BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 110007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE.
_________________________________/

VOLUME 1

Pages 1 through 229

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 1, 2011

TIME: Commenced at 10:56 a.m.
Concluded at 11:11 a.m.

REPORTED BY: LINDA BOLES, RPR, CRR
FPSC Reporter
(850) 413-6734

APPEARANCES:

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CAPTAIN SAM MILLER, Federal Executive Agencies, c/o AFCESA-ULFSC139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403-5319, appearing on behalf of Federal Executive Agencies.

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

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	219	219
2	Staff's Composite Exhibit 2	219	219
3	TJK-1 (Revised)	219	219
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24	DS-1	219	219
25	TGF-3	219	219
26	TGF-1	219	
27	TGF-2	219	
28	TGF-3 (Revised)	219	
29	TGF-4	219	
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31	HTB-1	219	219
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P R O C E E D I N G S

CHAIRMAN GRAHAM: And we will pick up Docket 110007, and we will open that docket and we will address the preliminary matters.

MS. BROWN: All right, Mr. Chairman. There are proposed stipulations on all issues, except Issues 1 through 4, 7, and 10G for PEF only. We have passed out a chart that shows the stipulated issues. I hate to admit this, I don't have a non-stipulated issue chart, just a stipulated one. If you all would like to mark that and enter it into the record.

CHAIRMAN GRAHAM: You want to mark this as Exhibit 88?

MS. BROWN: No. It would be Exhibit -- hold on just a minute -- 38, I think.

CHAIRMAN GRAHAM: I don't have that exhibit list in front of me.

MS. BROWN: We've passed out a Comprehensive Exhibit List for Docket 110007. Do you not have one, Mr. Chairman? No?

CHAIRMAN GRAHAM: So we'll mark that Exhibit 38.

MS. BROWN: It will be 38, yes. And we're passing these out to you, and I apologize.

CHAIRMAN GRAHAM: Okay. We will enter

Exhibit 38 into the record, unless there's any objections. Seeing none.

(Exhibit 38 marked for identification and admitted into the record.)

MS. BROWN: All right. The -- with respect to 11C, which is the substantive issue remaining outstanding for Gulf Power, the parties have recently filed a joint stipulation. And as a result of that stipulation, Witnesses Keith and Labauve for FP&L, Zeigler, Murray, and Sorrick for PEF, Bryant and Foster [sic] for TECO, and Dodd and Vick for Gulf have been excused from the hearing.

CHAIRMAN GRAHAM: Okay.

MS. BROWN: At this time we'd ask that the prefiled testimony for the excused witnesses, who were all identified with an asterisk in Section VI of the Prehearing Order, as well as Gulf's Witness Vick be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert that testimony into the record as if though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 110007-EI

APRIL 1, 2011

Q. Please state your name and address.

A. My name is Terry J. Keith, and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this or predecessor dockets?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery (ECR) Clause true-up costs associated with FPL Environmental Compliance activities for the period January 2010 through December 2010.

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

A. Yes, I have. My Exhibit TJK-1, contained in Appendix I, consists of nine forms.

- Form 42-1A reflects the final true-up for the period January 2010 through December 2010.
- Form 42-2A consists of the final true-up calculation for the period.
- Form 42-3A consists of the calculation of the interest provision for the period.
- Form 42-4A reflects the calculation of variances between actual and actual/estimated costs for O&M Activities.
- Form 42-5A presents a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A reflects the calculation of variances between actual and actual/estimated costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A consists of the calculation of depreciation expense and return on capital investment. Pages 49 through 53 of Form 42-8A provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Project.
- Form 42-9A presents the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period.

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

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

Q. Please explain the calculation of the Net True-up Amount.

A. Form 42-1A, entitled "Calculation of the Final True-up" shows the calculation of the Net True-Up for the period January 2010 through December 2010, an over-recovery of $5,036,426, which FPL is requesting to be included in the calculation of the ECR factors for the January 2012 through December 2012 period.

The actual End-of-Period over-recovery for the period January 2010 through December 2010 of $40,757,317 (shown on Form 42-1A, Line 3) minus the actual/estimated End-of-Period over-recovery for the same period of $35,720,891 (shown on Form 42-1A, Line 6) results in the Net True-Up over-recovery for the period January 2010 through December 2010 (shown on Form 42-1A, Line 7) of $5,036,426.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Form 42-2A, entitled "Calculation of Final True-up Amount," shows the calculation of the Environmental End -of -Period true-up for the period

January 2010 through December 2010. The End- of- Period true-up shown on Form 42-2A, Page 2 of 2, Lines 5 plus 6 is an over-recovery of $40,757,317. Additionally, Form 42-3A shows the calculation of the Interest Provision of $78,595, which is applicable to the End-of-Period true-up over-recovery of $40,678,722.

Q. Is the true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by the Commission as set forth on Commission Schedule A-2 "Calculation of the True-Up and Interest Provisions" for the Fuel Cost Recovery Clause.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to Environmental Compliance Projects approved by the Commission?

A. Yes, they are.

Q. How did actual expenditures for January 2010 through December 2010 compare with FPL's actual/estimated projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $1,794,814, or 7.7% lower than projected and Form 42-6A shows that total capital investment project costs were $1,006,181 or 0.8% lower than projected. Individual project variances are provided on Forms 42-4A and 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the actual period January 2010 through December 2010 are provided on Form 42-8A Pages 1 through 53.

Q. Please explain the reasons for the significant variances in O&M Projects and Capital Investment Projects.

A. The variances in FPL's 2010 O&M expenses and capital expenditures primarily relate to the following projects:

O&M Variance Explanations

Project 3a. Continuous Emission Monitoring Systems (CEMS)

Project expenditures were $79,925 or 6.6% lower than previously projected. This variance is primarily due to the following reasons:

- Lower than projected testing gas usage and replacement parts due to better than anticipated monitoring system performance.
- Costs related to the replacement of the Umbilical Cord at Putnam Plant were lower than originally projected due to the availability of spare parts on site.
- Project costs at Sanford Unit 3 were lower than projected due to less than anticipated replacement of CEMS parts because of the time that the unit was in inactive reserve status.
- Estimates for preventative maintenance and contract support expenses for the CEMS Unit 4 calibration swings at the Pt. Everglades plant were inadvertently omitted from the 2010 Actual/Estimated True-up filing.

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

Project expenditures were $394,958 or 18.0% lower than previously projected due to lower than projected bid results for maintenance, external coating, and tank roof replacement. Costs associated with the sandblasting of tank exteriors at Sanford Unit 3, Manatee Units 1 and 2, Ft Myers Gas Turbines, Port Everglades Units 3 and 4 and Port Everglades Terminal were lower than projected. Costs associated with the tank roof replacement project at Port Everglades Unit 3 were also lower than projected.

Project 17a. Disposal of Noncontainerized Liquid Waste

Project expenditures were $55,177, or 23.0% lower than previously projected. The variance is primarily due to the deferral of ash collection basin cleanout activities at the Martin Plant due to scheduling conflicts. This resulted in less processing of ash and lower than anticipated basin cleanout costs in 2010.

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

Project expenditures were $245,065 or 14.3% lower than previously projected. The variance is primarily due to a temporary six-month suspension of the regasketing program to revise FPL's regasketing specifications and provide training to all repair vendors. The revision to the regasketing specifications and vendor training was prompted by a transformer failure that occurred at the Turnpike Substation potentially caused by poor regasketing techniques by the vendor.

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

Project expenditures were $136,041 or 20.9% higher than previously projected. The variance is primarily due to unanticipated major regasketing work performed on two main output transformers at the Martin Power Plant. This work involved additional oil processing due to high moisture content from leaks. In addition, unexpected costs were encountered for one repaired transformer at the Broward Substation that also required additional oil processing due to high moisture content from leaks.

Project 22. Pipeline Integrity Management

Project expenditures were $67,276 or 15.6% lower than previously projected. The variance is primarily due to a delay in the pipeline in-line inspection at Martin Terminal because no oil cargo vessels were scheduled in the latter quarter of the year. Oil cargo delivery schedules vary due to weather, charter vessel availability and other cargo traffic at the port. This inspection will be conducted in 2011. The inspection of Manatee Terminal-16 line was completed as planned with the final cost being less than originally anticipated due to lower than projected confirmatory dig costs.

Project 23. Spill Prevention, Control & Countermeasures – SPCC

Project expenditures were $85,299 or 3.3% higher than previously projected. The variance is primarily due to the following reasons:

- More oil diversionary structure repairs were required at Delmar, Sanford, Laurel, Fort Pierce, Greenacres, Fruit Industries, and Ringling Substations than previously projected.
- Vendor bids for gunite repairs on the containment curbs at the Fort Lauderdale and Port Everglades plants and the containment wall at the Port Everglades Terminal were higher than anticipated. In addition, taxes and waste disposal costs for the gunite repair at the Port Everglades Terminal containment wall were higher than anticipated.

Project 24. Manatee Reburn

Project expenditures were $22,904 or 4.6% higher than previously projected. The variance is primarily due to higher than expected contractor and material costs and the completion of additional work due to a shift in the planned outage schedule from 2011 to 2010.

Project 25. Port Everglades Electrostatic Precipitators - ESP

Project expenditures were $80,960 or 8.4% lower than previously projected. The variance is primarily due to less than anticipated maintenance costs resulting from the installation of ESP Hopper Vibrators in Units 3 and 4, which reduced the maintenance of ESP hopper plugging issues by about $50,000 annually. In addition, these units were run less than projected, which reduced the amount of maintenance required.

Project 28. CWA 316(b) Phase II Rule

Project expenditures were $11,129 or 25.2% lower than previously projected. Costs associated with a final biological report for 316b requirements were inadvertently charged to a non-ECRC account and therefore not reflected in actual costs. This will be corrected in March 2011. Additionally, a technical specialist position was filled three months later than anticipated.

Project 29. Selective Catalytic Reduction Consumables (SCR)

Project expenditures were $30,961 or 8.3% lower than previously projected. The variance is primarily due to lower than projected use of ammonia at the Manatee and Martin plants due to a shift in the planned outage schedule from 2011 to 2010, which resulted in less plant operation.

Project 31. CAIR Compliance

Project expenditures were $153,311 or 6.0% lower than previously projected. The variance is primarily due to lower than anticipated consumption of ammonia for SCR operation at SJRPP as a result of the unit being run less than projected and lower unit price of the commodity.

Project 33. CAMR Compliance

Project expenditures were $879,906 or 35.6% lower than previously projected. Less Powdered Activated Carbon (PAC) was required for mercury removal in the operation of the SJRPP bag-house than originally projected.

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

Project expenditures were $134,446 or 13.5% higher than previously projected. The variance is primarily due to higher than anticipated costs to remove and dispose of debris from the velocity cap and pipe. The velocity cap and pipe contained substantially more debris than originally estimated.

Project 35. Martin Plant Drinking Water System Compliance

Project expenditures were $5,250 or 21.0% higher than previously projected. More water treatment was performed than projected due to higher than anticipated levels of disinfection byproducts in the water.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures were $33,445 or 3.3% lower than previously projected. The variance is primarily due to lower than projected costs associated with ground soil erosion control and soil repair work. Several ground soil erosion events resulting from heavy rainfall during the months of August through October 2010 were effectively mitigated due to site drainage system improvements.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures were $130,362 or 29.3% lower than previously projected. The variance is primarily due to lower than projected costs associated with grounds maintenance, materials and supplies, and employee costs. Grounds maintenance was significantly lower than estimated due to maintenance process improvements, lack of need for erosion repair work, and installation of rock under the PV modules at the Kennedy Space Center 1 MW facility. Additionally, equipment performed better than projected during initial plant startup, resulting in lower than expected plant support. Payroll expenses were lower than projected due to less support required as a result of the favorable equipment performance.

Project 39. Martin Next Generation Solar Energy Center

There were no O&M expenditures projected for this project at the time the actual/estimated filing was made. The Martin Solar Plant went in-service three weeks earlier than its target in-service date of December 31, 2010, thereby resulting in the variance of $8,941 for O&M expenses that were incurred in December 2010.

Project 40. Greenhouse Gas Reduction Program

Project expenditures were $59,000 or 100% lower than previously projected. The variance is primarily due to the ongoing evaluation of the purchase of a software product. It was anticipated that the software would be purchased in 2010. A vendor was selected in 2010 but the quote was not received until early 2011.

Project 41. Manatee Temporary Heating System

Project expenditures were $459,361 or 191.7 % higher than previously projected. The variance is primarily due to the installation of booms at the intake canal and the supplemental heating system at the Cape Canaveral site. As discussed in FPL's Notice of Additional Activities for this project that was filed on January 4, 2011, these installations were required after initial system testing indicated that, as configured, the electric heating system did not have enough thermal capacity to maintain the manatee embayment area at the necessary temperature.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures were $438,544 or 20.0% lower than previously projected. The variance is primarily due to a delay in engaging the ecological contractor, which resulted in a delayed decision on the areas where the ecological transect would be placed.

The Monitoring Plan was designed to be an adaptive plan resulting in the agencies increasing and/or decreasing the monitoring requirements. As a result, the incurrence of costs associated with the project vary based on the time it takes for the agencies to agree on specific details required by the Monitoring Plan.

<u>Capital Variance Explanations</u>

Project 31. CAIR Compliance

Project depreciation and return on investment were $113,056 or 0.3% lower than previously projected. The variance is primarily due to lower than projected construction costs for common SCR facilities. Additionally, other project costs were less than anticipated due to process improvements related to seal insulation, welding and stress relieving activities.

Project 33. CAMR Compliance

Project depreciation and return on investment were $86,109 or 0.7% lower than previously projected. The variance is primarily due to lower than projected costs associated with the baghouse PAC ash disposal facility and baghouse common facilities. Additionally, a minor delay in the construction of the baghouse at Plant Scherer was due to unfavorable weather conditions.

Project 36. Low-Level Radioactive Waste Storage

Project depreciation and return on investment were $19,671 or 100% lower than previously projected. The variance is due to a change in the projected in-service date for the LLW facilities at St. Lucie Plant from December 2010 to April 2011. The delay was due to longer than anticipated lead time on security clearances for construction personnel and issues with construction equipment not meeting company standards for use inside the protected area.

Project 38. Space Coast Next Generation Solar Energy Center

Project depreciation and return on investment were $24,367 or 0.3% lower than previously projected. The variance is primarily due to lower than projected final project costs.

Project 39. Martin Next Generation Solar Energy Center

Project depreciation and return on investment were $736,912 or 2.4% lower than previously projected. The Actual/Estimated True-up filing used an early estimated project completion date of November 2010. The project was placed in-service on December 10, 2010 ahead of the December 31, 2010 target.

Project 41. Manatee Temporary Heating System

Project depreciation and return on investment were $105,045 or 30.9% higher than previously projected. The variance is primarily due to a shift in the in-service date of the Cape Canaveral heaters from December 2010 to September 2010, which resulted in three additional months of depreciation.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project depreciation and return on investment were $112,245 or 86.8% lower than previously projected. The variance is primarily due to lower than anticipated capital costs as a result of lower contractor costs.

Q. Does this conclude your testimony?

A. Yes, it does.

ERRATA SHEET

Direct testimony of Terry J. Keith. Environmental Cost Recovery Projections for the January 2011 through December 2011 Actual/Estimated period, filed on August 1, 2011 in Docket No. 110007-EI.

10/19/11
DATE

Terry J. Keith
TERRY J. KEITH

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
2/18	Strike "$8,700,978" on line 18. Replace with "$8,708,673".	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
3/11	Strike "$150,790,937" on line 11. Replace with "$150,783,086".	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 110007-EI

August 1, 2011

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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/Estimated True-up associated with FPL's environmental compliance activities for the period January 2011 through December 2011.

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

A. Yes, I have. My exhibit TJK-2 consists of nine forms, PSC Forms 42-1E through 42-9E, included in Appendix I. Form 42-1E provides a summary of the Actual/Estimated True-up amount for the period January 2011 through December 2011. Forms 42-2E and 42-3E reflect the calculation of the Actual/Estimated True-up amount for the period. Forms 42-4E and 42-6E reflect the Actual/Estimated O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the period. Form 42-8E (pages 13 through 71) reflects return on capital investments, and depreciation by project. Form 42-9E provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery for the period January 2011 through December 2011.

Q. Please explain the calculation of the Environmental Cost Recovery Clause (ECRC) Actual/Estimated True-up amount you are requesting this Commission to approve.

A. Forms 42-2E and 42-3E show the calculation of the ECRC Actual/Estimated True-up amount. The Actual/Estimated True-up amount for the period January 2011 through December 2011 is an over-recovery, including interest, of $8,700,978 (Appendix I, Page 4, line 5 plus line 6). This Actual/Estimated True-up consists of January 2011 through June 2011 actuals and revised estimates for July 2011 through December 2011, compared to original projections for the same period.

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

A. Yes, with the exception of the St. Lucie Cooling Water Discharge Monitoring Project filed in this Docket on January 12, 2011, and the NPDES Permit Renewal Requirements Project, both of which are discussed and supported in the testimony of FPL witness Randall R. LaBauve.

Q. How do the Actual/Estimated project expenditures for January 2011 through December 2011 compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $24,089,224 or 5.3% higher than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $150,790,937 or 1.4% lower than projected. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment and Depreciation for each project for the Actual/Estimated period are provided on Form 42-8E (Appendix I, Pages 13 through 71). Following are variance explanations for FPL's approved O&M Projects and Capital Investment Projects with significant variances.

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

Project 1. Air Operating Permit Fees

Project expenditures are estimated to be $98,465 or 7.7% lower than previously projected. Lower than projected gas prices resulted in less run time than estimated for Port Everglades (PPE) Units 3 and 4, which only burn oil. Air Permit fees and payments to the State of Florida are based on actual unit operation and performance

Project 3a. Continuous Emission Monitoring Systems

Project expenditures are estimated to be $143,359 or 19.8% higher than previously projected. The variance is primarily due to the following reasons:

- The micro motion fuel oil monitors at Plant Manatee Units 1 and 2 were replaced due to normal wear and tear.
- The umbilical cords at Plant Martin Units 1 and 2 failed and were replaced
- Estimates for preventive maintenance at the Plant Port Everglades were inadvertently omitted from the 2011 Projection filing.
- Additional transformers were installed in each CEMS shelter to enable complete redundancy and provide a dependable backup power supply to avoid loss of data during a power outage.

Project 8a. Oil Spill Cleanup/Response Equipment

Project expenditures are estimated to be $20,877 or 10.6% higher than previously projected. The variance is primarily due to repairs of the boat ramp at Plant Sanford, which were not included in the original estimate. As a result of wear and tear caused by water-level fluctuations in the river, repairs to the boat ramp were required in order to make the ramp usable for launching the oil spill response boat and equipment.

Project 13. RCRA Corrective Action

Projected expenditures are estimated to be $92,127, versus an original estimate of $0. The variance is due to an amended agreement and amended consent order (AA & ACO) issued by the Florida Department of Environmental Protection (FDEP) in June of 2010. This new agreement and consent order included requirements for FPL to manage site rehabilitation of several contaminated areas at the St. Lucie Nuclear Plant, and provided options for closure of these areas under the RCRA program. In support of the AA & ACO and in response to FPL's report to FDEP with FPL's expected impact, FDEP issued a letter to FPL on April 15, 2011, requiring numerous actions. In order to meet the conditions of the AA & ACO, FPL recommended that FDEP consider a status change for the contaminated areas from "active remediation" to "no further action with controls" as allowed by the RCRA Contaminated Sites Program. The added costs of the actions required by the April 15, 2011 letter and of evaluating, developing and implementing control documents in connection with the status change are the reasons for the variance.

Project 17a. Disposal of Noncontainerized Liquid Waste

Project expenditures are estimated to be $161,000, or 71.2% lower than previously projected. The variance is primarily due to the deferral of ash processing at the Port Everglades, Turkey Point and Manatee plants because the plants are being run less on oil than originally anticipated due to the lower cost of natural gas.

Project 19a. Substation Pollutant Discharge Prevention & Removal

Project expenditures are estimated to be $435,512 or 13.4% lower than previously projected. The variance is primarily due to delays in the arsenic remediation work planned at the University, Princeton, Coconut Grove, Cutler, Lawrence, and Perrine substations located in Dade County, under the direction of the Department of Environmental Resources Management ("DERM"). Delays were encountered in securing approvals from DERM and city permits to proceed with source removal activities at five of the substations, and installation of a portable groundwater treatment system at the University substation. Source removal activities and installation of the portable groundwater treatment system are expected to be completed in 2012.

Project 19b. Substation Pollutant Discharge Prevention & Removal

Project expenditures are estimated to be $690,458 or 83.9% higher than previously projected. The variance is primarily due to unexpected major regasketing work performed on leaking transformers at the Martin Plant and Midway Substation. In addition, these transformers required additional oil processing to reduce the high moisture content due to the leaks.

N/A Amortization of Gains on Sales of Emissions Allowances

Amortization of Gains on Sales of Emissions Allowances is estimated to be $39,872 or 12.5% lower than previously projected.

The variance is primarily due to significantly lower than projected SO2 allowance market prices from the annual Environmental Protection Agency (EPA) auction. Allowances auctioned annually by the EPA were withheld from the original allocation to facilities in order to provide access to allowances for the new generating units that would not be allocated free allowances under the program. Each spring, EPA auctions 125,000 current year allowances and 125,000 7-year forward allowances. Last year, the spot market clearing price was $36.20 and the 7-year forward was $1.69, however this year's prices were $2.00 for spot and $0.16 for 7-year forward allowances. There has been a continual downward trend in allowance prices. The dramatic price decreases are a result of several successful challenges to recent EPA rules, which created substantial uncertainty regarding the future use and value of the SO2 allowances. Additionally, new regulations, which are likely to require substantial reductions in SO2, have led to a grossly over-supplied Acid Rain SO2 allowance market.

Project 23. SPCC -- Spill Prevention, Control & Countermeasures

Project expenditures are estimated to be $173,171 or 19.3% higher than previously projected. The variance is primarily due to more oil diversionary structure repairs identified during SPCC inspections than had been anticipated.

Project 24. Manatee Reburn

Project expenditures are estimated to be $102,856 or 20.6% higher than previously projected. The variance is primarily due to higher than expected costs associated with repair and replacement of burner assemblies that were identified during recent planned outages. Most of the work was completed in the spring, and the remaining work is scheduled to be completed during the Fall of 2011.

Project 25. Port Everglades Electrostatic Precipitator (ESP)

Project expenditures are estimated to be $449,118 or 224.6% higher than previously projected. The variance is primarily due to the early removal of Port Everglades Units 3 and 4 from inactive reserve. As a result of projected reduction in load demand, planned outage schedules and available capacity, FPL planned to place the units in an inactive reserve status, where the units would be maintained for return to service at a future date if necessary. As a result of revisions to the 2011 and 2012 planned outage schedule and a revised system demand forecast, FPL determined that returning units to service earlier than originally planned was the most cost effective option. As a result, additional activities such as the installation of an ESP Keys Interlock System and maintenance were necessary for continued operation of the units.

Project 31. CAIR Compliance

Project expenditures are estimated to be $292,239 or 15.3% lower than previously projected. The variance is primarily due to lower than expected expenses associated with the legal challenges to the CAIR rulemaking. The U.S. Circuit Court of Appeals vacated CAIR but remanded the rule and ordered EPA to promulgate a new rule that conformed to the Court's opinion. FPL had anticipated additional legal costs to ensure EPA promulgated a replacement rule within a timely period. On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule to replace the Clean Air Interstate Rule. FPL is currently evaluating the rule and has not yet decided whether a legal challenge of the replacement rule needs to be pursued. In addition, there was lower than anticipated ammonia consumption for the Selective Catalytic Reduction's (SCR) at SJRPP. This variance was partially offset by higher than expected common O&M costs at the FGD facilities and limestone handling areas.

Project 33. CAMR Compliance

Project expenditures are estimated to be $1,567,442 or 40.2% lower than previously projected. The variance is primarily due to a decrease in consumption of Powdered Activated Carbon (PAC) needed to meet the Georgia EPD requirements for mercury removal in the operation of the Scherer baghouse. Detuning the precipitators and allowing more fly ash to mix with the PAC injected into flue gases resulted in a decreased amount of PAC injection needed for effectively removing mercury.

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

Project expenditures are estimated to be $506,676 or 307.1% higher than previously projected. The variance is primarily due to a longer outage duration that allowed for pipe cleaning activities to be performed in 2011 that were originally projected for 2012.

Project 35. Martin Plant Drinking Water System Compliance

Project expenditures are estimated to be $5,174 or 30.4% higher than previously projected. The variance is primarily due to more required cleanings of the potable drinking water system than originally expected as a result of an aging system.

Project 37. DeSoto Next Generation Solar Energy Center

Project expenditures are estimated to be $68,780 or 6.6% lower than previously projected. The variance is primarily due to lower than expected payroll and related expenses. Plant performance and improvements in the plant's data monitoring system has reduced the need for overtime, technical support, and site management. Grounds maintenance costs were also slightly lower than projected, as erosion repair work is not expected to be required.

Project 38. Space Coast Next Generation Solar Energy Center

Project expenditures are estimated to be $96,375 or 15.4% lower than previously projected. The variance is primarily due to lower than expected payroll and related expenses. Plant performance and improvements in the plant's data monitoring system has reduced the need for overtime, technical support, and site management. Technology expenditures, contractor services, materials and supplies were all lower than projected due to conservative estimates based on Desoto operating experience. Space Coast continues to have less equipment issues due to the smaller size and fixed PV module design.

Project 41. Manatee Temporary Heating System Project

Project expenditures are estimated to be $865,031 or 182.3% higher than previously projected. The variance is primarily due to higher than expected costs at the Cape Canaveral plant associated with design changes that were identified during the previous manatee heating season (Oct 2010 thru Mar 2011). FPL found that the initial 34 MMBTU electric heater was capable of maintaining a closed refuge at the required 68°F only when river temperatures remained at 55°F or above. During the last season, a supplemental heating system was leased and installed to provide additional heating capacity as a result of lower than expected river temperature. In addition to the operation of the electric heaters, operation of the rental equipment occurs on an as-needed basis to meet the 68°F refuge requirement. FPL plans to use a rental heater in conjunction with the existing electric heater during the upcoming season to meet the manatee protection requirements. The variance reflects the increased heater rental cost, as well as the light oil and contracted manpower necessary to run the unit.

Project 42. Turkey Point Cooling Canal Monitoring Plan

Project expenditures are estimated to be $651,497 or 31.5% higher than previously projected. The variance is primarily due to sampling and analysis work deferred from 2010 to 2011 as a result of increased work scope required by the regulatory agencies for installation of the sampling wells.

Project 43. NESHAP Information Collection Request Project

Project expenditures re estimated to be $8,385, versus an original estimate of $0. The costs are associated with additional activities needed to support comments on EPA's draft Air Toxics Rule, in order to avoid regulation of specific air toxics in the final rule. FPL is providing comments regarding the justification for not regulating emissions of acid gases, Nickel, and Mercury from oil-fired generating units subject to the Air Toxics rule and will incur additional costs in July and August in its preparation of comments to the draft rule.

Project 44. Martin Plant Barley Barber Swamp Iron Mitigation Project

Project expenditures are estimated to be $5,000 or 100.0% lower than previously projected. Due to the lack of operating history with the iron mitigation system, costs associated with the operation and maintenance of valves and flow meters will not be incurred in 2011 as originally anticipated. Maintenance of valves and annual calibrations of flow meters will begin in 2012.

Capital Project Variances

Project 20. Wastewater Discharge Elimination & Reuse

Project depreciation and return on investment are estimated to be $27,928 or 17.2% lower than previously projected. Costs associated with the removal of the Basin Liner at Port Everglades plant were inadvertently included as capital costs when the new Basin Liner was placed in-service in 2010. The removal costs were recorded to the proper removal account in 2011.

Project 26. UST Replacement/Removal

Project depreciation and return on investment are estimated to be $20,646 or 38.7% lower than previously projected. The variance is primarily due to a retirement processed in April 2011 for the underground storage tanks located at FPL's General Office Building. These tanks, with a plant in service balance of $377,470 were included in the sale of FPL's General Office Building, but were not included in the original 2011 projections. An offset to the reserve for the sale proceeds of $345,901 will be made in July 2011's business which will bring the reserve balance to zero.

Project 31. CAIR Compliance

Project depreciation and return on investment are estimated to be $1,473,230 or 3.1% lower than previously projected. The variance is primarily due to lower than projected construction costs for SCR and Flue Gas Desulfurization (FGD) systems as a result of contractor efficiencies and reduced contingencies. This variance is partially offset by a change to the in-service date from 2010 to 2011 for the installation of the Boiler and Main Steam Drain project at the Manatee and Martin plants as a result of logic problems with the control system and system load demand. These issues had to be addressed prior to placing the systems in-service.

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

Project depreciation and return on investment are estimated to be $139,324 or 100.0% lower than previously projected. The variance is primarily due to a change in the projected in-service date for the Turtle Excluders from September 2011 to September 2013 as a result of a delay in the issuance of the Biological Opinion.

Project 36. Low-Level Radioactive Waste Storage

Project depreciation and return on investment are estimated to be $132,076 or 22.1% lower than previously projected. The variance is primarily due to a change in the projected in-service dates for the St. Lucie and Turkey Point Nuclear Plants due to the relocation of the Waste Storage facility at Turkey Point and limited resources to work on both projects. The St. Lucie projected in-service date was changed from December 2010 to July 2011 and the Turkey Point projected in-service date was changed from October 2011 to March 2012.

Project 41. Manatee Temporary Heating System Project

Project depreciation and return on investment are estimated to be $168,681 or 24.6% higher than previously projected. During the operation of the Cape Canaveral manatee heating system during the first heating season, from October 2010 through March 2011, the need for permanent modifications were identified to increase or maintain heat fed to the Interim Warm Water Refuge Area. These design modifications were specifically targeted to increase the efficiency of delivering and maintaining heated water in the manatee refuge area. The modifications include installing a sheet pile wall to provide a thermal and physical partition, installing a 4-inch natural gas pipe line, a concrete pad, an electrical power panel, and High Density Poly Ethylene (HDPE) piping changes to support the installation of the supplemental heating unit. All these modifications are targeted to be installed and tested prior to the beginning of the October 2011 thru March 2012 season.

Project 44. Martin Plant Barley Barber Swamp Iron Mitigation Project

Project depreciation and return on investment are estimated to be $15,001 or 65.2% lower than previously projected. The variance is primarily due to lower than anticipated vendor bids for engineering work.

Q. Does this conclude your testimony?

A. Yes, it does.

ERRATA SHEET

Direct testimony of Terry J. Keith. Environmental Cost Recovery Projections for the period January 2012 through December 2012, filed on August 26, 2011 in Docket No. 110007-EI.

10/19/11 Terry J. Keith

DATE TERRY J. KEITH

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
2/21	Strike "$8,708,682" on line 21. Replace with "$8,708,673".	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
2/22	Strike "$7,704"on line 22. Replace with "$7,695.	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
2/24	Strike "$8,708,682" on line 24. Replace with "$8,708,673".	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
3/2	Add after "Project No. 39" on line 2 "and a correction of the 2010 end of year amount of non-interest bearing CWIP for the Desoto Next Generation Solar Energy Center."	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
3/12	Strike "$182,053,636" on line 12. Replace with "$174,395,035".	1) Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012. 2) Revision to the 2012 projections and FPL's proposed ECRC factors

		for January 2012 through December 2012 to only include cost projections related to Subpart JJJJJ of the proposed IB MACT Project. 3) Revision to the 2011 actual/estimated true-up amount to reflect correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
3/13	Strike "$195,667,760" on line 13. Replace with "$188,014,660".	1) Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012. 2) Revision to the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012 to only include cost projections related to Subpart JJJJJ of the proposed IB MACT Project.
3/16	Strike "$8,708,682" on line 16. Replace with "$8,708,673".	Correction of 2010 end of year amount of non-interest-bearing CWIP for the Desoto Next Generation Solar Energy Center.
5/15 - 24	Strike lines 15 - 24	Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's

		proposed ECRC factors for January 2012 through December 2012.
6/1 - 24	Strike lines 1 - 24	Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012.
7/1 - 21	Strike lines 1 - 21	Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 110007-EI

AUGUST 26, 2011

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket or any other predecessor dockets?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2012 through December 2012 period.

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

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

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

A. Yes. Exhibit TJK-3 consists of eight documents, PSC Forms 42-1P through 42-8P and are provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the 2012 ECRC factors. Form 42-8P provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2012 through December 2012.

Q. Has FPL revised its 2011 ECRC Actual/Estimated True-up amount that was filed on August 1, 2011?

A. Yes. The 2011 ECRC Actual/Estimated true-up amount has been revised to an over-recovery of $8,708,682, which represents a difference of $7,704 from the 2011 Actual/Estimated true-up amount of $8,700,978 filed on August 1, 2011. This revised Actual/Estimated true-up over-recovery of $8,708,682 reflects a formula correction on Form 42-8E

(Appendix I, Page 58) for the Martin Next Generation Solar Energy Center Project No. 39. FPL requests that the Commission approve its revised 2011 Actual/Estimated true-up over-recovery of $8,708,682. Although only Forms 42-1E, 42-2E, 42-3E, 42-6E, 42-7E and Page 58 of Form 42-8E have been revised to reflect this correction, I have included a copy of my entire Exhibit TJK-2 with this filing for the convenience of the Commission, Staff and parties.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2012 through December 2012. Total environmental requirements, adjusted for revenue taxes, are $182,053,636 (Appendix I, Page 2, Line 5) and include $195,667,760 of environmental project jurisdictional revenue requirements for the January 2012 through December 2012 period (Appendix I, Page 2, Line 1c) decreased by the actual/estimated true-up over-recovery of $8,708,682 for the January 2011 - December 2011 period (Appendix I, Page 2, Line 2), and by the final true-up over-recovery of $5,036,426 for the January 2010 – December 2010 period (Appendix I, Page 2, Line 3).

Q. Please describe Forms 42-2P and 42-3P.

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand. The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI for all projects.

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 65) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 66 through 129) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 130) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 131) presents the calculation of the proposed 2012 ECRC factors by rate class.

Q. Please describe Form 42-8P.

A. Form 42-8P (Appendix I, Page 132) presents the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2012 through December 2012.

Q. Are all costs listed in Forms 42-1P through 42-8P attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the St. Lucie Cooling Water Discharge Monitoring Project filed in this Docket on January 12, 2011, the National Pollutant Discharge Elimination System (NPDES) Permit Renewal Requirements Project presented in the August 1, 2011 testimony of Randall R. LaBauve, and the Industrial Boiler MACT Project, for which FPL is now petitioning for approval and which is discussed and supported in Mr. LaBauve's August 26, 2011 testimony.

Q. Is FPL including any costs in its 2012 ECRC factors associated with its 800 MW Units ESP Project, approved by the Commission in Order PSC-11-0083-FOF-EI, issued on January 31, 2011?

A. Yes. FPL has included $411,120 of O&M expenses and $7,072,368 of return requirements associated with its 800 MW Unit ESP Project in its 2012 ECRC factors, per the stipulation approved in the above mentioned order. Under the stipulation,

> "FPL shall be allowed to recover the reasonable and prudent costs associated with its proposed 800 MW Units Electro Static Precipitators (ESPs) Project (the "ESP Project") for compliance

with the United States Environmental Protection Agency's (EPA's) maximum achievable control technology (MACT) rule in the following manner and under the following conditions:

1. FPL is authorized to proceed with implementation of the ESP Project at the time that EPA issues a proposed MACT rule that has the effect of requiring ESPs at oil-fired power plants, such as FPL's 800 MW units. FPL will consult with Staff and interested parties at the time that EPA issues the proposed MACT rule, concerning the rule's requirement for ESPs and FPL's decision on whether to proceed with the ESP Project pursuant to those proposed requirements.

2. During the period between EPA's issuance of the proposed MACT rule and issuance of the final MACT rule, FPL will exclude the costs incurred for the ESP project from the ECRC-recoverable accounts and instead will be authorized to record the cost of the ESP work in non-ECRC construction accounts and accrue a return at the then-current authorized AFUDC rate on the amounts recorded in the non-ECRC construction accounts.

3. If the final MACT rule requires ESPs, then FPL would be authorized to transfer the balance of all reasonable and prudent costs from the non-ECRC construction accounts, which would

include all accrued AFUDC, to ECRC-recoverable accounts and begin the normal process of ECRC recovery for those and future reasonable and prudent capital expenditures and O&M expenses associated with the ESP Project."

As presented in the testimony of FPL witness LaBauve, the Environmental Protection Agency (EPA) issued the proposed Air Toxics Rule on March 16, 2011, which was published in the Federal Register on June 21, 2011. FPL continues to believe that the installation of ESPs at the Martin and Manatee plants is the most effective method to comply with the requirements of the proposed rule.

FPL anticipates that EPA will finalize the Air Toxics Rule by the November 16, 2011 deadline in compliance with the Court's order. Assuming that occurs, then FPL will be entitled by the terms of the stipulation to recover costs for the 800 MW Unit ESP Project in its 2012 ECRC factors. As such, FPL believes it is appropriate to include costs associated with the project in the 2012 ECRC factors. Of course, if it turns out that the final Air Toxics Rule were significantly delayed or did not require ESPs at those units, then FPL would make appropriate adjustments to the 2012 ECRC recovery via the true-up mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 110007-EI

JANUARY 12, 2011

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes.

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 a new environmental compliance activity, the St. Lucie Plant Cooling Water Discharge Monitoring Project (the "Project"), which FPL must undertake at its St. Lucie Nuclear Plant (PSL) starting in 2011, to comply with Florida Department of Environmental Protection (FDEP) Administrative Order AO022TL (the "AO") and conditions in Industrial Wastewater (IWW) Permit No. FL0002208 (the IWW Permit") related to operation and limitations for the St. Lucie Cooling Water System ("CWS").

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

A. Yes. I am sponsoring the following exhibits:

- RRL-1 - St. Lucie IWW Permit No. FL0002208
- RRL-2 - St. Lucie Administrative Order No. AO022TL

Q. Please briefly describe FPL's proposed Project.

A. As a result of the increased heat output from the extended power uprate (EPU) project at St. Lucie Unit 1 and Unit 2, the discharge temperature of the PSL cooling water is expected to increase. This anticipated increase led FPL to submit to the FDEP a request to modify the IWW Permit, in order to authorize an increase above the permit's current discharge temperature limit. The FDEP has approved an increase in the discharge temperature limit, subject to FPL's complying with new study and monitoring requirements (and corrective action requirements if necessary) that are contained in the AO and IWW Permit.

At this time, the Project consists of preparing and implementing plans for (1) monitoring the ambient and CWS discharge water temperature, and (2) biological monitoring to demonstrate that conditions allow for the existence of a balanced, indigenous community of fish, shellfish and wildlife near the CWS discharge of PSL. If any corrective actions are required as a result of the monitoring activities, FPL will petition the Commission to amend the Project at that time.

Q. Please describe the environmental law or regulation requiring the Project.

A. This Project is required to comply with the AO and IWW Permit, which are issued by the FDEP pursuant to Section 403.088, Florida Statutes and Chapter 62-620, Florida Administrative Code. The IWW and AO Permit are included as exhibits RRL-1 and RRL-2, respectively.

Q. When did the AO and revised IWW Permit become effective?

A. The AO and the revised IWW Permit that require the Project became effective on December 23, 2010.

Q. Please describe the activities required by the Project.

A. FPL is seeking to recover the costs associated with the following activities that are required by the AO, which are incorporated into the amended IWW Permit:

- Preparation and submittal of an Ambient Monitoring Report (AMR) to identify an appropriate program for collecting data on ambient temperatures at the CWS intake structures.
- Implementation of the AMR by installing, calibrating and certifying new thermometer(s) to record ambient temperatures.

- Preparation and submittal of a Heated Water Plan of Study (HWPOS) to identify an appropriate program for collecting data on the impact of the CWS discharge on the temperature of surface water near the CWS outfall structures, adjacent coastal waters, and the ambient conditions at the CWS intake structures.
- Implementation of the HWPOS by collecting data for no less than 24 months and evaluating whether the data confirm FPL's mathematical modeling of the impact of the increased heat output from the EPU project.
- Preparation and submittal of the Heated Water Report reflecting the findings and conclusions of the HWPOS.
- Implementation of a Biological Plan of Study (BPOS) by collecting data for a period prior to the implementation of the EPU project and that extends at least 24 months after the EPU project is completed.
- Preparation and submittal of the Biological Report reflecting the findings of the BPOS.

Q. Are there any additional requirements in the AO?

A. Yes. If the Heated Water Report fails to demonstrate that the heated water discharge from PSL meets the requirements of the AO, then FPL must prepare and submit an Engineering Report to the FDEP, for review and approval, for the evaluation of engineering options to achieve the applicable discharge limitations. FPL will then be required to implement the highest ranked option within 24 months of FDEP's approval of the Engineering Report.

In addition, if the Biological Report fails to demonstrate that a balanced, indigenous population exists as required by the AO, then FPL must submit a feasibility study report for the evaluation of options to achieve a balanced, indigenous population. FPL will then be required to implement the highest ranked option within 24 months of FDEP's approval of the report.

Q. **Is FPL currently seeking authorization to recover the costs associated with these additional activities?**

A. No; not at this time. If any corrective actions are required as a result of the Heated Water Report or Biological Report, FPL will petition the Commission to recover those costs as an amendment to the Project.

Q. **What are the projected total O&M costs necessary to complete the Project?**

A. The total estimated O&M costs necessary to complete the Project are $2,567,000 associated with the preparation and implementation of the AMR, HWPOS, BPOS, and Heated Water and Biological reports.

Q. **What are the projected total capital costs necessary to complete the Project?**

A. FPL estimates that it will incur approximately $467,000 to acquire and install the temperature monitoring equipment and SONAR equipment required for the Project. Through extensive research and consultation with experts, FPL believes that the most effective and efficient way to perform population counts for indigenous fish, shellfish and wildlife in connection with the BPOS is to use the specialized SONAR equipment and therefore plans to propose this method of biological monitoring to the FDEP.

Q. Has FPL estimated the 2011 ECRC recoverable costs for the Project?

A. Yes. In 2011, FPL projects to incur $234,000 in capital costs, associated with the preparation and implementation of the Ambient, Thermal and Biological Monitoring programs. FPL projects to incur $549,000 of O&M costs associated with the preparation and implementation of the AMR, HWPOS, BPOS, and Ambient and Biological Monitoring programs.

Q. How will FPL ensure that the costs incurred for the Project are prudent and reasonable?

A. FPL plans to obtain competitive bids for all aspects of the Project:

- The AMR feasibility study report
- Implementation of the ambient monitoring program
- The HWPOS
- Implementation of the HWPOS

- Implementation of the Biological Plan of Study (BPOS)

In addition, the studies themselves are based on implementation of the highest ranked alternative for complying with the AO and amended IWW Permit. The ranking system is based in part upon the cost of the alternatives. Thus, FPL is implementing the Project in a manner that seeks to minimize its costs.

Q. Is FPL recovering the costs of these activities through any other mechanism?

A. No. The requirements of the AO and amended IWW Permit were not known or anticipated at the time that the minimum filing requirements for FPL's most recent rate case were prepared and the costs of these activities are not being recovered through any other mechanism.

Q. Does this conclude your testimony?

A. Yes.

ERRATA SHEET

Direct testimony of Randall R. LaBauve. Environmental Cost Recovery Projections for the period January 2012 through December 2012, filed on August 26, 2011 in Docket No. 110007-EI.

Sept 30, 2011
DATE

RANDALL R. LABAUVE

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
10/2 - 13	Strike lines 2 – 13.	Removal of projected costs associated with FPL's approved 800 MW ESP project from the 2012 projections and FPL's proposed ECRC factors for January 2012 through December 2012.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 110007-EI

August 1, 2011

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes.

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 for recovery through the Environmental Cost Recovery Clause (ECRC), a new environmental compliance activity, the National Pollutant Discharge Elimination System (NPDES) Permit Renewal Requirements Project. This project is associated with increased monitoring and reporting requirements contained in the latest NPDES permits that are or will be issued in the future by the Florida Department of Environmental Protection (FDEP). These changes will impact all of the FPL plants located in Florida, with the exception of the Turkey Point and West County plants. I also present updates for FPL's approved CWA 316 (b) Phase II Rule Project and Clean Air Interstate Rule (CAIR) Project.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-4 – Changes and Anticipated Changes in WET Testing for FPL Facilities
- RRL-5 – NPDES Permit No. FL0001538 - Port Everglades Plant

NPDES Permit Renewal Requirements Project

Q. **Please describe the environmental law or regulation requiring this Project.**

A. The Federal Clean Water Act requires all point source discharges into navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the U.S. Environmental Protection Agency's delegation of authority, FDEP implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration. In April 2009, the FDEP amended Rule 62-620.620 (3), F.A.C. requiring all new or renewed wastewater discharge permits for major facilities, including power plants, to contain whole effluent toxicity (WET) limits. Additionally, FDEP has required that facilities prepare a Storm Water Pollution Prevention Plan (SWPPP) that conforms to Rule 62-620.100 (m), F.A.C. and 40 CFR Part 122.44(k) when the NDPES permits are renewed. The purpose of the SWPPP is to identify possible pollutant sources that can affect the water quality of stormwater and to require best management practices (BMPs) that, when implemented, will reduce or eliminate any possible pollution impacts to stormwater. FPL has several NPDES permits that will have to be renewed over the remainder of 2011 and in 2012, and all of FPL's NPDES permits will have to be renewed over the next five years.

Q. **How does FPL plan to comply with these requirements?**

A. The FDEP has implemented the changes to the NPDES permits discussed above, as facilities apply for permit renewals. FPL is seeking recovery of costs associated with complying with new requirements that have resulted from changes to the Florida rules, as they become effective for renewals of FPL's NPDES permits. FPL's plan to comply with the new requirements is as follows:

1) Increased WET Testing – In accordance with this new regulatory requirement, all of the FPL NPDES permits issued in

Florida, going forward (except Turkey Point and West County), will include a new condition requiring FPL to conduct quarterly "chronic" WET testing to evaluate the effects of each plant's effluent on certain aquatic organisms. Chronic WET testing requires laboratory evaluation of the survival, reproduction and growth of representative fish and invertebrate species which are exposed to a series of effluent dilutions over a period of time, which is significantly more stringent and costly than previous testing required for permit compliance. Previous NPDES permits either had no requirement for WET testing or required only acute WET testing, which was significantly less expensive (about 50% less) than chronic WET testing. Included as RRL-4 is a table comparing prior WET testing requirements with the new requirements for affected plants. FPL will only be seeking recovery for the increment between the previous testing requirements and the new testing requirements.

2) Requirements for a Storm Water Pollution Prevention Plan (SWPPP) – As with the chronic WET testing described above, the most recent round of renewed NPDES permits are containing a requirement that each facility prepare a SWPPP pursuant to Rule 62-620.100 (m), F.A.C. and 40 CFR Part 122.44(k). The purpose of the SWPPP is to identify possible pollutant sources that can affect the water quality of stormwater and to require BMPs that, when

implemented, will reduce or eliminate any possible water quality impacts to the stormwater.

Exhibit RRL-5 is a copy of FPL's NPDES Renewal Permit for the Port Everglades Plant, which was issued on July 29, 2010. This permit illustrates the new requirements for chronic WET testing (pages 3-6) and SWPPP development (pages 20-24). These requirements are the same for all the NPDES permits issued since 2010 and will also be present in permits that are still to be issued. Therefore, FPL is including this one permit as representative of the requirements that appear in all impacted permits.

Q. Please describe the required activities associated with chronic WET testing.

A. Chronic WET testing requires laboratory evaluation of the survival, reproduction and growth of representative fish and invertebrate species which are exposed to a series of power plant wastewater effluent dilutions over a period of time. These dilutions, which involve mixing specific proportions of effluent with a sample of water taken upstream of the discharge in the receiving water body, range from 100% to 6.25% of the final effluent.

Routine toxicity tests are conducted once every three months. Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation FPL can request that FDEP reduce the test frequency to every six months. A valid test is a test that results in a less than a 25 percent reduction of survival, reproduction and growth of the test organisms from a control group of test organisms.

Routine tests consist of three-24-hour composite samples that are collected on the first, third and fifth day of the test. Tests are conducted on two types of organisms, an invertebrate and a fish species, using a control (100% effluent) and a minimum of five test dilutions. Very stringent quality assurances are required. Any failed tests must be followed by two additional follow-up tests and must be initiated within 28 days of the last day of the failed test. Results from all required tests shall be reported on a Discharge Monitoring Report.

Q. Please describe the required activities associated with the development of SWPPPs.

A. FPL must develop SWPPPs that address all activities which could or do contribute pollutants to the surface water discharge, including process, treatment, and ancillary activities. SWPPP requirements include topographic and site maps showing the facility, storm water conveyance and discharge structures, surface water and areas of existing and potential soil erosion. The SWPPP also requires a narrative describing the nature of the industrial activities conducted on the site, as well as existing or future controls, practices, procedures or plans related to the reduction of pollutants in storm water discharges and spill prevention, control and countermeasures. Additionally, the SWPPP requires a list of the types of pollutants that have the potential to be present in storm water discharges in significant quantities, an estimate of the size of the facility and a summary of existing sampling data describing pollutants in storm water discharges. As its NPDES permits are renewed, FPL will have to develop an SWPPP for each permitted site that addresses these requirements. Finally, FPL's SWPPPs will also have to identify a pollution prevention committee and address the FDEP's employee training and annual site inspection and revision requirements.

I should note that the NPDES renewal permits encourage, but do not require that a waste minimization assessment (WMA) be developed to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or stormwater streams. FPL believes programs currently in place perform a similar function and therefore does not currently plan to develop WMAs.

Q. What are the projected total O&M costs associated with Project requirements?

A. FPL expects to incur the following O&M costs for the Project:

1) Chronic WET testing –Total O&M costs, expected though 2015, are estimated to be $306,000. These costs will continue through future NPDES permit renewals.

2) SWPPP development – Total O&M costs are expected to be $100,000.

Q. What are the projected total capital costs necessary to complete these requirements?

A. At present, FPL does not anticipate incurring capital costs to comply with these requirements.

Q. Has FPL estimated the 2011 and 2012 ECRC recoverable costs for Project requirements?

A. Yes. FPL projects that it will begin incurring costs for the NPDES Permit Renewal Requirements Project in August 2011. FPL's cost estimate for the development of SWPPPs at its facilities is $10,000 per facility. FPL anticipates that it will need to develop SWPPPs for the Lauderdale and Port Everglades plants in 2011, at a total O&M cost of $20,000. In 2012, an SWPPP will be needed for the Ft. Myers Plant, at an O&M cost of $10,000.

FPL's 2011 and 2012 O&M cost estimates for compliance with the new chronic WET testing requirements are approximately $18,000 and $55,000 respectively. Chronic WET testing requirements will be on-going thereafter.

Q. How will FPL ensure that the costs incurred for the Project are prudent and reasonable?

A. Consistent with our standard practice for all consultant services procurements, FPL will competitively bid all of the activities performed by outside firms to ensure costs are prudently incurred. FPL will revise project estimates as specific costs become available through consultant specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs.

Q. Is FPL recovering the costs of these activities through any other mechanism?

A. No. As I previously stated in my testimony, some of the old permits had acute WET testing requirements, but FPL is only seeking recovery for the increment between costs incurred under those previous permit requirements and the costs that are incurred under the new permit requirements.

Q. Did FPL begin conducting chronic WET testing before it petitioned for approval of the Project?

A. Yes. Because of deadlines in the NPDES renewal permits for three plants, FPL had to begin chronic WET testing in August of 2010. However, FPL is seeking recovery only for work that is conducted after it petitioned the Commission for Project approval.

CWA 316 (b) Phase II Rule Project – Update

Q. What is the status of the CWA 316 (b) Phase II Project?

A. A new proposed 316(b) Rule entitled Cooling Water Intake Structures at Existing and Phase I facilities (Existing Facilities Rule) was published in the Federal Register on April 20, 2011. A Consent Decree requires EPA to sign the final Existing Facilities Rule by July 27, 2012 and, assuming this occurs, the final rule will become effective in October, 2012. The Existing Facilities Rule, as proposed, will regulate cooling water intake structures from power plants and industries that withdraw threshold limits of cooling water from waters of the U.S. The rule requirements are designed to reduce adverse environmental impacts that result from the impingement and entrainment of aquatic organisms by requiring facilities to install Best Technology Available to reduce the impacts to cooling water intakes.

The Existing Facilities Rule replaces the previous 316(b) Phase II Rule for Existing Facilities (Phase II Rule), that was issued in 2004 and challenged by environmental groups and six northeastern states. The Phase II Rule was subsequently remanded to the EPA by the Second Circuit Court of Appeals after aspects concerning cost to benefit analysis were ruled upon by the U.S. Supreme Court.

FPL's current CWA 316(b) Phase II Project was approved by the Commission in Order No. PSC-04-0987-PAA-EI, issued on October 11, 2004. The project included the recovery of costs associated with work required to respond to EPA requirements that facilities covered by the Phase II Rule complete and submit Comprehensive Demonstration Studies to determine the effect of cooling water intake structures on aquatic life. Additionally, in 2008 , Order No. PSC-08-0775-FOF-EI approved the recovery of legal and consulting activities associated with protecting the interests of FPL and its customers in the Phase II Rule development. The cost for these activities was projected to be $525,000. To date, however, FPL has not had to spend any of this projected amount because we have been able to work within the Utility Water Act Group and the Edison Electric Institute to have the Supreme Court rule on the 316 (b) Phase II Rule without assistance from outside consultants or outside legal counsel retained by FPL.

Q. Does FPL anticipate that it will now have to engage an outside consultant to assist in presenting FPL's positions on the newly proposed Existing Facilities Rule?

A. Yes. Comments on the Existing Facilities Rule are due on August 18, 2011. Because of the relatively short time frame to develop and submit comments, the amount of detail in the Rule, and the large potential financial impact to FPL and its customers if the Rule is not favorable, FPL feels it is still prudent to retain the services of a qualified consultant to assist in developing comments.

Q. Describe the work to be undertaken by the consultant that is preparing the Existing Facilities Rule comments.

A. FPL retained a consultant to perform the following activities:

- Identify specific issues with the Existing Facilities Rule and make specific recommendations to facilitate more cost-effective compliance for each FPL facility in Florida that is impacted by the new Rule (potentially 11 existing power plants).
- Help FPL understand what the proposed Rule would require, identify issues for those requirements, and suggest to EPA more workable solutions.
- Develop a set of general comments on the Rule as it affects FPL facilities and refine an approach to develop comments addressing approximately 10 different themes. For each theme, a set of evidence will be developed, along with analyses relevant to one or more FPL facilities, which illustrate and support that theme. A set of other more detailed comments, addressing engineering, biological and economic aspects of the Rule will also be developed.

Q. Has FPL estimated the cost of the projected activities?

A. FPL projects to incur approximately $40,000 of O&M costs for these consulting services, all in 2011.

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. Due to the extremely short time frame (originally 90 days) allowed for comments, FPL felt it was prudent to utilize a "single source" approach for selecting a vendor. The vendor that was selected had the following qualifications:

- An extensive and detailed understanding of the draft Existing Rule requirements.
- A detailed understanding of most of the FPL facilities affected by the Rule.
- Previously developed Comprehensive Demonstration Studies (summary of biological impact required by the previous version of the Phase II Rule) for six (6) FPL facilities and developed technical feasibility documents for many of these facilities. The contracts for that previous work were competitively bid.
- A detailed understanding of the relevant biological systems associated with each FPL plant.
- Maintain spreadsheet tools that have been previously reviewed and approved by FPL staff to evaluate costs and effectiveness of different compliance strategies.

Q. Is FPL recovering the costs of these activities through any other mechanism?

A. No.

Clean Air Interstate Rule (CAIR) Project -- Update

Q. Please briefly describe FPL's currently approved CAIR Project.

A. The original purpose of the CAIR project is to comply with the regulatory requirements established by EPA's promulgation of the Clean Air Interstate Rule, which was published in the Federal Register on May 12, 2005. FPL's CAIR project has included: an engineering study to evaluate the emission reduction options for its fossil generating units, implementation of Selective Catalytic Reduction (SCR) at St. John's River Power Park (SJRPP) to reduce NOx emissions; Flue Gas Desulphurization and SCR on Plant Scherer Unit 4 to reduce both SO2 and NOx emissions; the 800 MW cycling project to allow FPL's 800 MW units at Martin and Manatee plants to be removed from service when not needed reducing NOx emissions; installation of CEMS on the peaking combustion turbines; purchase of NOx emission allowances as needed for rule compliance; and a legal review and challenge of portions of the final rule in both Florida and Federal courts.

Q. What is the current status of FPL's CAIR Project?

A. Following the completion of the engineering study, the projects at Plant Scherer Unit 4, SJRPP, and the 800 MW units as well as the legal challenge to the final CAIR rule were initiated. To date, FPL has completed the installation of SCR at SJRPP, the 800 MW cycling project activities, and began construction of the controls on Scherer Unit 4, scheduled for completion in the spring of 2012.

Q. What is the status of the CAIR rulemaking?

A. FPL participated with other litigants in challenging CAIR. The challenges resulted in the Court of Appeals remanding the rule for EPA to develop a replacement rule within a reasonable period of time, with the existing rule remaining in effect until the replacement rule was promulgated. Because the existing rule remained in place, FPL was required to comply with the annual and ozone season NOx allowance programs for the 2009 compliance year and additionally with the SO2 compliance requirements of CAIR beginning in 2010.

On July 6, 2010, EPA finalized the CAIR replacement rule, which is referred to as the Cross-State Air Pollution Rule (CSAPR). In the final rule, EPA determined that Florida's contribution to downwind state fine particle (PM2.5) non-attainment areas was insignificant and provided that Florida electric generating units of 25 MW or greater would only remain in the CAIR program until the new CSAPR program begins on January 1, 2012. At that time, Florida electric generating units would be subject to NOx emission limitations only under the Ozone season portion of CSAPR and units subject to the Acid Rain Program would return to that program for compliance with SO2 emissions. FPL's Plant Scherer Unit 4 in Georgia was previously regulated only under the annual CAIR program but will then be regulated under the CSAPR annual programs and the Ozone season program.

Q. **Has FPL identified additional emissions controls or allowance purchases that will be required as a result of the CSAPR?**

A. No. While FPL's evaluation of the CSAPR is ongoing, a preliminary review has been conducted to evaluate whether proposed emission allowance allocations under the new rule would be sufficient to cover the projected future emissions from FPL's fossil generating stations. The CSAPR reduces Florida's ozone season NOx budget by nearly 50%, but FPL's preliminary projections show that it will have sufficient allowances to operate without having to install additional controls or buy allowances. This is because of the favorable emissions profile of FPL's generating fleet resulting from the addition of West County Units 1 – 3 and the previous installation of controls at SJRPP and Scherer Unit 4.

FPL is currently reviewing the 1,323 page rule and the hundreds of pages of the associated Technical Support Documents recently made available to the public. The final CSAPR contained significant changes from the Clean Air Transport Rule that EPA originally proposed as a CAIR replacement in 2010, and FPL has not yet evaluated those changes fully. If FPL's review indicates that any further compliance steps are required to comply with the CSAPR, the company will promptly notify the Commission.

Q. Is it possible that the CSAPR will be revised further by EPA?

A. Yes. FPL anticipates that the CSAPR will be subject to requests for reconsideration and petitions for judicial review once it has been published in the Federal Register. FPL will monitor all such challenges to determine if it should participate to protect the interests of its customers. Similar to CAIR, FPL also expects that any successful challenges to the CSAPR will lead to a remand to EPA with the CSAPR remaining in place until a new rule is promulgated.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 110007-EI

AUGUST 26, 2011

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this or predecessor dockets?

A. Yes, I have.

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 a new environmental project, the Industrial Boiler MACT Project. Additionally, my testimony provides a brief update on FPL's 800MW Units MACT Compliance Project.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-6 – Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart DDDDD

- RRL-7 – Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart JJJJJJ
- RRL-8 – EPA Delay of Subpart DDDDD
- RRL-9 – ERG Memorandum
- RRL-10 – FPL IB MACT Cost Matrix

Industrial Boiler MACT Project

Q. Please describe the law or regulation requiring the Industrial Boiler MACT Project.

A. The Environmental Protection Agency (EPA) regulates Hazardous Air Pollutants (HAPs) under Section 112 of the Clean Air Act (CAA). EPA promulgates emission standards for HAPs under 40 CFR Part 63 for stationary source categories. On February 21, 2011, the final Industrial/Commercial/Institutional Boiler Maximum Achievable Control Technology (IB MACT) rules were signed by the EPA Administrator. EPA's two rules address boilers and process heaters under Subpart DDDDD (40 CFR 63.7480) for affected units at major sources and Subpart JJJJJJ (40 CFR 63.11193) for affected units at area sources.

Subpart DDDDD (40 CFR 63.7480) affects FPL industrial boilers and process heaters at facilities that are classified as major sources of HAPs by requiring these smaller pieces of equipment to comply with the rule as applicable (i.e., testing, monitoring, tune-ups and site assessments as determined by the specifics of the equipment). The pertinent excerpts from Subpart DDDDD are included as Exhibit RRL-6 to my testimony.

Subpart JJJJJJ (40 CFR 63.11193) affects FPL industrial boilers at facilities that are classified as minor sources of HAPs by requiring the oil-fired boilers at the sites to comply with the rule as applicable (again, this entails testing, monitoring, tune-ups and site assessments as determined by the specifics of the equipment). The pertinent excerpts from Subpart JJJJJJ are included as Exhibit RRL-7 to my testimony.

FPL owns and operates units affected by both of these regulations at several power generation and fuel oil storage facilities. On May 18, 2011, EPA delayed the effective date of Subpart DDDDD until such time as judicial review is no longer pending or until the EPA completes its reconsideration of the rule. The section of the Federal Register that addressed EPA's delay of Subpart DDDDD is Exhibit RRL-8 to my testimony. FPL anticipates that EPA will lift its stay of the Subpart DDDDD effectiveness prior to spring 2012. The delay in the effective date for Subpart DDDDD does not apply to Subpart JJJJJJ, which became effective on March 21, 2011.

Because Subpart DDDDD is currently stayed, FPL has included in its 2012 ECRC projections only costs for compliance with Subpart

JJJJJJ. However, FPL requests that the Commission also authorize FPL to seek recovery of costs incurred to comply with Subpart DDDDD if the stay is lifted and the rule becomes effective. As noted above, EPA anticipates that the stay will be lifted no later than Spring 2012.

Q. How does the Industrial Boiler MACT affect FPL?

A. The IB MACT rule imposes new emission limitations, work practice standards, and operating limits on the affected source categories to reduce the emission of HAPs at major source (Subpart DDDDD) and area source (Subpart JJJJJJ) facilities. Major sources of HAPs are those facilities which have the potential to emit more than 10 tons of any one HAP, or 25 tons of a combination of HAPs in any one year. Area sources are those facilities that have the potential to emit HAPs in quantities below the major source thresholds. FPL's fossil generation plants are typically major sources for HAPs, so industrial boilers and process heaters at those plants would be impacted by Subpart DDDDD. FPL facilities classified as area sources for HAPs have boilers that must comply with Subpart JJJJJJ, but the rule does not apply to process heaters at those lower emitting sites. EPA has established different compliance requirements for sources by creating subcategories for different fuels under each rule and for new versus existing sources. Under Subparts DDDDD and JJJJJJ, a boiler is defined as new if construction commenced after June 4, 2010 and existing sources as those which were constructed prior to that date.

Equipment that is subject to the IB MACT rule includes fuel oil boilers that heat fuel at FPL oil terminals for storage and pipeline delivery to plants; auxiliary boilers for production of steam for gas turbine blade cooling during unit start-up; auxiliary boilers for steam turbine heating during combined cycle unit outages; process heaters for natural gas fuel heating for use in gas turbines; and auxiliary boilers for warm water discharge for manatee protection during cold weather events.

Q. Please describe the activities that FPL will initiate as a result of this project.

A. FPL's plan to comply with the requirements of the IB MACT rule includes the following:

- Submittal of initial notifications of applicability to agencies
- Development of site specific monitoring plans for those units which will not use continuous emission monitors
- Conducting initial emission stack tests to determine compliance status with applicable emission limits for oil-fired units
- Performing required fuel oil sampling and analyses for oil-fired units
- Conducting required biennial tune-up work practices including the purchase of required emission analyzers for boiler tune-ups
- Performing one-time energy assessment required for affected units at both area and major source facilities
- Installation of emission controls or replacement of existing units

that cannot demonstrate compliance with applicable emission standards

Q. What are the compliance dates for this project?

A. FPL is required to provide notification to the Florida Department of Environmental Protection of its area sources regulated under Subpart JJJJJJ no later than September 16, 2011. FPL proposes to conduct required emission testing in 2012 to develop its plan for the lowest cost of compliance for equipment at those areas sources which have emission specifications. Should affected emission units not meet the specifications, FPL will conduct an engineering study to evaluate compliance options including installation of controls or replacement of emission units.

FPL also plans to begin performing in 2012 the energy assessments at affected area sources that are required by Subpart JJJJJ and, once the stay of Subpart DDDDD is lifted, FPL will proceed with required facility energy assessments at the affected major-source facilities. FPL will have on-going compliance costs associated with newly required biennial unit tune-ups and from additional fuel oil testing. FPL does not yet know, and cannot yet estimate, whether any affected units would require installation of controls or replacement but anticipates that those costs would likely occur in 2013 or later. Under Section 112 of the CAA any required controls must be in place no later than three years after the final rule.

Q. How has FPL estimated the costs for compliance with the Industrial Boiler MACT rule?

A. In its development of the IB MACT rule, EPA estimated compliance costs. Exhibit RRL-9 provides the supporting document for the development of EPA's cost estimates. FPL has not yet sought bids for activities and equipment which may be required by the IB MACT rule and instead has used the EPA cost estimates for each of the applicable rule requirements for FPL's industrial boilers and process heaters. The preliminary estimate for the initial testing and energy assessment requirements are projected at $397,000 and annual emission/fuel testing costs are projected at $26,000. FPL has evaluated the expected compliance costs for each of its facilities that are subject to the requirements of Subpart JJJJJJ and Subpart DDDDD using the EPA cost estimates for required activities. Exhibit RRL-10 provides FPL's estimates of compliance costs with EPA's IB MACT rule. FPL cannot yet predict what compliance costs may have to be incurred for installation of controls or replacement of affected units.

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. Consistent with our standard practice for all contractor service procurements, FPL will competitively bid the contractor selection for the Industrial Boiler MACT project activities where possible.

Q. Is FPL recovering through any other mechanism the costs for the

Industrial Boiler MACT Project?

A. No. FPL is only requesting recovery of incremental activities associated with the Industrial Boiler MACT Project.

<u>**800 MW Units MACT Compliance Project Update**</u>

Q. Please provide an update of the EPA proposed Air Toxics Rule.

A. As anticipated in my testimony filed on August 27, 2010 in Docket No. 100007-EI, on March 16, 2011 the EPA issued a proposed rule that would reduce emissions of toxic air pollutants from power plants. Specifically, the proposed air toxics rule would reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF), from new and existing coal- and oil-fired electric utility steam generating units (EGUs). Following the publication of the proposed rule, on June 21, 2011 EPA extended the timeline for public input by 30 days on the proposed rule accepting comments on the proposal until August 4, 2011.

Q. Has FPL provided comments to EPA on the proposed Air Toxics Rule?

A. Yes. In FPL's review of the rule there were specific provisions of the rule which FPL believes were inappropriately included in the proposed rule. Specifically, FPL provided comments on the following issues: (1) Testing required to demonstrate eligibility as Low Emitting Units; (2) Startup, Shutdown and Malfunction exemption; (3) Use of emission averaging among affected units at a facility; (4) Filterable Particulate Matter (PM) measurement in lieu of total PM measurement; (5) Reconsideration and removal of nickel emission requirements for oil-fired units; (6) Re-evaluation and removal of acid-gas emission requirements for oil-fired units; and (7) Inclusion of a limited-use category for units with operation on oil limited to less than 10% annually. On August 4, 2011, FPL filed its comments via regulations.gov, Docket ID No. EPA-HQ-OAR-2009-0234. FPL also participated in joint comments filed on behalf of the Clean Energy Group and The Class of '85 regulatory group.

Q. Please provide an update on the 800 MW Units MACT Compliance Project.

A. Consistent with the stipulation approved by the Commission in Order No. PSC-11-0083-FOF-EI, issued in Docket No. 100007-EI on January 31, 2011, FPL began the process of installing an ESP on Manatee Unit 2 with the award of the contract to Siemens as amended on May 2, 2011. Construction site mobilization for this installation is projected to begin September 5, 2011 with unit construction activities projected to begin October 3, 2011. On October 5, 2011 Manatee Unit 2 will begin the planned outage and will be removed from service until May 26, 2012. Final acceptance of the ESP following initial operation and performance testing to ensure that manufacturer guarantees have been met is projected to occur on September 26, 2012. FPL's current construction plan for the installation of ESPs will ensure that the units will meet the deadline imposed under Section 112 of the CAA.

Q. Has FPL included costs associated with the 800 MW Units MACT Compliance Project in its 2012 ECRC projections?

A. Yes. FPL anticipates that EPA will meet the court's November 16, 2011 deadline for finalizing the air toxics rule as it did in meeting the court's March 16, 2011 deadline for proposing the rule. Assuming that the rule is finalized by the deadline and continues to require ESPs for the 800 MW generating units as FPL expects, then FPL's costs for the project will be eligible for 2012 ECRC recovery in accordance with the approved stipulation. Of course, if it turns out that the final rule were significantly delayed or did not require ESPs at those units, then FPL would make appropriate adjustments to the 2012 ECRC recovery via the true-up mechanism.

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. 110007-EI

April 1, 2011

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 Manager, Environmental Services and Strategy for Delivery and Services.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include managing environmental permitting and compliance activities for Energy Delivery Florida. Energy Delivery Florida is part of the Florida Distribution Business unit of which I support the Distribution, Transmission Operations and Planning, and the Corporate Services Departments.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in General Business Administration and Management from the University of South Florida. Prior to my current role, I was the Health and Safety Manager for Progress Energy Florida Transmission and Delivery. I have 19 years experience in the utility industry holding various operational, supervisor and managerial roles at Progress Energy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the actual project expenditures versus the Estimated/Actual project expenditures for environmental compliance costs associated with PEF's Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project 1 & 1a) and the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2).

Q. How did actual O&M expenditures for January 2010 through December 2010 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 was $199,655 or 2% higher than projected. The variance is attributed to higher amounts of subsurface contamination encountered during remediation of sites than was reprojected in the Estimated/Actual filing. PEF notes that the extent and depth of subsurface contamination can only be determined when the site is excavated. Furthermore, the amount of soil that needs to be removed to achieve FDEP clean-up target levels depends upon the results of tests conducted in the field as the remediation is conducted. As work proceeds, PEF updates unit cost estimates based upon actual invoices received from contractors.

Q. **How did actual O&M expenditures for January 2010 through December 2010 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 was $151,735 or 2% higher than projected. The variance is attributed to PEF remediating a higher number of sites than reprojected in the 2010 Estimated/Actual filing due to favorable crew availability and workloads.

Q. **Does this conclude your testimony?**

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

COREY ZEIGLER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

AUGUST 01, 2011

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 Manager, Environmental Permitting & Compliance.

Q. **What are your responsibilities in that position?**

A. Currently, my responsibilities include managing environmental permitting and compliance activities for Energy Delivery Florida. Energy Delivery Florida is part of the Florida Distribution Business unit of which I support the Distribution and Transmission Operation and Planning Departments.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in General Business Administration & Management from the University of South Florida. Prior to holding this role, I was the Health and Safety Manager for Progress Energy Florida's Delivery and Transmission Operations and Planning Departments. I have 19 years experience in the utility industry, holding various operational, supervisor and managerial roles at Progress Energy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the 2011 Estimated/Actual project expenditures versus the original 2011 cost projections for environmental compliance costs associated with the PSC-approved environmental programs under my responsibility. These include Progress Energy Florida (PEF)'s Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Projects 1 & 1a) and Distribution System Environmental Investigation, Remediation and Pollution Prevention Program (Project 2).

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation System Program (Project 1 & 1a) for the period January 2011 to December 2011.

A. O&M project expenditures for the Substation System Program are estimated to be $5,193,418 or 169% higher than originally projected. This increase is primarily attributable to several sites that had significantly higher amounts of subsurface contamination encountered during remediation that was not evident during the original visual environmental inspections. Because most contamination is below ground, it is difficult to determine remediation costs at substation sites until the remediation process actually begins. 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. Furthermore, the amount of soil that needs to be removed to achieve FDEP clean-up target levels depends upon the results of tests conducted in the field as the remediation is conducted. As work proceeds, PEF updates cost estimates based upon actual invoices received from contractors.

Q. **Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2) for the period January 2011 to December 2011.**

A. O&M project expenditures for the Distribution System Program are estimated to be $653,466 or 9% lower than originally projected. This decrease is due to continued refinement of the list of distribution sites expected to require remediation under the PSC-approved program.

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. 110007-EI

AUGUST 26, 2011

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 as Manager, Environmental Permitting and Compliance.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

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 2012 for Progress Energy Florida's ("PEF's" or "Company's") Substation Environmental Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a), previously approved in PSC Order No. PSC-02-1735-FOF-EI, Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project 2), previously approved in PSC Order No. PSC-02-1735-FOF-EI, and the Sea Turtle Coastal Street Lighting Program (Project 9), previously approved in PSC Order No. PSC-05-1251-FOF-EI.

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-3) attached to Thomas G. Foster's testimony:

- 42-5P page 1 of 18 - Substation Environmental Investigation, Remediation, and Pollution Prevention;
- 42-5P page 2 of 18 - Distribution System Environmental Investigation, Remediation, and Pollution Prevention; and
- 42-5P page 9 of 18 - Sea Turtle - Coastal Street Lighting.

Q. What costs do you expect to incur in 2012 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project 1 & 1a)?

A. For 2012, we estimate PEF will incur total O&M expenditures of approximately $4.1 million in remediation costs for the Substation System Investigation, Remediation and Pollution Prevention Program. This amount includes estimated costs for remediation activities at 49 substation sites that have already been identified as requiring remediation.

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

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

Q. What costs do you expect to incur in 2012 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project 2)?

A. For 2012, PEF estimates total Operations and Maintenance ("O&M") expenditures of approximately $0.3 million for the Distribution System Investigation, Remediation and Pollution Prevention Program to perform further testing and remediation at 20 sites. This estimate assumes 15 3-phase transformer sites at an average cost of $15,800 per site, 5 single-phase transformer sites at an average cost of $10,800 per site and deviation sampling costs of $2,000 per site. The average cost per site was based upon PEF's analysis of the prior two years of invoices associated with the remediation of TRIP 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, PEF closely monitors remediation work and provides quarterly reports to the FDEP on progress made in remediating sites.

Q. What costs do you expect to incur in 2012 in connection with the Sea Turtle/Street Lighting Program (Project No. 9)?

A. For 2012, estimated O&M expenses for the Sea Turtle/Street Lighting Program are $4,992 to ensure compliance with sea turtle ordinances in Franklin and Gulf

Counties and the City of Mexico Beach, and for ongoing sea turtle lighting study to test Florida Fish & Wildlife Conservation Commission recommended LED technology.

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. PEF cooperates with local governments and appropriate regulatory agencies to develop compliance plans that allow flexibility to make only those modifications necessary to achieve compliance. PEF 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, PEF evaluates emerging technologies and incorporate their use where reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KEVIN MURRAY

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

April 1, 2011

Q. Please state your name and business address.

A. My name is Kevin Murray. My business address is 299 First Avenue North, Saint Petersburg, Florida, 33701.

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

A. I am employed by Progress Energy as General Manager of Program and Project Development. My previous position was General Manager of Florida Construction Projects.

Q. What were your responsibilities as General Manager of Florida Construction Projects?

A As General Manager of Florida Construction Projects, I was responsible for the oversight of Progress Energy Florida's ("PEF") major fossil generation projects, including the Crystal River Units 4 and 5 air quality control system projects.

Q. Please describe your educational background and professional experience.

A. I received my Bachelor of Science Degree in Mechanical Engineering from the University of Arizona. I have 17 years of professional experience in engineering and project management within the electric power industry. I started my career in the power industry with Westinghouse Power Generation (now Siemens) based in Orlando, where I was employed as an engineer working on power plant proposals. During this time, I received an award for my work on a project in Thailand. I went to work for El Paso Corporation as an engineer and then as a project manager. I was involved in projects in both North and South America, including 1-year residency in Brazil. I joined Progress Energy in 2004 and served as the director of engineering for the Company's new fossil power projects. In 2008, I was promoted to General Manager of Florida Construction Projects for PEF, which included responsibility for implementing the Crystal River Units 4 and 5 air quality control system projects.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (KM-1), which is an organization chart showing the organizational structure the Company has established for management and oversight of internal company personnel and contractors involved in the Crystal River Project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the status of PEF's implementation of the Crystal River Project, including the variance between actual 2010 project expenditures and the Estimated/Actual projection submitted in Docket No. 100007-EI. I also will describe some of the measures PEF has taken to ensure that the costs incurred for the Crystal River Project are reasonable and prudent.

Q. What is the current status of the Crystal River Project?

A. The Crystal River Project met the in-service dates set forth in the Integrated Clean Air Compliance Plan originally approved by the Commission in Docket No. 070007-EI. Over the past year, we have achieved several significant project milestones including placing the Crystal River Unit 4 Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) systems in-service in May 2010.

All of the Crystal River Unit 4 and 5 projects are now in-service, and the targeted environmental benefits have been met or exceeded. The Unit 4 and 5 SCRs reduce nitrogen oxide (NO_x) emissions by approximately 90%. The Unit 4 and 5 FGDs remove 97% of the sulfur dioxide (SO_2) emissions. Currently the project team is focused on completing close out activities such as punch list items, demobilization and site restoration.

Q. How do the actual project expenditures for the Crystal River Project compare with PEF's estimated/actual projections for the period January 2010 to December 2010?

A. The actual total expenditures for the Crystal River Projects in 2010 were $55.8 million, which is approximately $5.8 million (10%) less than projected in PEF's Estimated/Actual projection. The difference is attributable to the unused portion of the project's contingency that is used to manage acknowledged risks that are likely to occur during the project. Risks projected to occur during 2010 did not materialize, but may still occur during the project closeout process.

Q. Please describe the management structure that was used to oversee implementation of the Crystal River Project?

A. PEF has established an organizational structure to ensure prudent decision-making and project oversight as implementation of the Integrated Clean Air Compliance Plan proceeds. The specific team for the Crystal River Project is as shown in Exhibit No.__ (KM-1). The Company assigned me as the General Manager with primary overall responsibility and accountability for the Crystal River Project. I oversaw all of the internal team members as well as all of the external contractors working on the project. My project management team, which also included a dedicated Project Engineer and Project Controls personnel, worked with Company personnel from other departments, including Environmental, Health and Safety Services, Corporate Services, Fossil Generation, Legal, and Regulatory Planning as needed.

To promote efficient integration of the new equipment with current operations, the Company also established a Plant Integration Team (PIT) that was involved through the startup and commissioning process. The PIT was established early in the life of the Project to allow for plant operational input into the technical and functional requirements incorporated in the Project design, operational design features, anticipated operation of the new systems and performance guarantees. During the construction phase, the PIT provided interface between me and plant operations, and had the primary responsibility for developing operational maintenance procedures for the new equipment. The PIT also participated in startup integration for commercial operation.

Q. Has the Company implemented policies and procedures to ensure proper management of the Crystal River Project and to control project costs?

A. Yes. The project is being implemented in accordance with the Generation Construction Department's policies and procedures, which prescribe specific requirements for project management, quality assurance/quality control (QA/QC), schedule management, cost accounting and reporting, and other aspects of the project implementation. These policies and procedures reflect the collective experience and knowledge of the Company. They have been tested on other capital projects of this nature and reflect lessons learned from those projects. They also are consistent with best practices for capital project management in the industry.

Q. Are employees involved in the Crystal River Project trained in the Company's project management and cost control policies and procedures?

A. Yes, they are. The project management team for the Crystal River Project has been trained in these policies and procedures.

Q. Does the Company verify that the project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits to verify that its program management and oversight control are in place and being implemented.

Q. Has the Company implemented other mechanisms to ensure proper oversight and review of the Crystal River Project?

A. Yes. We have implemented several mechanisms to ensure proper oversight and review of the Crystal River Project. Among other things, the project management team regularly prepares Project Cost Reports to track project expenditures against detailed project scopes to ensure that PEF receives what it contracted for and that any scope changes are properly evaluated and documented. These reports will continue during the project closeout process. Also, during construction, we conducted a wide variety of meetings to maintain supervision of the project and to ensure that Company management remained fully informed. We conducted regularly scheduled, monthly meetings with the EPC contractor (Environmental Projects Crystal River or "EPCR") and primary FGD and SCR design and procurement contractor (Babcock & Wilcox or "B&W") to review construction progress and the remaining scope of work. Following those meetings, we held regular monthly meetings with executive management to review the status of the project and its costs, as well as the administration of the various contracts. Executives from EPCR and B&W participated in these meetings to ensure that management expectations were communicated to the outside vendors as well as the project team.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DAVID SORRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

April 1, 2011

Q. Please state your name and business address.

A. My name is David Sorrick. 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 Florida in the capacity of 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 developing and implementing strategic and tactical plans to operate and maintain PEF's non-nuclear generation fleet; recommending projects and additions to the generation fleet; major maintenance programs; outage and project management; support services for the fleet; recommending retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; overseeing 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 Electrical Engineering from the University of Tennessee at Chattanooga in 1986 and an MBA from the University of South Florida in 2006. I am also a Florida Registered Professional Engineer and Licensed Electrical Contractor. I have 20 years of power plant and production experience in various engineering, supervisory, managerial and executive positions within Progress Energy managing Fossil Steam Operations, Combustion Turbine (CT) Operations, and CT Services as well as new plant construction. While at Progress Energy, I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience with Progress Energy and General Electric. My prior experience also includes nuclear engineering positions at Tennessee Valley Authority and project management experience with General Electric.

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

A. The purpose of my testimony is to explain material variances between the Actual operation and maintenance (O&M) expenditures and the Estimated

/Actual cost projections for environmental compliance costs associated with PEF's Integrated Clean Air Compliance Program for the period January 2010 through December 2010.

Q. **What current PSC-approved projects are you responsible for?**

A. I am responsible for the CAIR Crystal River Project No. 7.4 O&M costs.

Q. **How do the actual project expenditures for the CAIR Crystal River (Project 7.4) compare with PEF's Estimated/Actual projection project expenditures for the period January 2010 to December 2010?**

A. Actual expenditures incurred for the period January to December 2010, were $3,282,634 or 15% less than projected in the Estimated/Actual filing. This variance is mainly attributable to two factors: (1) $1,694,909 lower than anticipated costs for CAIR Crystal River Project 7.4 – Energy; and (2) $1,650,495 lower than anticipated costs for CAIR Crystal River Project 7.4 – Base.

Q. **Please explain the variance between the Actual project expenditures and the Estimated/Actual projections for the CAIR Crystal River (Project No. 7.4 – Energy) for the period January 2010 to December 2010.**

A. PEF's costs for reagents and by-products for 2010 were $1,694,909 or 17% lower than estimated in the Estimated/Actual Filing. This variance is attributed to lower fuel burn driven by fuel switching opportunities, the initial tuning of ammonia injection operation post start-up of the SCR system in 2010, and the continued effort to maximize beneficial reuse of synthetic gypsum at a lower cost than landfill disposal.

Q. Please explain the variance between the Actual project expenditures and the Estimated/Actual projections for the CAIR Crystal River (Project No. 7.4 – Base) for the period January 2010 to December 2010.

A. The $1,650,495 decrease is primarily attributable to lower than anticipated costs of $1.65 million due to warranty coverage. In 2010, a large portion of the materials that were used for routine maintenance activities were covered under the Vendor warranty agreement. For Crystal River Unit 4 (CR4), this vendor warranty ends May 2011 and for Crystal River Unit 5 (CR5), it ended December 2010. Additionally, there was a CR5 Scrubber warranty outage that was planned for the fall; however, favorable maintenance inspection results indicated that the scrubber warranty outage was not needed.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DAVID SORRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

AUGUST 1, 2011

Q. Please state your name and business address.

A. My name is David Sorrick. 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 Florida in the capacity of 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 developing and implementing strategic and tactical plans to operate and maintain PEF's non-nuclear generation fleet; recommend major modifications and additions to the generation fleet; major maintenance programs; outage and project management;

support services for the fleet; recommending retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; overseeing 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 Electrical Engineering from the University of Tennessee at Chattanooga in 1986 and an MBA from the University of South Florida in 2006. I am also a Florida Registered Professional Engineer and Licensed Electrical Contractor.

I have 20 years of power plant and production experience in various engineering, supervisory, managerial and executive positions within Progress Energy managing Fossil Steam Operations, Combustion Turbine (CT) Operations, and CT Services as well as new plant construction. While at Progress Energy, I have managed new unit projects from construction to operations and I have extensive contract negotiation and management experience with Progress Energy and General Electric. My prior experience also includes nuclear engineering positions at Tennessee Valley Authority and project management experience with General Electric.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project O&M and capital expenditures and the original cost projections for environmental compliance costs associated with PEF's, Integrated Clean Air Compliance Program for the period January 2011 through December 2011.

Q. What current PSC-approved projects are you responsible for?

A. I am responsible for the CAIR Crystal River Project No. 7.4 O&M and capital costs.

Q. How do the estimated/actual project expenditures for the CAIR Crystal River (Project 7.4) compare with PEF's projection project expenditures for the period January 2011 to December 2011?

A. PEF is projecting O&M expenditures to be $81,603 or 0.3% higher for this program than originally projected. This variance is being driven by a $944,129 decrease in CAIR Crystal River Project 7.4 – Energy, $914,325 increase in CAIR Crystal River Project 7.4 – Base and an $111,407 increase in CAIR Crystal River Project 7.4 – A&G.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the CAIR Crystal River (Project No. 7.4 – Energy) for the period January 2011 to December 2011.

A. The $0.9 million decrease in the project is primarily due to ammonia and limestone costs being $1.3 and $1.1 million lower than originally projected, respectively, and gypsum net disposal costs being $1.3 million higher than originally projected. Additionally, PEF incurred $0.2 million in costs for the purchase of caustic in order to condition the ph in the bottom ash. The caustic is required to adjust the ph level in the bottom ash to within acceptable limits.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the CAIR Crystal River (Project No. 7.4 – Base) for the period January 2011 to December 2011.

A. The $0.9 million increase in the project is primarily attributable to costs incurred to handle the fly ash from units 4 & 5. This fly ash has elevated levels of ammonia (NH3) present and requires more precautions while handling. These precautions take more effort and time, thereby increasing the cost to handle.

Q. How do the estimated/actual project expenditures for the Crystal River CAIR Project compare with PEF's projection project expenditures for the period January 2011 to December 2011?

A. The estimated/actual total capital expenditures for the Crystal River CAIR Projects in 2011 are $6.6 million, which is approximately $5.1 million or 345% higher than PEF's 2011 Projection filing. The difference is primarily attributable to project closeout work carried forward from 2010 to 2011. As mentioned in Mr. Kevin Murray's April 1st testimony, 2010 expenditures were approximately $5.8 million lower than projected in the 2010 estimated/actual filing. In Docket 100007, PEF expected to materially finish project closeout in 2010 but since that time some activities moved into 2011 due to outage schedules and the discovery of additional work required for close out.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DAVID SORRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 110007-EI

AUGUST 26, 2011

Q. Please state your name and business address.

A. My name is David Sorrick. 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 Florida (PEF) in the capacity of Vice President Power Generation – Florida.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. Have your responsibilities changed since you last submitted testimony in this proceeding?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide current estimates of costs that will be incurred in 2012 for environmental on-going capital and operation and maintenance (O&M) compliance costs associated with the Crystal River Units 4 and 5 (CR4 & CR5) air quality control assets in PEF's Integrated Clean Air Compliance Program (CAIR).

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-3) attached to Thomas G. Foster's testimony:

- 42-5P page 7 of 16 - Integrated Clean Air Compliance Plan (CAIR).

I am also sponsoring Exhibit No. __ (DS-1), which is an organizational chart associated with PEF's operation and maintenance of the CR 4 & CR5 CAIR assets.

Q. What O&M costs do you expect to incur in 2012 in connection with the operation of the air emission controls at Crystal River Unit 4 and 5 as part of the Integrated Clean Air Compliance Program (Project 7.4)?

A. PEF estimates that approximately $32.1 in O&M costs will be spent to support the operation and maintenance of the new air emissions controls that were installed at the Crystal River Energy Complex as outlined in the PEF Integrated Clean Air Compliance Plan. Labor costs are expected to be approximately $6.8 million. This estimate is based upon current staffing levels which were developed after review of similar operations outside of PEF as well as comparison of similar units within the Company. Administrative and General (A&G) expenses are expected to be approximately $0.3 million for incremental positions that were created to support the Integrated Clean Air Compliance Program project. Contractor expenses are expected to be approximately $3.1 million for activities such as post-construction modifications not covered by warrantee, new chimney maintenance, limestone and gypsum handling, urea handling, cleaning of pond systems, additional security, gypsum sampler and sample analysis, truck scale maintenance and contracted equipment maintenance and repairs. Miscellaneous costs for tools and equipment, rental equipment and other employee costs are expected to be approximately $0.4 million, and parts and materials are expected to be approximately $1.7 million. CR5 outage costs are expected to be approximately $1.1 million. Expenses for miscellaneous projects are expected to be approximately $0.2 million for CAIR AR pump overhauls, dewatering system overhauls, and oxidation air blower overhauls. Reagent costs (net gypsum sales / disposal, limestone, urea / ammonia, and bottom / fly ash) are expected to total approximately $18.4 million.

Q. Are there any ongoing capital costs in 2012 associated with the implementation of the Integrated Clean Air Compliance Program (Project 7.4)?

A. Yes. PEF estimates that $27.9 in capital costs will be incurred as part of the Integrated Clean Air Compliance Program in 2012. Such costs include:

- Installation of sulfuric trioxide (SO3) probes which are necessary to ensure adequate control of sulfuric acid mist emissions.

- Purchase and installation of a third layer of catalyst for the SCR's which are necessary to maintain the removal efficiency of the SCR system.
- An alternative water project which is necessary to comply with terms of the Crystal River water use permit.
- Development and engineering of an alternative wastewater system for FGD blowdown treatment which is needed to comply with FDEP wastewater permit conditions.
- A lower chloride set point operation project that is necessary to allow operation of the FGD system at lower chloride levels to protect the internal materials and FGD equipment.
- Projects related to bottom and fly ash due to pH and ammonia impacts resulting from operation of the new SCR and FGD systems. Impacts due to ammonia are still be evaluated and could require either the installation of a hydrated lime injection system or the installation of a benefication system.

Q. **What steps is the Company taking to ensure that the level of expenditures for the operation of the Crystal River 4 and 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 has established a dedicated unit to manage, operate and maintain the CAIR equipment. An organization chart is attached in Exhibit No.__ (DS-1). This unit consists of 54 employees and reports to the Crystal River plant manager. There are 8 managers, 25 operations employees and 21 maintenance 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 are available for emergent work after normal hours. In an effort to keep regular staffing levels lower, contractors are used for specialized or lower-skilled work. This 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 the plant uses to efficiently operate and maintain the CAIR equipment. First and foremost, the plant follows all OSHA and Progress Energy safety-related policies and procedures. It also uses operating procedures to efficiently operate equipment 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. In addition, equipment is maintained using equipment-specific preventive maintenance procedures. The operating and maintenance procedures were developed during construction and startup, and will continue to be revised as more experience and expertise is gained with the equipment.

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

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

A. 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 came to Progress Energy 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.

Equipment-specific training was accomplished during the construction and start-up phase of the project. 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 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 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, self-checks, use of checklists, procedure sign-offs and 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 operations and maintenance of CAIR equipment.

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 this equipment.

Q. Does this conclude your testimony?

A. Yes.

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 2010 through December 2010 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 2010 through December 2010 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, consisting of two pages, 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 2010 through December 2010 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $539,002 as the actual true-up amount for the January 2010 through December 2010 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2010 through December 2010 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2012 projection period?

A. Tampa Electric has calculated an under-recovery of $2,616,798 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2010 through December 2010 period. This adjusted net true-up amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the January 2010 through December 2010 period as depicted on Form 42-1A. The actual true-up amount for the January 2010 through December 2010 period is an over-recovery of $539,002 as compared to the $3,155,800 actual/estimated over-recovery amount approved in Commission Order No. PSC-10-0683-FOF-EI issued November 15, 2010.

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. Form 42-8A, page 20, provides expenditures associated with the Big Bend Unit 1 Selective Catalytic

Reduction ("SCR") project that was approved in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI and went in-service April 2010. The expenditures for January through March are included for identification and tracking purposes, but recovery of these expenditures during this period is not included in the 2010 ECRC True-Up. Consistent with the Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and 041376-EI, the company does not seek cost recovery until a project is placed in-service.

Q. Did Tampa Electric include costs in its 2010 final ECRC true-up filing for any environmental projects that were not anticipated and included in its 2010 factors?

A. No.

Q. How did actual expenditures for the January 2010 through December 2010 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 $1,046,835 or 5.8 percent more than the actual/estimated projections. Form 42-6A shows the total capital investment costs were $89,130 or 0.2 percent higher than the actual/estimated projections. O&M and capital investment projects with material variances from the 2010 Actual/Estimated True-Up filing are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance was $951,731 or 23.1 percent more than projected due to increased maintenance and absorber pump replacement.
- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $178,389 or 129.6 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 $766,834 or 10.0 percent more than projected due to increased maintenance and repair activities.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $102,528 or 21.9 percent less than projected due to maintenance that was planned to take place during Big Bend Unit 3 outage but was ultimately not necessary.

- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was 14,971 or 74.9 percent lower than projected due to the delay in correspondence from the Florida Department of Environmental Protection ("FDEP") with respect to data submitted in response to the agency's request for additional information regarding required thermal studies. Tampa Electric had anticipated being farther along in the process however it has taken FDEP longer to review and respond to the provided documentation.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $11,913 or 8.5 percent less than projected due to the sales of emissions allowances in February 2010. The proceeds from these sales are returned to customers through the clause.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $13,270 or 11.5 percent less than originally projected due to less ammonia consumed than originally anticipated.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $36,723 or 85.9 percent less than projected due to the delay in correspondence from FDEP with respect to data submitted in response to the agency's requests for additional information about how the company is complying with new

cooling water regulations. Tampa Electric had anticipated being farther along in the process however it has taken FDEP longer to review and respond to the provided documentation.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard program variance was $47,794 or 81.3 percent greater than projected due to a request by the FDEP for a soil characterization analysis at the Bayside Power Station.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance was $184,172 or 19.9 percent greater than projected due to the increase in ammonia cost as well as increased consumption.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance was $487,866 or 40.7 percent less than projected due to lower ammonia consumption as dictated by the system and emissions limits.
- **Clean Air Mercury Rule:** The Clean Air Mercury Rule project variance was $13,645 or 13.2 percent greater than originally projected due to the contractor costs involved with the stack testing at Polk Power Station in response to an Environmental Protection Agency data request.
- **Greenhouse Gas Reduction Program:** The Greenhouse gas Reduction Program variance was $99,899 or 63.1 percent lower than originally projected due to unforeseen delays

with the software integration. The project is anticipated to be complete in 2011.

Capital Investment Project Variances

- **Big Bend Unit 1 Pre-SCR**: The Big Bend Unit 1 Pre-SCR project variance was $42,848 or 16.0 percent less than projected due to maintenance activity extending into 2011 to accommodate the Unit 1 SCR outage timing.

Q. Did Tampa Electric make any adjustments to the 2010 true-up period?

A. Yes. Tampa Electric retired the neural network components of the Big Bend NO_x Emissions Reduction project and the Big Bend Unit 1 Pre-SCR. The neural network equipment for the Big Bend NO_x Emissions Reduction program was retired in December 2010 and is reflected in Form 42-8A page 13 of 26, line 1C.

As shown on Form 42-8A page 17 of 26, Big Bend Unit 1 Pre-SCR, the amount of $367,767 was removed from line 4, Construction Work in Progress.

The total adjustment of $199,213 is reflected on Form 42-2A, line 10. The return on investment and interest for the period since Tampa Electric began recovering dollars through the clause for the neural network components have been retroactively calculated and removed from the schedule.

Q. Does this conclude your testimony?

A. Yes, it does.

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 2011 through December 2011 estimated true-up amount to be refunded or recovered through the ECRC during January 2012 through December 2012. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2011, 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 2012 through December 2012.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2011 through December 2011?

A. Yes. Exhibit No. _____ (HTB-2), containing eight 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 2012 through December 2012.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2012 through December 2012 ECRC factors?

A. The estimated true-up applicable for the current period, January 2011 through December 2011, is an under-recovery of $464,090. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. Is Tampa Electric including costs in this estimated true-up filing for any environmental projects that were not anticipated and included in its 2011 factors?

A. No, Tampa Electric is not including costs that were not anticipated and included in its 2011 factors.

Q. What depreciation rates were utilized for the capital projects contained in the 2011 Actual/Estimated True-Up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-08-0014-PAA-EI issued on January 4, 2008 in Docket No. 070284-EI.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2011 through December 2011?

A. Tampa Electric relied upon the capital structure approved by the Commission in Docket No. 080317-EI, to calculate the revenue requirement rate of return found on Form 42-9E.

Q. How did the actual/estimated project expenditures for January 2011 through December 2011 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $777,819 greater than projected costs. Total capital expenditures itemized on Form 42-6E, were $242,514 lower 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 $574,357 or 96 percent less than projected. The variance was due to less cogeneration purchases than expected and the application of a lower rate than originally projected.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $199,787 or 42 percent less than projected due to a reduction in maintenance costs associated with implementing best operating practices that have been developed over time.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $43,495 or 145 percent greater than originally projected. The variance is due to an evaluation to determine a method of how to lower cooling water discharge temperatures.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions

Reduction project variance is estimated to be $70,284 or 141 percent lower than originally projected due to the sale of NO_x emissions allowance which offset maintenance activities.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $50,631 or 30 percent less than what was originally projected due to FDEP delay in approval of activity associated with project work.
- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is estimated to be $1,034,057 or 108 percent greater than originally projected due to increase in maintenance expenses associated with higher than projected contractor and material costs. In addition, ammonia usage was greater than projected.
- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is estimated to be $448,006 or 26 percent less due to actual consumption of ammonia being less than originally projected.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $682,934 or 90 percent greater due to maintenance costs being greater than originally projected as well as an increase in the usage of ammonia.
- **Clean Air Mercury Rule:** The Clean Air Mercury Rule

project variance is expected to be $18,839 or 236 percent greater than projected due to the Environmental Protection Agency's ("EPA") Information Collection Request requiring extensive air emission testing at Polk Power Station and Big Bend Station. EPA is collecting data in support of Clean Air Act National Emission Standards for Hazardous Air Pollutant rulemaking that is under way.

- **Greenhouse Gas Reduction Program:** The Greenhouse Gas Reduction Program variance is expected to be $13,142 or 23 percent less than projected due to the project taking less time than originally expected.

Capital Investment Project Variances

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $42,850 or 16 percent less than the original projection due to the retirement of the neural network component related to the Big Bend Unit 1 Pre-SCR program and the resultant decrease of the construction work in progress ("CWIP").
- **Big Bend Units FGD System Reliability:** The Big Bend FGD System Reliability program variance is estimated to be $226,803 or 12 percent less than originally projected due to the overall expenditures for the project now estimated to be less. Additionally, the original expenditures were

projected to occur throughout the year but will now be occurring during the latter part of the year. This timing change on expenditures lowered the original monthly CWIP amounts and thus the monthly return on average net investment amounts thereby creating the modest annual estimated variance.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 110007-EI
FILED: AUGUST 26, 2011

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 2012 through December 2012. 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 2012.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2012 through December 2012?

A. Yes. Exhibit No. ___ (HTB-3), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 8 contain Forms 42-1P through 42-8P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2012.

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 2012.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2012 through December 2012?

A. The net true-up applicable for this period is an under-recovery of $3,080,888. This consists of the final true-up under-recovery of $2,616,798 for the period of January 2010 through December 2010 and an estimated true-up under-recovery of $464,090 for the current period of January 2011 through December 2011. 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, 2011.

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 2012 through December 2012?

A. There were two major contributing factors that created the net under-recovery. First, the combination of O&M and capital project expenditures were greater than anticipated. 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 2012 through December 2012?

A. No, Tampa Electric is not including any new environmental compliance projects for ECRC cost recovery during 2012.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2012?

A. Tampa Electric proposes to include for ECRC recovery the 26 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2012. 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) Phillips Tank No. 1 Upgrade
7) Phillips Tank No. 4 Upgrade
8) Big Bend Unit 1 Classifier Replacement
9) Big Bend Unit 2 Classifier Replacement
10) Big Bend Section 114 Mercury Testing Platform
11) Big Bend Units 1 and 2 FGD
12) Big Bend FGD Optimization and Utilization
13) Big Bend NO_x Emissions Reduction
14) Big Bend Particulate Matter ("PM") Minimization and Monitoring
15) Polk NO_x Emissions Reduction
16) Big Bend Unit 4 SOFA
17) Big Bend Unit 1 Pre-SCR
18) Big Bend Unit 2 Pre-SCR

19) Big Bend Unit 3 Pre-SCR

20) Big Bend Unit 1 SCR

21) Big Bend Unit 2 SCR

22) Big Bend Unit 3 SCR

23) Big Bend Unit 4 SCR

24) Big Bend FGD Reliability

25) Clean Air Mercury Rule

26) SO_2 Emission Allowances

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 2012?

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 $61,487,092.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2012?

A. Tampa Electric proposes to include for ECRC recovery the 22 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2012. 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

22) Greenhouse Gas Reduction Program

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 2012?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $22,580,489 for 2012.

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 32.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2012?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $84,067,581.

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 2012 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 for the period of January through December 2012 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level is shown in Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through December 2012 proposed ECRC billing factors are as follows:

Rate Class	Factor by Voltage Level (¢/kWh)
RS Secondary	0.460
GS, TS Secondary	0.460
GSD, SBF	
Secondary	0.458
Primary	0.453
Transmission	0.449
IS	
Secondary	0.450
Primary	0.446
Transmission	0.441
LS1	0.457
Average Factor	0.459

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 2012.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2012 through December 2012?

A. Tampa Electric relied upon the capital structure approved by the Commission in Docket No. 080317-EI, 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 2012 through December 2012 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 0.459 cents per kWh. This includes the projected capital and O&M revenue requirements of $84,067,581 associated with a total of 32 environmental projects and a true-up under-recovery provision of $3,080,888 that is primarily driven by the combination of O&M and capital expenditures being greater than anticipated while ECRC revenue was less than expected. My testimony also explains that the projected environmental expenditures for 2012 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 110007
FILED: AUGUST 26, 2011

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 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 State 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, 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 2012 through December 2012 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 preliminary SO_2 emission reduction projects have been completed. However, additional work will occur in 2012 associated with the Big Bend Units 1 and 2 FGD and Big Bend FGD System Reliability programs to comply with the elimination of the allowed scrubber outage days for 2013.

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 2012 through December 2012.

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 2012, capital expenditures are anticipated to be $1,500,000 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 $390,400.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x emission reductions projects on Big Bend Units 1, 2 and 3 and pursuant to an amendment, for Big Bend Unit 4 projects to be 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 2012 through December 2012.

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. No capital expenditures are anticipated in 2012; however, Tampa Electric will perform maintenance on the previously approved and installed NO_x Reduction equipment. This activity is expected to result in approximately $395,000 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 2012 through December 2012.

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 2012 through December 2012, no capital or O&M expenditures are anticipated for the Big Bend Units 1 through 3 Pre-SCR projects. For 2012, there are no anticipated capital expenditures for Big Bend Units 1, 3 and 4 SCRs; however, the anticipated capital expenditure for Big Bend Unit 2 SCR is $2,000,000 for catalyst replacement. The 2012 SCR O&M expenses are projected to be $2,466,500 for Big Bend Unit 1 SCR, $2,536,400 for Big Bend Unit 2 SCR, $1,513,000 for Big Bend Unit 3 SCR and $998,300 for Big Bend Unit 4 SCR. O&M expenses are driven by 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")
9) Greenhouse Gas ("GHG") Reduction Program

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 2012 through December 2012.

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.

The projected January 2012 through December 2012 capital expenditures for the Big Bend Unit 3 FGD Integration project are $2,394,700 for controls upgrades as well as duct replacements. O&M expenses are anticipated to be $4,490,200 for consumables and ongoing maintenance. The projected January 2012 through December 2012 capital expenditures for the Big Bend FGD Units 1 and 2 project are $1,820,600 for improvements to waste water treatment reliability and the oxidation air header, both scheduled to occur during the spring outage. O&M expenses are anticipated to be $8,835,100 for consumables and ongoing maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 2012 through December 2012, there will be no capital expenditures for this program. Tampa Electric anticipates

O&M expenses will be approximately $20,000 for continuation of the ongoing study.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 2012 through December 2012, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $106,400 for the period.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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. In March 2011, the Clean Water Act 316(b) Existing Facilities Proposed Rule was issued. The comment period for the proposed rule was extended until August 18, 2011 and the final rule is expected in July 2012. Tampa Electric believes that the current work will continue to be useful for purposes related to the Phase II Rule and does not intend to suspend the work because it would not be cost-effective or appropriate to do so. Therefore, Tampa Electric anticipates O&M expenses associated with the 2012 planned study activities will be approximately $30,000. No capital expenditures are anticipated.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2012 through December 2012.

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 2012 through December 2012, the anticipated capital expenditures will be $3,076,900 for the fines filter installation; however, no O&M expenditures are anticipated for this project.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 2012 through December 2012, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $667,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

A. The CAMR program was approved by the Commission in Docket No. 060583-EI, Order No. PSC-06-0926-PAA-EI, issued November 6, 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.

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. 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.

Capital spending for this program is anticipated to continue in 2012 with ongoing monitoring and thereafter using company resources and consultants as needed. For the period of January 2012 through December 2012, the capital expenditures are anticipated to be $40,000 and the O&M expenditures projected to be $24,000.

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

A. In July 2010, the EPA proposed a new rule, the Clean Air Transport Rule to replace CAIR. In July 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). The remand of CAIR and the subsequent finalization of

CSAPR 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 are expected in late 2011 with implementation in 2014 or 2015. During this time of review of the proposed rules, the company will continue utilizing the resources already secured to establish a baseline of mercury and other emissions subject to the proposed rule.

Q. Please describe the GHG Reduction Program activities and provide the estimated capital and O&M expenditures for the period of January 2012 through December 2012.

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 is 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 2012. For 2012, this activity is not anticipated to require capital expenditures; however, it is expected to result in approximately $40,000 O&M expenses.

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 2012. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2012 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 and Exhibit of
James O. Vick
Docket No. 110007-EI
April 1, 2011

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 2010.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2010 through December 2010 with the approved estimated true-up amounts.
A. As reflected in Mr. Dodd's Schedule 6A, the actual recoverable capital costs were $128,090,570 as compared to the estimated true-up total of 128,112,677. This resulted in a variance of (22,107) or (0.02%).

Q. How do the actual O&M expenses for the period January 2010 to December 2010 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 $34,081,820, as compared to the estimated true-up of $35,001,904. This resulted in a variance of ($920,084) or (2.6%) below the estimated true-up. I will address eight O&M projects and programs that contribute to this variance: Title V, General Solid & Hazardous Waste, Above Ground Storage Tanks, Ash Pond Diversion Curtains, Sodium Injection, FDEP NOx Reduction Agreement, Annual NOx Allowances, and SO_2 Allowances.

Q. Please explain the variance of ($16,491) or (13.5%) in (Line item 1.3) Title V program.

A. Included in the air quality category, Title V (Line Item 1.3) represents ongoing expenses associated with implementation of Title V permits. This variance is due to expenses associated with Title V air operating permits being less than projected in the Estimated True-up filing.

Q. Please explain the variance of $558,057 or 108.9% 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. During October 2010, Plant Smith began excavating petroleum impacted soils that were discovered around an abandoned fuel line. As a result, the Plant Smith solid and hazardous wastes expenses were more than originally projected.

Q Please explain the variance of ($58,215) or (66.5%) in (Line item 1.12), Above Ground Storage Tanks.

A. Aboveground 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. Annual maintenance on the Plant Smith piping and equipment that was scheduled to be completed during fourth quarter of 2010 was delayed until January 2011 due to contractor scheduling conflicts. This resulted in a decrease in expenses for 2010.

Q. Please explain the variance of $71,431 or 9.7% in (Line Item 1.14), Ash Pond Diversion Curtains.

A. Line Item 1.14 includes replacing the Plant Crist_Ash Pond flow diversion curtains and dredging the ash pond. The variance in this line item is primarily due to project delays. The Plant Crist ash pond dredging went slower than expected due to weather conditions and the amount of time needed to settle total suspended solids to ensure environmental compliance. This project was completed in 2010.

Q. Please explain the variance of ($162,555) or (66.5%) in the Sodium Injection program (Line Item 1.16).

A. The expenses that Gulf incurs for this program are dependent on the quantity and quality of coal burned at Plant Crist and Plant Smith. During 2010, the need for sodium injection was less than projected because Gulf burned a type of coal that did not require as much sodium and Gulf burned less coal than originally projected.

Q. Please explain the variance of ($582,464) or (21.8%) 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 a change in the Plant Crist 7 SCR catalyst project. The Crist Unit 7 SCR has multiple layers of catalyst to provide catalyst management flexibility. As the catalyst degrades over time, a layer is added, replaced or regenerated to restore the needed catalytic activity. Gulf sent one SCR catalyst layer offsite for regeneration in January 2010 with a targeted December 2010 delivery date. However, in November 2010 the contractor determined they would not be able to regenerate the catalyst to meet the Crist Unit 7 outage schedule. Therefore, in order to meet the Jan 2011 outage schedule, Gulf purchased a catalyst layer. This resulted in a decrease in O&M expenses for this line item as the purchased layer was capitalized.

Q. Please explain the variance of ($443,746) or (5.1 %) in Annual Nox Allowances (Line Item 1.24).

A. This variance is due to Gulf surrendering fewer Annual NOx allowances because Gulf burned less coal at Plant Crist and Smith in 2010 than projected.

Q. Please explain the variance of ($217,246) or (7.9 %) in SO_2 Allowances (Line Item 26).

A This variance is due to Gulf surrendering fewer SO2 allowances because Gulf burned less coal at Plant Crist and Smith in 2010 than projected.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110007-EI

BEFORE me, the undersigned authority, personally appeared James O. Vick, who being first duly sworn, deposes and says that he is the Environmental Affairs Director for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

James O. Vick

James O. Vick
Environmental Affairs Director

Sworn to and subscribed before me this 24th day of March, 2011.

Theresa Tucker

Notary Public, State of Florida at Large

(SEAL)

THERESA TUCKER
MY COMMISSION # DD 772208
EXPIRES: March 25, 2012
Bonded Thru Notary Public Underwriters

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony
James O. Vick
Docket No. 110007-EI
August 1, 2011

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) estimated true-up for the period January through December 2011. 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 2011 through December 2011 with the approved projected amounts.
A. As reflected in Mr. Dodd's Schedule 6E, the recoverable capital costs approved in the original projection total $126,991,669 as compared to the estimated true-up amount of $127,285,793. This resulted in a variance of $294,124 or 0.2%. There are eight capital projects and programs that

contributed to the majority of this variance: The Crist 5,6 & 7 Precipitator Projects, Continuous Monitoring System(CEMS), Smith Water Conservation, Crist FDEP Agreement for Ozone Attainment, Crist Water Conservation, CAIR/CAMR/CAVR Compliance, Annual Nox Allowance and SO2 Allowances.

Q. Please explain the capital variance of $117,210 or 5.8% in the Crist 5, 6, & 7 Precipitator Projects (Line Item 1.2).

A. This variance is due to higher carrying cost than originally projected on the Crist Unit 6 Precipitator project. Some of the construction was moved up to coincide with the Crist Unit 6 Selective Catalytic Reduction (SCR) project schedule.

Q. Please explain the capital variance of $71,608 or 5.3% in the Continuous Emissions Monitoring System (CEMS) Program (Line Item 1.5).

A. This variance is due to higher carrying cost than originally projected because the cost of the Crist CEMS by-pass project was greater than anticipated. The original project estimate was based on similar work at other plants.

Q. Please explain the capital variance of ($456,695) or (83.3%) in the Smith Water Conservation Program (Line Item 1.17).

A. As stated in the 2011 Projection filing, Gulf will determine whether the existing site properties make it feasible for injection of used reclaimed water in 2011. Gulf will also make decisions on the completion of additional injection wells and the associated monitoring wells that would be required by the Florida Department of Environmental Protection (FDEP) Underground Injection Control Group. Gulf is currently in the drilling and testing phase of the test well for the Smith Water Conservation and consumptive use efficiency program project. As a result of the testing and evaluation process not being complete, the decision to move forward with the project has not yet been made; therefore, this resulted in lower carrying costs for this project than projected.

Q. Please explain the capital variance of ($80,757) or (0.5%) in the Crist FDEP Agreement for Ozone Attainment Program (Line Item 1.19).

A. This variance is primarily attributed to a retirement of the Plant Crist Unit 7 SCR catalyst that was not included in the 2011 projections. This retirement resulted in a lower than estimated depreciation expense.

Q. Please explain the capital variance of $156,605 or 6.0% in the Crist Water Conservation Program (Line Item 1.24).

A. This variance is primarily due to expenditures related to the ECUA reclaimed water project. In order to remain in compliance with the Plant Crist NPDES permit, piping changes were required to re-route spent reclaimed water back to the plant for re-use.

Q. Please explain the capital variance of $342,322 or 0.4% in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. This variance is primarily due to portions of the Crist Unit 6 SCR project being placed in-service during 2011, instead of in 2012. When work first began on the Crist Unit 6 SCR, it was anticipated that all items would be placed in service at the completion of the Unit 6 SCR project in 2012. However, during 2011, three station service transformers which are needed to power the induced draft fans and a large section of ductwork required for the Unit 6 SCR were placed in service. Also contributing to the variance are the property taxes on the Plant Daniel low NOx burners and a new backup raw water pump that was installed for the Plant Crist scrubber make-up water system. These items were not included in the 2011 Projection filing.

Q. Please explain the capital variance of $54,604 or 20.2% in Annual NOx Allowances (Line Item 1.29).

A. This variance is due to a higher allowance inventory balance at the beginning of the year than was originally projected. This results in higher carrying costs than were originally projected.

Q. Please explain the capital variance of $65,739 or 7.5% in SO2 Allowances (Line Item 1.31).

A. This variance is due to a higher allowance inventory balance at the beginning of the year than was originally projected. This results in higher carrying costs than were projected.

Q. How do the estimated/actual 2011 O&M expenses compare to the original 2011 projections?

A. Mr. Dodd's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated at $25,391,528 as compared to $35,412,914. This results in an estimated year-end variance of ($10,021,386) or (28.3%). I will address eight O&M projects and programs that contribute to this variance: General Water Quality, General Solid & Hazardous Waste, Sodium Injection, FDEP NOx Reduction Agreement, CAIR/CAMR/CAVR Compliance, Crist Water Conservation programs, Seasonal NOx and SO2 Allowances.

Q. Please explain the O&M variance of $160,328 or 31.1% in (Line Item 1.6) General Water Quality Program.

A. The General Water Quality variance is primarily due to expenses associated with the Plant Crist dechlorination system and the Plant Crist impoundment integrity inspections. Both activities were undertaken pursuant to the recently renewed Plant Crist National Pollutant Discharge Elimination System (NPDES) permit. The Plant Crist NPDES permit includes limitations and monitoring requirements for Free Available Oxidants when an oxidant such as chlorine is used in the industrial wastewater system. During 2011 Plant Crist incurred unexpected maintenance expenses associated with the sodium bi-sulfite injection system that is used to dechlorinate once through cooling water discharged from the plant.

In addition, the Plant Crist NPDES permit renewal issued during January of 2011 requires that a qualified person with knowledge and training in impoundment integrity inspect all ash impoundments at Plant Crist annually. This covers the required inspections and any follow up actions that may be identified.

Q. Please explain the O&M variance of $351,233 or 84.4% in (Line item 1.11) General Solid and Hazardous Waste Program.

A. This variance is primarily due to the Plant Smith solid and hazardous waste expenses being greater than originally projected. As discussed in the 2010 Final True-up, Plant Smith began excavating petroleum impacted soils that were discovered around an abandoned fuel line. The excavation at Plant Smith was completed in February 2011. During July 2011, the Site Assessment Report for this excavation was submitted to the FDEP. After reviewing the Site Assessment Report, the FDEP will determine if further work is required at this site.

Q. Please explain the O&M variance of ($162,636) or (71.0%) in (Line item 1.16) Sodium Injection program.

A. The expenses that Gulf incurs for this program are dependent on the characteristics of the coal supply which determines the necessity for sodium injection. The 2011 projected need for sodium injection is less than originally budgeted because the type of coal being supplied does not require as much sodium as anticipated.

Q. Please explain the O&M variance of ($1,080,570) or (35.8%) in (Line Item 1.19) FDEP NOx Reduction Agreement.

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 program variance is a result of using less ammonia and urea than originally projected because Plant Crist has been burning less coal than projected.

Q. Please explain the O&M variance ($8,593,848) or (38.3%) 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 Crist Units 4 through 7 scrubber, the Smith Units 1 and 2 SNCRs, and the Scholz mercury monitoring project. 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. The line item variance is primarily due to Gulf projecting to purchase less limestone in 2011 than originally expected primarily due to lower than projected coal burn.

Q. Please explain the O&M variance of $144,944 or 100% 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 new Plant Crist reclaimed water system, such as valve and pump replacements. Gulf Power entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to utilize reclaimed water from ECUA's wastewater treatment plant to reduce the demand for groundwater and surface water withdrawals. Gulf began receiving reclaimed water from ECUA in November of 2010. As stated in the 2011 Projection filing, expenses had yet to be determined and would be addressed in the 2011 Estimated True-up. Therefore, based on Gulf's experience operating this system, Plant Crist is now projecting $144,944 for operation and maintenance of the new system.

Q. Please explain the O&M variance of ($104,162) or (86.8%) in Seasonal Allowances (Line Item 1.25).

A. This variance is due to the current projected cost of allowances to be surrendered being significantly less than the cost originally projected.

Q. Please explain the O&M variance of ($695,141) or (35.9%) in SO2 Allowances (Line Item 1.26).

A. This variance is the result of Gulf surrendering fewer SO2 allowances than projected due to a lower than originally projected burn. Gulf's generation mix is more heavily weighted to natural gas- fired generation than projected due to its current lower economic dispatch cost. Natural gas fired generation also has significantly lower SO2 emission rates than coal- fired generation.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110007-EI

BEFORE me, the undersigned authority, personally appeared James O. Vick, who being first duly sworn, deposes and says that he is the Environmental Affairs Director for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

James O. Vick

James O. Vick
Environmental Affairs Director

Sworn to and subscribed before me this 29th day of July, 2011.

Natalie Milstead

Notary Public, State of Florida at Large

(SEAL)

NATALIE MILSTEAD
MY COMMISSION # EE091117
EXPIRES May 08, 2015
(407) 398-0153
FloridaNotaryService.com

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 110007-EI
August 26, 2011

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. 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 2012 through December 2012.

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

A. Yes, my exhibit consists of the Plant Crist NPDES Permit.

Counsel: We ask that Mr. Vick's exhibit consisting of the plant Crist NPDES Permit be marked as Exhibit No. _____ (JOV-1).

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. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects and the costs for emission allowances. 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 six projects that were previously approved by the Commission with activities that have projected capital expenditures during 2012. Five of the projects are related to Gulf's existing Air Quality programs: the Crist 5, 6, & 7 Precipitator Projects, Crist FDEP Agreement for Ozone Attainment, the CAIR/CAMR/CAVR Compliance Program, Seasonal NOx Allowances, and Annual NOx Allowances. The Smith Reclaimed Water Project is also projected to have capital expenditures during 2012.

Q. Mr. Vick, please describe the project included in the 2012 projection for (Line Item 1.2) the Crist 5, 6, & 7 Precipitator Projects.

A. The Plant Crist Unit 6 precipitator project was originally undertaken in the early 1990's and approved for environmental cost recovery in Docket No. 930613-EI. Inspections of the Crist Unit 6 precipitator have indicated the precipitator internals will need to be replaced. Plant Crist will complete detailed design and award the construction bid package in 2011 and the major equipment is expected to be delivered in the Fall of 2011. This project is expected to be completed in the Spring of 2012. The projected 2012 expenditures for this line item are $25 million.

Q. Mr. Vick, please describe the capital project included in Gulf's Crist FDEP Agreement for Ozone Attainment (Line item 1.19) that will impact the 2012 projected ECRC revenue requirements.

A. Gulf plans to replace one layer of the Plant Crist Unit 7 SCR catalyst during 2012. The projected 2012 expenditures for this line item are $1.8 million.

Q. Mr. Vick, please describe the capital projects included in Gulf's CAIR/CAMR/CAVR Compliance Program (Line Item 1.26) that will impact the 2012 projected ECRC revenue requirements.

A. For the purpose of the 2012 projection of ECRC revenue requirements in Mr. Dodd's testimony, $229 million is projected to be cleared to plant-in-service for the CAIR/CAMR/CAVR Compliance Program. The projected expenditures are primarily related to the completion of the Plant Crist Unit 6 SCR that will be placed-in-service during the Spring of 2012. Also, as part of the Crist Scrubber project, costs related to the Plant Crist Unit 6 and 7 turbine upgrades will be placed in-service in 2012.

Q. Mr. Vick, are you including the purchase of allowances in your 2012 projection filing?

A. Yes, we are currently projecting the need to purchase additional annual and seasonal NOx allowances under the CAIR replacement rule, the Cross-State Air Pollution Rule (CSAPR), during 2012. Gulf's compliance strategy continues to include possible forward contracts, swaps, and spot market purchases of allowances depending on market prices.

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

A. The Smith Reclaimed Water Project is part of the Smith Water Conservation and consumptive use efficiency program required by the Plant Smith consumptive water use permit. Gulf must determine a suitable method to dispose of beneficially used reclaimed water prior to agreeing to accept reclaimed water from suppliers in the Bay County area. Gulf is continuing to investigate the feasibility of utilizing an underground injection well to dispose of used reclaimed water at Plant Smith. Based on the findings of geophysical logs, testing of the deep subsurface intervals later this year and preliminary testing of the upper formation materials, Gulf will make a final determination on whether to move forward with the Plant Smith Reclaimed Water project. If it is determined that the project should be pursued, additional activities such as the installation of additional shallow well(s), monitoring well(s) and the initiation of design of support equipment for the injection of spent fluids into the subsurface would take place. The support equipment necessary for this activity would include but not be limited to the injection pump system, tanks, and piping systems. The projected 2012 expenditures for this line item are $3.5 million.

Q. Mr. Vick, are there any other capital projects that you would like to discuss?

A. Yes, as discussed in the 2011 Compliance Plan Update, if the Utility MACT requirements expected to be released in November 2011 are consistent with the proposed rule, Gulf Power may be required to install additional emission control equipment as early as 2015. Even with a possible one-year extension of the compliance deadline it will be difficult if not impossible to install all of the necessary controls in time. To attempt to install additional controls, such as baghouses, by 2015-2016, Gulf Power would need to begin making capital expenditures in 2012. Gulf projects expenditures of approximately $25 million in 2012 for compliance activities related to the Utility MACT rule. This project qualifies for AFUDC treatment and therefore is not included in Gulf's projected 2012 ECRC factor. The Utility MACT rule should be final in late 2011 and at that time, Gulf will review the final rule to determine the most effective compliance strategy.

Q. How do the Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Mr. Dodd's Exhibit 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, except for the Impoundment Integrity Inspections project that is included in the previously approved General Water Quality Program, Line Item 1.6.

Q. Please describe the O&M activities included in the air quality category that have projected expenses during 2012.

A. There are five O&M activities included in the air quality category that have projected expenses in 2012. 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 2012 recovery period total $825,374. 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 2012 estimated expenses for the Title V Program are $121,936.

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 expenses projected for the recovery period total $1,400.

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 2012 recovery period for these activities total $640,443.

The FDEP NOx Reduction Agreement (Line Item 1.19) includes O&M costs associated with the Plant Crist Unit 7 SCR and the Crist Units

4 through 6 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 the 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 2012 recovery period total $1,673,050.

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, Dechlorination, Groundwater Monitoring, Surface Water Studies, the Cooling Water Intake Program, the Impaired Waters Rule, and Storm Water Maintenance. The expenses expected to be incurred during the projection period for this line item totals $898,066 which includes $127,000 for the new Impoundment Integrity Inspection project discussed below.

The Plant Crist NPDES permit renewal issued during January of 2011, provided as Schedule 1 of my Exhibits, requires that a qualified person with knowledge and training in impoundment integrity inspect all ash impoundments at Plant Crist annually. The permit requires that summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments must be documented and kept onsite and made available to FDEP inspectors. All findings and corrective actions related to impoundment integrity at Plant Crist must be complied with per the permit condition.

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

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 $2,083,868 of incremental expenses for this line item during the 2012 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 $34,500 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 $16,480 during the 2012 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. 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 2012 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 $457,994 in 2012.

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 2012. They are the Above Ground Storage Tanks program, the Sodium Injection System, the CAIR/CAMR/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 $162,457 are projected to be incurred during 2012.

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 $74,000 are projected to be incurred during 2012 for this line item.

Q. What activities are included in the CAIR/CAMR/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/CAMR/CAVR Compliance Program. The projected 2012 expenses for this line item total approximately $16.4 million which includes $7.9 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 $156,000 are projected to be incurred during 2012 for this line item.

Q. Please describe the emission allowance line items 1.24 through 1.26.
A. These line items include projected allowance expenses for Gulf's generation. Line Items 1.24 and 1.25 include projected expenses for annual and seasonal NOx allowances of $103,671 and $1,719,025 respectively. Line Item 1.26 includes $716,998 of projected expenses for SO_2 allowances.

Q. Do each of the capital projects and O&M activities that have projected costs in 2012 meet the ECRC statutory guidelines?
A. Yes. The projects included in Gulf's 2012 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, does this conclude your testimony?
A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
) Docket No. 110007-EI
COUNTY OF ESCAMBIA)

Before me the undersigned authority, personally appeared James O. Vick, who being first duly sworn, deposes, and says that he is the Director of Environmental Affairs of Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

James O. Vick

James O. Vick
Director of Environmental Affairs

Sworn to and subscribed before me this 24th day of August, 2011.

Natalie Milstead

Notary Public, State of Florida at Large

Commission Number: # EE091117

Commission Expires: May 08, 2015

NATALIE MILSTEAD
MY COMMISSION # EE091117
EXPIRES May 08, 2015
(407) 398-0153
FloridaNotaryService.com

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110007-EI
Date of Filing: April 1, 2011

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 Rates and Regulatory Matters 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 Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters 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 2010 through December 2010 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 2010 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 2012?

A. An amount to be refunded of $861,325 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $861,325 to be refunded was calculated by taking the difference between the estimated January 2010 through December 2010 under-recovery of $234,779 as approved in FPSC Order No. PSC-10-0683-FOF-EI, dated November 15, 2010, and the actual over-recovery of $626,546, which is the sum of lines 5 and 6 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 2010 through December 2010. 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 2010 through December 2010 with the estimated/actual O&M expenses approved in conjunction with the November 2010 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 2010 through December 2010 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2010 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 28-31 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. In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements associated with ECRC investment is based on the capital structure and cost rates approved in Gulf's last rate case, Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002. Please see Schedule 9 of my exhibit for the derivation of debt and equity components.

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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110007-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Rates & Regulatory Matters Supervisor for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W Dodd

Richard W. Dodd
Rates & Regulatory Matters Supervisor

Sworn to and subscribed before me this 29th day of March, 2011.

Vickie L. Marchman

Notary Public, State of Florida at Large

(SEAL)

NOTARY PUBLIC STATE OF FLORIDA
Vickie L. Marchman
COMMISSION # DD866249
EXPIRES: JUN. 26, 2013
WWW.AARONNOTARY.com

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110007-EI
Date of Filing: August 1, 2011

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 Rates and Regulatory Matters 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 Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters 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 2011 through December 2011 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 2011 through December 2011 period to be refunded or collected in the period January 2012 through December 2012?

A. The estimated true-up for the current period is an over-recovery of $14,380,513 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 2010 final true-up over-recovery amount of $861,325. The sum of $15,241,838 will be refunded to customers during the January 2012 through December 2012 period. The detailed calculations supporting the estimated true-up for 2011 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 over-recovery of environmental costs for the period January 2011 through December 2011. 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 2011 through December 2011 to the projected O&M expenses approved by the Commission in conjunction with the November 2010 hearing. 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 2011 through December 2011 compares the estimated/actual recoverable costs related to investment to the projected amount approved in conjunction with the November 2010 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 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 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. 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. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 12.0% for the period January 1, 2011 through December 31, 2011.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110007-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Rates & Regulatory Matters Supervisor for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W. Dodd

Richard W. Dodd
Rates & Regulatory Matters Supervisor

Sworn to and subscribed before me this 29th day of July, 2011.

Natalie Milstead
Notary Public, State of Florida at Large

(SEAL)

NATALIE MILSTEAD
MY COMMISSION # EE091117
EXPIRES May 08, 2015
(407) 398-0153 FloridaNotaryService.com

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110007-EI
Date of Filing: August 26, 2011

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 Rates and Regulatory Matters 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 Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters 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 2012 through December 2012.

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 8 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of eight schedules be marked as Exhibit No. _____(RWD-3).

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

A. As discussed in the testimony of J. 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 O&M expenses to be recovered through the ECRC calculated?

A. Mr. Vick has provided me with projected recoverable O&M expenses for January 2012 through December 2012. Schedule 2P of my exhibit 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 the Clean Air Act Amendments of 1990 (CAAA) were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. O&M expenses associated with Gulf's Clean Air Interstate Rule (CAIR) and Clean Air Visibility Rule (CAVR) Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 010949-EI.

Q. Please describe Schedules 3P and 4P of your exhibit.

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 June 2002 through May 2003 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 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. 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. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 12.0% for the period January 1, 2012 through December 31, 2012.

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

A. The investment costs associated with compliance with the CAAA were considered to be energy-related consistent with Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994, in Docket No. 930613-EI. The investment costs associated with Gulf's CAIR and CAVR Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining investment costs of environmental compliance were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last approved cost-of-service study. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2012 through December 2012?

A. The total projected jurisdictional recoverable costs for the period January 2012 through December 2012 is $169,103,827 as shown on line 1c of Schedule 1P. This includes costs related to O&M activities of $25,215,471 and costs related to capital projects of $143,888,356 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 2012 through December 2012 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $153,972,770 for the period January 2012 through December 2012 as shown on line 5 of Schedule 1P. This amount includes the recoverable costs related to the projection period and the total true-up cost of $15,241,838 to be refunded. 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.

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 2009 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 1 through 9 on Schedule 6P.

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 summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $144,972,155 for the period January 2012 through December 2012 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $9,000,615 for the period January 2012 through December 2012 was allocated using the demand allocator, as shown in column 4 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 5.

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 $13.28 monthly for the period January 2012 through December 2012.

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 2012 and will continue through the last billing cycle of December 2012.

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

A. Yes.

MS. BROWN: The prefiled testimony for PEF Witnesses Garrett, West, and Foster will be admitted when they take the stand.

CHAIRMAN GRAHAM: Okay.

MS. BROWN: The Comprehensive Exhibit List that we just passed out to you, we would like to mark and move into the record the list itself as Exhibit 1, and includes Staff's stipulated composite exhibit as Exhibit 2. The other exhibits on the list should be numbered as indicated, and those marked with an asterisk can be moved into the record at this time, including -- give me just one minute -- Exhibit 34, JOV-1.

CHAIRMAN GRAHAM: Read that out again.

MS. BROWN: Exhibit 34 for Gulf Power Company, JOV-1.

CHAIRMAN GRAHAM: Okay. Are there any objections --

MS. BROWN: So --

CHAIRMAN GRAHAM: Are there any objections to those exhibits read by Staff entered into the record? We will put those in the record.

(Exhibits 1 through 37 marked for identification.)

(Exhibits 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 22, 23, 24, 25, 31, 32, 33, 34, 35, 36, and 37 admitted into the record.)

MS. BROWN: The remaining exhibits can be moved for admission when the sponsoring witnesses have taken the stand.

And now with respect to the proposed stipulations, we recommend that the Commission address the parties' stipulation on Issue 11C separately since it also refers to Docket Number 110138-EI. That's Gulf's rate case. And 11C is the turbine upgrade issue. The parties proposed a stipulation on Friday that agreed to remove all of the costs associated with the Crist turbine upgrades from the ECRC and then request supplemental testimony to be filed in the rate case according to a schedule that they proposed so that, that Gulf can address how it would like to treat those turbine costs in the rate case. We're recommending that you should you approve that stipulation to remove the projected Crist turbine upgrade costs from Gulf's ECRC and refer the joint request to file supplemental testimony on the turbine upgrades in Gulf's rate case to the Prehearing Officer in Docket Number 110138-EI. And with that, with an approval on that stipulation, the other outstanding issues, which are fallout issues for Gulf, can also be approved.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you.

A question for Staff, as I have all of this paper in front of me, has the stipulation that you have just described for Issue 11C regarding the turbine upgrade cost, has that stipulation been entered into the record?

MS. BROWN: No, it has not. I have a copy of it. We could mark it, if you would like, and enter it.

COMMISSIONER EDGAR: It seems to me that for purposes of the record and for purposes of me keeping track of all of the paper and the documents, that that might be a helpful thing to do at this time.

MS. BROWN: Certainly. You all should have a copy of that. I think I remembered to pass that out. Let me see if I can find it.

MR. STONE: If the Commissioners do not have a copy, I have a copy of it. And I would join in the request that that be marked as an exhibit in this proceeding.

COMMISSIONER EDGAR: Then, Mr. Chairman, I would ask at this time that we mark the proposed stipulation as Exhibit 39.

CHAIRMAN GRAHAM: Is it Issue 11C, is that what's before us in this? I guess it's on page 2 of -- I don't even know this docket, what this is called.

Stipulated and -- stipulation and agreement regarding issues related to cost recovery and Plant Crist turbine upgrades. Is that --

MS. BROWN: I'm sorry, Mr. Chairman. I couldn't hear you. Could you repeat that?

Yes. What you're looking for is In Re: Environmental Cost Recovery Clause, In Re: Petition for Increase in Rates by Gulf Power Company, Docket Number 110007 and Docket Number 110138, stipulation and agreement regarding issues related to cost recovery of Plant Crist turbine upgrades and joint request for approval. And I think, Mr. Chairman, I'm going to have to make some copies. Oh, you have it? Okay.

CHAIRMAN GRAHAM: Yeah. That's what we have before us.

Okay. Commissioner Edgar, you have the floor. Is this the document that you were looking for?

COMMISSIONER EDGAR: Thank you, Mr. Chairman. Yes, it is. And I would ask that we mark it as Exhibit 39 and enter it into the record at this time. And then when we are ready to discuss stipulations, we can refer to it in that way.

CHAIRMAN GRAHAM: Any objections to entering this into the record as Exhibit 39?

MR. STONE: No objections.

CHAIRMAN GRAHAM: Seeing none, we will do that.

(Exhibit 39 marked for identification and admitted into the record.)

MS. BROWN: I think at this point, Mr. Chairman, we're ready to make a recommendation that you approve the stipulations on all issues, all stipulated issues in 07, which would include all issues except Issue 10G, which is related to Issue 1C in 01 for Progress.

CHAIRMAN GRAHAM: Hold on a second. We have a Commissioner that wants to speak. I know he's not going to throw a monkey wrench into this. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I just have a quick question for Staff on Exhibit 39, which is the proposed stipulation for Issue 11C. I just want to confirm that this stipulation is consistent with what the Commission did for Florida Power & Light for, I believe, the Scherer turbine upgrades; is that correct?

MS. BROWN: Yes, that is correct.

COMMISSIONER BALBIS: Where it was removed from this clause and recommended be placed into a base rate proceeding.

MS. BROWN: Yes. That's correct.

COMMISSIONER BALBIS: Okay. Thank you.

MR. PERKO: Mr. Chairman, I hate to interrupt, but on behalf of Progress, we discussed at the prehearing conference a minor change to the wording of Issue 10E, to take out the word "annual," and I don't think that -- inadvertently I think that was not done. So if we could just make that correction, I think we can go forward.

CHAIRMAN GRAHAM: Staff and Prehearing Officer?

COMMISSIONER BRISÉ: Thank you, Mr. Chairman. I think we had agreed to have that done. It was just a, I guess, scrivener's error that it wasn't done.

MR. PERKO: Thank you.

CHAIRMAN GRAHAM: Staff?

MS. BROWN: That's correct. It was a scrivener's error.

CHAIRMAN GRAHAM: We will consider that a scrivener's error.

MS. BROWN: My scrivener's error.

CHAIRMAN GRAHAM: Now we're at bench decision? No. Where are we, Staff?

MS. BROWN: We are at a bench decision on the proposed stipulations.

CHAIRMAN GRAHAM: Okay. Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. I would propose at this time that we adopt and approve the proposed stipulations in the 07 docket, which would include the list of issues on Exhibit 30A and the stipulation for Exhibit 39, with the one correction to Issue 10E included.

MR. BEASLEY: May I make a point of inquiry, sir?

CHAIRMAN GRAHAM: Sure.

MR. BEASLEY: On the Exhibit 38 it shows Issue 8, effective date, FPUC only, and I thought that was all the companies, but.

COMMISSIONER EDGAR: Then, Mr. Chairman, I would pose that to Staff.

MS. BROWN: It should be all utilities.

MR. BEASLEY: Thank you.

COMMISSIONER EDGAR: Then I would add that correction to Exhibit 38 as part of my motion.

CHAIRMAN GRAHAM: It's been moved and seconded, the motion as stated by Commissioner Edgar. Any further discussion? Seeing none, all opposed -- all in favor, say aye.

(Affirmative response.)

Any opposed?

(No response.)

By your action, you've approved those issues as stipulated.

Okay. So now we are to Issue 10G; is that correct, Staff?

MS. BROWN: Yes, Commissioner, except that I think at this point we need to put 07 on the table and go back to 01. Because if you look on our Prehearing Order, Issue 10G, the Staff's position is that your decision in this case should be consistent with how you make your decision in 01.

CHAIRMAN GRAHAM: Okay. But are we at the point with 07 to release all the other utilities?

MS. BROWN: Yes.

CHAIRMAN GRAHAM: Okay.

MS. BROWN: Yes, we can do that. And just keep Progress Energy.

CHAIRMAN GRAHAM: All right.

MS. BROWN: But I don't think we ought to address 10G at this time.

CHAIRMAN GRAHAM: Okay. So we will lay docket 110007 on the table.

COMMISSIONER EDGAR: But before we do that -- thank you, Mr. Chairman. I apologize. Before we do that, while we're still on the 07 docket, I wanted to mention that by adopting the stipulation referring to 11C in Exhibit 39, that that does require me as Prehearing Officer in the 110138 docket to look at the question of additional testimony. I've talked with Staff, and we will make a decision on that very quickly and get out a revised OEP that addresses that. And thank you for letting me throw that in before we closed out this docket for the moment.

CHAIRMAN GRAHAM: We're going to lay that docket on the table, with that being said.

COMMISSIONER EDGAR: Thank you.

MR. STONE: Chairman Graham -- Mr. Butler.

MR. BUTLER: It was a race. I'm not sure who won. I would ask that for FPL's witnesses, I believe this applies for TECO and Gulf as well, that the witnesses and counsel for those utilities be dismissed, excused from Docket 110007 because all of our witnesses are excused and all of our issues have been stipulated.

CHAIRMAN GRAHAM: We will excuse you from that docket. And thank you all for your time and effort, and thank you for suggesting moving to 07 so we can clear everything out of here and stay single focused.

MR. BUTLER: Thank you very much.

CHAIRMAN GRAHAM: Travel safe.

MR. BUTLER: Thank you.

MR. BEASLEY: Thank you.

(Proceeding recessed.)

(Transcript continues in sequence in Volume ***)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 2nd day of November, 2011.

Linda Boles

LINDA BOLES, RPR, CRR
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