guidelines Information Collection Request (ICR) Program (Project 15), National Pollutant Discharge Elimination System (NPDES) Program (Project 16), Mercury & Air Toxics Standards (MATS) Program – Crystal River (CR) 4&5 (Project 17), and MATS Program CR1&2 (Project 17.2) for the period January 2013 through December 2013.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Pipeline Integrity Management Program (Project 3) for the period January 2013 to December 2013.

A: O&M expenditures for the PIM Program are expected to be $221,000 or 37% lower than originally projected. This decrease is primarily attributable to a delay of a Florida Department of Transportation (FDOT) project and smaller scope of environmental risk reduction work than originally projected.

Capital expenditures for the PIM Program are expected to be $1.1 million lower than originally projected. This decrease is due to the correction of prior years accounting adjustments as explained in the direct testimony of Thomas G. Foster.

Q. Please explain the variance between estimated/actual project expenditures and original projections for the CAIR/CAMR – Peaking Program (Project 7.2) for the period January 2013 to December 2013.

A. O&M expenditures for the CAIR/CAMR – Peaking Program are expected to be $47,000 or 69% higher than originally projected. This variance is mainly due to payments for air emissions testing performed at the Bartow and Higgins plants in accordance with 40 CFR Part 75, Appendix E, made in 2013 versus 2012.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Best Available Retrofit Technology Program (Project 7.5) for the period January 2013 to December 2013.

A: O&M expenditures for the BART Program are expected to be $12,000 or 74% lower than originally projected. This variance is primarily due to performance of annual routine particulate matter emissions testing at full load to demonstrate BART compliance instead of various partial loads resulting in reduced testing costs.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Arsenic Groundwater Standard (Project 8) for the period January 2013 to December 2013.

A: O&M expenditures for the Arsenic Groundwater Standard are expected to be $10,000 or 32% lower than originally projected as a result of reduced consultant fees to finalize the plan of study addendum report for submittal to the Florida Department of Environmental Protection (FDEP) .

Q. Please explain the variance between estimated/actual project expenditures and original projections for the Thermal Discharge Permanent Cooling Tower (Project 11.1) for the period January 2013 to December 2013.

A. Capital expenditures for the Thermal Discharge Permanent Tower are expected to be $135,000 or 65% lower than originally projected. As explained in the petition filed in Docket No. 130007-EI and Docket 130091-EI, DEF announced on February 5, 2013, that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal loading resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the National Pollutant Discharge Elimination System Program (Project 16) for the period January 2013 to December 2013.

A: O&M expenditures for the NPDES Program are expected to be $98,000 or 21% lower than originally projected mainly due to timing of FDEP's approval of the plan of studies (POS) at the Anclote plant and a copper mixing zone study at the Suwannee plant. Anclote's POS was approved by the FDEP in May 2013 and implementation is expected to commence during the fourth quarter of 2013.

Suwannee's POS was approved by the FDEP the first quarter of 2013 and monitoring commenced the second quarter of 2013.

Capital expenditures for the NPDES Program are expected to be $9.3 million higher than originally projected. This variance is primarily due to the development of a comprehensive compliance plan for the Bartow freeboard project, with more certainty regarding scope and associated costs. With the concurrence of FDEP, the compliance deadline for this project is expected to move to December 2014. The scope of this work includes the civil, structural, mechanical piping and equipment, electrical, instrumentation and controls engineering, fabrication and installation for re-routing waste water from existing percolation ponds to either a Waste Water Containment Tank, a Reuse Surge Tank and a Discharge Surge Tank and/or to the plant cooling water loop between the existing intake screens and the existing condensers for discharge to surface water. This scope of work includes the repurposing of two existing fuel oil tanks to function as the Reuse Surge Tank and Discharge Surge Tank which consists of the removal of any fuel oil sludge, removal of the internal floating roofs, and sandblasting and epoxy coating of the inside of the tanks for waste water storage. The FDEP has been made aware of the change in project scope and is in agreement with the Company's plan to comply with the NPDES permit.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Mercury & Air Toxics Standards (MATS)

Program – CR4&5 (Project 17) for the period January 2013 to December 2013.

A: O&M expenditures for the MATS – CR4&5 Program are expected to be $198,000 higher than originally projected. This variance is due to operating expenses associated with the carbon traps used to monitor mercury emissions and chemical profiling of mercury emissions to better understand their fate in the emissions stream.

Capital expenditures for MATS – CR4&5 are expected to be $9.6 million or 96% lower than originally projected. The variance is due to the decision to limit capital expenditures to the installation of particulate matter emission monitors and rely upon carbon traps to monitor mercury in lieu of continuous emissions monitors, offset by the transfer of $94,901 of CAIR/CAMR CMMS CR4&5 costs to the MATS – CR4&5 Program. Considering the MATS rule has replaced CAMR, DEF believes that it is appropriate to subsume its CAIR/CAMR CMMS CR4&5 costs into the MATS project. This will better facilitate execution of MATS compliance program activities and provide a central collection point for all costs associated with the MATS program. This was proposed and approved for Florida Power and Light's Continuous Mercury Emission Monitor costs by the Commission in Order No. PSC-12-0613-FOF-EI, Docket No. 120007-EI. It was also proposed and approved for Tampa Electric Company CAMR program costs by the Commission in Order No. PSC-13-0191-PAA-EI, Docket No. 120302-EI.

Q: Please explain the variance between estimated/actual project expenditures and original projections for the Mercury & Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2) for the period January 2013 to December 2013.

A: O&M expenditures for the MATS – CR1&2 Program are expected to be $786,000 for alternative coal trials on Crystal River Units 1&2 as discussed in my April 1, 2013, direct testimony filed in this docket. DEF is evaluating alternative fuel options that would allow CR1&2 to continue operating in compliance with MATS for a limited period of time.

Capital expenditures for MATS – CR1&2 Program are shown to be $194,000 higher than originally projected due to the transfer of CAIR/CAMR CMMS CR1&2 costs to the MATS – CR1&2 Program. As explained above, given the MATS rule has replaced CAMR, DEF believes that it is appropriate to subsume its CAIR/CAMR CMMS CR1&2 costs into the MATS project.

Q: Please provide an update of Best Available Retrofit Technology (BART) regulations.

A: In 2012 DEF worked with the Florida Department of Environmental Protection (FDEP) to develop and finalize specific BART permits to address the SO2 and NOx requirements for Crystal River Units 1&2. Subsequently, FDEP submitted to EPA a revised State Implementation Plan (SIP) containing unit-specific BART determinations for Crystal River Units 1&2. The SO2 and NOx BART permits for these units call for installation of dry flue gas desulfurization (Dry

FGD) and selective catalytic reduction (SCR) by December 31, 2017, or alternatively the discontinuation of the use of coal in Units 1&2 by December 31, 2020. On April 30, 2013, Duke Energy provided notice to the FDEP that the Company has decided to cease burning coal in Units 1&2 by December 31, 2020. The EPA SIP is expected to be finalized in August 2013.

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

A: On June 23, 2013, the EPA announced that it reached an agreement with the Riverkeeper to re-extend the deadline for issuing the 316(b) rule to November 4, 2013.

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

DOCKET NO. 130007-EI

AUGUST 30, 2013

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, Florida, 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013 and August 1, 2013.

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 the year 2014 for Duke Energy Florida's (DEF or Company) Pipeline Integrity Management (PIM) Program (Project 3), Above Ground

Storage Tank Program (Project 4), Phase II Cooling Water Intake (Project 6), CAIR/CAMR Continuous Mercury Monitoring System (CMMS) (Projects 7.2 & 7.3), Best Available Retrofit Technology (BART) Program (Project 7.5), Arsenic Groundwater Standard (Project 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower Project (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury TMDL (Project 13), Hazardous Air Pollutants (HAPs) ICR Program (Project 14), Effluent Limitation Guidelines Information Collection Request (ICR) Program (Project 15), 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 sponsoring Exhibit No. ___ (PQW-2), which is a copy of the U.S. Environmental Protection Agency's proposed revised effluent limitation guidelines and standards for the steam electric generating industry. I am also co-sponsoring the following portions of Exhibit No. __(TGF-5) to Thomas G Foster's direct testimony:

- 42-5P page 3 of 21 - Pipeline Integrity Management.
- 42-5P page 4 of 21 - Above Ground Storage Tank Containment.
- 42-5P page 6 of 21 - Phase II Cooling Water Intake.
- 42-5P page 7 of 21 – Clean Air Interstate Rule (CAIR).
- 42-5P page 8 of 21 – Best Available Retrofit Technology (BART).

- 42-5P page 9 of 21 - Arsenic Groundwater Standard.
- 42-5P page 11 of 21 - Underground Storage Tanks.
- 42-5P page 12 of 21 - Modular Cooling Towers.
- 42-5P page 13 of 21 - Crystal River Thermal Discharge Project.
- 42-5P page 14 of 21 - Greenhouse Gas Inventory and Reporting.
- 42-5P page 15 of 21 - Mercury TMDL.
- 42-5P page 16 of 21 - Hazardous Air Pollutants (HAPs) ICR Program.
- 42-5P page 17 of 21 - Effluent Limitation Guidelines ICR Program.
- 42-5P page 18 of 21 – National Pollutant Discharge Elimination System (NPDES).
- 42-5P page 19 of 21 – Mercury and Air Toxics Standards (MATS) Program – CR4&5.

Q. What costs does DEF expect to incur in 2014 in connection with the Pipeline Integrity Management Program (Project 3)?

A. DEF estimates O&M costs of approximately $370,000 for the PIM Program to comply with the PIM regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

Q. What costs does DEF expect to incur in 2014 in connection with the Above Ground Storage Tank Secondary Containment Program (Project 4)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. DEF estimates O&M costs of approximately $800,000 for the Phase II Cooling Water Intake Program to evaluate compliance with the 316(b) rule. As the Commission is aware, as a result of the July 17, 2012 second amendment to the settlement agreement among the U.S. Environmental Protection Agency (EPA) and plaintiffs, EPA was expected to issue a final rule establishing cooling water intake standards pursuant to Section 316(b) of the Clean Water Act rule in June 2013. As discussed in DEF's response to FPSC's Information Request dated May 19, 2011, the proposed rule would establish standards for impingement mortality that can be achieved in either one of two ways: 1) modify traveling intake screens with fish collection and return systems that demonstrate that 88% of the fish collected will survive the process or 2) reduce the intake flow velocity to 0.5 feet per second. The proposed 316(b) rules would establish that state permitting authorities (the Florida Department of Environmental Protection (FDEP) in Florida) determine requirements for entrainment mortality on a case-by-case, site specific basis. The permittee must collect data, conduct studies and submit information that would be used by the state permitting authorities to make its decision regarding compliance plans. DEF is assessing several options that may be required to comply with the rule. The options under consideration may change once the final rule is issued and its impacts better understood; therefore, the exact costs that DEF will incur under 316(b) cannot be predicted. On June 23, 2013, the EPA announced that it reached an agreement with

Riverkeeper to re-extend the deadline for issuing the 316(b) rule to November 4, 2013.

Q. What costs does DEF expect to incur in 2014 in connection with the CAIR / CAMR Program (Project 7.2)?

A. DEF estimates O&M costs of approximately $44,000 for the CAIR/CAMR Program for data acquisition system maintenance of combustion turbine units and 40 CFR 75, Appendix E, Section 2.2 air emissions compliance testing. This regulation requires the Company to perform air emissions testing to reset correlation curves every 20 quarters and must be performed on all of its Predictive Emissions Monitoring Systems (PEMS).

Q: What costs does DEF expect to incur in 2014 in connection with the Best Available Retrofit Technology (BART) Program (Project 7.5)?

A: DEF is currently evaluating potential software and hardware changes that may be necessary to enable data from the precipitators to be measured and recorded to fulfill requirements of the Compliance Assurance Monitoring Plan. If changes are determined to be necessary, DEF will likely to incur costs in late 2013 or early 2014.

Q. Please provide an update of the status of Florida Regional Haze State Implementation Plan (SIP).

A. As discussed in the update to DEF's Integrated Clean Air Compliance Plan submitted as Exhibit No. __ (PQW-1) to my April 1, 2013 testimony, FDEP submitted a revised Regional Haze SIP to EPA earlier this year. On August 14, 2013, EPA formally approved the revised SIP, with publication to follow in the *Federal Register*. As approved by EPA, the revised SIP reflects DEF's decision to cease coal-firing at CR1&2 by December 31, 2020. The revised SIP will become effective 30 days after publication of EPA's approval in the *Federal Register* and the deadline for seeking judicial review is 60 days after publication.

Q. What costs does DEF expect to incur in 2014 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. DEF estimates O&M costs of approximately $40,000 for the Arsenic Groundwater Standard Program to prepare and submit a parameter exemption petition to the FDEP, if required, once its groundwater plan of study (POS) is approved by the agency. The POS was submitted to the FDEP on April 26, 2013.

Q. What costs does DEF expect to incur in 2014 in connection with the Underground Storage Tanks Program (Project 10)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Modular Cooling Tower Program (Project 11)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect any expenditures in 2014. As explained in Mr. Foster's direct testimony, DEF announced on February 5, 2013 that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal loading resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary.

Q. What costs does DEF expect to incur in 2014 in connection with the Greenhouse Gas (GHG) Inventory and Reporting Program (Project 12)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Mercury TMDL Program (Project 13)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Hazardous Air Pollutants (HAPs) Information Collection Request (ICR) Program (Project No. 14)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the National Pollutant Discharge Elimination System (NPDES) Program (Project No. 16)?

A. DEF estimates O&M costs of approximately $477,000 of O&M costs for the NPDES Program to conduct studies including thermal evaluations and whole effluent toxicity testing (WET) at the Anclote, Bartow and Suwannee plants, and copper mixing zone study at the Suwannee plant. Capital expenditures in 2014 are expected to be approximately $1.2 million for completion of the Bartow freeboard project to comply with the FDEP NPDES permit.

Q. What costs does DEF expect to incur in 2014 in connection with the Mercury and Air Toxics Standards (MATS) Program – CR4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $406,000 for CR4&5 MATS compliance: $36,000 for Appendix K mercury monitoring costs, $190,000 for mercury re-emission chemical costs, $100,000 for particulate matter (PM) continuous emissions monitors (CEMS) equipment installation costs and $80,000 for MATS Work Practice Standards costs. Capital expenditures are expected to be approximately $3.4 million: $3 million for mercury re-emission chemical and $400,000 for PM CEMS Installation.

Appendix K monitoring includes study equipment costs for mercury carbon traps used to capture baseline mercury emissions data on CR4&5. DEF will use the baseline data capture mercury speciation profiles to determine what, if any, mercury trim controls are necessary to meet MATS compliance. Potential options include brominated fuel additives and a flue gas desulfurization re-emission chemical.

The mercury re-emission chemical is an additive that suppresses mercury re-emission at CR4&5. On electric generating units equipped with wet scrubbers, re-emission may account for a portion of the total mercury emission. The extent of re-emission at CR4&5 will be assessed in the mercury speciation profile mentioned previously. The chemical would only be used on an as needed basis, primarily during unit start-up.

PM CEMS equipment installation costs are for continuous particulate matter measurement required for MATS compliance.

MATS Work Practice Standards costs include costs associated with combustion tuning activities that must be performed to comply with these standards.

Q. Is DEF requesting recovery of costs for any new environmental programs?

A. Yes. In April 2013, EPA proposed revised effluent limitation guidelines and standards (ELGs) for the Steam Electric Generating Industry pursuant to the federal Clean Water Act. The new rule will establish new or additional requirements for wastewater streams from various processes and byproducts associated with steam electric power generation, including: flue gas desulfurization, fly ash, bottom ash, non-chemical metal cleaning wastes and flue gas mercury control. As explained in the *Federal Register* notice for the proposed rule, EPA is considering several options and has identified four preferred alternatives for regulation of discharges from existing sources. *See* 78 *Fed. Reg.* 34431-34543 (June 7, 2013) (Copy attached as Exhibit No. __(PQW-2)). These four proposed options differ in the number of waste streams covered, the size of the units controlled and the stringency of the controls that would be imposed.

Q. Has the Company projected the costs it will incur for the new program?

A. DEF is in the process of analyzing potential compliance options for affected units and expects to incur compliance costs in 2014. However, the full extent of compliance activities and associated expenditures cannot be determined at this time because the rule has not been finalized and because DEF has not had sufficient opportunity to analyze each of the four preferred alternatives. EPA is under a court-ordered mandate to adopt a final rule in May 2014.

Q. Do the costs for the new program qualify for recovery through the ECRC?

A. Yes. Costs for the new program meet the requirements for ECRC recovery previously established by the Commission. Specifically, the expenditures are being prudently incurred after April 13, 1993; the activities are legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in PEF's last rate; and none of the costs of the new program are being recovered through base rates or any other cost recovery mechanism.

Q. Has the Commission previously approved recovery of costs for similar activities associated with development of environmental compliance measures?

A. In Order No. PSC-12-0613-FOF-EI issued on November 16, 2012, the Commission found that FPL's costs associated with the revised ELG rule are eligible for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

BENJAMIN M. H. BORSCH

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

April 1, 2013

Q. Please state your name and business address.

A. My name is Benjamin M. H. Borsch. 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 the Integrated Resource Planning and Analytics Department of Progress Energy Florida (PEF) as Director of Integrated Resource Planning and Analytics for Florida.

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ENG 4
GCL 1
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Q. What are your responsibilities in that position?

A. Currently, my responsibilities include overseeing preparation of resource plans and economic evaluations of proposed major projects for PEF and ensuring that analytical support is provided to strategic decision-making particularly around asset evaluations.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I am a professional engineer licensed in Florida and North Carolina. I have been employed in a variety of positions in machine manufacturing, chemical and petrochemical engineering, environmental equipment design and environmental consulting for a range of industries including citrus, phosphate, manufacturing, independent and utility power plant development and generation. From 2000 – 2006, I was Director of Environmental Health & Safety for the Southeastern Region of Calpine Corporation. I joined PEF in 2008 and have worked in new project development and resource planning, assuming my current position at the time of the merger with Duke Energy.

Q. Are you sponsoring any Exhibits?

A. I am co-sponsoring Exhibit No. __ (PQW-1), along with Patricia Q. West, specifically Section IV (parts B,1 and 2, C, and D) of the Integrated Clean Air Compliance Plan. These sections of the exhibit are true and accurate.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the portions of the Clean Air Compliance Plan related to the lifecycle analysis completed by the Company in connection with the decision on cost effective Mercury and Air Toxic Standards (MATS) compliance options for Crystal River Units 1 and 2.

Q. What options did the Company consider for compliance with the MATS regulations for Crystal River Units 1 and 2?

A. PEF cannot continue to operate the Crystal River Units 1 and 2 without implementation of additional measures to bring the units into compliance with MATS. Accordingly, the two main options that PEF considered were: (1) installing new emission control systems to reduce NO_X, SO_2 and mercury emissions; and (2) retiring the units and replacing the generation.

Q. How did PEF analyze these two options?

A. To determine the most cost-effective compliance option for CR 1 and 2, PEF conducted a lifecycle cost analysis of all costs associated with both options. This analysis is presented in detail in Section IV.C.1 of Exhibit No. __ (PQW-1). In the analyses, PEF focused on the comparative economics of a scenario in which Crystal River Units 1 and 2 continue to operate through 2041, equipped with significant life extension upgrades, state of the art emission control systems and a long term supply of low cost coal, versus a scenario where the units are retired in 2016. The Company compared operations and investment costs between the two alternatives and characterized the results in terms of the present value of annual and cumulative revenue requirements (PVRR and CPVRR). The base (reference) case was evaluated using the corporate mid-range fuel price forecasts, corporate forecasts for the cost of capital, projections for emission allowances and a proxy forecast for potential CO_2 allowance costs that were all used in the 2012 regulatory studies. Sensitivities reflecting higher gas prices and/or no CO_2 allowance costs were also prepared for comparison.

Q. What were the results of the CPVRR analysis?

A. In the base case analysis (corporate mid-range fuel prices, proxy forecast for potential CO2 allowance costs) the lifecycle projected system cost (CPVRR) for the option of retiring Crystal River Units 1 and 2 was $1.32B lower overall than the system CPVRR for the option of installing the environmental controls, i.e. a projected system savings, of $1.32 billion in 2012 dollars. When considering the sensitivity scenarios, the retirement alternative is favorable in all cases except for the high gas price, no CO_2 price case.

Q. Did the Company consider qualitative factors in the analysis?

A. Yes, as explained in Section IV.C.3 of Exhibit No. __ (PQW-1), PEF considered a number of qualitative factors with respect to the two options for MATS compliance. Factors in favor of the retirement option included age of the facility, construction risk, and long term operability. The main factor in favor of installing emission controls at Crystal River Units 1 and 2 would be to maintain additional fuel diversity.

Q. What did the Company decide as a result of its quantitative and qualitative analysis?

A. As detailed in Section IV.C. of Exhibit No. __ (PQW-1), PEF has decided that installing emission controls at Crystal River Units 1 and 2 is not the most cost-effective option to achieve MATS compliance. As explained in the Integrated

Clean Air Compliance Plan, the Company is evaluating alternate options for compliance that may impact the exact retirement date for the units.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF SWARTZ

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 130007-EI

April 1, 2013

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida (PEF) as Vice President – Power Generation Florida.

Q. What are your responsibilities in that position?

A. As Vice President of PEF's Power Generation organization, my responsibilities include overall leadership and strategic direction of PEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain PEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset

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allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating 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 1985. I have 11 years of power plant and production experience in various managerial and executive positions within Progress Energy managing Fossil Steam Operations, Combustion Turbine (CT) Operations and Nuclear plant operations. While at Progress Energy, I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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 project expenditures and estimated/actual project expenditures for environmental compliance costs associated with PEF's Integrated Clean Air Compliance Program (Project 7.4) for the period January 2012 through December 2012.

Q. How do actual expenditures for the CAIR Crystal River Project compare with PEF's estimated expenditures for the period January 2012 to December 2012?

A. CAIR Crystal River Project operation and maintenance (O&M) expenditures were $2,747,465 or 11% higher than projected in the Estimated/Actual Filing. This variance is primarily attributable to $2,005,846 higher than expected costs for CAIR Crystal River Project 7.4 – Energy and $717,286 higher than expected costs for CAIR Crystal River Project 7.4 - Base.

Q. Please explain the variance between actual project expenditures and the estimated/actual projections for the CAIR Crystal River Project – Energy for the period January 2012 to December 2012?

A. PEF's costs for reagents and by-products for 2012 were $2,005,846 or 22% higher than in the Estimated/Actual Filing. This variance is attributable to a combined limestone and hydrated lime pricing and usage variance of $1,216,760, a $481,958 gypsum variance due to increased costs to facilitate removal from the site, and a $307,128 ammonia pricing and usage variance as a result of increased fuel burn at Crystal River Units 4 and 5.

Q: Please explain the variance between actual project expenditures and the estimated/actual projections for the CAIR Crystal River Project – Base for the period January 2012 to December 2012?

A: PEF costs were $717,286 or 5% higher than in the Estimated/Actual Filing. This variance is primary driven by a change in accounting classification related to the Vehicle Barrier System (VBS) and removal of Crystal River Units 4 and 5 clinker deposits. $412,487 of the variance is due to classifying costs for fixing a VBS drainage issue as capital versus O&M in the 2012 Estimated/Actual Filing. $386,610 of the variance is due to costs necessary to remove clinkers within the interior of the absorber.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 1, 2013

Q. Please state your name and business address.

A. My name is Jeff 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. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013.

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 2013 estimated/actual cost projections versus original 2013 cost projections for environmental compliance costs associated with FPSC-approved environmental programs under my responsibility, including DEF's Integrated Clean Air Compliance Program (Project 7.4).

Q. How do the estimated/actual O&M project expenditures compare with original projections for the CAIR Crystal River Program (Project 7.4) for the period January 2013 to December 2013?

A. O&M expenditures are expected to be $7.2 million or 26% higher for this program than originally projected. This variance is primarily driven by a $6.7 million or 63% increase in CAIR Crystal River Project 7.4 – Energy.

Q. Please explain the variance between the estimated/actual O&M project expenditures and the original projections for the CAIR Crystal River (Project 7.4 – Energy) for the period January 2013 to December 2013.

A. The $6.7 million increase is primarily due to higher ammonia, limestone, hydrated lime and gypsum costs as compared to projections.

Q. How do the estimated/actual capital project expenditures compare with original projections for the CAIR Crystal River Program (Project 7.4) for the period January 2013 to December 2013?

A. Capital expenditures are expected to be $6.7 million or 145% higher for this program than originally projected. This difference primarily consists of $445,000 of lower CR4 catalyst project costs due to a reduction in vendor pricing, $1.9 million deferral of 2013 FGD blowdown treatment project costs to 2014 due to permit delays, $661,000 of Crystal River Unit 4 clinker mitigation costs shifted from O&M to capital due to the nature of work that is going to be performed, $681,000 of industrial waste water costs due to a FDEP consent order requiring this project not known at the time of the original projection filing, and $7.6 million of hydrated lime costs planned for 2012 that were carried over to 2013 due to material delivery delays.

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

DOCKET NO. 130007-EI

AUGUST 1, 2013

(Revised OCTOBER 7, 2013)

Q. Please state your name and business address.

A. My name is Jeff 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. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013.

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 2013 estimated/actual cost projections versus original 2013 cost projections for environmental compliance costs associated with FPSC-approved environmental programs under my responsibility, including DEF's Integrated Clean Air Compliance Program (Project 7.4).

Q. How do the estimated/actual O&M project expenditures compare with original projections for the CAIR Crystal River Program (Project 7.4) for the period January 2013 to December 2013?

A. O&M expenditures are expected to be $7.2 million or 26% higher for this program than originally projected. This variance is primarily driven by a $6.7 million or 63% increase in CAIR Crystal River Project 7.4 – Energy.

Q. Please explain the variance between the estimated/actual O&M project expenditures and the original projections for the CAIR Crystal River (Project 7.4 – Energy) for the period January 2013 to December 2013.

A. The $6.7 million increase is primarily due to higher ammonia, limestone, hydrated lime and gypsum costs as compared to projections.

Q. How do the estimated/actual capital project expenditures compare with original projections for the CAIR Crystal River Program (Project 7.4) for the period January 2013 to December 2013?

A. Capital expenditures are expected to be $9.0 million or 194% higher for this program than originally projected. This difference primarily consists of $445k of lower CR4 catalyst project costs due to a reduction in vendor pricing, $1.9 million deferral of 2013 FGD blowdown treatment project costs to 2014 due to permit delays, $661k of Crystal River Unit 4 clinker mitigation costs shifted from O&M to capital due to the nature of work that is going to be performed, $681k of industrial waste water costs due to a FDEP consent order requiring this project not known at the time of the original projection filing, and $9.9 million of hydrated lime costs planned for 2012 that were carried over to 2013 due to material delivery delays.

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

DOCKET NO. 130007-EI

AUGUST 30, 2013

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. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013 and August 1, 2013.

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 2014 for Duke Energy Florida's (DEF or Company) CAIR/CAMR Continuous Mercury Monitoring System (CMMS) (Project 7.3), Integrated

Clean Air Compliance Program (Project 7.4) 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. __ (TGF-5) to Thomas G. Foster's direct testimony:

- 42-5P page 7 of 21 – Clean Air Interstate Rule (CAIR).
- 42-5P page 21 of 21 – Mercury and Air Toxics Standards (MATS) Program – CR1&2.

Q. What O&M costs does DEF expect to incur in 2014 in connection with the 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 $35.7 million to support the operation and maintenance of air emissions controls that were installed at the Crystal River Energy Complex as outlined in DEF's Integrated Clean Air Compliance Plan as follows:

- Labor costs are estimated at approximately $7.1 million. This estimate is based on current staffing levels. Contractor expenses are estimated at approximately $4.3 million for various services.
- Parts and materials are estimated at approximately $1.9 million.

- Other costs are estimated at approximately $0.6 million.
- Crystal River Units 4&5 outage costs are estimated at approximately $2.2 million.
- Project expenses for ball mill, absorber recycle pump, oxidation air blower, dewatering system and conveyor maintenance are estimated at approximately $1 million.
- Reagent costs (ammonia, limestone, dibasic acid, hydrated lime, caustic and net gypsum sales/disposal) are estimated to total approximately $18.6 million.

Q. What capital costs does DEF expect to incur in 2014 associated with the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?

A. DEF estimates capital costs of approximately $3.2 million for the Integrated Clean Air Compliance Program in 2014 including:

- $0.7 million for a clinker mitigation system on CR5 to reduce clinker formation. Clinkers are hard masses forming in the FGD inlet ducts of CR4&5 as a result of the high temperature differential between the flue gas and limestone slurry. The project installs a permanent water spray system in the FGD flue gas inlet which will reduce the temperature differential thereby reducing clinker formation. The CR4 clinker mitigation project was completed in 2013.
- $2 million of development and engineering of a FGD wastewater system for FGD blowdown needed to comply with FDEP wastewater permit conditions.

- $0.5 million of development and engineering of a reclaimed water reuse system, an alternative water project, to comply with the Conditions of Site Certification requirements regarding the rolling annual average daily withdrawal rate of groundwater from the CR4&5 well field.

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

A. Plant management monitors and controls costs by several methods. Work is scheduled and conducted proactively and efficiently. Expenditures are reviewed and 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. An organization chart is attached as Exhibit__(JS-1). This unit consists of 52 employees that report to the Crystal River Energy Complex station manager and 1 employee who reports to the Manager PEF Generation Finance. There are 8 managers and 45 maintenance, operations and support employees. The operators work rotating shifts in order to staff the operations of the facility 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 operations and maintenance costs.

Q. Are there policies and procedures in place to efficiently operate and maintain these assets?

A. Yes, there are several different policies and procedures used to efficiently operate and maintain the CAIR equipment. First and foremost, the plant follows all OSHA and DEF 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 operating and maintenance 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, the personnel selected to operate and maintain CAIR equipment have to meet specific job-related qualifications in order to qualify for the positions they are selected to perform. Some employees are hired from outside companies and come to DEF with previous experience operating this type equipment at other utilities. Other operations employees are selected to participate in an 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 the employee progress through different levels of task proficiency. Maintenance employees are selected based on their skills and experience, and are also provided equipment specific training to optimize the maintenance of the equipment.

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 these policies and procedures using several different training methods that include required reading and review of the policies and procedures, small group discussions, one-on-one discussions with subject matter experts, computer based training (CBT) and on the job task training.

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

A. The Company 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 these assets?

A. Along with the above-mentioned 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 costs does DEF expect to incur in 2014 in connection with the Mercury and Air Toxics Standards (MATS) Program – CR1&2 (Project 17.2)?

A. DEF estimates O&M costs of approximately $1.1 million for CR1&2 MATS compliance. These costs are to perform alternative coal trials to demonstrate DEF's ability to safely and reliably use alternative coal at CR1&2 to comply with MATS beyond the 2015 compliance date provided in the rule. These costs are subject to change as the Company continues to explore options to reduce emissions into the ranges required for MATS compliance.

Q. What is the current status of the alternative coal trials?

A. DEF performed initial fuel tests in June 2013 that demonstrated stable plant operations with alternative lower constituent coal. Additional analysis and testing is planned to further explore the options available to DEF to reduce emissions into the ranges required for MATS compliance. These costs are subject to change as the Company continues to explore options to reduce emissions into the ranges required for MATS compliance. If DEF moves forward with alternative coal as the MATS compliance strategy, it will need to incur some capital costs to make changes to CR1&2 so that the units can successfully burn the coal. Depending on the engineering results, such costs may be incurred in the 2014 timeframe. However, given that the engineering analysis has not been completed, DEF has not included any capital costs for this project at this time.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130007-EI
FILED: 04/01/13

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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 graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position, I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on ECRC activities since 2001 as well as conservation and load management activities, DSM goals setting, DSM plan approval dockets and other ECCR dockets since 1993.

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 ECRC and the calculations associated with the environmental compliance activities for the January 2012 through December 2012 period.

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

A. Yes. Exhibit No. _____ (HTB-1) consists of nine forms prepared under my direction and supervision.

- Form 42-1A, Document No. 1, Final true-up for the January 2012 through December 2012 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, provides details to the calculation of the interest provision for the period;
- Form 42-4A, Document No. 4, reflects the calculation of 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 details of the calculation of 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 25, consist of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 26 calculates the net expenses associated with maintaining an SO_2 allowance inventory.

- Form 42-9A, Document No. 9, details the calculation of Tampa Electric's capital structure, components and cost rates.

Q. What is the source of the data presented by way of your testimony or exhibits in this process?

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

Q. What is the actual true-up amount Tampa Electric is requesting for the January 2012 through December 2012 period?

A. Tampa Electric has calculated and is requesting approval of an under-recovery of $15,457,712 as the actual true-up amount for the January 2012 through December 2012 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2012 through December 2012 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2014 projection period?

A. Tampa Electric has calculated an under-recovery of $3,702,886 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2012 through December 2012 period. This adjusted net true-up amount is the difference between the actual under-recovery and the actual/estimated under-recovery for the January 2012 through December 2012 period as depicted on Form 42-1A. The actual true-up amount for the January 2012 through December 2012 period is an under-recovery of $15,457,712 as compared to the $11,754,826 actual/estimated under-recovery amount approved in Commission Order No. PSC-12-0613-FOF-EI issued November 16, 2012.

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

Q. Did Tampa Electric include costs in its 2012 final ECRC true-up filing for any environmental projects that were not anticipated and included in its 2012 factors?

A. No.

Q. How did actual expenditures for the January 2012 through December 2012 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total O&M activities costs were $1,337,560 or 4.3 percent more than the actual/estimated projections. Form 42-6A shows the total capital investment costs were $11,538 less than the actual/estimated projections. O&M projects with material variances from the 2012 Actual/Estimated True-Up filing are explained below. Variances for capital investment projects are quite modest; therefore, explanations are not provided.

O&M Project Variances

- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $11,106 or 111.5 percent less than projected. The variance was due to less cogeneration purchases than originally projected.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance was $1,218,414 or 6.9 percent more than projected due to increase in operations, which in turn, caused an increase in chemical consumption. Additionally, there was an increase in steel utilization to sustain the integrity of the structure.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $127,723 or 32.3 percent less than projected due to a decrease in operational maintenance from the original projection.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $256,554 or 67.4 percent less than projected due to maintenance activity being less than expected during planned outages.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $8,985 or 55 percent lower than projected due to less maintenance needed than originally projected.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $54,818 or 45 percent greater than projected due to an increase in ammonia costs attributed to an increase in the $/ton cost of the product as well as an overall increase in ammonia consumption.

- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $9,046 or 16.1 percent less than projected due to the EPA's postponement of the final rule until July 2013. As such; Tampa Electric has delayed any additional work related to same.
- **Arsenic Ground Water Standard Program:** The Arsenic Groundwater Standard program variance was $22,353 or 26.5 percent greater than projected due to the area containing arsenic contaminated soil being larger than expected. Subsequently, outside resources were contracted to perform services regarding contamination levels near wetlands as well as a land survey.
- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance was $251,278 or 10.8 percent greater than projected due to the increase in ammonia consumption driven by the increase in generating unit production.
- **Clean Air Mercury Rule:** The Clean Air Mercury Rule Project variance was $10,955 or 43.1 percent less than originally projected due to the occurrence of fewer sample tests than what was originally projected as well as a reduction in costs for sorbent traps.

Q. Did Tampa Electric make any adjustments to the 2012 true-up period?

A. Yes. Tampa Electric made an adjustment of $18,669 in January 2012 which was comprised of two items. First, two capital projects were inadvertently included in CWIP while collecting AFUDC; therefore, ROI should not have been calculated for collection. Second, a specific project associated with Big Bend Units 1 & 2 FGD had been assigned an incorrect depreciation rate. When both corrections were made, the aforementioned adjustment was necessary.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130007-EI
FILED: 08/01/13

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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 graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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 January 2013 through December 2013 estimated true-up amount to be refunded or recovered through the ECRC during January 2014 through December 2014. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2013, based on six months of actual data and six months of estimated data. This information will be used to determine the environmental cost recovery factors for January 2014 through December 2014.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2013 through December 2013?

A. Yes. Exhibit No. _____ (HTB-2), containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E which show the current period estimated true-up amount to be used in calculating the cost recovery factors for January 2013 through December 2013.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2013 through December 2013 ECRC factors?

A. The estimated true-up applicable for the current period, January 2013 through December 2013, is an over-recovery of $1,243,352. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. What is the nature of the adjustment on line 10 of Form 42-2E?

A. The adjustment of $15,513 on line 10 of Form 42-2E is due to changes to CWIP during August through December 2012. The projects associated with the CWIP increase are Big Bend Unit 3 FGD Integration, totaling $7,354, Big Bend Unit 4 SCR totaling $807,793 and lastly, Mercury Air Toxics Standards ("MATS"), totaling $63,500. These changes resulted in an increase of $15,513 to the 2012 ROI and interest.

Q. Is Tampa Electric including costs in this estimated true-up filing for any new environmental projects that were not anticipated and included in its 2013 factors?

A. Yes, Tampa Electric is including costs for the MATS project approved by the Commission in Docket No. 120302-EI, Order No. PSC 13-0191-PAA-EI, issued on May 6, 2013 for inclusion in its 2013 factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2013 Actual/Estimated True-Up?

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

Q. What capital structure, components and cost rates did

Tampa Electric rely on to calculate the revenue requirement rate of return for January 2013 through December 2013?

A. Tampa Electric relied upon the capital structure, components and cost rates approved by the Commission in Docket No. 120007-EI, Order No. PSC-12-0425-PAA-EU on August 16, 2012 to calculate the revenue requirement rate of return found on Form 42-9E.

Q. How did the actual/estimated project expenditures for January 2013 through December 2013 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $51,630 less than the projected costs. The total capital expenditures itemized on Form 42-6E, were $1,161,348 less than originally projected. O&M and capital investment projects with material variances are explained below.

O&M Project Variances

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $9,783 or 42.6 percent less than projected. The variance is due to less cogeneration purchases than expected and the application of a lower emission allowance rate than originally projected.

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $488,769 or 125.3 percent greater than projected due to an increase in the scope of daily inspections resulting in the addition of two additional Best Operating Practice contractors.

- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $12,500 or 100 percent less than originally projected. This variance is due to the Florida Department of Environmental Protection ("FDEP") not requiring a demonstration study this permit cycle.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is estimated to be $12,643 or 44.4 percent less than originally projected due to an extended outage at the Polk Power Station in addition to a reduction in water costs and maintenance associated with the saturator that is used to reduce NO_x emissions.

- **Bayside SCR Consumables:** The Bayside SCR Consumables variance is estimated to be $52,201 or 49.2 percent greater than originally projected due to an increase in ammonia costs attributed to an increase in the cost per ton of consumable ammonia as well as an overall increase in ammonia consumption.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project incurred expenses of $177,672 compared to an original projection of no anticipated costs due to unscheduled repairs to the blades associated with the Pre-SCR.

- **Clean Water Act Section 316(b)Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $60,000 or 100 percent less than originally projected due to the EPA's postponement of the final rule until July 2013. As such, Tampa Electric has delayed any additional work related to same.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $363,950 or 54.6 percent less than what was originally projected due to FDEP delay in approval of activity associated with project work.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $88,449 or 5.7 percent greater than originally projected due to actual consumption of ammonia for the SO_3 mitigation system being greater than originally projected as a result of outages on Units 1 and 2, requiring Unit 3 to experience greater operation hours than originally forecasted.

- **Mercury Air Toxics Standards f/k/a Clean Air Mercury Rule:** The MATS program variance is expected to be $301,421 or 1,507.1 percent greater than originally projected due to MATS not being an approved program at the time of the original projection filing. The Commission approved MATS in Docket No. 120302-EI, Order No. PSC-13-0191-PAA-EI, issued on May 6, 2013. As such, the O&M expenditures associated with this project pertain to mercury, hydrochloric acid and particulate matter testing as well as expenditures for the former Clean Air Mercury Rule ("CAMR") O&M that includes umbilical mercury testing.

Capital Investment Project Variances

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $264,860 or 13.6 percent less than projected due to the construction contract and equipment packages being less than originally projected.

- **Mercury Air Toxics Standards f/k/a Clean Air Mercury Rule:** The MATS program variance is estimated to be $177,158 or 111.6 percent greater than originally projected due to MATS not being an approved program at the time of the original projection filing. The variance includes the purchase of a Mercury Spectrometer that will be used for monitoring mercury emissions. The MATS costs include the previously projected Clean Air Mercury Rule capital expenditures.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130007-EI
FILED: 08/30/2013

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

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

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

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

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

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 ECRC factors for the period of January 2014 through December 2014. The projected ECRC factors have been calculated based on the current allocation methodology as well as the allocation methodology proposed by Tama Electric in Docket No. 130040-EI. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for the year 2014.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2014 through December 2014?

A. Yes. Exhibit No. ___ (HTB-3), containing nine 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 O&M and capital expenditures that support the development of the environmental cost recovery factors for 2014 using the current 12 coincident peak ("CP") and 25 percent average demand ("AD") basis. Document No. 9, consisting of two pages, supports the proposed ECRC factors allocated on a 12CP and 50 percent AD basis, as proposed in Docket No. 130040-EI.

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. _____ (HTB-3), Document No. 7, on Form 42-7P. These annualized factors will apply for the period January through December 2014.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2014 through December 2014?

A. The net true-up applicable for this period is an under-recovery of $2,459,534. This consists of the final true-up under-recovery of $3,702,886 for the period of January 2012 through December 2012 and an estimated true-up over-recovery of $1,243,352 for the current period of January 2013 through December 2013. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-9E of Exhibit No. ___ (HTB-2) filed with the Commission on August 1, 2013.

Q. What were the major contributing factors that created the net under-recovery to be applied to the company's ECRC rates for the period January 2014 through December 2014?

A. There were two major contributing factors that created the net under-recovery. First, the increased O&M expense associated with the management of the gypsum production at Big Bend Station. Second, ECRC revenues were less than expected.

Q. Will Tampa Electric include any new environmental compliance projects for ECRC cost recovery for the period from January 2014 through December 2014?

A. No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2014.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2014?

A. Tampa Electric proposes to include for ECRC recovery the 25 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2014. These projects are:

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 1 Upgrade
5) Big Bend Fuel Oil Tank 2 Upgrade
6) Big Bend Unit 1 Classifier Replacement
7) Big Bend Unit 2 Classifier Replacement
8) Big Bend Section 114 Mercury Testing Platform
9) Big Bend Units 1 and 2 FGD
10) Big Bend FGD Optimization and Utilization

11) Big Bend NO_x Emissions Reduction

12) Big Bend Particulate Matter ("PM") Minimization and Monitoring

13) Polk NO_x Emissions Reduction

14) Big Bend Unit 4 SOFA

15) Big Bend Unit 1 Pre-SCR

16) Big Bend Unit 2 Pre-SCR

17) Big Bend Unit 3 Pre-SCR

18) Big Bend Unit 1 SCR

19) Big Bend Unit 2 SCR

20) Big Bend Unit 3 SCR

21) Big Bend Unit 4 SCR

22) Big Bend FGD System Reliability

23) Clean Air Mercury Rule now known as Mercury Air Toxics Standard ("MATS")

24) SO_2 Emission Allowances

25) Big Bend New Gypsum Storage Facility

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

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2014?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $60,027,417.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2014?

A. Tampa Electric proposes to include for ECRC recovery the 23 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2014. These projects are:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) SO_2 Emissions Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) NPDES Annual Surveillance Fees
8) Gannon Thermal Discharge Study
9) Polk NO_x Emissions Reduction
10) Bayside SCR and Ammonia
11) Big Bend Unit 4 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) Clean Air Mercury Rule now known as Mercury Air Toxics Standard

22) Greenhouse Gas Reduction Program

23) Big Bend New Gypsum Storage Facility

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

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2014?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $28,383,951 for 2014.

Q. Do you have 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 31.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2014?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $88,411,368.

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 calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total MWH sales and then adjusted for losses for each rate class. This information was based on applying historical rate class load research to the 2014 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 by rate class based on a 12 CP and 25 percent AD allocation method for the period of January through December 2014 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level utilizing the 12 CP and 25 percent AD methodology is shown in Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through December 2014 proposed ECRC billing factors are as follows:

Rate Class	**Factor by Voltage Level (¢/kWh)**
RS Secondary	0.498
GS, TS Secondary	0.498
GSD, SBF	
Secondary	0.496
Primary	0.491

Transmission	0.486
IS, SBI	
Secondary	0.487
Primary	0.482
Transmission	0.477
LS1	0.493
Average Factor	0.496

Q. What are the ECRC billing factors by rate class based on a 12 CP and 50 percent AD allocation method for the period of January through December 2014 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level utilizing the 12 CP and 50 percent AD methodology is shown in Exhibit No. ____ (HTB-3) Document No. 9, Proposed Allocations and Factors. In summary, the January through December 2014 proposed ECRC billing factors are as follows:

Rate Class	**Factor by Voltage Level (¢/kWh)**
RS Secondary	0.497
GS, TS Secondary	0.498
GSD, SBF, IS, SBI	

Secondary	0.495
Primary	0.490
Transmission	0.485
LS1	0.494
Average Factor	0.496

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 2014.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2014 through December 2014?

A. Tampa Electric relied upon the weighted average cost of capital methodology approved by the Commission in Order No. PSC-12-0425-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 2014 through December 2014 consistent with criteria established for

ECRC recovery in Order No. PSC-94-0044-FOF-EI?

A. Yes. The costs for which ECRC treatment 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 are based; and,
3. Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.496 cents per kWh. This includes the projected capital and O&M revenue requirements of $88,411,078 associated with a total of 31 environmental projects and a true-up under-recovery provision of $2,459,534 that is primarily driven by the combination of O&M expenditures being greater than anticipated while ECRC revenue was less than expected.

My testimony also explains that the projected environmental expenditures for 2014 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED SUPPLEMENTAL TESTIMONY

OF

HOWARD T. BRYANT

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

A. My name is Howard T. Bryant. 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. Are you the same Howard T. Bryant that submitted prepared direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to address how the company's Environmental Cost Recovery ("ECRC") clause is affected as a result of the Stipulation and Settlement Agreement ("settlement") reached between Tampa Electric and interveners and approved by the Commission in Docket No. 130040-EI on September 11, 2013.

Q. Have you prepared an exhibit to support your supplemental testimony?

A. Yes. Revised Exhibit No. ___ (HTB-3), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contains Forms 42-1P through 42-8P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2014.

Q. How has the settlement affected the ECRC clause?

A. The settlement resulted in two modifications on how the 2014 projected costs were calculated. The first modification was the change to the approved 12 Coincident Peak and $1/13^{th}$ Average Demand allocation methodology for demand-related costs. The second modification occurred to include the settlement return on equity and equity ratio in the calculation of capital project costs.

Q. Based on these modifications, what are the proposed ECRC billing factors by rate class for the period of January through December 2014 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level is shown in revised Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through December 2014 proposed ECRC billing factors are as follows:

Rate Class	Factor by Voltage Level (¢/kWh)
RS Secondary	0.483
GS, TS Secondary	0.483
GSD, SBF	
Secondary	0.482
Primary	0.477
Transmission	0.472
IS, SBI	
Secondary	0.472
Primary	0.468
Transmission	0.463
LS1	0.478
Average Factor	0.482

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2014.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130007-EI
FILED: 08/30/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL 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 & 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 policies 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 2014 through December 2014 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with 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. I will also discuss other programs previously approved by the Commission for recovery through the ECRC.

Q. Please provide an overview of the ongoing environmental compliance requirements that are the result of the CFJ and the CD ("the Orders").

A. The general ongoing 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.

Q. What do the Orders require for SO_2 emission reductions?

A. The Orders require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the flue gas desulfurization systems ("FGD" or "scrubbers"). The plans were submitted to the EPA in two phases, and were approved in July 2000, and February 2001, respectively.

Phase I required Tampa Electric to work scrubber outages around the clock and to utilize contract labor, when necessary, to speed the return of a malfunctioning scrubber to service. In addition, Phase I required Tampa

Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II outlined capital projects Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the SO_2 emission reduction projects have been completed.

Q. What do the Orders require for PM emission reductions?

A. The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP") and complete and implement a best available control technology ("BACT") analysis of the ESPs at Big Bend Station. The Orders also require the company to demonstrate the operation of a PM continuous emission monitoring system ("CEM") on Big Bend Units 3 and 4 and demonstrate the operation of a second PM CEM on another Big Bend unit. The first PM CEM was installed in February 2002. The installation and certification of the second PM CEM was completed in August 2009. Over time, however, the first PM CEM did not perform satisfactorily and replacement was required. Installation and certification of the replacement was completed in December 2010.

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 2014 through December 2014.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-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. In 2014, capital expenditures are anticipated to be $1,868,700 for BOP and BACT equipment while O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures are expected to be $900,000.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x emission reduction projects on Big Bend Units 1, 2 and 3. Pursuant to an amendment, Big Bend Unit 4 projects were substituted for Big Bend Unit 3 projects. The NO_x emission reductions use the 1998 NO_x emissions as the baseline year for determining the level of reduction achieved. Tampa Electric was also required by the Orders to demonstrate innovative technologies or provide additional NO_x technologies beyond those required by the early NO_x emission reduction activities.

Q. Please describe the Big Bend NO_x Emission Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2014 through December 2014.

A. The Big Bend NO_x Emission Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-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 2014; however, the company will perform maintenance on the previously approved and installed NO_x reduction equipment. This activity is expected to result in approximately $375,000 of O&M expenses.

Q. Please describe long-term NO_x requirements associated with the Orders and Tampa Electric's efforts to comply with the requirements.

A. The Orders require Big Bend Unit 4 to begin operating with a Selective Catalytic Reduction ("SCR") system or other NO_x control technology, be repowered, or shut down and scheduled for dismantlement by June 1, 2007. Thus, Big Bend Units 3, 2 and/or 1 must operate with an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement one unit per year by May 1, 2008, May 1, 2009 and May 1, 2010, respectively.

In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and install the necessary NO_x reduction technologies was the most cost-effective alternative to satisfy the NO_x emission reductions required by the

Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket No. 040750-EI in August 2004.

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 2014 through December 2014.

A. In Docket No. 040750-EI, Order No. PSC-04-0986-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. 041376-EI, Order No. PSC-05-0502-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. These Pre-SCR technologies include windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Units 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 2014 through December 2014, no capital or O&M expenditures are anticipated for the Big Bend Units 1 through 3 Pre-SCR projects and there are no anticipated capital expenditures for Big Bend Units 1 through 4 SCRs. However, the 2014 SCR O&M expenses are projected to be $2,407,100 for Big Bend Unit 1 SCR, $2,949,700 for Big Bend Unit 2 SCR, $1,974,800 for Big Bend Unit 3 SCR and $1,141,300 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:

1) Big Bend Unit 3 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) Clean Air Mercury Rule ("CAMR")now known as the Mercury and Air Toxics Standards ("MATS")
9) Greenhouse Gas ("GHG") Reduction Program
10) Big Bend New Gypsum Storage Facility

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 2014 through December 2014.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those 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.

There are no projected capital expenditures during January 2014 through December 2014 for the Big Bend Unit 3 FGD

Integration project; however, O&M expenses are anticipated to be $5,624,000 for consumables and ongoing maintenance. The projected January 2014 through December 2014 capital expenditures for the Big Bend FGD Units 1 and 2 project are $458,200 for the installation of a stack test port installation and installation of a new chlorination system. O&M expenses are anticipated to be $10,965,200 for consumables 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 2014 through December 2014.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-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 2014 through December 2014, there are no 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. It is anticipated that no additional study will be required.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M expenditures for the period of January 2014 through December 2014.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2014 through December 2014, Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $150,000 for the period.

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 2014 through December 2014.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. On March 20, 2007 the EPA announced that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. On April 20, 2012, EPA published a proposed rule for existing steam electric generators, with the final rule expected in

July 2012. In July 2012, the final rule was postponed once again until June 2013. In June 2013, the final rule was postponed until November 4, 2013. Due to the current status of the rulemaking, Tampa Electric does not anticipate any O&M expenditures associated with this project.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital expenses for the period of January 2014 through December 2014.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-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 SCR systems on the generating units. For the period of January 2014 through December 2014, 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 2014 through December 2014.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-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 approval for prudently incurred costs. The new groundwater standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

For the period of January 2014 through December 2014, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $422,000.

Q. Please describe the MATS program activities and provide the estimated capital and O&M expenditures for the period of January 2014 through December 2014.

A. The MATS program was approved by the Commission in Docket No. 120302-EI, Order No. PSC-13-0191-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. The proposed rule calls for continued mercury monitoring requirements comparable to CAMR and additional monitoring and testing of other pollutants by 2014. On February 16, 2012, the EPA published the final rule for MATS. The rule revised the mercury limits and provided more flexible monitoring/recordkeeping requirements. Additionally, monitoring of acid gases and particulate matter will be required. Existing sources will have through February 16, 2015 to comply with the rule. Tampa Electric must conduct extensive emissions testing and engineering studies at Big Bend Station and Polk Power Station to determine what actions are required to meet the proposed standards.

For 2014, the anticipated capital expenditures are \$5,314,400 for replacement of required equipment for mercury monitoring and upgrades to the FGD systems to meet the emission standards required by the rule, and the anticipated O&M expenditures, are \$218,500 for testing requirements and maintenance of equipment.

Q. What is the impact of the remand of the CAIR and vacatur of the CAMR on Tampa Electric's ECRC projects?

A. On July 6, 2010, the EPA proposed a new rule, the Clean Air Transport Rule to replace CAIR. On July 6, 2011, the EPA issued the final CAIR replacement rule, now called the Cross State Air Pollution Rule ("CSAPR"). CSAPR is focused on reducing SO_2 and NO_X in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. In the final rule, Florida is subject to the ozone season control program (May through September). In December 2011, the final rule was stayed by the United States Court of Appeals District of Columbia Circuit. The stay on the finalized CSAPR and the remand of CAIR have minimal impact on Tampa Electric's ECRC projects associated with NO_x and SO_2 abatement. These projects were initiated as a result of the CD signed between the EPA and Tampa Electric; therefore, the company anticipates continuing its efforts to complete and maintain the projects. The completed ECRC projects support compliance with CSAPR.

The vacatur of CAMR occurred after Tampa Electric had begun the procurement of equipment necessary to meet the intent of the original rule; however, the company was able to stop a significant portion of the total equipment purchase. Subsequent to the vacatur, the company has continued utilizing the resources already secured to establish a baseline of mercury emissions.

On May 3, 2011 the EPA proposed rules under National Emission Standards for Hazardous Air Pollutants pursuant to a court order referred to as the Utility Maximum Achievable Control Technology ("U MACT"). The proposed rules are to replace CAMR and are expected to reduce not only mercury but acid gas, organics and certain non-mercury metals emissions and require MACT. The final U MACT rules were released in February 2012 with implementation in May 2015. The company continues to utilize the resources already secured to establish a baseline on mercury and other emissions subject to the proposed rule and expects to purchase other equipment that will be required to comply with the rules.

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2014 through December 2014.

A. Tampa Electric's GHG Reduction Program approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PPA-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 to the EPA for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2014. For 2014, this activity is not anticipated to require capital expenditures; however, it is expected to result in approximately $114,100 in O&M expenses.

Q. Please describe the Big Bend New Gypsum Storage Facility activities and provide the estimated capital and O&M expenditures for the period of January 2014 through December 2014.

A. The Big Bend New Gypsum Storage Facility program was approved by the Commission in Docket No. 110262-EI, Order No. 12-0493-PAA-EI, issued September 26, 2012. In that Order, the Commission found that the program meet the requirements for recovery through ECRC. The completion of the project and in-service date is projected to be May 2014. The total installed capital cost at that time is estimated to be $21,000,000 and the O&M for 2014 is projected to be $1,051,200.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects that are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2014. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2014 activities and projected expenditures.

Q. Does this conclude your testimony?

A. Yes it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 130007-EI
April 1, 2013

Q. Please state your name and business address.

A. My name is James O. Vick, 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. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. In August 1978, I joined Gulf Power Company as an Associate Engineer and have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, 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. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?
A. Yes.

Q. Mr. Vick, 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 2012.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2012 through December 2012 with the approved estimated true-up amounts.
A. As reflected in Mr. Dodd's Schedule 6A, the actual recoverable capital costs were $126,706,388 as compared to $127,553,064 included in the Estimated True-up filing. This resulted in a net variance of ($846,676) below the estimated true-up. I will address two projects and/or programs that

contributed to this variance: Crist 5, 6, & 7 Precipitator Projects and CAIR/CAMR/CAVR Compliance.

Q Please explain the capital variance of ($122,932) or (2.7%) in the Crist 5, 6, & 7 Precipitator Projects (Line Item 1.2).

A. Plant Crist Unit 6 Precipitator upgrades were completed in 2012 and the total expenditures came in less than anticipated. As a result, the carrying cost and depreciation expense were lower than originally projected in the Estimated True-up filing.

Q Please explain the capital variance of ($747,299) or (0.8%) in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. This variance is primarily due to Mississippi property tax expenses related to Plant Daniel scrubber currently under construction being lower than projected in the Estimated True-up filing.

Q. How do the actual O&M expenses for the period January 2012 to December 2012 compare to the amounts included in the Estimated True-up filing?

A. Mr. Dodd's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $24,726,373, as compared to the estimated true-up of $23,824,688. This resulted in a variance of $901,685 or 3.8% above the estimated true-up. I will address eight O&M projects and/or programs that contribute to this variance: General Water Quality, Groundwater Contamination Investigation, General Solid & Hazardous Waste, Above Ground Storage Tanks, FDEP NOx Reduction Agreement, CAIR/CAMR/CAVR Compliance, Crist Water Conservation, and SO_2 Allowances.

Q. Please explain the variance of ($77,461) or (8.9%) in (Line item 1.6) General water.

A. General Water Quality (Line Item 1.6) includes costs associated with Soil Contamination Studies, Dechlorination, Groundwater Monitoring, Surface Water Studies, the Cooling Water Intake Program, the Impaired Waters Rule, and Storm Water Maintenance. This variance is primarily due to a delay in the issuance of a final 316(b) rule by the United States Environmental Protection Agency (EPA) which resulted in Gulf not performing work associated with that rule in 2012. The issuance of a final rule was expected in 2012, but the EPA has extended the issuance of the rule until June of 2013.

Q. Please explain the variance of $268,080 or 12.3% in (Line Item 1.7), Groundwater Contamination Investigation.

A. This line item includes expenses related to substation investigation and remediation activities. This variance is primarily due to additional excavation of contaminated soils that was required in 2012 that was not included in the estimated true-up filing. Additional soils were required to be excavated at the Highland City substation to bring it in compliance with the Florida Department of Environmental Protection Clean-up standards.

Q. Please explain the variance of $216,523 or 32.7% in (Line item 1.11), General Solid & Hazardous Waste.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This variance is primarily due to costs associated with transformer oil spills and associated disposal costs for Gulf's power delivery operations that were not projected. The exact number and cost of these events cannot be predicted in advance.

Q. Please explain the variance of ($93,897) or (65.7%) in (Line item 1.12), Above Ground Storage Tanks.

A. The above ground storage tank variance is primarily due to delaying the Plant Smith American Petroleum Institute API 653 inspections from fourth quarter 2012 to first quarter 2013. Contract negotiations with the company selected to perform the tank inspections took longer than originally anticipated. In addition, installation of level indicators on the Plant Crist turbine oil tank was not completed in 2012 as originally projected.

Q Please explain the variance of $1,141,688 or 56.0% 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 Crist Units 4 through 6 SNCR projects 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 Crist Unit 7 SCR requiring additional maintenance in the form of painting/corrosion control. The cost projection utilized in the Estimated True-up filing was based on preliminary estimates prior to receiving the actual cost proposal. The actual costs were higher because the painting required far more scaffolding costs than expected.

Q. Please explain the O&M variance ($208,225) or (1.4%) in the CAIR/CAMR/CAVR Compliance Program, (Line Item 1.20).

A. During 2012, the CAIR/CAMR/CAVR Compliance Program primarily includes O&M expenses associated with the Crist Units 4 through 7 scrubber and the Smith Units 1 and 2 SNCRs. More specifically, this line item includes the cost of urea, limestone, and general operation and maintenance activities included in Gulf's CAIR/CAMR/CAVR Compliance Program. This variance is primary due to the scrubber maintenance expenses being less than originally projected partially offset by an increase in limestone expenses which resulted in a net variance of ($208,225) or (1.4%).

Q. Please explain the O&M variance of ($72,972) or (39.0%) in the Crist Water Conservation Program (Line Item 1.22).

A. The Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system. This variance is primarily due to chemical and maintenance costs being less than originally projected.

Q. Please explain the variance of ($252,703) or (45.9 %) in SO_2 Allowances (Line Item 1.26).

A. This variance is the result of Gulf surrendering fewer SO_2 allowances than originally projected due to the lower utilization of the coal units as a result of low natural gas prices.

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibits of
James O. Vick
Docket No. 130007-EI
April 1, 2013

Q. Please state your name and business address.

A. My name is James O. Vick, and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed?

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

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

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Master's of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, 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 such 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. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?
A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?
A. The purpose of my testimony is to support Gulf Power Company's ("Gulf", "Gulf Power" or the "Company") 2013 Environmental Compliance Program Update. Specifically, I will support Gulf Power Company's Mercury and Air Toxics Standards (MATS) compliance strategy. Gulf's MATS compliance strategy for Plant Smith and Plant Crist is based on an economic evaluation performed by Gulf's witness Cain.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I am sponsoring two Exhibits, JOV-1 and JOV-2. Exhibit JOV-1, Gulf's 2013 Environmental Compliance Program Update (the "Compliance Program"), was prepared under my direction and control, and the

information contained therein is true and correct to the best of my knowledge and belief. Exhibit JOV-2 is the Federal Register publication of the MATS regulation.

Q. Mr. Vick, please provide an overview of the changes to Gulf's Compliance Program since the 2012 Compliance Program Update.

A. Gulf's Compliance Program Update for 2013 identifies the timing and current estimates of costs for specific projects planned by the Company in order to comply with the new MATS requirements along with information regarding the relative value of the planned projects compared to other viable compliance alternatives, if any. In addition, Gulf's 2013 Compliance Program Update provides a status update on projects that have already been approved by the Florida Public Service Commission ("FPSC" or "the Commission") in the Environmental Cost Recovery Clause (ECRC) as part of Gulf's Compliance Program. Gulf's 2013 Compliance Program Update also includes a description and results of the evaluation process that lead Gulf to conclude that the chosen means of compliance is the most reasonable, cost-effective alternative.

Q. Please describe the Mercury and Air Toxics Standards (MATS) regulation.

A. The MATS regulation imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The United States Environmental Protection Agency (EPA) issued the final MATS rule on February 16, 2012 with a compliance deadline of April 16, 2015 for existing sources. The MATS rule allows for one and two year extensions under limited circumstances.

Particulate matter compliance with the MATS limit of 0.03 lb/mmBtu will be demonstrated by the use of quarterly particulate emissions testing or particulate monitors. For generating units with a Flue Gas Desulfurization (FGD) scrubber, acid gas compliance may be demonstrated by a surrogate SO_2 Continuous Emission Monitoring System (CEMS) limit of 0.2 lb/mmBtu. For units without a scrubber, acid gas compliance can be demonstrated with a hydrochloric acid monitor or by quarterly testing to meet the MATS limit of 0.002 lb/mmBtu. Mercury compliance with the MATS limit of 1.2 lb/TBtu will be demonstrated using sorbent traps or CEMS mercury monitors located in the stack.

Q. Which of Gulf's generating units are affected by the new MATS rule requirements?

A. Gulf must address impacts of the MATS requirements for Plant Crist Units 4-7, Plant Daniel Units 1 and 2, Plant Smith Units 1 and 2, and Plant Scholz Units 1 and 2. My testimony will discuss the MATS compliance strategy selected for Gulf's Plant Crist and Plant Daniel. While Gulf has not completed its final compliance strategy for Plant Smith, I will discuss the first part of its MATS strategy for Plant Smith. I will also summarize the results of the Plant Scholz MATS evaluation.

Q. Please provide a summary of the alternatives Gulf Power considered in its MATS compliance strategy for these plants.

A. Gulf's MATS compliance analysis includes determining compliance alternatives for each site and conducting an economic/engineering evaluation for each applicable alternative. Compliance options considered include fuel switching, retrofitting the units with additional emission controls, unit retirement/replacement, and/or completing transmission system improvements.

Q. Please discuss how the MATS requirements will impact Plant Crist Units 4 through 7.

A. Available data indicates that during normal operation with the scrubber and SCRs in-service, Plant Crist should meet MATS requirements without any additional environmental controls. However, the MATS rule does limit the ability of the units to operate in the event of a scrubber malfunction or outage for any meaningful period of time without the installation of additional environmental controls. This mode of operation is termed "scrubber maintenance" or "scrubber bypass" mode. With the scrubber bypassed, the SO_2 and mercury emissions emitted from the bypass stacks would not meet their respective MATS limits, and Plant Crist would be unable to operate until the scrubber is back in service. This MATS limitation is an important consideration in evaluating MATS compliance for Plant Crist because generation from this plant helps meet reliability requirements for Gulf's transmission system. These transmission obligations dictate that Plant Crist be designated as a must-run facility. In scrubber by-pass mode with the MATS limitation making the units unavailable, Plant Crist cannot meet its must-run obligation.

Q. Please describe the options for compliance with MATS that were evaluated for Plant Crist.

A. Gulf identified four options to address the impact of the MATS requirements on Plant Crist. Each option is listed below and addressed in more detail in Exhibit JOV-1, pages 14-19.

Option 1- Natural Gas Generation

Option 2- Natural Gas & Coal Generation with Activated Carbon Injection (ACI) and Dry Sorbent Injection (DSI) Emission Controls

Option 3- Natural Gas and Transmission Upgrades

Option 4- Transmission Upgrades Only

Q. Mr. Vick, please summarize the results of the economic analysis of the MATS options for Plant Crist.

A. The economic analysis of the MATS compliance options for Plant Crist was performed by Gulf witness Cain. A detailed discussion of that evaluation and its results can be found in Section 3.3.1 of Gulf's Compliance Program (Exhibit JOV-1).

Option 4, Transmission Upgrades Only, has the lowest total NPV cost and the lowest risk of the available compliance options. The costs associated with Option 4 have a higher level of certainty, and the transmission upgrades do not cause any plant operational risks or costly must-run constraints. Option 4 has the benefit of removing the must-run requirement from Plant Crist, which will allow Gulf to operate the plant the most economically, generating a production cost savings for Gulf's customers.

Option 1 was eliminated from consideration due to it having the highest cost of the evaluated options. Option 2 was eliminated for both cost and operational reasons. Option 3 was eliminated for operational reasons and cost uncertainty. The low end of the cost range for Option 3 was comparable to, but still higher than, the lowest cost option, Option 4. The high end of the cost range for Option 3 was much higher than the cost of Option 4. The cost of Option 3 is also subject to future natural gas price volatility and other variable market conditions which leave Gulf's customers exposed to the risk of costly must-run operations rather than the benefit of operating the Plant Crist units in economic system dispatch. Additionally, this option required a commitment to generate with only natural gas firing during scrubber bypass. This operational constraint at Plant Crist would require an engineering study to more fully understand the challenges with this new mode of operation.

Q. Describe Gulf's MATS compliance strategy for Plant Crist.

A. After evaluation of the available options for compliance, Gulf has determined that construction of the transmission upgrades in Option 4, Transmission Upgrades Only, would be the best, most reasonable and cost-effective compliance strategy for Gulf to achieve and maintain compliance with the new MATS requirements. These transmission upgrades are the lowest cost MATS compliance option for Plant Crist. The transmission upgrades have a higher level of certainty than other available options and will not create any plant operational risks. The transmission upgrades will remove any must-run obligations for Plant Crist and allow the plant to operate under economic dispatch with significant cost savings to Gulf's customers.

Q. What is the projected cost of the Plant Crist Transmission Upgrades?

A. The projected capital cost for the Plant Crist transmission upgrades is approximately $76 million. The initial transmission upgrades are currently projected to be completed by April 2016 with the remaining projects being placed in-service by 2018.

Q. Please discuss how the MATS requirements will impact Plant Daniel Unit 1 and Unit 2.

A. Available emissions data from Plant Daniel as well as data from similar units (without scrubbers) indicates that Plant Daniel Units 1 and 2 can meet the MATS particulate matter (PM) limit with existing environmental controls, but will be unable to meet the acid gas and mercury limits imposed by the MATS rule. As discussed in previously approved Compliance Program Updates, the Company determined that at a minimum Plant Daniel Units 1 and 2 would require installation of the scrubbers in order to comply with MATS as well as CAIR, CAVR, and the anticipated NAAQS.

The scrubbers are currently under construction with projected in service dates of fourth quarter 2015. After the Plant Daniel scrubbers are installed, Plant Daniel will be able to meet the MATS acid gas limits but additional controls will be needed to reduce mercury emissions.

The available options for Plant Daniel Units 1 and 2 to achieve and maintain compliance with the MATS mercury emissions limit include installation of a baghouse with ACI or the use of ACI and bromine injection without a baghouse. The capital cost for baghouse installations is approximately $135 million more than the capital cost for bromine injection and ACI. Given the substantial cost difference in the two options for compliance, Gulf has selected bromine injection and ACI as the most reasonable, cost-effective compliance strategy for Plant Daniel Units 1 and 2. Both injection systems will be placed in service with the scrubber during fourth quarter of 2015.

Q. Please discuss how the MATS requirements will impact Plant Smith.

A. Plant Smith Units 1 and 2 are subject to the MATS rule. Plant Smith emissions data, as well as data from similar units, indicate that while the MATS particulate matter limit would be met, neither the acid gas nor the mercury limits can be met without additional environmental controls. As a result, Plant Smith Units 1 and 2 will be unable to generate past 2015 without the installation of environmental controls.

Q. Mr. Vick, describe the MATS compliance options evaluated for Plant Smith.

A. Available emission control systems were reviewed to determine the most cost-effective MATS emission controls for Plant Smith. The lowest cost emission control system for Plant Smith Units 1 and 2 consists of ACI, DSI, conversion of the hot precipitators to cold precipitators, and the use of low sulfur and low chloride coal. While these MATS controls would allow Plant Smith Units 1 and 2 to meet the MATS regulatory requirements, the controls would greatly increase the variable operating cost of Plant Smith Units 1 and 2 due to the heavy use of sorbent injection as well as the use of a premium-priced (low sulfur/low chloride) coal for both units.

In addition, generation from Plant Smith Units 1 and 2 is needed to meet transmission reliability requirements, making Plant Smith a must-run facility. Maintaining Plant Smith Units 1 and 2 as must-run units with an increase in operation costs for injection emission controls would have significant cost impacts to Gulf's customers over the remaining life of the two units.

For that reason, at Gulf's request, witness Cain evaluated two options that would allow for continued operation of Plant Smith Units 1 and 2: Option 1- install MATS controls and continue to operate the three Plant Smith units as must-run, and Option 2 - install MATS controls along with additional transmission upgrades to eliminate the must-run status of Plant Smith.

Q. Please summarize the results of the economic analysis of the MATS compliance options for Plant Smith Units 1 and 2.

A. The economic analysis of the options for compliance at Plant Smith Units 1 and 2 was performed by Gulf witness Cain. A detailed discussion of that evaluation and its results can be found in Section 3.3.3 of the Compliance Program (JOV-1). Gulf determined that Option 2, installing MATS controls along with additional transmission upgrades, is the most economic option for continued operation of Plant Smith Units 1 and 2 due to the high variable operating costs of Plant Smith Units 1 and 2 caused by MATS compliance. With Option 1 there is risk and uncertainty due to future fuel prices and CO_2 regulatory impacts. Option 2, MATS controls and transmission upgrades, had the lowest total NPV as well as lower risk and less uncertainty.

Q. What is Gulf's strategy for MATS compliance for Plant Smith Unit 1 and Unit 2?

A. Gulf has determined that the Option 2 transmission upgrade projects should be a part of its Plant Smith Units 1 and 2 MATS compliance strategy. As discussed in Section 3.3.3 of Gulf's Compliance Program, the transmission upgrades identified for Option 2 are the same transmission upgrades that are necessary if Plant Smith Units 1 and 2 retire. Replacement of Plant Smith Units 1 and 2 with new generation by 2015 is not a viable option leaving only retirement and advancement of these transmission upgrades or the installation of environmental controls and advancement of these same transmission upgrades as the only economically viable options. Therefore, the transmission upgrades identified in Option 2 will be part of the most economic strategy for MATS compliance for Plant Smith Units 1 and 2. Gulf proposes the addition of these transmission upgrades as the first part of its compliance strategy for Plant Smith to achieve and maintain cost-effective compliance with the MATS rule. Construction of the identified transmission upgrades preserves the decision to install MATS controls or to retire the two units for a future time when more is known with regard to costs of compliance requirements associated with additional environmental regulations. The Plant Smith Transmission Upgrades are currently projected to be placed in service in 2015 for MATS compliance. The capital cost for the Plant Smith Transmission Upgrades project is projected to be approximately $77 million.

Q. Please describe the results of Gulf's MATS evaluation for Plant Scholz.
A. In response to finalization and evaluation of the MATS rule, Gulf has decided to cease coal-fired operation of Plant Scholz as of April 1, 2015. Gulf has determined that it is not economical to add the environmental controls at Plant Scholz necessary to comply with MATS.

Q. Mr. Vick, please summarize your testimony.
A. Gulf's 2013 Environmental Compliance Program Update describes Gulf's ongoing compliance projects as well as new MATS compliance projects

selected for Plant Crist, Plant Daniel, and Plant Smith. The proposed Plant Daniel bromine and ACI Project, the Plant Crist Transmission Upgrades Project, and the Plant Smith Transmission Upgrades Project were added to Gulf's Compliance Program during 2013. Gulf Power is requesting approval of inclusion of these projects in the Company's Compliance Program.

The best option for MATS compliance at Plant Crist for Gulf's customers is to proceed with the identified transmission projects in order to allow Plant Crist to commit and dispatch in the most economic manner, while avoiding the installation of additional environmental controls.

For Plant Daniel, the Company has confirmed that bromine and ACI rather than more capital intensive controls such as baghouses will be sufficient to meet the final MATS mercury emissions standard.

Gulf has determined that the first part of the Plant Smith MATS compliance strategy will include installation of the transmission upgrades that are needed for MATS compliance in 2015. Gulf will submit revisions to its Environmental Compliance Program for the Commission's review after a decision is made to install additional MATS controls or to retire the units.

Gulf Power's Environmental Compliance Program, which is based upon analytically sound technical and economic evaluations of alternatives, is the most reasonable, cost effective compliance program available to Gulf and its customers under current planning assumptions. Gulf Power's environmental Compliance Program assures environmental compliance and preserves flexibility for dealing with ever changing requirements and assumptions. As shown in the cost analysis, each of the selected MATS compliance options is the lowest compliance cost and risk and therefore the best option for Gulf's customers.

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

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony
James O. Vick
Docket No. 130007-EI
August 1, 2013

Q. Please state your name and business address.

A. My name is James O. Vick, 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. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science degree in Marine Biology. I also hold a Bachelor's degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Master of Science degree in Management from Troy State University, Pensacola, Florida. In August 1978, I joined Gulf Power Company as an Associate Engineer and have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, 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. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?
A. Yes.

Q. Mr. Vick, 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 2013. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 2013 through December 2013 with the approved projected amounts.
A. As reflected in Mr. Dodd's Schedule 6E, the recoverable capital costs approved in the original projection total $120,835,974 as compared to the estimated true-up amount of $122,740,511. This results in a variance of $1,904,537 or 1.6%.

Q. Are there any factors that impact multiple capital projects?

A. Yes. The recoverable capital costs included in the estimated true-up calculation are approximately $2.2 million greater than the capital costs included in the 2013 Projection filing due to two items. One is the difference between the weighted average cost of capital (WACC) used in the 2013 Projection filing versus the WACC applied to the July through December 2013 period in this 2013 Estimated/Actual True-up filing. In accordance with Commission Order No. PSC-12-0425-PAA-EU, the 2013 Projection filing used the WACC presented in Gulf's May 2012 Earnings Surveillance Report for January through December 2013. In this 2013 Estimated/Actual True-Up filing, the projected July through December 2013 period uses the WACC presented in Gulf's May 2013 Earnings Surveillance Report. The second factor contributing to this variance is the impact of including the dismantlement costs in the 2013 Estimated/Actual True-up filing that were inadvertently omitted from Gulf's 2013 Projection filing. After taking these two items into consideration, there is a negative variance of approximately ($300,000) that is largely attributed to three capital projects: 1) the Crist 5, 6, & 7 Precipitator Projects ($255,505), 2) Substation Contamination Remediation ($34,116), and 3) Crist FDEP Agreement for Ozone Attainment ($82,917). The variances attributed to these programs will be discussed below.

Q. Please explain the capital variance of ($255,505) or (5.2%) reflected in the Crist 5, 6, & 7 Precipitator Projects (Line Item 1.2).

A. Plant Crist Unit 6 Precipitator upgrades were completed in 2012 and the total expenditures were less than anticipated. As a result, the carrying costs are lower than originally projected in the 2013 Projection Filing.

Q. Please explain the capital variance of ($34,116) or (20.4%) reflected in Substation Contamination Remediation (Line item 1.6).

A. This variance is primarily due to a delay in the Highland City substation site soil remediation project. This phase of the project is expected to be completed in September 2013 instead of mid 2013 as originally projected. This delay resulted in a decrease in carrying costs expenses.

Q. Please explain the capital variance of ($82,917) or (0.6%) reflected in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is attributed to the retirement of the Plant Crist Unit 6 SNCR that was not included in the 2013 Projection filing. As a result, the depreciation expenses were lower than anticipated.

Q. How do the estimated/actual 2013 O&M expenses compare to the original 2013 projections?

A. Mr. Dodd's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $23,784,222 as compared to $24,724,007. The Estimated/Actual expenses are $939,785 or 3.8% below the amount projected in the 2013 Projection Filing. I will address ten O&M projects and programs that contribute to this variance: Air Emission Fees, General Water Quality, General Solid & Hazardous Waste, Sodium Injection, FDEP NOx Reduction Agreement, CAIR/CAMR/CAVR Compliance Program, Crist Water Conservation, Annual NOx Allowances and SO2 Allowances.

Q. Please explain the O&M variance of ($103,590) or (16.4%) in (Line Item 1.2) Air Emission Fees.

A. The Air Emission Fees represent the expenses projected for the annual fees required by the Clean Air Act Amendments (CAAA) of 1990 that are payable to the FDEP and Mississippi Department of Environmental Quality. These fees are based on annual tons of emissions regulated under the Title V Air Program. Gulf's 2013 Air Emissions Fees are less than expected due to lower utilization of Gulf's coal-fired units than expected.

Q. Please explain the O&M variance of $536,563 or 63.0% in (Line item 1.6), the General Water Quality program.

A. The General Water Quality variance is primarily due to work on the Plant Crist impoundment pond that was necessary to maintain pond integrity in compliance with the Plant Crist National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit.

Q. Please explain the O&M variance of $78,769 or 16.8% in (Line item 1.11) General Solid and Hazardous Waste Program.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This variance is primarily due to costs associated with cleanup of transformer oil spills and disposal costs for Gulf's power delivery operations that were not projected.

Q. Please explain the O&M variance of ($30,410) or (41.1%) in Sodium Injection (Line item 1.16).

A. The line item variance is primarily due to chemical expenses being less than originally projected due to the lower than expected utilization of Gulf's coal-fired units at Plant Crist.

Q. Please explain the O&M variance of $238,602 or 14.3% 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 related to the activities undertaken in connection with the Plant Crist FDEP Agreement related to Ozone Attainment. This variance is primarily due to an increase in chemical expenses for the Plant Crist Unit 7 SCR the Plant Crist SNCRs. The Plant Crist Unit 7 SCR is projected to use more ammonia due to recent retuning of the unit. The cost increase for the

Plant Crist SNCRs urea is primarily due to an increase in the amount of urea needed for the Unit 4 and 5 SNCRs compared to the 2013 Projection filing.

Q. Please explain the O&M variance ($1,441,486) or (8.7%) in the CAIR/CAMR/CAVR Compliance Program, (Line Item 1.20).

A. The CAIR/CAMR/CAVR Compliance Program currently includes O&M expenses associated with the Plant Crist scrubber, the Crist Unit 6 SCR and the Smith Units 1 and 2 SNCRs. More specifically, this line item includes the cost of urea, ammonia, limestone, and general operation and maintenance activities included in Gulf's CAIR/CAMR/CAVR Compliance Program. The line item variance is primarily due to a decrease in the projected Plant Crist scrubber limestone expenses due to lower utilization of Gulf's coal-fired units than expected. This decrease is partially offset by expenses associated with the Plant Smith baghouse project which is no longer a viable compliance option.

Q. Please explain the O&M variance of ($48,470) or (16.6%) in the Crist Water Conservation Program (Line Item 1.22).

A. The Plant Crist Water Conservation line item includes general O&M expenses associated with the Plant Crist reclaimed water system. This variance is primarily due to projected chemical and maintenance costs being less than originally anticipated in the 2013 projection filing due to lower utilization of Plant Crist Unit 6 than expected.

Q. Please explain the O&M variance of ($76,022) or (18.4%) in Annual NOx Allowances (Line Item 1.24) and ($55,920) or (9.3%) in SO_2 Allowances (Line Item 1.26).

A. These variances resulted from Gulf surrendering fewer Annual NOx and SO_2 allowances due to lower utilization of Gulf's coal-fired units than expected.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 130007-EI
Date of Filing: August 30, 2013

Q. Please state your name and business address.

A. My name is James O. Vick, 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. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Master of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, 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 such 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. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?
A. Yes.

Q. Mr. Vick, 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 2014 through December 2014.

Q. Mr. Vick, 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, 4P, and 5P of Witness Dodd's Exhibit RWD-3. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects. Mr. Dodd compiled these schedules and has calculated the associated

revenue requirements for Gulf's requested recovery. Of the projects shown on Mr. Dodd's schedules, there are three programs that were previously approved by the Commission with activities that have projected capital expenditures during 2014. These programs include: Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, and the CAIR/NAAQS/MATS/CAVR Compliance program.

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

A. As stated in previous filings, Gulf has been conducting an engineering evaluation and testing to determine whether the existing Plant Smith site properties make it feasible for the deep well injection of used reclaimed water. Both the test injection well and monitoring well required by the Florida Department of Environmental Protection (FDEP) have been permitted and installed. Gulf conducted testing of the existing well and found that it is feasible to inject water into the injection well system. We are currently in phase two of the permitting process for converting the initial injection well (IW-1) into a Class I injection and are in the initial permitting phase for up to four additional wells. During the latter part of 2013 and into 2014, Gulf anticipates conducting further testing of the existing well, designing a pump system, installing the additional injection wells and conducting testing of the injection well system. Costs associated with these activities reflected in the 2014 projection filing are $8.8 million.

Q. Mr. Vick, please describe the project included in the 2014 projection for (Line Item 1.19) Crist FDEP Agreement for Ozone Attainment.

A. Gulf plans to replace one layer of the Plant Crist Unit 7 SCR catalyst during 2014. Based on the past usage and the remaining service hours, the catalyst in layer four needs to be replaced during the fall of 2014. The projected 2014 expenditures for this line item are $1.6 million.

Q. Mr. Vick, please describe the projected 2014 capital expenditures for the CAIR/NAAQS/MATS/CAVR Compliance program (Line Item 1.26).

A. The projected 2014 expenditures for this line item include new controls and monitoring equipment needed for Plant Daniel and Plant Crist to comply with the MATS regulation. Also, projected for this line item are capital retrofit projects for the Plant Crist scrubber and the Plant Crist Unit 6 SCR.

Q, Please discuss the controls and monitoring equipment needed to comply with the MATS regulations.

A. As discussed in Gulf's April 2013 Compliance Program update, Gulf Power has determined that bromine injection upstream of the precipitator with activated carbon injection (ACI) at Plant Daniel will be required to comply with the MATS mercury standards. Engineering, procurement, and construction of the Plant Daniel bromine and ACI systems are scheduled to begin in 2014 and last for approximately two years. The projected 2014 cost for Gulf's ownership portion of the Plant Daniel ACI and bromine injection projects is approximately $4.72 million. The ACI and bromine injection projects were included in Gulf's third supplemental petition regarding Gulf's environmental compliance program that was filed on April 1, 2013.

Gulf Power will begin installing mercury monitoring systems at Plant Daniel and Plant Crist in 2014 in order to comply with the MATS rule. The mercury monitors were included in Gulf's original Compliance Plan that was filed on March 29, 2007. The Plant Daniel and Plant Crist mercury monitors were two of the 10 specific components of Gulf's program that were agreed to as part of a stipulation approved on August 14, 2007. The stipulation is included in Order No. PSC-07-0721-S-EI. The projected cost for the mercury monitoring systems is $2.72 million.

Q, Please discuss the capital retrofit projects planned for the Plant Crist Unit 6 SCR and the Plant Crist scrubber.

A. A new catalyst layer will be purchased in late 2014 for installation in the Plant Crist Unit 6 SCR during the 2015 spring outage. The 2014 projected cost for the catalyst is $557,000.

Gulf Power has two scrubber retrofit projects planned for the Plant Crist scrubber system during 2014. The first retrofit project includes replacing the operating and engineering control systems with equipment that runs on an updated Windows operating system. The software upgrades are needed to maintain compliance with Gulf's cyber security requirements. The 2014 projected cost for the scrubber controls upgrade is $353,373.

The second scrubber retrofit project includes replacing two of the scrubber system raw water pumps. The pumps have previously been rebuilt and repaired over time, but have reached the point where they must be replaced. The projected cost to replace the water pumps is $281,000.

Q. Mr. Vick, are you including the purchase of allowances in your 2014 projection filing?

A. No, we are not currently projecting the need to purchase additional allowances during 2014.

Q. Mr. Vick, please provide an update on the status of the Plant Daniel scrubber projects?

A. Gulf Power is nearing completion of the engineering, design, and procurement phases of the Plant Daniel scrubber projects. The primary construction activities that are occurring in 2013 include foundation development as well as stack and vessel construction. As of July 2013, foundations for the vessels, stack, fans, process tanks, and duct supports have been completed. The stack shell has been poured and 50% of the stack liners have been fabricated. Axial fan, process vessel, and ductwork construction have begun. Over 770 tons of structural steel to support the ductwork has been installed. The 2014 capital expenditures for Gulf's ownership portion of the scrubber are projected to be $106 million. This project qualifies for AFUDC treatment and therefore these expenditures are not included in Gulf's projected 2014 ECRC factor.

Q. How do the projected Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Mr. Dodd's Exhibit RWD-3 compare to the O&M activities approved for cost recovery in past ECRC proceedings?

A. All of the O&M activities 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 2014.

A. There are five O&M activities included in the air quality category that have projected expenses in 2014. 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 that are payable to the FDEP and Mississippi Department of Environmental Quality. The expenses projected for the 2014 recovery period total $471,000.

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 2014 estimated expenses for the Title V Program are $135,771.

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 projected expenses for this line item are $1,500. 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 expenses expected to be incurred during the 2014 recovery period for these activities total $673,160.

The FDEP NOx Reduction Agreement (Line Item 1.19) includes 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. 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 projected expenses for the 2014 recovery period total $2.9 million which includes $1 million for the exterior surface maintenance project for the Plant Crist Unit 7 SCR.

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, Surface Water Studies, the Cooling Water Intake Program, the Impaired Waters Rule, and Stormwater Maintenance. The expenses expected to be incurred during the projection period for this line item totals $3.3 million. The projected cost includes approximately $1.8 million for dredging the Plant Crist ash pond to increase retention time and $680,000 for the cooling water intake program 316(b) studies at Plant Crist and Plant Smith.

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 $2.6 million of incremental expenses for this line item during the 2014 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 for Gulf's three generating facilities in Florida. These expenses are expected to be $57,000 during the projected recovery period.

Finally, 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 $16,476 during the 2014 projection period.

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. Dodd's Exhibit RWD-3. 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. Expenses totaling $7,000 are expected during the 2014 recovery period.

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

A. This solid and hazardous waste activity 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. This program is a previously approved program that is projected to incur incremental expenses totaling $582,573 in 2014.

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

A. There are five other O&M activities that have been approved in past proceedings which have projected expenses during 2014. They are the Above Ground Storage Tanks program, the Sodium Injection System, the CAIR/NAAQS/MATS/CAVR Compliance Program, Crist Water Conservation, and Emission Allowances.

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

A. Above Ground Storage Tanks (Line Item 1.12) includes maintenance activities and fees required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $144,613 are projected to be incurred during 2014.

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 and Plant Smith. Expenses totaling $40,000 are projected to be incurred during 2014 for this line item.

Q. What activities are included in the CAIR/NAAQS/MATS/CAVR Compliance Program (Line Item 1.20)?

A. This line item includes O&M expenses associated with the capital projects approved for ECRC recovery under the CAIR/NAAQS/MATS/CAVR Compliance Program. This line item includes the cost of anhydrous ammonia, hydrated lime, urea, limestone and general O&M expenses. The projected 2014 expenses for this line item total approximately $15.9 million which includes $7.2 million for limestone costs associated with operation of the Plant Crist scrubber.

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 system, such as piping and valve maintenance and pump replacements. Expenses totaling $297,430 are projected to be incurred during 2014 for this line item.

Q. Please describe the emission allowance line items 1.24 and 1.26.

A. These line items include projected allowance expenses for Gulf's generation. Line Items 1.24 and 1.26 include projected expenses for the Annual NOx and SO_2 allowances of $184,394 and $654,837 respectively.

Q. Do each of the capital projects and O&M activities that have projected costs in 2014 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2014 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. Dodd'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. Vick, are you familiar with the purpose of Witness O'Sheasy's testimony in this proceeding?

A. Yes. Witness O'Sheasy discusses and recommends an enhancement to the manner in which certain clean air and other air quality capital costs are allocated within the Environmental Cost Recovery Clause. I agree with Witness O'Sheasy's recommendation regarding cost allocation of certain clean air and other air quality capital costs.

Q. Mr. O'Sheasy quotes a 1994 Order referencing the Clean Air Act Amendments of 1990 (CAAA) as the Commission's reason for the current ECRC cost allocation method. Did the CAAA change Gulf's approach towards compliance with air quality legislation/regulation?

A. Yes. The passage of the CAAA marked a shift from traditional "command and control" environmental regulation to a "market-based' or "Cap and Trade" regulatory paradigm.

Prior to the CAAA, compliance with air quality regulations was typically achieved by a "command and control" approach. This meant that in order to comply with a specific emission limit or an ambient air quality standard, a company would be required to design, construct and operate a physical piece of pollution control equipment. An example of this would be the design, construction and operation of an electrostatic precipitator (ESP) to capture particulate matter that is produced when coal is burned. The sole purpose of the ESP is to physically capture and remove particulate matter (typically >99.9% removal) from the flue gas in order to meet a particulate emission standard or limit that has been imposed by an air operating permit. In other words, the precipitator is the "control" that is put in place in order to meet the emission standard or the "command". Gulf Power installed ESPs on all of its coal-fired units during the 1970's through the mid-1990's to meet the command and control regulations. This fixed piece of pollution control equipment performs the same functions today as it did then.

Q. How did the passage of the CAAA change this regulatory paradigm?

A. The CAAA introduced the first "market-based" approach to reducing certain air emissions. This has also been referred to as a "cap and trade" regulatory program. The CAAA and its innovative cap and trade program, for the first time, allowed Gulf Power and the rest of the electric utility industry a degree of flexibility in determining how to comply with the new requirements.

Q. Please discuss the concept of a cap and trade regulatory program.

A. A cap and trade program is a market-based approach to reducing emissions. The concept is: the U.S. Environmental Protection Agency (EPA) caps, or limits, the total annual or seasonal mass emissions of a pollutant such as SO_2. The cap is divided into emission allowances that are allocated to each affected source. Each emission allowance represents an authorization to emit one ton of SO_2 over a specified time period (e.g., calendar year). To demonstrate compliance, a source is required to hold a number of allowances greater than or equal to its emissions in the regulated time period. Since the total number of allowances allocated to the affected sources is less than the pre-program ("baseline") mass emissions from those sources, the program reduces the mass emissions of the regulated pollutant.

This market-based approach allows sources to determine the most cost-effective way to comply. Sources may reduce emissions by investing in pollution control technologies (i.e. scrubbers, SCRs, and/or baghouses), employing energy conservation measures, reducing utilization, switching fuels, or other strategies. Sources also are allowed to buy and sell allowances from each other to ensure that each unit has enough allowance credits in its account to cover its emissions. In this manner, a cap and trade program reduces emissions at a lower cost than traditional pollution control regulations and policies, by setting a goal and allowing market forces to determine how the goal is met.

Q. What strategy did Gulf Power utilize to comply with the CAAA?

A. Phase I of CAAA became effective on January 1, 1995, with a nationwide cap set for SO_2. Gulf Power's primary strategy to comply with the SO_2 cap consisted of fuel switching to a low sulfur coal supply. Gulf's allowance allocation was based on a higher sulfur coal that had been burned during the historical baseline period. This resulted in Gulf Power banking SO_2 allowances in some years and having to go to the market to purchase SO_2 allowances in other years when its emissions were higher than our allocation. Therefore, the cost of compliance varied with the generation (kWh) output of Gulf's generating plants. This strategy was very cost-effective in meeting the CAAA requirements for SO_2. The allowance market provided Gulf the flexibility to defer making significant capital investments in SO_2 pollution control equipment such as scrubbers.

Q. Is Gulf Power's strategy to comply with air quality legislation/regulation the same today as it was in 1994 when the ECRC mechanism was first established for Gulf?

A. No. In the last few years, Gulf Power and the rest of the utility industry have had to reevaluate their strategy as it relates to complying with today's environmental laws and regulations. Although the CAAA and its cap and trade program are still in place today and have proven that a market-based approach to pollution control can be a very cost-effective tool to achieve significant reductions in air emissions, the new environmental air regulations in today's regulatory environment are largely based on the old command and control philosophy that existed prior to the CAAA.

Command and control regulations such as the Mercury Air Toxics Standards (MATS) and the Clean Air Visibility Rule (CAVR) have very stringent emission limits for numerous pollutants. There are no cap and trade or allowance programs for pollutants such as mercury. The only options a utility has to comply with such rules are to either make significant capital investments in fixed pollution control equipment such as scrubbers, SCRs, and baghouses, as a retrofit to existing generating units or to close the units permanently. The required pollution control equipment of this nature is a fixed cost—it is there whether the generating unit runs or not. A consequence of these command and control regulations is that the widespread introduction of pollution control equipment such as scrubbers, SCRs and baghouses have all but eliminated the allowance markets.

In summary, the CAAA gave the utility industry the flexibility as to how it would comply with the CAAA requirements and incentivized the achievement of emission reductions in the most economic manner. Utilities could invest significant capital in large fixed pieces of pollution control equipment or purchase allowances that would allow the utilities to continue to operate without significant capital expenditures. The regulations the industry faces today are a throwback to the command and control type. The only option available to utilities, short of retiring the plant, is to make significant capital investments in state-of-the-art pollution control equipment.

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

A. Yes.

nature is a fixed cost—it is there whether the generating unit runs or not. A consequence of these command and control regulations is that the widespread introduction of pollution control equipment such as scrubbers, SCRs and baghouses have all but eliminated the allowance markets.

In summary, the CAAA gave the utility industry the flexibility as to how it would comply with the CAAA requirements and incentivized the achievement of emission reductions in the most economic manner. Utilities could invest significant capital in large fixed pieces of pollution control equipment or purchase allowances that would allow the utilities to continue to operate without significant capital expenditures. The regulations the industry faces today are a throwback to the command and control type. The only option available to utilities, short of retiring the plant, is to make significant capital investments in state-of-the-art pollution control equipment.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael T. O'Sheasy
Docket No. 130007-EI
Date of Filing: August 30, 2013

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

A. My name is Michael T. O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice President with Christensen Associates, Inc.

Q. State briefly your education background and experience.

A. I received a Bachelor of Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Masters in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company -- Division of the Carnation Company -- as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant, and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position of supervisor, during which time I began serving as an expert witness in costing. I testified as Gulf Power Company's (Gulf, or the Company) cost-of-service witness and provided other support to Gulf in matters before the Florida Public Service Commission (FPSC, or the Commission). In 1990, I became Manager of Product Design for Georgia Power Company and have testified before the Georgia Public Service Commission as an expert witness on rate design and pricing. I retired from Georgia Power Company on May 1, 2001 and became a consultant with Christensen Associates.

Q. Are you the same Michael T. O'Sheasy who is presently the cost-of-service witness for the Gulf Power Company in Docket No 130140-EI?

A. Yes.

Q. Please identify the specific dockets in which you have previously testified before the FPSC.

A. I testified before the FPSC on behalf of Gulf as their cost-of-service witness in their last rate case filing, Docket No. 110138-EI, and in prior rate cases in Docket Nos. 010949-EI, 891345-EI and 881167-EI. I was extensively involved in the preparation of exhibits and Minimum Filing Requirements (MFRs) in those cases. Also, I was the back-up cost-of-service witness for Gulf in its 1984 rate case, Docket No. 840086-EI, where I helped prepare the related analyses. I also testified in Docket No. 850673-EU regarding standby back-up electric service.

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

A. The purpose of my testimony is to discuss and recommend an enhancement to the manner in which certain clean air and other air quality capital costs which are recovered in the Environmental Cost Recovery

Clause (ECRC) are allocated to the retail jurisdiction and then to each rate class within the clause.

Q. Are your comments and recommendation in this testimony dealing strictly with the allocation of clean air and other air quality projects' capital costs?

A. Yes.

Q. How are ECRC capital costs currently allocated in ECRC to rate class?

A. Clean air and other air quality projects' capital costs are allocated upon energy. This is different from all other environmental capital costs recovered through the ECRC which are allocated upon 12-MCP and 1/13 energy, the same methodology used in Gulf's base rates.

Q. Is the current allocation methodology used in ECRC the same methodology Gulf Power Company recommended in its original ECRC filing?

A. No. In Gulf's initial ECRC filing back in 1993, the Company recommended that capital cost associated with the Clean Air Act Amendments of 1990 (CAAA) be allocated upon 12-MCP and 1/13 energy which was the Commission accepted allocation methodology from Gulf's prior base rate case filing for production related capital costs and all rate cases since. Then and now, Gulf's recommended methodology allocates most of these cost upon each rate class's contribution to Gulf's 12 monthly system peak hours.

Q. What was the explanation by the Commission in 1994 for the Commission ordering an energy allocator to rate class instead of Gulf's filed 12-MCP and 1/13 energy?

A. In Docket No. 930613-EI, Order No. PSC-94-0044-FOF-EI at page 23, the following explanation was provided:

> *We find that those costs required for compliance with the Clean Air Act Amendments of 1990 (CAAA) shall be allocated to the rate classes on an per kilowatt hour, or energy basis. Such an energy allocation is appropriate because the purpose of the CAAA is to reduce the level of emissions of air pollutants such as sulphur dioxide and nitrogen oxides. The level of the emissions of such pollutants is dependent in large part on how many kilowatt hours are generated. (TR 396) Consequently, we find that an energy allocation method results in the most equitable apportionment of these particular compliance costs. We have adopted this treatment of environmental compliance costs has been adopted in the past: in Tampa Electric Company's last rate case, the approved cost-of-service study classified and allocated the costs of the scrubber on its Big Bend 4 coal plant on an energy basis. (Docket No. 920324-EI)*

Q. Do you agree that continued use of a simple energy allocator for CAAA and other air quality capital costs recovered through the ECRC is appropriate?

A. No, I do not. I recommend the use of 12-MCP and 1/13 energy allocation methodology for these capital costs for the following reasons:

a. A simple energy allocator is not consistent with cost causation for these costs which do not vary with kWh unit output.
b. These CAAA and other air quality capital cost are fixed in nature and justify a fixed cost allocator.
c. A simple energy allocator is not consistent with how these costs would be allocated in a cost-of-service study for similar investments recovered through base rates.
d. The impact upon rates and customer bills of using a simple energy allocator in setting ECRC cost recovery rates is not cost-based.

Q. Why do you believe that a simple energy allocator is inappropriate and does not best reflect cost causation for CAAA and other air quality capital cost allocation?

A. A common cost-of-service philosophy is that capital costs, when incurred, become fixed costs, and fixed costs are demand-related. Costs that are influenced by other activities (such as the output of a power plant) and fluctuate as those activities change are considered variable. Therefore, variable costs are deemed energy-related. [I am excluding the cost categories known as customer and revenue related as they are not applicable to this discussion.] Much of the CAAA costs are fixed as stated by this Commission in Order No. PSC-94-0044-FOF-EI at page 24:

> *We do not take issue with the fact that many of the costs associated with CAAA compliance are fixed costs, and that they are sized to meet peak demands.*

This commission has preferred a 12-MCP and 1/13 energy allocator for Gulf Power's production capital cost in prior Gulf Power base rate cases, and Gulf has agreed to do so. We are merely requesting that these fixed CAAA and other air quality capital cost be allocated similarly in ECRC. This will also align clean air and other air quality capital cost allocation with the allocation of all other capital cost recovered in the ECRC.

Q. What was the basis in the 1994 order for allocating these capital/fixed costs upon a variable (energy) allocator?

A. The Commission's order indicated that it was more appropriate to consider the "purpose" and the effect that these costs would have which would be to lower emissions of pollutants and thereby meet legislative requirements. The order further suggests that these pollutants are in large part a function of the number of kWh produced and therefore concluded that equipment to reduce the pollutants must therefore be energy related.

Q Do you agree that the ultimate "purpose" of the CAAA and other air quality capital cost is to reduce the emission of air pollutants?

A. Yes, however while incurring these capital costs does indeed reduce emissions of pollutants from what they would otherwise be, the fact is that they are fixed in nature and deserving of a fixed cost allocator. As discussed in Witness Vick's testimony, over time environmental regulations have moved from a "command and control" approach to a "cap and trade" program and now back to a "command and control" philosophy. Under cap and trade, compliance options such as allowances or fuel switching lend support to an energy allocator for these compliance costs. As stated by Mr. Vick in his testimony, under the cap and trade philosophy "…the cost of compliance varied with the generation (kWh) output of Gulf's generating plants." However, as Mr. Vick further states in his testimony, under the current command and control philosophy "…the required pollution control equipment of this nature is a fixed cost—it is there whether the generating unit runs or not." Once incurred, these significant fixed capital investments in environmental control equipment do not vary with kWh output or kWh sales for the rate classes.

This is analogous to the requirement written years ago in the automotive industry to require catalytic converters on cars. The cost incurred to equip a vehicle with a catalytic converter is generally the same (fixed), regardless of the amount of emissions the car's engine produces. Another example is Occupational Safety and Health Act (OSHA) requiring certain safety measures for all industries including the electricity industry to construct and operate a plant (note even though the purpose of these safety related fixed costs are to protect employees in an electricity generating plant, we don't allocate these costs upon employees or customers). Another example is fuel handling equipment which enables more or less energy to be produced depending upon how much fuel is input by the fuel handling equipment. But, fuel handling equipment is a capital cost requirement for a production plant and, therefore, a fixed cost to be allocated upon a production plant fixed cost allocator. In the case of Gulf Power Company the fixed capital cost of production plant are allocated upon 12-MCP and 1/13 energy.

Simply put, the environmental regulations for a production plant in effect today require additional costs to allow for the continued operation of the plant. However, these additional costs are not significantly influenced by the amount of energy (kWh) expected to be or actually produced by the plant. While the end result of this environmental equipment is lowered emissions, the cost is still fixed.

Q. What are some types of CAAA and other air quality equipment that are fixed cost and not variable costs?

A. Some examples include:

1. Capital cost of the Plant Crist scrubber (enables lower SO_2 and mercury emissions)
2. Capital cost of Selective Catalytic Reduction (SCR) equipment (enables lower NO_x emissions)
   Capital cost of Selective Non-Catalytic Reduction (SNCR) equipment (enables lower NO_x emissions)
3. Capital cost of over-fired air equipment (enables lower NO_x emissions)

4. Capital cost of low NO_x burners (enables lower NO_x emissions) Note that the significant investment cost of each of these items is not dependent on the kWh output of the generator.

Q. How would these CAAA and other air quality fixed costs be treated in an embedded cost-of-service study?

A. Since they are fixed production costs, they would have been allocated to rate class upon 12-MCP and 1/13 energy which is the Commission approved allocation methodology for fixed production cost ordered in Gulf Power Company's last rate case - Docket No. 110138-EI.

These fixed costs are not like fuel cost found within the fuel cost recovery clause which are "allocated" to customers on a per kWh basis. Fuel costs do vary with kWh usage. CAAA and other air quality capital related environmental costs do not vary with kWh usage.

Q. What is the impact on customers of an energy only allocator of CAAA and other air quality fixed costs as opposed to 12-MCP and 1/13 energy allocator?

A. In general, high load factor customers receive more cost allocation under an energy only allocator than under a 12-MCP and 1/13 energy allocator. Low load factor customers receive less cost allocation under an energy only allocator than under a 12-MCP and 1/13 energy allocator. However the "impact" should not be the driver in how costs are to be allocated – the driver should be cost causation. The present ECRC clause is less cost based than it would otherwise be if 12-MCP and 1/13 energy were used as the allocator to rate class, and therefore Gulf is requesting this change to cost allocation. The ultimate "impact" of this cost allocation improvement on customer rates and bills is addressed by Witness Dodd.

SUMMARY

Q. Can you summarize your opinion on ECRC cost allocation?

A. Cost allocation whether within an embedded cost-of-service study or a cost-based recovery clause should be conducted upon cost causation. A guiding principle of cost of service is that it should reflect cost causation:

a. *"FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation."*[1]

b. *"To attribute costs to different categories of customers based on how those customers cause cost to be incurred"*[2]

c. *"A cost-of-service study is a model of utility accounting and financial data which relies on various engineering data and concepts to appropriately assign the detailed cost elements to the customer groups using the principle of cost causation."*[3]

Cost should not be allocated upon benefits of the cost incurred nor the purpose/intention of the cost incurred – for example the benefits and purpose of an owner's automobile are to transport the owner from one place to another, yet auto manufacturers do not sell them on distance to be traveled; they sell them with a consideration of the fixed cost to produce. The CAAA and other air quality compliance costs are required and integral to the planning and operation of a production plant just as are

[1] "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers", Third Edition, Edison Electric Institute, 1994.

[2] "Electric Utility Cost Allocation", Overview of Cost of Service Studies and Cost Allocation – Chapter 2, NARUC, 1992.

[3] "Electricity Pricing: Engineering Principles and Methodologies" Mr.Lawrence J. Vogt, 2009.

boilers, turbines, and fuel handling equipment. This CAAA and other air quality compliance equipment is generally designed on the size of the plant and does not vary with the plant's kWh output.

Neither the end result use or "purpose" of a piece of equipment nor the benefits of a piece of equipment should dictate how its cost is allocated—cost causation should drive cost allocation. The overarching cause for these CAAA and other air quality related fixed costs to have been incurred were to enable a production technology choice to be licensed to function, and to operate within legislative requirements. They are "part and parcel" to the composite plant and should receive a 12-MCP and 1/13 allocation to rate class.

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

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 130007-EI
Date of Filing: April 1, 2013

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Regulatory and Cost Recovery area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery Department.

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 2012 through December 2012 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. Dodd's exhibit consisting of nine schedules be marked as Exhibit No. _____ (RWD-1).

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2012 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 amount to be refunded or collected in the recovery period beginning January 2014?

A. An amount to be collected of $3,704,022 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $3,704,022 to be collected was calculated by taking the difference between the estimated January 2012 through December 2012 over-recovery of $7,453,359 as approved in FPSC Order No. PSC-12-0613-FOF-EI, dated November 16, 2012, and the actual over-recovery of $3,749,337, which is the sum of lines 5, 6 and 9 on Schedule 2A of my exhibit.

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

A. Schedule 2A shows the calculation of the actual over-recovery of environmental costs for the period January 2012 through December 2012. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. This 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 2012 through December 2012 with the estimated/actual O&M expenses approved in conjunction with the November 2012 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. Vick's final true-up testimony.

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

A. Schedule 6A for the period January 2012 through December 2012 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2012 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. 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. Vick's final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 31 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, and the cost of emission allowances. Pages 1 through 27 of Schedule 8A show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and costs related to emission allowances.

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

A. Consistent with Commission policy, the capital structure used in calculating the rate of return for recovery clause purposes is based on the capital structure approved in Gulf's last completed rate case. For the period January 2012 through April 10, 2012, the rate of return for the ECRC is based on the capital structure approved in Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI dated June 10, 2002. Gulf's new base rates resulting from its recent base rate case, Docket No. 110138-EI, were effective April 11, 2012. Therefore, the rate of return used to calculate the ECRC revenue requirements for the period April 11, 2012 through December 31, 2012 is based on the capital structure and a return on equity of 10.25% approved in this proceeding.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 130007-EI
Date of Filing: August 1, 2013

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

A. My name is Richard W. Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts degree in Accounting. I also received a Bachelor of Science degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department. In 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Regulatory and Cost Recovery area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

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 2013 through December 2013 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. My exhibit consists of nine schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of nine schedules be marked as Exhibit No. _____(RWD-2).

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

A. Yes, I have.

Q. What has Gulf calculated as the estimated true-up for the January 2013 through December 2013 period to be refunded or collected in the period January 2013 through December 2014?

A. The estimated true-up for the current period is an under-recovery of $4,084,856 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be added to the 2012 final true-up under-recovery amount of $3,704,022. The sum of $7,788,878 will be collected from customers during the January 2014 through December 2014 period. The detailed calculations supporting the estimated true-up for 2013 are contained in Schedules 2E through 8E.

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

A. Schedule 2E shows the calculation of the estimated under-recovery of environmental costs for the period January 2013 through December 2013. Schedule 3E of my exhibit is the calculation of the interest provision on the average true-up balance. This 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 4E and 5E of your exhibit.

A. Schedule 4E compares the estimated/actual O&M expenses for the period January 2013 through December 2013 to the projected O&M expenses approved by the Commission in Docket No. 120007-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. Per the Staff's request, emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Mr. Vick describes the main reasons for the expected variances in O&M expenses in his true-up testimony.

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

A. Schedule 6E for the period January 2013 through December 2013 compares the estimated/actual recoverable costs related to investment to the projected amount approved in Docket No. 120007-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. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements. Mr. Vick describes the major variances in recoverable costs related to environmental investment for this estimated true-up period in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 31 pages that provide the monthly calculations of recoverable costs associated with each approved capital investment for the current recovery period. As stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the return on working capital associated with emission allowances. Pages 1 through 27 of Schedule 8E show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and return related to emission allowances.

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?

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 2013 through June 2013 is based on the weighted average cost of capital (WACC) presented in Gulf's May 2012 Earnings Surveillance Report. For July 2013 through December 2013 the rate of return used is the WACC presented in Gulf's May 2013 Earnings Surveillance Report. The WACC for both periods includes a return on equity of 10.25%.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 130007-EI
Date of Filing: August 30, 2013

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

A. My name is Richard W. Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Regulatory and Cost Recovery area. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery Department.

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 2014 through December 2014.

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

A. Yes, I have two separate exhibits I am sponsoring as part of this testimony. Exhibit RWD-3 consists of 8 schedules that present the projected recoverable costs for 2014 and resulting cost recovery factors utilizing the $12/13^{th}$ demand and $1/13^{th}$ energy (12-MCP and $1/13^{th}$ energy) cost allocation methodology for investment-related costs that Gulf has proposed in this filing and that Witness O'Sheasy supports in his testimony filed in this docket. Exhibit RWD-4 presents a comparison of typical monthly customer bills using Gulf's proposed allocation methodology and the methodology historically used.

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

A. As discussed in the testimony of Witness James O. Vick, 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 we have 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. Vick has provided me with projected recoverable O&M expenses for January 2014 through December 2014. Schedule 2P of Exhibit RWD-3 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 in Docket No. 110138-EI.

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

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. These schedules also include the calculation of the jurisdictional amount of recoverable revenue requirements. Mr. Vick has provided me with 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 approved January 2012 through December 2012 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 applicable tax rate to taxable investment. In Florida, pollution control facilities are taxed based only on their salvage value. For the recoverable environmental investment located in Florida, the amount of property taxes is estimated to be $0. In Mississippi, there is no such reduction in property taxes for pollution control facilities. Therefore, property taxes related to recoverable environmental investment at Plant Daniel are calculated by applying the applicable millage rate to the assessed value of the property.

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) presented in Gulf's May 2013 Earnings Surveillance Report. This rate of return used to calculate ECRC revenue requirements includes a return on equity of 10.25 percent for the period January 1, 2014 through December 31, 2014.

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

A. Historically, investment costs incurred for compliance with air quality related environmental regulations were treated as energy-related per Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994, in Docket No. 930613-EI. The remaining investment costs of environmental compliance were allocated based on the 12-MCP and 1/13th energy allocator that is consistent with cost-of-service studies approved in Gulf's base rate cases for over 30 years and proposed in the current base rate case. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P of Exhibit RWD-3.

Q Is Gulf proposing a modification as to how the investment costs recovered in the ECRC are broken down between energy-related and demand-related in this proceeding?

A. Yes, as presented in Witness O'Sheasy's testimony, Gulf proposes that investment costs incurred for compliance with air quality environmental regulations recoverable through ECRC be broken down within the retail jurisdiction in the same manner as other investment costs of environmental compliance which are based on the 12-MCP and 1/13th energy allocator. As noted earlier, use of this allocator is consistent with cost-of-service studies approved in Gulf's prior base rate cases. Gulf proposes that this change be made effective January 1, 2014.

Q. Why is Gulf proposing this change in allocation methodology for investment costs incurred for compliance with air quality environmental regulations recoverable through ECRC?

A. As discussed at length in Mr. O'Sheasy's testimony, Gulf's proposed change to the 12-MCP and 1/13th energy allocator is a more appropriate cost recognition for the investment-related (fixed) costs incurred to comply with environmental regulations. Based on Mr. O'Sheasy's testimony, it is my understanding that allocating these costs to the various rate classes based on their cost causation provides for derivation of a cost recovery factor that best represents the cost incurred for each class.

Q. Is Gulf also proposing to change how air quality environmental compliance investment costs are allocated between the retail and wholesale jurisdictions?

A Yes. Consistent with the methodology presented by Mr. O'Sheasy, Gulf is proposing to allocate all ECRC investment costs, including air quality costs, to the retail and wholesale jurisdictions based on the 12-MCP and 1/13th energy allocator.

Q. What is the total amount of projected recoverable costs related to the period January 2014 through December 2014?

A. The total projected jurisdictional recoverable costs for the period January 2014 through December 2014 is $142,486,731 as shown on line 1c of Schedule 1P of Exhibit RWD-3. This includes costs related to O&M activities of $27,166,217 and costs related to capital projects of $115,320,514 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2014 through December 2014 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $150,383,807 for the period January 2014 through December 2014 as shown on line 5 of Schedule 1P of Exhibit RWD-3. This amount includes the recoverable costs related to the projection period and the total true-up cost of $7,788,878 to be collected. 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 Schedules 6P and 7P of Exhibit RWD-3.

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

A. The demand allocation factors used in the ECRC were calculated using the 2012 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. 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 one through nine on Schedule 6P of Exhibit RWD-3.

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

A. As I described earlier in my testimony, Schedule 1P of Exhibit RWD-3 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $36,545,383 for the period January 2014 through December 2014 was allocated using the energy allocator, as shown in column three on Schedule 7P of Exhibit RWD-3. The demand-related recoverable revenue requirement of $113,838,425 for the period January 2014 through December 2014 was allocated using the demand allocator, as shown in column four 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 five.

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 $15.54 monthly for the period January 2014 through December 2014.

Q. Have you quantified the impact of implementing Gulf's proposed 12-MCP and 1/13th energy cost allocation methodology for air quality investment costs?

A. Yes. My Exhibit RWD-4 presents a comparison of typical monthly bill amounts for residential and some non-residential rates using the proposed 12-MCP and 1/13th energy cost allocation methodology for air quality investment costs versus the historical energy cost allocation methodology.

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 2014 and will continue through the last billing cycle of December 2014.

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

A. Yes.

CHAIRMAN BRISÉ: Exhibits.

MR. MURPHY: Staff has prepared a Stipulated Comprehensive Exhibit List which includes the prefiled exhibits attached to the witnesses' testimony and staff's 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.

One late-filed deposition exhibit and several deposition errata sheets are missing from the deposition transcripts. The missing exhibit is identified on the exhibit list with a notation that it will be introduced in the December hearing.

CHAIRMAN BRISÉ: All right. Thank you.

Are you seeking to move some exhibits into the record?

MR. MURPHY: Yes, sir. At this time staff would like to move Exhibits 1 through 61 into the record as set forth in the Comprehensive Exhibit List.

CHAIRMAN BRISÉ: Okay. We will move Exhibits 1 through 61 into the record as set forth in the Comprehensive Exhibit List, seeing no objections.

(Exhibits 1 through 61 marked for identification and admitted into the record.)

CHAIRMAN BRISÉ: Okay. Commissioners? Go ahead.

MR. MURPHY: Well, since there are proposed stipulations on all the issues except those related to FPL's NO2 compliance project, staff suggests that the Commissioners could make a bench decision in this case. If the Commission decides that a bench decision is appropriate, staff recommends that the proposed stipulations for Issues 1 through 9 and 12 through 17 should be approved by the Commission. All parties either support or do not oppose the proposed stipulations.

CHAIRMAN BRISÉ: All right. Thank you very much.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

In recognition, as has been described by counsel, that those issues in this docket which require further review have been spun out into a proceeding that will take place next month, I move approval at this time of proposed stipulations for Issues 1 through 9 and 12 through 17.

COMMISSIONER BROWN: Second.

CHAIRMAN BRISÉ: Okay. It has been moved and seconded.

Any further discussion or questions?

Seeing none, all in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: All right. Thank you.

Are there any other matters that need to be addressed in Docket 07?

MR. MURPHY: Commissioner, since there's a bench decision, there is no need for post-hearing filings, and a final order on this part of the case will be issued by December 1.

The hearing on the remaining issues will be, again, on December 19th and 20th.

CHAIRMAN BRISÉ: Okay. Thank you. So we will continue Docket 07, and the hearing will be continued until December 19th, 2013, when testimony will be heard regarding FPL's proposed NO2 compliance project; Issues 10, 10A, B, C, and D, and 11.

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, 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 8th day of November, 2013.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732