BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050007-EI

In the Matter of

ENVIROMENTAL COST RECOVERY
CLAUSE.
_______________________________/

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VOLUME 1

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR COMMISSIONER ISILIO ARRIAGA
DATE:	Monday, November 7, 2005
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR (850) 413-6732

APPEARANCES:

LEE L. WILLIS, ESQUIRE and JAMES D. BEASLEY, ESQUIRE, Ausley & McMullen, P.O. Box 391, Tallahassee, 32302, appearing on behalf of Tampa Electric Company.

JOHN W. MCWHIRTER, JR., ESQUIRE, McWhirter Reeves & Davidson, P.A., 400 North Tampa Street, Suite 2450, Tampa, Florida 33601-3350, and TIMOTHY J. PERRY, McWhirter Reeves & Davidson, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JOHN T. BUTLER, ESQUIRE, Squire, Sanders & Dempsey, LLP, including Steel, Hector & Davis, 200 South Biscayne Boulevard, Suite 4000, Miami, Florida 33131-2398, and R. WADE LITCHFIELD, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

GARY V. PERKO, ESQUIRE and CAROLYN S. RAEPPLE, ESQUIRE, Hopping Green & Sams, P.O. Box 6526, Tallahassee, Florida 32314, and ALEXANDER GLENN, ESQUIRE, Progress Energy Service Co, LLC, 100 Central Avenue, St. Petersburg, Florida 33701-3324, appearing on behalf of Progress Energy Florida, Inc.

APPEARANCES CONTINUED:

PATRICIA CHRISTENSEN, ESQUIRE, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., #812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

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

I N D E X

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Staff's Comprehensive List of Exhibits	168	168
2	Stipulations	168	168
3 - 27	Exhibits as Listed and Described in Staff's Comprehensive List of Exhibits	168	168

	ID.
CERTIFICATE OF REPORTER	183

P R O C E E D I N G S

CHAIRMAN BAEZ: Good morning. Call the hearing to order.

Please read the notice.

MS. FLEMING: Pursuant to notice issued by the Commission clerk, this time and place has been set for a hearing in following dockets: 050001-EI, 050002-EG, 050003-GU, 050004-GU and 050007-EI.

CHAIRMAN BAEZ: Thank you. We will take appearances, and if you would kindly -- I know a lot of you are here on more than one docket. If you just list for the record the dockets that you are appearing on behalf of your clients, and we will just start with my left, Mr. Butler.

MR. BUTLER: Good morning, Commissioners, I am John Butler of Squire, Sanders and Dempsey, and I will be appearing in Dockets 050001 and 050007 along with Wade Litchfield. Mr. Litchfield and Natalie Smith will also be appearing in Docket 050002.

MR. BEASLEY: Good morning, Commissioners. James D. Beasley appearing with Lee L. Willis in Dockets 01, 02, and 07. I would also like to enter an appearance for Ansley Watson, Jr. and Matthew Costa in Docket Numbers 050003 and 0004.

MR. RANGE: Good morning. Thomas Range appearing for myself and Bill Bryant on behalf of Florida City Gas in Dockets 03 and 04.

MR. HORTON: Good morning, Commissioners. Norman H. Horton, Jr., appearing on behalf of Florida Public Utilities Company in Dockets 01, 02, 03, and 04.

MR. PERKO: Good morning, Commissioners. Gary Perko, Hopping Green & Sams law firm, appearing on behalf of Progress Energy Florida in the 01, 02, and 07 dockets. And appearing with me are Mr. Alex Glenn, Deputy General Counsel, Progress Energy Services Company, and my law partner, Carolyn Raepple.

MS. WHITE: Good morning, Commissioners. I'm Lieutenant Colonel Karen White, and I am appearing in Docket 050001.

MS. CHRISTENSEN: Good morning. I'm Patricia Christensen with the Office of Public Counsel appearing with Joe McGlothlin and Charlie Beck in the 01, 02, and 07 dockets, and also putting in an appearance on behalf of John Marks who is appearing in the 03 docket.

MR. McWHIRTER: My name is John McWhirter of the law firm of McWhirter, Reeves and Davidson. I am here appearing assisting Tim Perry in this case in Dockets 01, 02, and 07.

MR. SCHIEFELBEIN: Good morning. Wayne Schiefelbein appearing on behalf of Chesapeake Utilities Corporation in the 04 docket.

MR. TWOMEY: Good morning, Commissioners. Mike Twomey appearing on behalf of AARP and its approximately 2.7 million Florida members, appearing in the 01 docket.

MR. WRIGHT: Good morning, Mr. Chairman, Commissioners. Robert Scheffel Wright and John T. Lavia, III, Landers & Parsons, P.A., 310 West College Avenue, Tallahassee, appearing on behalf of the Florida Retail Federation in Docket 050001 and 050007.

CHAIRMAN BAEZ: Is there anyone else that needs to enter an appearance?

MS. BROWN: Mr. Chairman.

CHAIRMAN BAEZ: All right.

MS. BROWN: I'm Martha Carter Brown appearing on behalf of the Commission in the 02 and 04 dockets.

CHAIRMAN BAEZ: Thank you.

MS. STERN: Marlene Stern appearing on behalf of the Commission in the 07 docket.

MS. VINING: Adrienne Vining and Jennifer Rodan appearing on behalf of the Commission in the 01 docket.

MS. FLEMING: Katherine Fleming appearing on behalf of the Commission in the 03 docket.

CHAIRMAN BAEZ: Thank you all. Preliminary matters, we have many of them. And I guess, staff, we can start off by noting for the record that there are some parties that have been excused from attending the hearing, and at this point I have St. Joe and Gulf.

MS. VINING: That is correct.

CHAIRMAN BAEZ: Is that the balance?

MS. VINING: As far as I know, yes.

CHAIRMAN BAEZ: All right. Very well. Also, ladies and gentlemen, since we are taking up five dockets on this day, we have tried to set an order which will allow us to dispense with the dockets. There are some dockets that have been fully stipulated. The order will be we will take up 03, 04, 02, 07, and 01 in that order. And I guess we can move on to the separate dockets at this point.

MS. FLEMING: Yes, Chairman.

* * *

CHAIRMAN BAEZ: Ms. Stern, we are now on 07.

MS. STERN: Yes.

CHAIRMAN BAEZ: Do we have preliminary matters?

MS. STERN: No, there are no preliminary matters that I'm aware of at this time.

CHAIRMAN BAEZ: Do the parties have any preliminary matters at this time?

Now, we have some excused witnesses at this point, Ms. Stern?

MS. STERN: Yes, all of the witnesses have been excused except for two, Javier Portuondo from Progress, and Kory Dubin for FPL. So at this time I suggest that we move the testimony of the other witnesses into the record.

CHAIRMAN BAEZ: Very well. With the exception of Witnesses Portuondo and Dubin, if there are no objections, we will admit the prefiled testimony of all other witnesses to be inserted into the record at though read.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 050007-EI
April 1, 2005

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 such as Air Quality Engineer and Senior Environmental Licensing Engineer. 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 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 true-up for the period from January 1, 2004 through December 31, 2004.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2004 through December 2004 with the approved estimated true-up amounts.
A. As reflected in Ms. Davis' Schedule 6A, the recoverable capital costs included in the estimated true-up total $12,429,822, as compared to the actual recoverable capital costs of $12,455,428. This results in a small variance of $25,606 or 0.2%. I will address four projects that contribute to this variance.

Q. Please explain the capital project variance of ($62,558) in the Crist 5, 6 & 7 Precipitator Projects (Line Item 1.2).

A. This deviation primarily resulted from retiring the Plant Crist Unit 7 precipitator a month ahead of schedule.

Q. Please explain the (9.6%) variance of ($2,384) in the Smith Waste Water Treatment Facility (Line Item 1.15).

A. The Smith Waste Water Treatment Facility was not placed in service during 2004 due to permitting delays. Construction was completed in 2004, but the system could not be placed in service until the Florida Department of Environmental Protection (FDEP) industrial wastewater permit modification was completed. The project delay created an under budget variance in the Smith Waste Water Treatment facility line item (Line item 1.15).

Q. Please explain the variance of $69,985 in the Crist DEP Project (Line Item 1.19).

A. Since the Unit 7 precipitator was placed in service on April 22, 2004, other related components have been completed and placed in service as well. These include the precipitator insulation and platform.

Q. Please explain the capital project variance of ($5,542) or (74.1%) in the Crist Switchyard Stormwater (Line Item 1.20).

A. Construction of the Crist Switchyard Stormwater project was postponed from 2004 to 2005 due to project design delays. Design modifications were necessary because the original design incorporated the abandoned Unit 6 discharge structure which was reutilized after Hurricane Ivan damaged the Unit 6 cooling tower. Plant Crist plans to begin construction of the redesigned stormwater structure during May 2005.

Q. How do the actual O&M expenses for the period January 2004 to December 2004 compare to the estimated true-up?

A. Mrs. Davis' Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $2,676,757, as compared to the estimated true-up of $2,665,823. This results in a year-end net variance of only $10,934. I will address ten O&M projects and programs that contribute to this variance.

Q. Please explain the variance of ($23,906) in Title V (Line Item 1.3).

A. Gulf Power submitted Title V permit renewal applications for Plants Crist, Smith, and Scholz during 2004. The revised permits became effective on January 1, 2005. The 2004 permit implementation costs were less than originally anticipated because several of the projects were not completed until 2005.

Q. Please explain the variance of ($41,396) in Emission Monitoring (Line Item 1.5).

A. Gulf anticipated that two Quality Assurance / Quality Control (QA/QC) tests per unit would be required at Plant Scholz. Based on good performance, greater than 7.5% relative accuracy, the testing frequency was reduced to one annual test per unit for both units. This reduced testing schedule resulted in a ($22,000) deviation in the Emission Monitoring category. The Emission Monitoring variance also resulted from Plant Daniel personnel being unable to complete the scheduled Continuous Emissions Monitoring training during 2004 and the Plant Crist compliance assurance monitoring testing being less than originally anticipated.

Q. Please explain the variance of ($23,058) in the category General Water Quality (Line Item 1.6).

A. This variance was primarily due to rebidding the surface water studies laboratory analysis contract and reducing the entrainment sampling at Plant Smith.

Q. Please explain the variance of $41,517 in the category Groundwater Contamination Investigation (Line Item 1.7).

A. The Long Point substation soil excavation costs were greater than the projected expenses creating a variance in the Groundwater Contamination Investigation line item. During the fourth quarter, transportation costs per load were greater than originally projected for the project.

Q. Please explain the variance of $34,526 in the category State NPDES Administration (Line Item 1.8).

A. This variance resulted from booking the 2005 annual state National Pollution Discharge Elimination System (NPDES) industrial wastewater permit fees during December of 2004. The fees were projected for January of 2005.

Q. Please explain the 30% variance of $2,697 in the category Lead and Copper Rule (Line Item 1.9).

A. The Plant Smith chemical usage costs for corrosion control treatment in the potable water system were more than the projected expenses creating a variance in the Lead and Copper Rule line item.

Q. Please explain the variance of $12,894 in the category entitled Environmental Auditing/Assessment (Line Item 1.10).

A. This variance primarily resulted from an assessment of Gulf's stormwater permitting programs at the corporate, plant, and district levels. This item was not included in the 2004 budget.

Q. Please explain the variance of ($27,335) in the category entitled General Solid & Hazardous Waste (Line Item 1.11).

A. This variance resulted from waste removal and disposal costs at Gulf's facilities being less than originally anticipated during normal operations. The amount of solid and hazardous waste generated widely varies from one period to the next.

Q. Please explain the variance of $16,844 in Sodium Injection (Line Item 1.16).

A. The expenses that Gulf incurs for this program are dependent on the available coal supply and the necessity for sodium injection. The need for sodium injection was more than what was anticipated for the 2004 projection period during due to a change in the coal supply .

Q. Please explain the variance of ($8,486) in Line Item 1.17, Gulf Coast Ozone Study (GCOS).

A. GCOS modeling is currently being conducted at a slower rate than originally expected because the project is approaching completion. Gulf Power anticipates that the GCOS project will be completed by 2006.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 050007-EI
August 12, 2005

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 and Senior Environmental Licensing Engineer. 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 am responsibile 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 estimated true-up for the period from January 1, 2005 through December 31, 2005. This true-up is based on six months of actual and six months of projected expenses.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 1, 2005 through December 31, 2005 with approved projected amounts.

A. As reflected in Mrs. Davis' Schedule 6E, the recoverable capital costs approved in the original projection total $22,496,105, as compared to the estimated true-up amount of $22,593,654. This results in a projected variance of $97,549 or 0.4%. There are seven capital projects and programs with significant variances: Crist 7 Flue Gas Conditioning; Low NOx Burners; Smith Water Conservation; Crist FDEP Agreement for Ozone Attainment; Crist Storm Water Projects, Precipitator Upgrades for CAM, and finally, SO_2 allowances. These variances are discussed below.

Q. Please explain the capital project variance of ($34,209) in Crist 7 Flue Gas Conditioning (Line Item 1.3).

A. The Line Item 1.3 variance resulted from retirement of the Crist Unit 7 Flue Gas Conditioning system due to the installation of the FDEP NOx Reduction Agreement emission control systems.

Q. Please explain the variance of $64,626 in the capital category entitled Low NOx Burners, Crist 6 & 7 (Line Item 1.4).

A. The variance of $64,626 over the original projection resulted from capital additions being over budget in the fourth quarter of 2004. These fourth quarter expenditures had not been incurred when the projection for 2005 was prepared.

Q. Please explain the ($11,585) variance in the capital category entitled Smith Water Conservation (Line Item 1.17).

A. The Plant Smith closed loop cooling project for the laboratory sampling system has been delayed while further design options are evaluated. Gulf expects to complete the project design by October 2005 with construction commencing in November 2005.

Q. Please explain the $290,175 variance in the capital category entitled Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. Costs associated with the Selective Catalytic Reduction (SCR) system construction and startup were greater than originally expected. The overall project involved the retrofitting of major pollution control equipment (a precipitator and the SCR) to an existing plant. With a project of this magnitude, Gulf expected to fine-tune the equipment as we worked to harmonize operation of the new pieces of equipment with the operation of the generating unit itself. During that process Gulf has encountered some startup delays and issues which have resulted in increased costs.

Q. Please explain the capital project variance of ($24,992), or 66.7% in the Crist Storm Water Projects - Switchyard & Other Areas (Line Item 1.20).

A. The original Crist Switchyard Stormwater design incorporated the use of the abandoned Crist Unit 6 discharge structure. After Hurricane Ivan, the Unit 6 structure was reutilized to allow Unit 6 to operate on once through cooling. This has resulted in design modifications to the Crist Switchyard Storm Water project.

Q. Please explain the variance of ($200,463) in the capital category entitled Precipitator Upgrades for CAM compliance (Line Item 1.22).

A. The Plant Smith labor construction costs were less than originally projected because the successful bid was lower than Gulf's initial cost projection.

Q. Please explain the ($28,454) variance in SO_2 allowances in Line Item 1.23.

A. The Company's proceeds from the spring allowance auction are unpredictable from year to year and were therefore unbudgeted for the current period.

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

A. Mrs. Davis' Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated to be $3,432,403 as compared to the original projection of $3,991,191. This will result in a year-end variance of ($558,788). There are seven O&M projects and programs that contributed to the majority of this variance that I will discuss – General Water Quality; State NPDES Administration; Lead and Copper Rule; General Solid and Hazardous Waste; Sodium Injection; FDEP NOx Reduction Agreement; and SO_2 Allowances.

Q. Please explain the ($71,350) variance in General Water Quality (Line Item 1.6).

A. The General Water Quality variance primarily resulted from the Cooling being less than originally projected.

Q. Please explain the variance of ($33,735) in the category State NPDES Administration (Line Item 1.8).

A. This variance resulted from booking the 2005 annual state National Pollution Discharge Elimination System (NPDES) industrial wastewater permit fees early. The fees were projected for January of 2005.

Q. Please explain the variance of ($7,939) in the category entitled Lead and Copper Rule (Line Item 1.9).

A. The Lead and Copper Rule line item includes corrosion control treatment and analysis expenses for the potable water systems at Gulf's generating facilities. The 2005 expenses will be less than originally projected at Plant Crist and Plant Smith because both facilities will be purchasing a smaller amount of corrosion inhibitor. Plant Crist plans to abandon its potable water system to tie into the Escambia County water supply system during August 2005 and Plant Smith has sufficient treatment chemicals.

Q. Please explain the variance of $69,993 or 32.6% in General Solid and Hazardous Waste (Line Item 1.11).

A. This variance resulted from waste removal and disposal costs for Gulf's distribution systems being more than originally anticipated during normal operations. The amount of solid and hazardous waste generated varies from one period to the next.

Q. Please explain the variance of $210,791 in Sodium Injection (Line Item 1.16).

A. The Sodium Injection System, approved in Docket Number No. 990667-EI for inclusion in the ECRC, involves sodium injection on the coal supply to enhance precipitator efficiencies when burning certain low sulfur coals. The expenses that Gulf incurs for this program are dependent on the available coal composition and the necessity for sodium injection. Plant Crist began routinely using sodium injection on Unit 4 and Unit 5 during 2005 creating a $210,791 deviation in the Line Item 1.16 year end projection.

Q. Please explain the variance of ($163,815) in Line Item 1.19, FDEP NOx Reduction Agreement.

A. The FDEP NOx Reduction Agreement (Line Item 1.19) includes the cost of anhydrous ammonia, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Plant Crist FDEP Agreement for Ozone Attainment. The variance in this line item primarily resulted from the anhydrous ammonia usage being less than originally anticipated for the January – June 2005 recovery period. The Crist-Unit 7 SCR was completed earlier this year and is now operational. The overall project involved the retrofitting of major pollution control equipment (a precipitator and the SCR) to an existing plant. With a project of this magnitude, Gulf expected to fine-tune the equipment as we worked to harmonize operation of the new pieces of equipment with the operation of the generating unit itself. During that process Gulf has encountered some startup delays and issues that are temporarily causing the unit to operate at a expected due to these startup delays and temporarily restricted loads.

Q. Please explain the ($562,733) variance in SO2 allowances in Line Item 1.20?

A. The Company's proceeds from the spring allowance auction and associated gains returned to customers are unpredictable from year to year and were therefore unbudgeted for the current period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony and Exhibit of

James O. Vick

Docket No. 050007-EI

September 16, 2005

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) during the period from January 2006 through December 2006.

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

A. Yes, I have. My exhibit includes the following documents:

- Written concurrence from Florida Department of Environmental Protection (FDEP) that the NO_x reduction activities Gulf proposes to implement for the Plant Crist Units 4, 5, and/or 6 are reasonable and necessary to achieve the emission limit specified in the terms of the August 28, 2002 agreement with FDEP.

- Plant Crist Consumptive Use Permit
- Northwest Florida Water Management District (NWFWMD) correspondence regarding the proposed Crist Water Conservation Plan.

Counsel: We ask that Mr. Vick's' Exhibit consisting Consisting of three documents be marked as Exhibit No. _____(JOV-1).

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

A. A listing of the environmental capital projects for which Gulf seeks recovery through the ECRC has been provided to Ms. Davis and is included in Schedules 3P and 4P of her testimony. Schedule 4P reflects the expenditures, clearings, retirements, salvage and cost of removal currently projected by month for each of these projects. These amounts were provided to Ms. Davis, who has compiled the schedules and calculated the associated revenue requirements for Gulf's requested recovery.

Q. Have all of the capital projects shown on Ms. Davis's schedules been previously approved by the Commission?

A. No. Gulf's 2006 ECRC capital projection includes new projects in addition to capital programs previously approved by the Commission.

Q. Mr. Vick, please describe the new projects within Gulf's Air Quality programs that are to be considered for cost recovery.

A. The first project (Line Item 1.26), the Scrubber Project (PE 1222), is necessary to comply with the Clean Air Interstate Rule (CAIR) promulgated by the United States Environmental Protection Agency (EPA) on March 10, 2005. The CAIR, which is published in Chapter 40 of the Code of Federal Regulations (CFR) Parts 51, 72, 73, 74, 77, 78, and 96, restricts sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") air emissions that contribute to fine particulate and ground level ozone in downwind states. The CAIR will use a two phase approach to reduce SO_2 emissions from electric generating units in 28 eastern states including Florida in 2010 and 2015, respectively. FDEP has proposed rulemaking to adopt CAIR by January 2006 with a State Implementation Plan due by September 2006. EPA has indicated that compliance with CAIR may also meet the Best Available Retrofit Technology (BART) emission control requirements under the Regional Haze Rule. The Regional Haze Rule was promulgated by EPA on July 6, 2005 to reduce visibility impairing pollutants from twenty-six source categories, including electric generating units. The FDEP will begin rulemaking in 2006 to adopt a State Implementation Plan requiring BART-eligible sources to propose BART controls or to demonstrate through modeling why they should be exempt from BART regulation.

It is expected that CAIR will require the installation of Scrubber technology at Plant Crist. The 2006 projected scrubber expenditures, totaling $44.2 million, include materials, contract services, as well as engineering and design costs to determine the best strategy to comply with CAIR. The estimated in-service date for the Plant Crist scrubber system is April, 2010.

The second new air quality project (PE 1461) is the Plant Smith Baghouse Project on Unit 2 (Line Item 1.27). The baghouse installation is necessary to meet the Clean Air Mercury Rule (CAMR) (Chapter 40 CFR Parts 60, 72, and 75) requirements adopted by EPA on March 15, 2005. The CAMR limits mercury emissions from new and existing coal fired power plants. CAMR will achieve a 70% reduction in mercury emissions in two phases effective in 2010 and 2018. The FDEP will begin rulemaking in 2005 to adopt a State Implementation Plan by November 2006. Gulf will begin incurring costs for preliminary engineering and strategy development during 2006 due to the thirty-six month lead time for design and construction. The 2006 estimated expenditures are $4.7 million.

Q. Mr. Vick, please describe the new Water Quality programs that Gulf seeks to recover.

A. The first new project (Line Item 1.23) is the Plant Groundwater Investigation (PEs 1218 and PE 1361). The FDEP published a new arsenic groundwater standard that lowered the limit from 0.05 mg/L to 0.01 mg/L, effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicate that these facilities may not be able to comply with the lower standard. Gulf is currently conducting a groundwater study as part of the previously approved O & M General Water Quality program due to projected groundwater concentrations exceeding the new arsenic standard. The studies will determine the nature of the potential impacts to groundwater and identify solutions necessary to resolve this issue. Gulf expects to incur capital expenditures of $500,000 during 2006 to ensure continued compliance with the groundwater standards.

The Crist Water Conservation Program included in Line Item 1.24 (PE 1227), is part of Gulf's water conservation and consumptive use efficiency program required by the Company's consumptive water use permit. Plant Crist's consumptive use permit, issued by the NWFWMD, requires the plant to implement measures to increase water conservation and efficiency at the facility.

Plant Crist plans to install automatic level controls on the fire water tanks during 2006 to reduce groundwater usage. Plant Crist estimates that the proposed system will reduce water consumption by approximately 1.3 million gallons per year. The NWFWMD has agreed that this is a valid project to pursue for continued implementation of the water conservation effort. The projected capital expenditure for this project is $100,000. Correspondence from the NWFWMD regarding the Crist Water Conservation Project is included in my Exhibit, JOV-1.

The third 2006 water quality project (Line Item 1.25) is the Crist Condenser Tubes (PE 1204). The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code, were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist NPDES industrial wastewater permit.

Plant Crist plans to install stainless steel condenser tubes on Unit 6 during 2006 in an effort to meet the revised water quality standards. The copper limit is calculated from an equation that is dependent upon the river water hardness concentration. Rainfall events decrease river water hardness consequently lowering the copper limit.

Surface water studies were conducted from 2003 through 2005 to determine the source of aqueous copper in the effluent. The results of the study concluded that the Crist Unit 6 condenser is the main source of the incremental copper increase in the Plant Crist discharge. The condenser tubes are expected to be placed in-service during May 2006 with project expenditures totaling $5.5 million.

Q. Mr. Vick, please identify expenditures for the 2006 projection period related to expansions of previously approved capital projects that are required for environmental compliance.

A. There are seven other previously approved capital projects that have additional capital expenditures. Four of the projects are related to Gulf's existing Air Quality programs: Continuous Emission Monitoring (CEMs) replacements, Precipitator Upgrades for CAM Compliance, the Sodium Injection Program, and the Plant Crist FDEP Agreement for Ozone Attainment. The Plant Daniel Ash Management project, the Plant Crist

SPCC Switchyard project, and the SO2 allowances will also have projected capital expenditures in 2006.

1. CEMs- (Line 1.5)

During the 2006 recovery period the CEMs project includes the replacement and relocation of flow monitors, gas analyzers, and the CEMs shelter at Plant Smith (PEs 1444 and 1445). The gas analyzers and flow monitors are necessary in order to provide the accuracy and reliability needed to measure SO_2, NO_x, CO_2, and gas flow and further maintain compliance with the Clean Air Act Amendment (CAAA) requirements. The existing analyzers and monitors are approaching the end of their useful life, and will be retired upon replacement. Relocating the monitors to the stack will also reduce the cost of future mercury emission monitoring. The 2006 expenditures are expected to be $600,000.

2. Sodium Injection Systems (Line Item 1.13)

Plant Crist plans to install an automatic sodium injection system on Units 4 and 5 during the fourth quarter of 2005 to regulate the amount of sodium added to the coal supply. This project includes a silo storage tank system and components that inject sodium bicarbonate directly onto the coal feeder belt to enhance precipitator performance when low sulfur coal is used at Plant Crist. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with Clean Air Act provisions. The 2005 projected expenditures for this project are

$300,000. Sodium Injection at Plant Smith was approved in Docket Number No. 990667-EI for recovery through the ECRC.

3. Daniel Ash Management Project (Line 1.16)

Plant Daniel began preliminary design and permitting for a new on-site ash storage facility during 2005 in preparation for the completion and closure of the existing storage area. Expenditures for the new ash storage facility are expected to be approximately $2.9 million in 2006. During 1994, the FPSC granted ECRC approval for the recovery of the Daniel Ash Management Project in Order Number PSC-94-0044-FOF-EI.

4. Crist FDEP Agreement for Ozone Attainment (Line 1.19)

For the 2006 projection, Gulf has included capital costs associated with the final phase of the Plant Crist FDEP Agreement for Ozone Attainment (PE 1287) to meet the terms of the August 28, 2002 agreement with FDEP. There are six activities described in the Agreement which the Commission has declared are environmental compliance costs under the requirements of Section 366.8255(1) (d) (7) of the Florida Statutes as amended in 2002. Gulf was granted approval for recovery of the costs prudently incurred in connection with these six activities in Docket No. 020943-EI through proposed agency action order PSC-02-1396-PAA-EI (the "Order") which was made final by consummating order PSC-02-1593-CO-EI issued November 18, 2002.

The sixth activity described in the Agreement and approved by the Order is the implementation of NO_x emission reduction strategies on Crist Units

4, 5, and/or 6 by May 1, 2006. Gulf Power received written concurrence from FDEP on August 10, 2004 that the Selective Non-Catalytic Reduction (SNCR), low NO_x burner/overfire air technologies for Plant Crist Unit 6, and Units 4 and 5 if necessary, meet the intent of the Agreement and are prudent for the purposes of ensuring that Plant Crist supports the Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standard. A copy of the 2004 concurrence letter from FDEP is contained in my Exhibit, JOV-1.

Gulf expects the Crist Unit 6 SNCR, low NO_x burner/overfire air technologies totaling approximately $15 million to go in service in December 2005. SNCR technologies may be installed on Units 4 and 5 during 2006 if the facility does not meet the 0.2 lb/mmbtu Agreement limit after the Unit 6 SNCR is placed in-service. The 2006 expenditures for the Crist Unit 4 and 5 SNCRs are estimated to be $2.3 million

5. Crist Switchyard Stormwater Project (Line 1.20)

Completion of this project (PE 1272) has been postponed from 2005 until 2006. The original design incorporated the use of the abandoned Crist Unit 6 discharge structure. After Hurricane Ivan, the Unit 6 structure was reutilized to allow Unit 6 to operate on once through cooling. This has resulted in design delays due to modifications to the Crist Switchyard Storm Water project. Gulf expects the Crist Switchyard Stormwater project totaling approximately $854,000 to go in service in December 2006.

6. Precipitator Upgrades for CAM Compliance (Line Item 1.22)

CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (CAAA) which require a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and submitted the results to the FDEP as part of a CAM plan which was included in Gulf's renewed Title V Air Permit effective in January of 2005. The precipitator upgrades that are included under this line item on Ms. Davis's schedules are necessary to meet the more stringent surrogate opacity standards under CAM. The first phase of this project, the Smith Unit 2 precipitator project, was placed in-service during April 2005. The Unit 2 project was approved for ECRC recovery in Order Number PSC-04-1187-FOF-EI. The second phase, the Smith Unit 1 precipitator upgrade (PE 1461), will be initiated in 2006 with an estimated completion date of April 2007. The 2006 projected project expenditures total $4.3 million. Gulf anticipates the need for similar precipitator upgrade projects related to the new CAM regulations at other Gulf coal fired generating units that will ultimately be included within this project title in future recovery periods.

7. SO_2 Allowances (Line Item 1.28)

Gulf Power has included the purchase of additional SO_2 allowances in the 2006 projection filing. Part of Gulf's strategy to comply with the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. This bank has slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf's allowance bank is expected to be completely depleted in the year 2007. Gulf proposes to meet this shortfall by executing forward contracts to secure 15,000 2006 vintage allowances and 15,000 2007 vintage allowances. Additional forward contracts for future vintage year allowances will be executed if future forecasts predict a continuous need. Gulf's strategy also includes possible spot market purchases of allowances as prices dictate. The reasoning behind the strategy of forward contracts and spot market purchases to secure allowances in 2006 and 2007 is Gulf's concern over the availability and the price of SO_2 allowances as the compliance deadline for CAIR approaches. The price of allowances have almost quadrupled in the last eighteen months. Additionally, many utilities are no longer selling any allowances in anticipation of their own shortfall in the coming years.

Q. Please compare the Environmental Operation and Maintenance (O & M) activities listed on Schedule 2P of Ms. Davis's Exhibit to the O & M activities approved for cost recovery in past ECRC proceedings.

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

Q. Please describe the O & M activities included in the Air Quality category that have projected expenses in 2006.

A. There are five O & M activities included in the Air Quality category that have projected expenses in 2006. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the CAAA that are payable to the FDEP. The expenses projected for the recovery period total $779,874.

Included in the Air Quality category, Title V (Line Item1.3), represents projected expenses associated with the implementation of the Title V permits. The total estimated expenses for the Title V Program during 2006 is $72,460.

On Schedule 2P, Asbestos Fees (Line Item 1.4), consists of the fees required to be paid to the FDEP for the purpose of funding the State's asbestos abatement program. The expenses projected for the recovery period total $2,000.

Emission Monitoring (Line Item1.5) on Schedule 2P reflects an ongoing O & M expense associated with the Continuous Emission Monitoring (CEM) 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 LinearityTests. Other activities within this category include the testing, development, and implementation of new compliance assurance monitoring requirements associated with the Clean Air Act Amendment. The expenses expected to occur during the 2006 recovery period for these activities total $545,520.

The FDEP NO_x Reduction Agreement (Line Item 1.20), includes the O & M cost associated with the Plant Crist Unit 7 SCR and Crist Units 4-6 SNCR projects that were included as part of the 2002 agreement with FDEP. This O & M 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. Gulf was granted approval for recovery of the costs incurred to complete these activities in Docket No. 020943-EI through Order Number PSC-02-1396-PAA EI. The projected expenses for the 2006 recovery period total $4,250,000.

Q. What O & M activities are included in Water Quality?

A. The first activity, General Water Quality (Line Item 1.6), identified in Schedule 2P, includes Soil Contamination Studies, Dechlorination, Groundwater Monitoring Plan Revisions, Surface Water Studies, and the Cooling Water Intake Program. The expenses expected to be incurred during the projection period for this Line Item total $517,166.

The second activity listed 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 activity is projected to incur incremental expenses totaling $1,166,752.

Line Item 1.8, State NPDES Administration, was previously approved for recovery in the ECRC and reflects expenses associated with 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 lead and copper in drinking water. These expenses are expected to total $12,500 during the 2006 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 Ms. Davis'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 $1,300 are expected during the 2006 recovery period.

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

A. Only one program, General Solid and Hazardous Waste (Line Item 1.11) is included in the Solid and Hazardous Waste category on Schedule 2P. This 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 $351,165.

Q. In addition to the four major O & M categories listed above, are there any other O & M activities which have been approved for recovery that have projected expenses?

A. Yes. There are three other O & M categories which have been approved in past proceedings which have projected expenses. They are the Above Ground Storage Tanks activity, the Sodium Injection System, and SO_2 Allowances.

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

A. Only one program, Above Ground Storage Tanks (Line Item 1.12), is included in this category. This program is expected to incur $95,600 of expenses during 2006.

Q. What activity is included in the Sodium Injection (Line Item 1.16) category?

A. The Sodium Injection System, approved in Docket Number No. 990667-EI for inclusion in the ECRC, involves sodium injection to the coal supply to enhance precipitator efficiencies when burning certain low sulfur coals at the plant. The line item projected expenses for the 2006 recovery period total $240,000.

Q. Please describe the activity included in the SO_2 Allowances (Line Item 1.20).

A. This program includes expenses for SO_2 allowances for Gulf's generating plants. The purchase of additional allowances has increased the weighted average cost of allowances being expensed.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 050007-EI
Date of Filing: April 1, 2005

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Regulatory Team Leader in the Rates and Regulatory Matters Department of Gulf Power Company.

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

A. I graduated in 1979 from Mississippi College in Clinton, Mississippi with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf Power in Accounts Payable, Financial Reporting, and Cost Accounting. In

1993, I joined the Rates and Regulatory Matters area, where I have participated with increasing responsibility in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 2004, I was promoted to my current position. My responsibilities include supervision of: the Company's Cost Recovery Clause filings, retail tariff administration, the review of other regulatory filings submitted by the Company, and various treasury activities.

Q. Are you the same Terry A. Davis who has previously testified before this Commission in this on-going docket?

A. Yes.

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 Ms. Davis' Exhibit consisting of 8 schedules be marked as Exhibit No. _____(TAD-1).

Q. Are you familiar with the Environmental Cost Recovery Clause (ECRC) True-up Calculation for the period of

January through December 2004 set forth in your exhibit?
A. Yes. These documents were prepared under my supervision.

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

Q. What is the amount to be refunded or collected in the recovery period beginning January 2006?
A. An amount to be refunded of $628,050 was calculated which is reflected on Line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?
A. The $628,050 to be refunded was calculated by taking the difference between the estimated January 2004 through December 2004 under-recovery of $113,651 as approved in Order No. PSC-04-1187-FOF-EI, dated December 1, 2004 and the actual over-recovery of $514,399 which is the sum of lines 5, 6, and 10 on Schedule 2A.

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 2004 through December 2004. Schedule 3A of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel Cost Recovery (FCR) and Purchased Power Capacity Cost (PPCC) 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 2004 through December 2004 with the estimated/actual O & M expenses included in the approved estimated true-up filed in conjunction with the November 2004 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. Mr. Vick describes the main reasons for the variances in O & M expenses in his true-up testimony.

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

A. Schedule 6A for the period January 2004 through December 2004 compares the actual carrying costs related to investment with the estimated/actual amount included in the approved estimated true-up filed in conjunction with the November 2004 hearing. The recoverable costs include the return on investment, depreciation expense, dismantlement accrual, and property tax 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 carrying costs associated with each project, along with the calculation of the jurisdictional carrying costs. Mr. Vick describes any major variances in recoverable costs related to environmental investment for this true-up period.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A provides the monthly calculation of the recoverable costs associated with each capital project for the recovery period. As I stated earlier, these costs include return on investment, depreciation expense, dismantlement accrual, property tax, and the cost of emission allowances. Pages 1 through 21 of Schedule 8A show the investment and associated costs related to capital projects, while page 22 shows the investment and costs related to emission allowances.

Q. Ms. Davis, does this conclude your testimony?
A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 050007-EI
Date of Filing: August 12, 2005

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Treasury and Regulatory Matters at Gulf Power Company.

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

A. I graduated in 1979 from Mississippi College in Clinton, Mississippi with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf Power in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated with increasing responsibility in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 2004, I was promoted to my current position.

My responsibilities now include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, the regulatory filing function of the Rates and Regulatory Matters Department, and various treasury activities.

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

A. Yes, I have.

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 Ms. Davis' Exhibit
consisting of 8 schedules be marked
as Exhibit No. _____(TAD-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 2005 through December 2005 period to be refunded or collected in the period January 2006 through December 2006?

A. The estimated true-up for the current period is an over-recovery of $646,587 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 2004 final true-up over-recovery amount of $628,050 (see Schedule 1A to my testimony filed April 1, 2005). The sum of $1,274,637 will be refunded to the customers during the January 2006 through December 2006 period. The detailed calculations supporting the estimated true-up for 2005 are contained in Schedules 1E 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 2005 through December 2005. Schedule 3E of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel Cost Recovery (FCR) and Purchased Power Capacity Cost (PPCC) 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 2005 through December 2005 with the projected O & M expenses approved by the Commission in conjunction with the November 2004 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 2005 through December 2005 compares the estimated/actual carrying costs related to investment with the projected amount approved in conjunction with the November 2004 hearing. The recoverable costs include the return on investment, depreciation expense, dismantlement accrual, and property tax 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 carrying costs associated with each project, along with the calculation of the jurisdictional carrying costs. 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 23 pages that provide the monthly calculations of recoverable costs associated with each approved capital project for the current recovery period. As I stated earlier, these costs include return on investment, depreciation expense, dismantlement accrual, property tax, and the return on working capital associated with emission allowances. Pages 1 through 22 of Schedule 8E show the investment and associated costs related to capital projects, while page 23 shows 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?

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, Order No. PSC-02-0787-FOF-EI dated June 10, 2002. The rate of return used to calculate ECRC revenue requirements includes a jurisdictional return on equity of 12.0% for the period January 2005 through December 31, 2005.

Q. Ms. Davis, does this conclude your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 050007-EI
Date of Filing: September 16, 2005

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Treasury and Regulatory Matters for Gulf Power Company.

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

A. I graduated in 1979 from Mississippi College in Clinton, Mississippi with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for seven years at a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf Power in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated with increasing responsibility in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 2004, I was promoted to my current position.

My responsibilities now include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, the regulatory filing function of the Rates and Regulatory Matters Department, and various treasury activities.

Q. Have you previously filed testimony before this Commission in connection with Gulf's Environmental Cost Recovery Clause (ECRC)?
A. Yes, I have.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period of January 2006 through December 2006.

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 7 schedules, each of which were prepared under my direction, supervision, or review.
Counsel: We ask that Ms. Davis's Exhibit consisting of 7 schedules be marked as Exhibit No. _____ (TAD-3).

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

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 2006 through December 2006. Schedule 2P of my exhibit shows the calculation of the recoverable O & M expenses broken down between the demand-related and energy-related expenses. Also, Schedule 2P 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 were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 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 for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment. 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 and the monthly costs for emission allowances. From that information, I calculated Plant-in-Service and Construction Work In Progress-Non Interest Bearing (CWIP-NIB). Depreciation and dismantlement expense and the associated accumulated depreciation balances were calculated based on Gulf's approved depreciation rates and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which are not included in the approved projected 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?

A. The rate of return used is based on Gulf's capital structure as approved in Gulf's last rate case, Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI, dated June 10, 2002. This rate of return incorporates a return on equity of 12.0 percent.

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

A. The investment-related costs 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, dated January 12, 1994 in Docket No. 930613-EI. The remaining investment-related costs of environmental compliance not associated with the CAAA were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last 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 2006 through December 2006?

A. The total projected jurisdictional recoverable costs for the period January 2006 through December 2006 are $41,572,348 as shown on line 1c of Schedule 1P. This includes costs related to O & M activities of $12,930,319 and costs related to capital projects of $28,642,029 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $40,326,725 for the period January 2006 through December 2006 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 $1,274,637 to be refunded. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. I allocated these amounts to 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 2003 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 $35,563,397 for the period January 2006 through December 2006 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $4,763,328 for the period January 2006 through December 2006 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 $3.64 monthly for the period January 2006 through December 2006.

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

A. The factors will be effective beginning with the first Bill Group for January 2006 and continuing through the last Bill Group for December 2006.

Q. Ms. Davis, does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 050007-EI

August 8, 2005

Q. Please state your name and business address.

A. My name is Kent D. Hedrick. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Florida as Manager of Environmental Performance and Technical Assessment.

Q. What is the scope of your duties?

A. Currently, my responsibilities include management of the environmental compliance functions and performing environmental technology assessments for Progress Energy Florida (PEF or "Company").

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in Environmental Engineering from the University of Florida. In addition, I am a registered professional engineer in the State of Florida. Currently I hold the position of Manager of Environmental Performance and Technical Assessment. Before then, I held several environmental management positions with the Company.

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

A. Yes, I have.

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

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures versus the original cost projections for environmental compliance costs associated with PEF's Substation and Distribution System Environmental Investigation, Remediation, and Pollution Prevention Programs for the period January 2005 through December 2005. My testimony also describes a new environmental compliance program that falls within my responsibility and for which Progress Energy is seeking cost recovery in this docket.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. __ (KDH-1) – a copy of Rule 62B-55.006, F.A.C.;
- Exhibit No. __ (KDH-2) – a copy of Lighting Ordinance for Marine Turtle Protection of Franklin County Florida;
- Exhibit No. __ (KDH-3) – a copy of An Ordinance of Gulf County, Florida, Creating Regulations for the Protection of Sea Turtles and other Enumerated Species within Certain Beaches of Gulf County . . . , and
- Exhibit No. __ (KDH-4) – a copy of An Ordinance Regulating Lighting for the Protection of Marine Turtles and Aquatic Sea Life for the Beaches of Mexico Beach . . . .

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Program for the period January 2005 to December 2005 (Project #2).

A. Project expenditures for the Distribution System Program are estimated to be $460,825 higher than originally projected. This is due to the roll over of remediation activities of 126 single-phase sites from the 2004 work plan into the 2005 work plan as a result of work delays.

Q. Are there any new environmental programs that fall within your responsibilities for which PEF is seeking recovery in this docket?

A. Yes. PEF is seeking ECRC recovery of a new Sea Turtle Lighting Program, which falls within the scope of my responsibilities.

Q. Are you familiar with the requirements that environmental costs must meet to be eligible for recovery through the ECRC?

A. Yes. The general requirements are that all expenditures must have been prudently incurred after April 13, 1993; all activities must be legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

Q. Does the new Sea Turtle Lighting Program qualify for cost recovery under these criteria?

A. Yes. As discussed in more detail below, the Sea Turtle Lighting Program is being implemented in response to new environmental requirements which were created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in the Company's last rate case, Docket No. 000824-EI and were not included in the MFRs submitted in the current rate case before this commission in Docket No. 050078-EI. None of the costs of this program are being recovered through base rates or any other cost recovery mechanism. PEF is seeking recovery of costs incurred after the date of the filing of this testimony.

Q. Why is the Company implementing the Sea Turtle Lighting Program?

A. PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. See Rule 62B-55, F.A.C. (Copy provided as Exhibit No. ___(KDH-1)). The model ordinance is used by the local governments to develop and implement local ordinances within their jurisdiction.

To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County and the City of Mexico Beach in Bay County, all of which are within PEF's service territory. Copies of the Franklin County, Gulf County, and Mexico Beach ordinances are provided as Exhibits No. __ (KDH-2), No.__ (KDH-3) and No. __ (KDH-4). Since 2004, officials from the various local governments, as well as FDEP, FFWC and USFWS, have advised PEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances, As a result, the local governments are requiring PEF to take additional measures to satisfy new criteria being applied to ensure compliance with the ordinances.

Q. What compliance activities does PEF expect to undertake in connection with the new Sea Turtle Lighting Program?

A. PEF will be working with the local governments and regulatory agencies to determine the most cost-effective compliance measures for each site. Potential compliance measures include retrofitting or replacing existing streetlights and, in certain cases, monitoring to determine the effectiveness of the new or retrofitted lights.

Q. Has the Company projected the costs that it will incur for the Sea Turtle Lighting Program in 2005 after the date of filing of your testimony?

A. Yes. PEF projects to incur capital costs of $92,500 and O&M costs of $80,000 in 2005. Capital cost estimates are based on the modification of 500 lighting fixtures to add lens shielding and/or buffering at a cost of approximately $185 per unit. PEF estimates O&M costs of $80,000 for monitoring the effectiveness of these retrofits. Actual costs may vary depending upon discussions with regulatory agencies to determine the most cost-effective and appropriate compliance measures for specific sites.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 050007-EI

SEPTEMBER 8, 2005

Q. Please state your name and business address.

A. My name is Kent D. Hedrick. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Florida as Manager of Environmental Performance & Technical Assessment.

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

A. Yes, I have.

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. My testimony provides estimates of the costs that will be incurred in the year 2006 for PEF's Substation and Distribution System Investigation, Remediation and Pollution Prevention Programs (Projects #1 and #2, respectively), which were previously approved in PSC Order No. PSC-02-1735-FOF-EI, and for PEF's new Sea Turtle/Street Lighting Program (Project #9) for which the Company is seeking approval in this docket. The new Sea Turtle/Street Lighting Program is described in more detail in my testimony of August 8, 2005.

Q. What costs do you expect to incur in 2006 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project #1)?

A. For 2006, we estimate Progress Energy will incur total O&M expenditures of $1,160,692 in remediation costs for the Substation System Investigation, Remediation and Pollution Prevention Program. This amount includes estimated costs for remediation activities at 24 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. The Company completed a comprehensive bid process to select the qualified contractors to carry out the remediation activities necessary to comply with FDEP criteria and to ensure the level of expenditures is reasonable and prudent.

Q. What costs do you expect to incur in 2006 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project #2)?

A. For 2006 we estimate total O&M expenditures of $4,451,692 for the Distribution System Investigation, Remediation and Pollution Prevention Program to perform remediation activities at 450 sites. This estimate assumes 90 3-phase transformer sites at an average cost of $14,500 per site; 360 single-phase transformer sites at an average cost of $8,500 per site; and program management costs.

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

A. The Company frequently reviews invoices for accuracy and proper documentation. In addition, the Company has worked with the remediation contractors to reduce fees for remediation activities and improve process efficiency.

Q. What costs do you expect to incur in 2006 in connection with the Sea Turtle/Street Lighting Program (Project #9)?

A. For 2006, we estimate that Progress Energy will incur a total of $234,382. This amount includes $108,767 in O&M costs and $125,615 in capital expenditures to satisfy new criteria that local governments are applying to ensure compliance with sea turtle ordinances in Franklin and Gulf Counties and the City of Mexico Beach. Capital cost estimates are based on the modification of 679 lighting fixtures that could include adding lens shielding, adjusting fixture height and/or buffering at an average cost of approximately $185 per unit. The estimated O&M costs are for monitoring the effectiveness of these retrofits. Actual costs may vary depending upon discussions with regulatory agencies to determine the most cost-effective and appropriate compliance measures for specific sites.

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. Progress Energy will work with local governments and appropriate agencies to develop a compliance plan that allows flexibility to utilize only those modifications that are necessary to achieve compliance. Case-by-case evaluation of each streetlight requiring modification will occur so only those activities necessary to achieve compliance are performed in a reasonable and prudent manner. In addition, Progress Energy will evaluate emerging technologies and incorporate their use where reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 050007-EI

SEPTEMBER 8, 2005

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

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

A. I am employed by the Environmental Services Section of Progress Energy Service Company, LLC. ("Progress Energy" or "Company") as Manager of Competitive Commercial Operations / Energy Supply Florida. In that position, I have responsibility for the implementation of compliance strategies pertaining to new regulatory requirements for energy supply facilities in Florida.

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

A. Yes, I have.

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

A. No. Due to organizational changes within Progress Energy, I have been reassigned to focus on the environmental matters affecting all power generating facilities in Florida. These responsibilities include development of budgets, cost estimates, and implementation of compliance strategies.

Q. What is the purpose of your testimony?

A. This testimony provides estimates of the costs that will be incurred in the year 2006 for environmental programs that fall within my responsibilities. These programs include the Pipeline Integrity Management Program (Project 3), Above ground Storage Tanks Secondary Containment Program (Project 4), and the Phase II Cooling Water Intake 316(b) Program (Project 6) previously approved by the Commission in 2003 and 2004, as well as additional programs for which the Company requested approval this year.

Q. Please identify the additional programs within your responsibility for which the Company is seeking approval.

A. In May 2005, the Company filed a petition in Docket No. 050316-EI requesting approval of a new environmental program for cost recovery through the ECRC. That program, entitled the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) program (Project 7), is being implemented in order to comply with new requirements established by the U.S. Environmental

Protection Agency ("EPA") in new rules codified as 40 CFR 25, 162 (CAIR) and 40 CFR Part 60 Subpart Da and 40 CFR Part 60, Subpart HHHH (CAMR).

In addition, through my August 8, 2005 testimony, the Company requested approval of three additional environmental programs for cost recovery through the ECRC in this docket. These programs include the Arsenic Groundwater Standard Program (Project 8), the Groundwater Reclassification Program, and the Underground Storage Tanks Program (Project 10). As discussed below, the Company is withdrawing its request for approval of the Groundwater Reclassification Program at this time.

Q. What costs do you expect to incur in 2006 in connection with the Pipeline Integrity Management Program (Project 3)?

A. For 2006, we estimate that Progress Energy will incur a total $717,000 in O&M and $95,000 in capital expenditures to comply with the Pipeline Integrity Management ("PIM") regulations (49 CFR Part 195) and the Company's PIM Plan. These figures include: PIM Program Administration ($237,000 O&M) and the cost of integrity risk reduction projects ($480,000 O&M; and $95,000 capital). The integrity risk reduction projects include items such as corrosion repairs, smart pig validation, inadequate cover restoration, traffic protection of above ground valve operators near a busy highway, and pressure control upgrades.

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

A. As services are required to comply with the PIM regulations and the Company's PIM Plan, Progress Energy will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. What costs do you expect to incur in 2006 in connection with the Aboveground Storage Tank Secondary Containment Program (Project 4)?

A. Progress Energy is currently estimating $1,263,000 in capital expenditures in 2006. These costs are for the double-bottoming of storage tanks and installation of double-walled piping at the Avon Park, Intercession City, Bayboro, Suwannee, and Turner Combustion Turbine sites. An estimated $5,000 in O&M expenditures are expected for project management support from contractors. This work will be performed in accordance with Rules 62-761.510(3)(d), F.A.C., Table AST U(1), and 62-761.510 (3)(d), F.A.C., Table AST U(2)(a).

Q. What steps is the Company taking to ensure that the level of expenditures for the Aboveground Storage Tank Secondary Containment Program is reasonable and prudent?

A. As services are required to comply with the Aboveground Storage Tank regulations, Progress Energy will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. What costs do you expect to incur in 2006 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. Progress Energy is currently estimating $1,466,749 in O&M expenditures in 2006. These costs include conducting field studies at the Anclote, Bartow, Crystal River, and Suwannee sites as part of the Comprehensive Demonstration Studies. These estimated costs also include $338,775 associated with the work that was deferred from 2005 into the 2006 work plan as discussed in my testimony filed on August 8, 2005. During the latter part of the year engineering technology evaluations are expected to begin.

Q. What steps is the Company taking to ensure that the level of expenditures for the Phase II Cooling Water Intake Program is reasonable and prudent?

A. As services are required to comply with the Phase II Cooling Water Intake Program, Progress Energy will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. You mentioned that the Company has filed a petition for approval of the Company's new program designed to achieve compliance with the new CAIR and CAMR rules. Please provide an overview of those rules.

A. The U.S. Environmental Protection Agency (EPA) formally promulgated the CAIR rule on May 10, 2005, and the CAMR rule on May 18, 2005. See 70 Fed. Reg. 25162 (May 12, 2005) (CAIR) and 70 Fed. Reg. 28606 (May 18, 2005)

(CAMR). CAIR imposes significant new restrictions on emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from power plants in 28 eastern states, including Florida,. The rule restricts emissions in two phases for both pollutants. During the first phase for SO_2 (2010-14), region-wide SO_2 emissions from power plants will be capped at approximately 3.6 million tons per year. In the second phase (2015 and beyond), the region-wide cap will be approximately 2.5 million tons per year. Region-wide NO_x emissions from power plants will be capped at 1.5 million tons per year during the first phase (2009-14) and 1.3 million tons during the second phase (2015 and beyond). According to EPA, the phase II caps represent a 73 percent emission reduction for SO_2 and a 65 percent reduction for NO_x when compared with 2003 levels.

The CAIR rule apportions region-wide SO_2 and NO_x emission reduction requirements to the individual states. The rule further requires each affected state to revise its State Implementation Plans ("SIP") by September 2006 to include measures necessary to achieve its emission reduction budget within the prescribed deadlines for phase I and phase II. States must achieve the required emission reductions by requiring power plants to participate in an EPA-administered interstate cap-and-trade system that caps emissions in the two stages outlined above, or by establishing alternative measures.

Under EPA's "cap-and–trade" program, EPA will allocate each power plant owner a certain number of "allowances" each year for SO_2 and NO_x. Beginning in 2009 for NO_x and 2010 for SO_2, at the end of each year, the power plant owner must hold one NO_x allowance for each ton of NO_x emitted, and two SO_2 allowances for each ton of SO_2 emitted. In 2015, the SO_2 allowance requirement will be increased to 2.86 for each ton of SO_2 emitted. When a power plant owner, like PEF, projects emissions in excess of the number of allowances it will be allocated under the new caps, the owner can either reduce emissions to ensure that annual emissions of each pollutant do not exceed the number of allowances held at the end of that year for each pollutant, or it must obtain additional allowances from other allowance holders in the CAIR region to make up any deficiency between the number of allowances it holds and the number of tons emitted from its units.

EPA adopted the CAMR rule at essentially the same time as the CAIR rule because SO_2 and NO_x emissions controls also can reduce mercury emissions; thus, according to EPA, the coordinated regulation of mercury, SO_2, and NO_x allows mercury reductions to be achieved in a cost effective manner. Much like the CAIR Rule, the CAMR rule employs a cap on total mercury emissions from coal-fired power plants in order to achieve significant emissions reductions. Mercury emissions from new and existing coal-fired utility units will be capped at specified, nation-wide levels. The first phase cap of 28 tons per year will become effective in 2010 and a second phase cap of 15 tons per year will become effective in 2018. According to EPA, the 2018 cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling SO_2 and NO_x under CAIR.

Like the CAIR rule, the CAMR rule allows states to achieve the required reductions by joining an EPA-managed cap-and-trade program for electric coal-fired power plants, or by imposing specific control requirements to ensure that the required emissions reductions are achieved. Under the EPA-managed cap-and-trade program, facilities would demonstrate compliance with the standard by holding one allowance for each ounce of mercury emitted in any given year. Allowances would be readily transferable among all regulated facilities.

Q. Please describe the Company's plan for complying with the CAIR and CAMR Rules.

A. In anticipation of the CAIR and CAMR rules, PEF has considered numerous options for reducing emissions and/or trading allowances in order to develop the most cost-effective, company-wide compliance strategy. Because SO_2 and NO_X controls also are effective in reducing mercury emissions, PEF is developing an integrated compliance strategy for the CAIR and CAMR rules. PEF continues to analyze numerous compliance options, including changes in fuel types and quality, operational restrictions and unit retirements, repowerings, installation of pollution control technology, and allowance trading. Based on the analyses performed to date, regardless of the compliance program ultimately chosen by the State of Florida, PEF likely will need to install emission controls on several of its electric generating units in order to achieve compliance. Such controls likely will include flue gas desulfurization ("FGD") for SO_2 emissions, selective catalytic reduction ("SCR") and low NO_x burners ("LNBs") for NO_x emissions, and some combination of FGD, SCR, LNB, and/or particulate controls (e.g., electrostatic precipitators or "ESPs") for mercury emissions.

Q. Are you familiar with the requirements that environmental costs must meet to be eligible for recovery through the ECRC?

A. Yes. The general requirements are that all expenditures must have been prudently incurred after April 13, 1993; all activities must be legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

Q. Does the new CAIR- CAMR program qualify for cost recovery under these criteria?

A. Yes. The new program is being implemented in response to new environmental requirements which were created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in the Company's last rate case, Docket No. 000824-EI, and were not included in the MFRs submitted in the current rate case before this Commission in Docket No. 050078-EI. None of the costs of the three new programs are being recovered through base rates or any other cost recovery mechanism. PEF is seeking recovery of costs incurred after the date of the filing of its Petition on May 24, 2005.

Q. What costs do you expect to incur in 2006 in connection with the CAIR / CAMR Program (Project 7)?

A. PEF anticipates spending approximately $52,964,514 on CAIR/CAMR compliance projects. These projects include the following:

- Crystal River Unit 4 SCR System: design, engineer and begin procurement of equipment and initial construction of an SCR system for reducing NO_x emissions from Unit 4's flue gasses by approximately 90%. While primarily for reducing NO_x emissions for compliance with the CAIR, the SCR will also oxidize mercury in the flue gasses, which will allow the FGD system to more efficiently remove the mercury, as is required by the CAMR. This system is expected to begin operation in the Spring of 2008. Approximately $17.6 Million is expected to be spent on this project in 2006.
- Crystal River Unit 5 FGD System: design, engineer and begin initial procurement of equipment and initial construction of an FGD system for reducing SO_2 emissions from Unit 5's flue gasses by approximately 97%. While primarily for reducing SO_2 emissions for compliance with the CAIR, the FGD will also remove mercury from the flue gasses for compliance with the CAMR. This system is expected to begin operation in the Spring of 2009. Approximately $22.0 Million is expected to be spent on this project in 2006.
- Crystal River Unit 5 SCR and Crystal River Unit 4 FGD Systems: As Crystal River Units 4 and 5 are nearly identical; much of the design and engineering work for the FGD and SCR systems will be common to both units. However, with in-service dates of Spring, 2009 for the Unit 5 SCR and Fall, 2009 for the

Unit 4 FGD, initial design work for both of these systems will also commence in 2006, along with some of the initial construction work on the Unit 4 FGD. Approximately $4.1 Million is expected to be spent on these projects in 2006.

- Anclote Unit 1 NOx Reduction Projects: NO_x reductions at the Anclote oil-fired units are expected to be part of the CAIR compliance plan. To take advantage of a planned maintenance outage on Anclote Unit 1 in the Fall of 2006, it is anticipated that a Low-NO_x burner system and some form of Overfire Air system will be installed on this unit. Studies are currently underway in 2005 to determine the technologies to be installed, and it is anticipated that approximately $9.1 Million will be spent for NOx reduction equipment at Anclote in 2006.
- Combustion Turbine Projects: The CAIR rule requires that forty-four emission sources associated with thirty-one of PEF's combustion turbine units must install new Predictive Emission Monitoring Systems. In 2006, test ports will be installed to facilitate the necessary testing. The cost for this work is estimated at approximately $200,000. Costs for subsequent years' activities have not been established but will include contractor costs for performance of the tests, data analysis and reporting. Regulatory citations for this requirement are: 40 CFR 96.104(a), Annual NO_x Program; 40 CFR 96.204(a), Annual SO_2 Program; and, 40 CFR 96.304(a), NO_x Ozone Season Program.

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

A. This is being addressed in two ways. An initial screening of technology and fuel choice options indicated that the projects being undertaken would be cost effective in complying with the preliminary CAIR and CAMR that were published in 2004. Subsequent to this initial screening and the March, 2005 issuance of the final CAMR and CAIR (with its shorter time frame and fewer allowances for NO_x than in the preliminary rule), more in-depth analyses are currently in progress to confirm these options and "fine tune" the overall compliance strategy for PEF.

Secondly, utilization of the "Alliance" that was established by Progress Energy Carolinas for compliance with the North Carolina Clean Smokestacks Act is expected to result in lower project costs than would otherwise be achievable. This Alliance, comprised of an Engineering Firm, a Scrubber Equipment Supplier, and a Construction Firm, has already demonstrated the ability to design, engineer and construct these types of projects in as cost-effective, or more cost-effective a manner, than similar projects at other utilities. Furthermore, the Alliance partners have experience at PEF's electric generating units and are available to perform this work for PEF. Also, it is expected that with the similarity in size between North Carolina units and the Crystal River units, there will be savings associated with being able to utilize engineering and design information that has been developed by the Alliance Partners for the North Carolina projects and to take advantage of "quantity discounts" with many of the major equipment vendors. And finally, PEF will use additional qualified contractors where needed.

Q. What costs do you expect to incur in 2006 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. Progress Energy is estimating O&M expenditures of approximately $50,000 for compliance activities associated with this program. These costs may include analytical testing and consultant costs associated with development of compliance strategies. These strategies will depend upon analytical results and discussions with FDEP.

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

A. As services are required to comply with the new Arsenic standard, Progress Energy will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. Does Progress Energy still seek approval of the Groundwater Reclassification Program?

A. No. The Company's request for approval of the Groundwater Reclassification Program was premised on new requirements that the Company expected the Florida Department of Environmental Protection (FDEP) to impose in the renewal of the industrial wastewater permit for the Crystal River Plan. Based on recent discussions with FDEP, it does not appear the renewal permit will include the new requirements that we had anticipated. For that reason, the Company is withdrawing its request for approval of this Program. However, the Company reserves the right to seek approval in the future if the renewal permit or subsequent permits include new environmental requirements.

Q. What costs do you expect to incur in 2006 in connection with the Underground Storage Tanks Program (Project 10)?

A. Progress Energy is currently estimating $300,000 in capital expenditures in 2006. These costs are for the removal and replacement of four tanks: two at the Crystal River coal-fired plant ($200,000), and two at the Bartow oil-fired plant ($100,000). This work will be performed in accordance with Rule 62-761.510(5).

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

A. As services are required to comply with the Underground Storage Tank regulations, Progress Energy will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 050007-EI

AUGUST 8, 2005

Q. **Please state your name and business address.**

A. My name is Patricia Q. West. My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or "Company") as Manager of Environmental Projects and Strategy. In that position, I have responsibility for the development of compliance strategies pertaining to new regulatory requirements for energy supply facilities in Florida, North Carolina, South Carolina and Georgia.

Q. **Please describe your background and experience in the environmental field.**

A. I obtained my B.S. degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department from 1983-1986 and by the Florida Department of Environmental Protection ("FDEP") from 1986-1990. At DEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. In 1990, I joined Florida Power Corporation as an Environmental Project Manager and then held progressively responsible positions in the company's environmental services department, including the position of team leader for the integration of the environmental functions of Florida Power and Carolina Power and Light. From 2001-2002, I served as Manager of Water Programs in the Environmental Services Section of PEF's Technical Services Department. In 2002, I assumed my current position as Manager of Environmental Programs and Strategy.

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

A. Yes.

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

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures and the original cost projections for environmental compliance costs associated with PEF's Pipeline Integrity Management, Aboveground Storage Tank Secondary Containment, and Section 316(b) Cooling Water Intake Programs for the period January 2005 through December 2005.

I also will explain the projected expenditures associated with PEF's integrated compliance program necessitated by the U.S. Environmental Protection Agency's (USEPA's) new Clean Air Interstate Rule (CAIR) and Clean Air

Mercury Rule (CAMR) for the remainder of 2005. PEF petitioned the Commission for approval of cost recovery for this program on May 6, 2005. *See* Docket No. 050316-EI.

Finally, I will describe three additional new environmental compliance programs that fall within my responsibility and for which PEF is seeking cost recovery in this docket.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. __ (PQW-1) – a copy of Rule 62-550.310, Florida Administrative Code (F.A.C.);
- Exhibit No. __ (PQW-2) – a copy of Rule 62-520.420, F.A.C.; and
- Exhibit No. __ (PQW-3) -- Rule 62-761.510, F.A.C.
- Exhibit No. __ (PQW-4) – List of underground storage tanks required to be upgraded under Rule 62-761.510, F.A.C.

Q. Please describe the variance between the Estimated/Actual project expenditures and the original projections for the Pipeline Integrity Management Program for the period January 2005 to December 2005.

A. PEF projects a year-end variance of $ $208,000 in O&M costs for the Pipeline Integrity Management ("PIM") Program. This variance is primarily attributable to implementation of unanticipated activities undertaken to ensure pipeline protection for areas found to have inadequate coverage or other risk reduction measures, in accordance with the PIM regulations and the company's PIM Plan. In addition total year-end capital expenditures for this program are estimated to be $1,130,629 higher than previously forecasted. As discussed in Mr. Portuondo's testimony, this increase is primarily attributable to a reclass of expenses in 2005 which were erroneously charged to another project in 2004.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Aboveground Storage Tank Program for the period January 2005 to December 2005.

A. PEF projects that total year-end costs for this program will be $240,385 less than originally projected. The variance is primarily due to the rescheduling of individual tank upgrades to ensure system availability during the critical hurricane season. The original estimate was based upon the completion of upgrades of two large tanks at the Intercession City Site. To ensure generation capability during the 2005 hurricane season only one tank and the fuel oil pipeline secondary containment at this site was completed. However, a small aboveground storage tank at PEF's Avon Park site which was originally scheduled in the 2006 work plan will be moved up and completed during the third and fourth quarters of 2005. Engineering of the Bayboro and Suwannee piping upgrades will also occur in 2005.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Section 316(b) Cooling Water Intake Program for the period January 2005 to December 2005.

A. PEF projects that total year-end costs for this program will be $338,775 less than originally projected. The variance is the result of delays in starting field sampling work at the Anclote and Bartow sites ($75,000) and FDEP's approval (via NPDES permit issued in May 2005) of deferring work for one year at Crystal River ($262,775).

Q. What costs do you expect to incur in 2005 in connection with the Clean Air Interstate Rule and the Clean Air Mercury Rule?

A. On May 6, 2005, PEF petitioned the Commission for approval of cost recovery for a new environmental program required to comply with these new regulations adopted by the USEPA. For the remainder of 2005, we estimate total capital expenditures of $2,000,000 for preliminary engineering activities and strategy development work necessary to determine the Company's integrated compliance strategy for the new rules.

Q. Are there any other new environmental programs that fall within your responsibilities for which PEF is seeking recovery in this docket?

A. Yes. PEF is seeking ECRC recovery of three additional new programs which fall within the scope of my responsibilities. The three new programs include a new Arsenic Groundwater Standard Program, a new Groundwater Compliance Program, and a new Underground Storage Tank Program.

Q. Are you familiar with the requirements that environmental costs must meet to be eligible for recovery through the ECRC?

A. Yes. The general requirements are that all expenditures must have been prudently incurred after April 13, 1993; all activities must be legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

Q. Do the three new programs qualify for cost recovery under these criteria?

A. Yes. As discussed in more detail below, all three of the new programs are being implemented in response to new environmental requirements which were created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in the Company's last rate case, Docket No. 000824-EI and were not included in the MFRs submitted in the current rate case before this commission in Docket No. 050078-EI. None of the costs of the three new programs are being recovered through base rates or any other cost recovery mechanism. PEF is seeking recovery of costs incurred after the date of the filing of this testimony.

Q. Please describe the new Arsenic Groundwater Standard Program.

A. On January 22, 2001, the USEPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water, replacing the previous standard of 0.050 mg/L with a new MCL of 0.010 mg/L (10ppb). Effective January 1, 2005, the FDEP established the USEPA MCL as Florida's drinking water standard. See, Rule 62-550.310(1)(c), F.A.C. (Copy attached as Exhibit No. ___ (PQW-1).

The new standard has implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. (Copy provided as Exhibit No. __ (PQW-2)). Lowering the arsenic standard requires new analytical methods for sampling groundwater at numerous PEF sites. Results from these tests will determine the extent of future compliance activities and associated costs.

Q. Has any other utility obtained approval of a similar program to comply with the new arsenic standard?

A. Yes, the Commission approved Gulf Power Company's program for compliance with this new standard in Order No. PSC-04-1187-FOF-EI, issued in Docket No. 040007-EI.

Q. Has PEF projected the costs associated with the new Arsenic Groundwater Standard Program?

A. Current O&M projections for testing are estimated to be $50,000 for 2005. Future compliance activities and costs will depend on the analytical results and discussions with FDEP. None of the costs for complying with the new standard are being recovered in base rates or through other cost recovery mechanisms.

Q. **Please describe the new Groundwater Compliance Program.**

A. In the mid 1990s, PEF evaluated naturally-occurring groundwater at some of its generating facilities to determine its ability to be used as a drinking water supply. PEF discussed the results with FDEP in the context that the existing designation of the groundwater as "GII" (potential drinking water source) may not be appropriate and, therefore, groundwater discharges should not be held to the more stringent standards befitting of such designation. Based on these discussions, subsequent permits included language that required the groundwater discharges at these sites to meet a less stringent "GIII" standard. In 2004, however, the FDEP reversed its position on the issue in subsequent permitting actions for PEF's Bartow and Anclote Plants which applied the more stringent GII standard in Chapters 62-520 and 62-550, FAC. The upcoming renewal of the FDEP industrial wastewater (IWW) permit for PEF's Crystal River Plant is expected to include this change as well. As a result of these recent developments, PEF expects to incur costs for installation of new wells and monitoring to determine whether and to what extent additional measures must be taken to ensure compliance with the GII standards.

Q. Has PEF projected costs of the new Groundwater Compliance Program?

A. Yes. PEF preliminarily projects additional compliance costs of approximately $72,000 for new well installation and monitoring at the Crystal River Plant beginning as early as the latter half of 2005. Costs for future compliance activities and costs will depend on the analytical results and discussions with FDEP. None of the costs associated with the new Groundwater Compliance Program are being recovered in base rates or through other cost recovery mechanisms.

Q. Please describe the new Underground Storage Tank Program.

A. FDEP rules require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by December 31, 2009. See Rule 62-761.510(5), F.A.C. (Copy provided as Exhibit No. __ (PQW-3). PEF has identified four storage Category A tanks that must comply with this rule: two at the Crystal River power plant and two at the Bartow power plant. Exhibit No. __ (PQW-4) is a list of the specific tanks that must be upgraded.

Q. Has any other utility obtained approval of any similar programs to comply with DEP 's Underground Storage Tank rules?

A. Yes, the Commission previously approved an underground storage tank program for Florida Power and Light Company in Order No. PSC-03-1348-FOF-EI, Docket No. 030007-EI.

Q. Has PEF projected the costs associated with the Underground Storage Tank Program?

A. Yes. PEF projects capital costs of $300,000 ($200,000 at Crystal River and $100,000 at Bartow) for the Underground Storage Tank Program. PEF expects to incur these costs in 2006. None of these costs are being recovered in base rates or through other cost recovery mechanisms.

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. 050007-EI

SEPTEMBER 8, 2005

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, 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 Regional Haze Rule, Best Available Retrofit Technology (BART) Compliance Project.

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

A. Yes. It consists of Document RRL-4 - Regional Haze Rule.

Q. Please describe the law or regulation requiring the BART Compliance Project.

A. The Regional Haze Rule was promulgated by the Environmental Protection Agency (EPA) on July 6, 2005, imposing potential emissions reduction requirements on 26 source categories, including electric generating units (EGUs), for visibility impairing pollutants, including sulfur dioxide (SO2), oxides of nitrogen (NOx), particulate matter (PM), Volatile Organic Compounds (VOCs), and ammonia, pursuant to Section 169A of the Clean Air Act (CAA). The rule is designed to remedy visibility impairment in designated Class 1 Federal Areas resulting from man-made air pollution. The Rule requires that Best Available Retrofit Technology (BART) be applied to BART-eligible sources built between 1962 and 1977.

Q. How does BART affect FPL?

A. BART is required for any applicable source that emits any air pollutant, which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class 1 Federal area. FPL has 13 BART-eligible units.

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

A. FPL will have to demonstrate on a case-by-case basis, through approved modeling methods, whether each of its 13 BART-eligible units causes or contributes to visibility degradation. If a unit is found to impact any Class 1 Area by more than 0.5 deciviews, the metric for visibility degradation, BART controls will be required.

Q. What type of equipment may be required?

A. The BART eligible plants that are found to impact any Class 1 Area by more than 0.5 deciviews will be identified through the modeling process mentioned above. FPL must then conduct evaluations of the type of equipment necessary to achieve the visibility improvements and demonstrate to the Florida Department of Environmental Protection (FDEP) what constitutes BART for each of the identified units. Due to differences in technology, configuration of the generating units, and the limitations of space at some facilities, an array of pollution control equipment may be required.

For NOx emissions control, FPL may consider the addition of Selective Catalytic Reduction (SCR), reburn technology, or low NOx burners to reduce NOx. As directed by the Regional Haze Rule, consideration must be given to: 1) the costs of compliance; 2) the energy and non-air quality environmental impacts of compliance; 3) any existing pollution control technology in use at the source; 4) the remaining useful life of the source; and 5) the degree of improvement that may reasonably be anticipated to result from the use of such technology.

In the case of SO2 controls, FPL and the EPA are not aware of economically viable or commercially available control technology that would be acceptable to install at oil-fired steam generating units. EPA has required States to consider requiring the use of a one-percent or lower by weight fuel oil in all BART-eligible oil-fired EGUs, taking into account fuel oil availability. To meet the SO2 compliance requirements of BART at fuel-oil fired facilities, FPL anticipates utilizing both co-firing with additional natural gas and lower sulfur fuel-oil. For coal units, EPA has determined that SO2 scrubbers are readily available and cost effective for SO2 control. FPL is evaluating the installation of an SO2 scrubber on its co-owned Scherer 4 coal unit operated by Georgia Power Company.

If additional particulate controls are required by the FDEP or EPA, FPL may consider the use of electrostatic precipitators (ESPs) at oil-fired steam generating units. For FPL's coal-fired units additional particulate controls may include wet ESPs or baghouses.

Q. What are the compliance dates for this project?

A. The FDEP has indicated that it will begin evaluating utilities' BART determinations in mid-2006 to develop its Regional Haze Implementation Plan by December 2007. BART controls must be in place by January 1, 2013.

Q. Has FPL estimated the cost of the BART Compliance Project?

A. The ultimate cost of the Project will depend on the rules and State Implementation Plan (SIP) developed by the FDEP.

In order to estimate Project costs, FPL must rely on the results of the upcoming modeling and engineering studies which will determine the method(s) that will be implemented to comply with BART. Therefore, at this time FPL can only provide preliminary estimates for 2006 costs. The initial modeling and engineering studies will be followed up with more detailed studies that will be used to develop a compliance strategy consisting of the application of cost-effective emissions reduction technology, fuel switching or co-firing options. Wherever possible new pollution control equipment will be installed during scheduled outages for the units.

Q. Has FPL estimated how much will be spent on the Project in 2006?

A. Yes, FPL plans to begin preliminary modeling and engineering work in January of 2006. FPL expects to spend approximately $50,000 on these preliminary modeling and engineering activities.

FPL's response to the BART rule will depend on the results of modeling the visibility impacts of the BART eligible units. Additionally, EPA has indicated that compliance with the Clean Air Interstate Rule (CAIR), signed by EPA on May 12, 2005, may meet the requirements of BART. Therefore, FPL's strategy for meeting BART requirements will also be dependent on the engineering analysis and litigation currently in progress for FPL's CAIR Project.

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

A. Consistent with our standard practice for all contractor services procurements, FPL will competitively bid the contractor selection for the visibility modeling in order to ensure the lowest overall cost to our customers. FPL has contracted for visibility modeling in the past for repowering and expansion projects and has a working knowledge of the appropriate costs that should be incurred for this task. We will ensure that the contractor utilizes standard industry practices for completing this project and provides a reasonable cost estimate before initiating the project.

Following the modeling completion, FPL will utilize the BART related visibility data and CAIR project engineering evaluation to determine the most cost-effective compliance response for the FPL units that must comply with BART.

Q. Is FPL recovering through any other mechanism the costs for the Regional Haze Rule for which it is seeking ECRC recovery?

A. No.

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. 050007-EI

August 8, 2005

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 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, two new environmental projects - the Hydrobiological Monitoring Program (HBMP), and the Clean Air Interstate Rule (CAIR) Compliance Project.

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

A. Yes. It consists of the following documents:

- Document RRL-1 – Florida Power & Light Company Manatee Unit 3 Power Plant Siting Application No. PA 02-44 – Final Order of Certification and excerpt from Conditions of Certification – Section XXXIII – Water Management District.
- Document RRL-2 – HBMP Compliance Activities and Dates.
- Document RRL-3 – Clean Air Interstate Rule.

HYDROBIOLOGICAL MONITORING PROGRAM (HBMP)

Q. Please describe the law or regulation requiring the HBMP.

A. Per the Southwest Florida Water Management District (SWFWMD), as a condition of the Florida Power & Light Company Manatee Unit 3 Power Plant Siting Application No. PA-02-44 Final Order of Certification, FPL is required to implement a HBMP of the Little Manatee River.

Q. How does this new law or regulation affect FPL?

A. This is a requirement arising from the certification of Unit # 3 under the Power Plant Siting Act. FPL has to make withdrawals from the Little Manatee River, to operate the Manatee Plant Unit 3. As a condition of certification of the FPL Manatee Plant Unit 3, the SWFWMD has required that FPL undertake a HBMP of the Little Manatee River.

Q. Please describe the HBMP.

A. The Manatee Plant site contains a 4,000 acre cooling pond, which provides cooling water to Manatee Units 1 and 2. Cooling water for Manatee Unit 3 will be provided by the same cooling pond. Makeup water for the cooling pond is withdrawn from the Little Manatee River, pursuant to diversion schedules established under a Permit Agreement between FPL and the SWFWMD.

The Little Manatee River is approximately 40 miles long from its origins to its mouth at Tampa Bay. The FPL Manatee Plant is about 18.5 miles above the mouth of the river. From its mouth up to about river mile 12, the vegetation in this part of the river is mangroves, salt marsh, and tidal marsh. At river mile 12 and above, the river is generally freshwater with freshwater bottom land stream swamp vegetation. Water flows and levels exhibit significant variability.

Withdrawals from the Little Manatee River have the effect of reducing flow in the river, which could affect water levels along the river, as well as the location of the saltwater interface in the river itself. The saltwater interface represents the point at which fresh and saltwater meet, and it may move up and down the river due to river flow and tidal forces.

There have been no adverse effects on the ecology of the Little Manatee River or its estuary from the historical withdrawals for the Manatee Plant. Hydrologic analyses indicate that the effects of withdrawals under the proposed diversion schedule associated with the inclusion of Manatee Unit 3 on water levels, water flows, and salinity in the Little Manatee River will all be within the natural variability of the river and similar to the effects of the historical withdrawals for the Manatee Plant. Additionally, no significant adverse effects on the ecological features of the Little Manatee River will result from withdrawals under the proposed diversion schedule. Flora and fauna in the river are well adapted to fluctuating water levels and salinity. The proposed diversion schedule will more closely mimic natural rainfall patterns and will be more environmentally sensitive than the existing schedule.

The SWFWMD has required that FPL undertake a HBMP which will map and monitor vegetation in the Little Manatee River and collect data on salinity and tides in the river. The HBMP will require regular reports to the SWFWMD on the effects of FPL's withdrawals on the ecology of the river and its estuary.

Q. **Please describe the HBMP monitoring requirements.**

A. **Salinity**: Two fixed stations are to be established at locations in the lower tidal river channel. Specific Conductivity is to be measured at approximately mid-depth with automated instruments and converted to salinity using calculations approved by the SWFWMD. Automated specific conductance measurements shall be made at 15-minute intervals and the time of day shall be recorded for each measurement. Data reported include the mean, minimum, and maximum salinity values for each tidal cycle, with time of day retained for the daily minimum and maximum values.

Tidal Stage: One continuous tide stage recorder is to be installed near one of the salinity recorders within the lower tidal river channel. Tide measurements shall be made at 15-minute intervals and the time of day recorded for each measurement. Data reported include the mean, minimum, and maximum values for each tidal cycle, with time of day retained for the daily minimum and maximum values.

Color Infra-red Aerial Photography: Infra-red aerial photographs of the Little Manatee River estuary and its associated 100 year floodplain between river miles 3 and 11 shall be collected in 2004, 2007, and 2011. Aerial photography is to be produced at a minimum scale of 1"=1000' with 60% stereo overlap, and shall be geo-referenced for scale with all subsequent photographs scaled to the same references. All photography shall be taken in early October, as practicable. Should October photography prove impracticable, FPL shall notify the SWFWMD Resource Regulation Director and photography shall be completed as shortly after the October timeframe, as practicable.

Vegetative Community Mapping: A combination of infra-red aerial photography and concurrent field reconnaissance of the river shall be performed to identify the distribution of major plant communities such as mangroves, salt marshes, brackish marshes, and freshwater aquatic and floodplain communities. Within these communities more discrete diagnostic plant assemblages shall be located and described, including stands of individual species or mixtures of species (e.g. red mangrove (*Rhizophora mangle*), black needlerush (*Juncus roemerianus*), sawgrass (*Cladium jamaicense*), cattails (*Typha* spp.), leather ferns (*Acrostichum* spp.), spatterdock (*Nuphar luteum*), or other conspicuous indicator species).

The distribution of these communities (included assemblages) shall be digitized into a Geographic Information System (GIS) compatible with the SWFWMD GIS system. Both electronic and hard copy versions of the maps shall be provided for each mapping episode and the changes in the vegetation of the river shall be described by comparing the distribution of plant communities on the maps and quantifying the total area for each community. The location of these communities along the estuarine gradient shall be described and potential relationships to changes in salinity and freshwater inflows and withdrawals by FPL shall be described.

Q. What are the compliance dates for this project?

A. The compliance dates of activities required by the HBMP along with a brief description of each are listed in Document RRL-2. As can be seen on Document RRL-2, project activities are currently scheduled to continue through May 2013, at which time FPL is to submit its Final Interpretive Report.

Q. Please describe the HBMP after the year 2013.

A. After 2013, if the results of the HBMP demonstrate that FPL's withdrawals have not adversely impacted the water quality, vegetation, animal populations, salinity distributions, or aesthetic and recreational qualities of the river, the HBMP may be discontinued or modified as required by the SWFWMD. After 2013, if additional data is required as determined by the HBMP, FPL is required to continue the HBMP and submit Data Summary Reports every two years and Interpretive Reports every four years. Implementation of the HBMP and reporting requirements will continue until sufficient information is gathered for the SWFWMD to determine that FPL's withdrawals have not adversely impacted the water quality, vegetation, animal populations, salinity distributions, or aesthetic and recreational qualities of the river.

Q. Has FPL estimated the cost of the proposed Project?

A. FPL's O&M cost estimate for the HBMP Project is $279,000 to be incurred in 2005 through 2013, or approximately $28,000 per year.

To date, FPL has incurred approximately $14,000 in O&M and $46,000 in capital expenditures, all of which occurred before Manatee Unit 3 went into commercial operation on June 30, 2005. These costs have been included in the costs of the Manatee Unit 3 expansion project; therefore, FPL is not seeking recovery of these O&M and capital costs through the ECRC.

Q. Does FPL expect to incur Project costs in the remainder of 2005?

A. Yes. FPL expects to spend $17,300 of O&M costs from August 8, 2005 to the end of the year, primarily associated with data collection on river chemistry, flow and vegetation conditions.

Q. Has FPL estimated how much will be spent on the Project in 2006?

A. FPL expects to spend $28,000 of O&M costs in 2006, primarily associated with data collection on river chemistry, flow and vegetation conditions and the development of plots of mean, minimum and maximum salinity values for all tidal cycles and tables of salinity data.

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

A. FPL has performed cost/benefit analyses to evaluate and select the most cost-effective vendor that meets FPL's quality requirements to ensure the

HBMP has no adverse affects on the Little Manatee River.

CLEAN AIR INTERSTATE RULE (CAIR) COMPLIANCE PROJECT

Q. Please describe the law or regulation requiring the CAIR Compliance Project.

A. The Clean Air Interstate Rule (CAIR) was promulgated by the Environmental Protection Agency (EPA) on May 12, 2005, imposing emissions reduction requirements on electric generating units for sulfur dioxide (SO2) and oxides of nitrogen (NOx) to assist in achieving attainment of the 8-hour ozone and fine particulate (PM2.5) standards in the eastern U.S. The rule is designed to reduce the transport of fine particulates (PM2.5) and ozone forming pollutants to downwind non-attainment areas. The emissions reduction requirements will establish an average limit or cap for SO2 and NOx emissions. FPL can meet this reduction limit by actual emissions reductions or through the purchase of additional SO2 and NOx allowances. Owners of each generating unit will be required to surrender allowances equal to the total tons of SO2 and NOx emitted from that unit. The rule affects 28 states including the District of Columbia and Florida.

The CAIR requires a 50% reduction in NOx emissions in 2009 and approximately a 65% reduction in 2015. The final rule established a 2.86:1

surrender ratio. SO2 emissions reductions of 50% and approximately 75% are required in 2010 and 2015 respectively. An annual emissions trading program and an ozone season NOx trading program will be implemented similar to the existing Title IV trading program currently in place for SO2.

Q. How does CAIR affect FPL?

A. As presently written, CAIR will require FPL to reduce NOx and SO2 emissions from applicable generating units. The emissions reduction requirements will establish an average limit or cap for SO2 and NOx emissions. FPL can meet this reduction limit by actual emissions reductions or through the purchase of additional SO2 and NOx allowances. Owners of each generating unit will be required to surrender allowances equal to the total tons of SO2 and NOx emitted from that unit. Emissions reductions can be achieved through the addition of pollution control equipment or fuel switching. FPL will be evaluating the most cost- effective manner to meet these reduced emissions limits. Significant costs for engineering evaluation and design will be incurred in future months and as necessary equipment deployment will be initiated at units requiring pollution control equipment. As necessary FPL will purchase emissions allowances on the open market.

Q. Does FPL agree that the EPA is properly applying the CAIR requirements to FPL?

A. No. FPL participated extensively in the CAIR rulemaking but was surprised by certain aspects of the final rule that were raised by EPA for the first time in the final rule and/or lack valid factual support. FPL believes that the CAIR unfairly and unnecessarily burdens FPL's customers with the costs of complying with the rule by requiring participation in a flawed interstate emissions trading program and by potentially requiring the installation/operation of pollution control equipment that is unnecessary.

It is likely that emissions reductions would be required from the FPL oil-fired and co-owned coal-fired generating units.

Q. What is FPL doing to address these concerns?

A. In order to protect its own and its customers' interests, FPL is compelled to challenge the CAIR by addressing the deficiencies in EPA's emissions modeling analysis and its arbitrary assumptions that will be unfairly burdensome to FPL's customers.

FPL Group has petitioned the EPA for reconsideration of the rule's applicability to electric generating units in southern Florida and the inclusion of a fuel-type adjustment provision that reduces the number of allowances allocated to oil and gas-fired electric generating units. This fuel-type adjustment unfairly penalizes cleaner generating facilities and was improperly noticed during the CAIR rulemaking process. In addition, FPL is a participant in the Florida Association of Electric Utilities (FAEU), which filed a separate Petition for Reconsideration addressing CAIR's inclusion of southern Florida electric generating units. Both FPL Group and the FAEU have also filed petitions for review of the rule by the United States Court of Appeals for the D.C. Circuit. The FAEU includes nine other electric generating entities in the State of Florida who likewise agree that CAIR unfairly burdens Florida customers with unnecessary compliance requirements.

The results of these rule challenges could affect the impact of the rule on FPL's generating units, but given the 2009 and 2010 compliance dates, FPL must proceed with engineering and other preliminary steps to comply with the rule as presently written. To address this tight compliance schedule FPL is proceeding with a preliminary engineering evaluation of all fossil electric generating units and developing the most cost-effective compliance strategy to meet the CAIR requirements. Following the preliminary engineering evaluation FPL will initiate, as necessary, detailed engineering design and procurement of pollution control equipment.

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

A. CAIR presently applies to all of FPL's fossil electric generating units. While

FPL is hopeful that the concerns discussed above will be addressed by the EPA and/or the D.C. Circuit, unless and until CAIR is revised FPL must assume that it will be required to assess the contribution of NOx and SO2 emissions from the entire generating fleet pursuant to the current terms of the rule. It is likely that reductions would only be required from the oil-fired and co-owned coal steam generator units. Engineering studies will be required to evaluate the necessary retrofits of units and the type of equipment that may be installed. Where equipment is required, FPL will schedule installation in order to minimize reliability concerns to the system.

Q. What type of equipment may be required?

A. FPL will conduct evaluations of the type of equipment necessary to achieve the emissions reductions required by the CAIR. Due to differences in technology, configuration of the generating units, and the limitations of space at some facilities, an array of pollution control equipment may be required. In some cases, FPL may consider the addition of Selective Catalytic Reduction (SCR), reburn technology, or low NOx burners to reduce NOx. FPL will also utilize NOx allowances to achieve the required CAIR compliance limits. In the case of SO2 controls, FPL is not aware of economically viable or commercially available control technology that would be acceptable to install at oil-fired steam generating units. To meet the SO2 compliance requirements of the CAIR at fuel-oil and natural gas-fired facilities, FPL anticipates utilizing a blend of co-firing with additional natural gas, lower sulfur fuel-oil, and surrendering SO2 emissions allowances. For coal units, the EPA has determined that SO2 scrubbers are readily available and cost effective for SO2 control. FPL is evaluating the installation of an SO2 scrubber on its co-owned Scherer 4 coal unit operated by Georgia Power Company.

Q. What are the compliance dates for this project?

A. NOx emissions limits will be in effect January 1, 2009 while SO2 emissions limits will start in 2010. The Florida Department of Environmental Protection (DEP) has indicated that it may begin rulemaking workshops on the State Implementation of the CAIR in September of this year.

Q. Has FPL estimated the cost of the CAIR Compliance Project?

A. The ultimate cost of the Project will depend on the rules and State Implementation Plan (SIP) developed by the DEP. The DEP is required by the EPA to adopt either the Federal Implementation Plan (FIP) for allocating emissions allowances under the CAIR or to develop and seek approval of a separate SIP within 18 months of the rules' publication in the Federal Register (May 12, 2005). The details of either the FIP or the Florida SIP may significantly impact the costs to Florida generating facilities depending on the emissions allowance allocation method(s) used.

In order to estimate Project costs, FPL must rely on the results of the upcoming engineering studies which will determine the method(s) that will be implemented to comply with the CAIR. Therefore, at this time, FPL can only provide preliminary estimates for 2005 and 2006. The initial engineering studies will be followed up with more detailed studies that will be used to develop a compliance strategy consisting of the application of cost-effective emissions reduction technology, fuel switching or co-firing options, and as necessary, the use of NOx and SO2 allowances for the balance of FPL's system. Wherever possible, new pollution control equipment will be installed during scheduled outages for the units.

Q. Does FPL expect to incur Project costs in 2005?

A. Yes. Due to the considerable lead time associated with air emission control projects, FPL plans to begin preliminary engineering work in August of 2005. FPL expects to spend $27,500 and $296,000 for O&M and capital expenditures, respectively, resulting from these preliminary engineering activities and from legal expenses incurred in pursuing its petitions before the EPA and the D.C. Circuit.

The anticipated O&M costs will be related to the requirement for new staff to manage this large and complex Project. Activities associated with the additional requirements of the CAIR are incremental tasks for FPL not previously required under other regulatory programs. The tasks include the management and coordination of new NOx and SO2 trading programs, emissions modeling, engineering/planning and coordination of new compliance requirements. In the future, following the engineering evaluation, if pollution control equipment is required, additional incremental staff will be required at FPL generating facilities for the O & M processes associated with this new equipment.

The costs for challenging the CAIR in the D.C. Circuit Court and through reconsideration by EPA will include costs for attorney's fees and emissions modeling to address the deficiencies in EPA's data. EPA's failure to include sub-regional (fine-grained) modeling in their analysis of Florida emissions led them to include all generating units in Florida in the CAIR. This action, combined with EPA's arbitrary and capricious application of a fuel-type adjustment to the methodology used for allowance allocations, resulted in a significant economic and operational burden that will be borne by FPL and, ultimately, its customers. If successful, our rule challenges will result in savings to FPL's customers that could total hundreds of millions of dollars in avoided costs for unnecessary pollution control equipment or emissions allowance purchases.

Q. Has FPL estimated how much will be spent on the Project in 2006?

FPL's preliminary estimates for 2006 are $85,000 and $7.9 million for O&M and Capital expenditures, respectively. These estimates are for the completion of preliminary engineering studies, as well as for the design, detailed engineering work, and purchase of long lead time equipment for Reburn technology projects at Martin and Cape Canaveral Units 1 and 2. As I previously indicated, these are preliminary numbers and are subject to change based on the results of FPL's petitions to the EPA and the D.C.

Circuit, as well as results of detailed engineering studies which could result in a completely different compliance strategy.

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

A. As our standard practice with all equipment procurements, FPL will competitively bid the Pollution Control Equipment in order to ensure the lowest overall cost to our customers. Emissions allowances are purchased through auctions or on the open market. FPL will have designated staff to evaluate the emissions allowance market in order to purchase needed allowances at an optimum price. FPL will also provide additional environmental support staff to assist our generating facilities with the compliance and administrative requirements of complying with the rule. The staff functions described above will be incremental additions to existing staff as a result of the new environmental compliance requirements and the addition of the NOx trading program never before required in Florida.

Q. **Is FPL recovering through any other mechanism the costs for the HBMP or the CAIR Compliance Project for which it is petitioning for ECRC recovery?**

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

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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 actual true-up amount for the ECRC and the calculations associated with the environmental compliance activities for the January 2004 through December 2004 period.

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

A. Yes. Exhibit No. _____ (HTB-1) consists of eight forms prepared under my direction and supervision. Form 42-1A, Document No. 1, presents the final true-up for the

January 2004 through December 2004 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, details 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 23, consists of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 24 calculates the costs associated with maintaining an SO_2 allowance inventory.

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 2004 through December 2004 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $7,364,860 as the actual true-up amount for the January 2004 through December 2004 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2004 through December 2004 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the next projection period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $35,849 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2004 through December 2004 period. This adjusted net true-up amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the January

2004 through December 2004 period as depicted on Form 42-1A. The actual true-up amount for the January 2004 through December 2004 period is an over-recovery of $7,364,860 as compared to the $7,329,011 actual/estimated over-recovery amount approved in FPSC Order No. PSC-04-1187-FOF-EI issued December 1, 2004.

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. However, Form 42-8A, pages 20 - 23, provides expenditures associated with Big Bend Units 1 - 4 Selective Catalytic Reduction ("SCR") projects and are only included at this time for identification and tracking purposes. Recovery of these expenditures is not included in the 2004 ECRC True-Up. Consistent with the Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and Tampa Electric's position in Docket No. 041376-EI, the company will not seek recovery of the costs associated with these environmental compliance projects until each project is both approved and placed in-service. Big Bend Unit 4 SCR was approved in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI and is projected to be in-service June 2007. Tampa Electric's Petition for Approval of Big Bend Units 1-3 SCRs is currently before the Commission in Docket No. 041376-EI and is scheduled for the April 5, 2004 Agenda Conference. The anticipated in-service dates for these SCR projects are June 2008, June 2009 and June 2010 for Big Bend Unit 3, Unit 2 and Unit 1, respectively. Therefore, recovery of project costs will not begin until Commission approval and in-service dates have occurred.

Q. Please explain the one-time adjustment of $936,288 contained on Form 42-2A, line 10.

A. During the 2004 Commission audit of Tampa Electric's 2003 ECRC True-Up, an inadvertent error in cost allocation between two projects was discovered in the 2003 data. The initial adjustment was a $194,350 over-recovery. This adjustment amount was included in the company's 2004 ECRC Actual/Estimated True-Up filed August 4, 2004. After additional review, it was determined that the error in allocation of expenses began in 2000 and occurred intermittently through 2002. Therefore, an additional adjustment of $741,938 was necessary. As a result, the total one-time adjustment on Form 42-2A, line 10 is an over-recovery of $936,288, including interest.

Q. How did actual expenditures for the January 2004 through December 2004 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 $1,584,888 or 64.7 percent greater than actual/estimated projections. Form 42-6A shows the total capital investment costs were $18,344,415 or 0.4 percent lower than actual/estimated projections. O&M and capital investment projects with material variances from the 2004 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 $158,560 or 8.1 percent greater than projected due to increased maintenance work which was not originally planned in 2004.
- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $310,935 or 4.1 percent greater than projected due to higher payments to cogenerators and

greater allowance costs than projected.

- **Big Bend Unit 1 & 2 Flue Gas Desulfurization:** The Big Bend Units 1 & 2 Flue Gas Desulfurization project variance was $445,364 or 9.3 percent higher than projected due to an outage schedule change to allow for the replacement of an oxidation air compressor on Big Bend Unit 2. This maintenance activity was not originally planned for 2004.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $96,000 or 9.6 percent lower than projected due to lower than anticipated maintenance in 2004.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $28,847 or 5.8 percent lower than projected due to less testing and maintenance related to coal fineness.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was $109,793 or 72.0 percent lower than projected. The variance was due to the unanticipated delay in receiving the Florida Department of Environmental Protection's approval of the final sampling plan. Ultimately, the study activities commenced in the fourth quarter of 2004.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $7,979 or 34.4 percent

higher than projected. The variance was due to a greater than projected amount of maintenance to the reverse osmosis system and saturator.

- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $15,343 or 22.1 percent lower than projected due to lower than anticipated running rates for the units. Additionally, the units are operating much cleaner than projected; therefore, lower amounts of ammonia are required.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance was $50,000 or 100.0 percent lower than projected due to the equipment not requiring the maintenance originally anticipated.

Capital Investment Project Variances

- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance was $17,881 or 5.9 percent lower than projected due a reduction in capital expenditures achieved through strong management of construction activities and costs.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance was $9,548 or 84.1 percent lower than projected due to the project being deferred to coincide with a scheduled outage in the fall of 2005.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance was $1,000 or 6.1 percent lower than

projected due to less work associated with the secondary air controllers and lower than anticipated subcontracted installation costs.

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance was $12,713 or 100.0 percent lower than projected due to the project being deferred to coincide with a scheduled outage in the fall of 2005.

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 2005 through December 2005 true-up amount to be refunded or recovered through the ECRC in the projection period January 2006 through December 2006. My testimony addresses the recovery of capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for 2005, 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 2006.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2005 through December 2005?

A. Yes. Exhibit No. _____ (HTB-2), containing one document, was prepared under my direction and supervision. It includes Forms 42-1E through 42-8E which show the current period true-up amount to be used in calculating the cost recovery factors for 2006.

Q. Please explain the two adjustments of $11,089 and $78,494 contained on Form 42-2E, line 10.

A. The adjustment for $11,089 represents SO_2 allowance revenue from economy sales made from Tampa Electric's generating system during 2004. This revenue is an offset to SO_2 allowance costs collected through the ECRC; however, the company discovered the inadvertent omission of this revenue subsequent to filing the 2004 ECRC true-up. With this adjustment and its associated interest, customers have been made whole.

During the 2005 Commission audit of Tampa Electric's 2004 ECRC true-up, it was determined that the company had not updated depreciation rates for certain capital projects to be consistent with the rates approved in Docket No. 030409-EI, Order No. PSC-04-0815-PAA-EI, issued August 20, 2004. The adjustment for $78,494 represents an over-recovery of depreciation expense with associated interest resulting from the revised depreciation rates being applied to the appropriate projects for 2004.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied in the January 2006 through December 2006 ECRC factors?

A. The estimated true-up applicable for the current period, January 2005 through December 2005, is an over-recovery of $101,061,442. 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 ECRC true-up filing for any environmental projects that were not anticipated and included in its 2005 factors?

A. Yes. On November 10, 2004, Tampa Electric filed a petition for approval of cost recovery for the Clean Water Act Section 316(b) Phase II Study project. In Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005, the Commission granted cost recovery approval for prudent costs associated with the project. The project costs anticipated for 2005 are included in this estimated ECRC true-up filing.

Q. How did the actual/estimated project expenditures for January 2005 through December 2005 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $101,754,300 lower than projected costs. Total capital expenditures itemized on Form 42-6E, were $661,454 or 3.5 percent lower than originally projected. O&M and capital investment projects with material variances 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 is estimated to be $284,625 or 12.7 percent greater than originally projected due to an increase in the use of consumables, principally limestone and chemicals, stemming from greater unit output than originally projected.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $102,057,512 less than originally projected. The significant variance is due to the optimization and use of Tampa Electric's allocated allowances on a system wide basis, while continuing to comply with the requirements of the Consent Decree. Tampa Electric was able to take advantage of favorable pricing in the SO_2 allowance market and thereby pass the revenue from the allowance sales directly to customers as an offset to the otherwise projected allowance expenses for 2005.
- **Big Bend Unit 1 & 2 Flue Gas Desulfurization:** The Big Bend Unit 1 & 2 Flue Gas Desulfurization project variance is estimated to be $553,659 or 12.6 percent greater than originally projected due to an increase in consumables from a higher unit output than originally projected. Additionally, repairs are necessary on the oxidation air piping header; these repairs will occur during the fall outage.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $657,988 or 62.7 percent less than originally projected due to continuous emissions monitoring activity that will be delayed until 2006. Also, contracted labor for maintenance has been reduced for the year through the

utilization of internal labor resources not recovered through the clause.

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be \$87,273 or 18 percent greater than originally projected due to the unanticipated weld overlay protection utilized in conjunction with other low NO_x measures installed on Big Bend Unit 4.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be \$62,914 or 12.6 percent less than originally projected. The variance is due to unusually wet season conditions which limited dry season sampling. Dry season sampling is now expected to continue into early 2006.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is estimated to be \$51,000 or 44.3 percent less than originally projected. This variance is due to a lower running rate for the units than originally projected. Additionally, the units continue to operate much cleaner than originally anticipated; therefore, a lower amount of ammonia is projected to be consumed.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be \$44,000 or 88 percent less than originally projected due to the newness of the equipment and it requiring less maintenance than

originally anticipated.

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $27,000 or 100 percent less than originally projected due to the capital project not being placed in-service in 2005.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $23,000 or 100 percent less than originally projected due to the capital project not being placed in-service in 2005.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $66,000 or 100 percent less than originally projected due to the capital project not being placed in-service in 2005.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $310,172 greater due to the project not being filed at the time of the submission of the 2005 projection filing.

<u>**Capital Investment Project Variances**</u>

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be $160,978 or 19.9 percent less than the original projection due to the in-service date for the project moving from mid-2005 to early 2006; therefore, the recovery of depreciation expenses has been delayed.

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $138,850 or 11.6 percent less than the original projection due to the in-service date for the project moving from January to July of 2005; therefore, the recovery of depreciation expenses has been delayed.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $39,862 or 38.3 percent less than the original projection due to one component of the project, windbox modifications, being postponed until a later unit outage.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $121,146 or 99.5 percent less than the original projection due to a shift in coal air flow monitoring activity until early 2006 and the postponement of secondary air control, neural network soothblowing and windbox modification activities until a planned unit outage in 2008.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $181,600 less than the original projection due to the inclusion of the return on average net working capital that was omitted from the original projection.

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") 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, both the calculation of the revenue requirements and the projected ECRC factors for January 2006 through December 2006. 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 2006.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2006 through December 2006?

A. Yes. Exhibit No. ___ (HTB-3), containing one document, was prepared under my direction and supervision. It includes Forms 42-1P through 42-7P which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2006.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2006 through December 2006?

A. The net true-up applicable for this period is an over-recovery of $101,097,291. This consists of the final true-up over-recovery of $35,849 for the period of January 2004 through December 2004 and an estimated true-up over-recovery of $101,061,442 for the current period of January 2005 through December 2005. The detailed calculation supporting the estimated net true-up was provided on revised Forms 42-1E through 42-8E of Exhibit No. ___ (HTB-2) filed with the Commission on September 6, 2005.

Q. What is the major contributing factor that has created the significant over-recovery to be applied to the company's ECRC rates for the period January 2006 through

December 2006?

A. The major contributing factor that has created the significant over-recovery is the sale of approximately \$100 million worth of surplus SO_2 emission allowances during 2005.

Subsequent to the repowering project at Bayside Power Station, Tampa Electric conducted a thorough evaluation of its SO_2 emission allowance needs for a 20 year horizon. The evaluation indicated two key facts: 1) the company would have a significant surplus of allowances, and 2) the allowance needs for the company's generation fleet would be adequately covered by the remaining allowance inventory after the sale of the surplus. Enhancing the decision to sell the surplus was the high allowance prices available in the marketplace. Additional details associated with the sale are provided by Tampa Electric witness Gregory M. Nelson.

The revenues from the allowance sales have an immediate, direct benefit to Tampa Electric customers since they offset environmental expenses. Form 42-7P of my attached exhibit provides the proposed 2006 ECRC factors by rate class. As demonstrated, the average ECRC factor is a credit of 0.373 cents per kilowatt hour ("kWh") or $3.73 per 1,000 kWh.

Q. Has Tampa Electric proposed any new environmental compliance projects for ECRC cost recovery for the period from January 2006 through December 2006?

A. Yes. On November 10, 2004, Tampa Electric filed a petition for approval of cost recovery for the Clean Water Act Section 316(b) Phase II Study project. In Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005, the Commission granted cost recovery approval for prudent costs associated with the project. The O&M project costs anticipated for 2006 are included in this ECRC projection filing.

On December 7, 2004, Tampa Electric filed a petition for approval of cost recovery for the Big Bend Units 1 through 3 Selective Catalytic Reduction ("SCR") projects. In Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI, issued May 9, 2005, the Commission granted cost recovery approval for prudent costs associated with the projects. However, consistent with the Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and 041376-EI, the company will not seek recovery of the costs associated with these environmental compliance projects until each project is placed in-service. The anticipated in-service dates for these SCR projects are June 2008, June 2009 and June 2010 for Big Bend Unit 3, Unit 2 and Unit 1, respectively. Therefore, recovery of these project costs, as well as costs associated with the previously approved Big Bend Unit 4 SCR project, will not begin until the in-service dates have occurred. At that time, the associated depreciation expenses and allowance for funds used during construction for the projects will be requested for ECRC recovery.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2006?

A. Tampa Electric proposes to include for ECRC recovery the 20 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2006. 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 Unit 1 Classifier Replacement, 5) Big Bend Unit 2 Classifier Replacement, 6) Big Bend Section 114 Mercury Testing Platform, 7) Big Bend Units 1 and 2 FGD, 8) Big Bend FGD

Optimization and Utilization, 9) Big Bend Particulate Matter ("PM") Minimization and Monitoring, 10) Big Bend NO_x Emissions Reduction, 11) Polk NO_x Emissions Reduction, 12) Big Bend Unit 4 SOFA, 13) Big Bend Fuel Oil Tank No. 1 Upgrade, 14) Big Bend Fuel Oil Tank No. 2 Upgrade, 15) Phillips Tank No. 1 Upgrade, 16) Phillips Tank No. 4 Upgrade, 17) Big Bend Unit 1 Pre-SCR, 18) Big Bend Unit 2 Pre-SCR, 19) Big Bend Unit 3 Pre-SCR, and 20) SO_2 Emission Allowances. Some of these projects will be described in more detail by Tampa Electric witness Gregory M. Nelson.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2006?

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 24, provides the calculations of the costs which result in recoverable jurisdictional capital costs of $17,859,088.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2006?

A. Tampa Electric proposes to include for ECRC recovery the 14 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2006. These projects are: 1) Big Bend Unit 3 FGD Integration, 2) Big Bend Units 1 and 2 Flue Gas Conditioning, 3) Big Bend Units 1 and 2 FGD, 4) Big Bend PM Minimization and Monitoring, 5) Big Bend NO_x Emissions Reduction, 6) Polk NO_x Emissions Reduction, 7) Bayside SCR Consumables, 8) Big Bend Unit 4 SOFA, 9) SO_2 Emissions Allowances (purchases and sales), 10) NPDES Annual Surveillance Fees, 11) Gannon Thermal Discharge Study, 12) Big Bend Unit 1 Pre-SCR, 13) Big Bend Unit 2 Pre-SCR, and 14) and Big Bend Unit 3 Pre-SCR. Some of these projects will be described in more detail by Tampa Electric witness Gregory M. Nelson.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2006?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $9,895,708 for 2006.

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 28.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2006?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $27,754,796.

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 kWh sales and then adjusted for losses for each rate class. This information was obtained from Tampa Electric's 2003 load research study. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the 2006 ECRC billing factors by rate class for which Tampa Electric is seeking approval?

A. The computation of the billing factors is shown on Form 42-7P. In summary, the 2006 proposed ECRC billing factors are credits as follows:

Rate Class	Factor (¢/kWh)
Average Factor	(0.373)
RS, RST	(0.372)
GS, GST, TS	(0.374)
GSD, GSDT	(0.376)
GSLD, GSLDT, SBF	(0.373)
IS1, IST1, SBI1, IS3, IST3, SBI3	(0.368)
SL, OL	(0.384)

Q. When does Tampa Electric propose to begin applying these environmental cost recovery credits?

A. The environmental cost recovery credits will be effective concurrent with the first billing cycle for January 2006.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2006 through

December 2006 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 (0.373) cents per kWh which includes projected capital and O&M revenue requirements of $27,754,796 associated with a total of 28 environmental projects and a true-up over-recovery provision of $101,097,291 primarily driven by SO_2 allowance sales. My testimony also explains that the projected environmental expenditures for 2006 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GREGORY M. NELSON

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

A. My name is Gregory M. Nelson. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental, Health and Safety in the Generation Services.

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

A. I received a Bachelors Degree in Mechanical Engineering from the Georgia Institute of Technology in 1982 and a Masters of Business Administration from the University of South Florida in 1987. I am a registered Professional Engineer in the State of Florida. I began my engineering career in 1982 in Tampa Electric's Engineering Development Program. In 1983, I worked in the Production Department where I was responsible for power plant performance projects. Since 1986, I have held various environmental permitting and compliance positions. In 1997, I was promoted to Administrator - Air Programs in the Environmental Planning Department. In this position, I was responsible for all air permitting and compliance programs. In 1998, I was promoted to Manager, Environmental Planning and in 2000 I became Director, Environmental Affairs. In 2003, I became Director, Environmental, Health and Safety and my present responsibilities include the management of Tampa Electric's environmental permitting and compliance programs as well as generation safety programs.

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

A. Yes, I have provided testimony regarding environmental projects and their associated environmental requirements in various Environmental Cost Recovery Clause ("ECRC") proceedings before this Commission.

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 ECRC for the 2006 projection period are activities necessary for the company to comply with 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. Finally, I will discuss the sulfur dioxide ("SO_2") emission allowance sales for 2005 and how the company is positioned for future allowance needs.

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 requirements of the Orders include repowering Gannon Station and providing further reductions for SO_2, particulate matter ("PM") and nitrous oxides ("NO_x") emissions at Big Bend Station. The repowering of Gannon Station from coal to natural gas was completed in early 2004 and the plant has been renamed the H. L. Culbreath Bayside Power Station.

Regarding SO_2 emissions reductions at Big Bend Station, 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 plan was submitted to EPA in two phases, and both were approved.

Phase I of the plan required that Tampa Electric work scrubber outages around the clock and with contract labor, when necessary, 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 of the plan outlined capital projects that 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 emissions reduction projects have been completed. However, there will be additional work required to comply with the elimination of the allowed scrubber outage days for 2009 and 2012.

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

A. Concerning PM emission reductions, the Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP"), complete and implement a Best Available Control Technology ("BACT") analysis of the ESPs at Big Bend Station, demonstrate the operation of a PM Continuous Emissions Monitoring System ("CEM") and evaluate the possibility of installing a second PM CEM. Nearly all of the PM emission reduction projects have been completed and there are no projects scheduled for 2006. However, there will be some required BOP projects in the future which are expected to primarily consist of limited wide plate spacing upgrades for Big Bend Units 1 and 3.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x reduction projects on Big Bend Units 1 through 3 and allowed, pursuant to an amendment, for Big Bend Unit 4 to be substituted for Big Bend Unit 3. These early NO_x reductions use 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 or provide additional NO_x technologies beyond those required by the early reduction activities. All of the early NO_x reduction activities have been completed. There are no new projects scheduled for 2006.

Q. Please describe the existing Big Bend Early NO_x Emissions Reduction program activities and provide the estimated O&M expenses for 2006.

A. The Big Bend NO_x Emissions 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. For 2006, Tampa Electric will perform the requisite maintenance on the previously approved NO_x reduction projects. This maintenance activity is expected to result in approximately $700,000 of O&M expenses..

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated O&M and capital expenditures for 2006.

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. No new capital improvement projects are planned for 2006. However, there will be O&M expenses associated with existing and newly installed BOP and BACT equipment and continued implementation of the BOP procedures. These projects are expected to result in approximately $800,000 of O&M expenses.

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

A. The programs previously approved by the Commission that I will describe include Big Bend Unit 3 Flue Gas Desulfurization Integration, Big Bend Units 1 and 2 Flue Gas Desulfurization, Gannon Thermal Discharge Study, Bayside SCR Consumables, Big Bend Unit 4 Separated Over-fired Air ("SOFA") and the Clean Water Act Section 316(b) Phase II Study.

Q. Please describe the Big Bend Unit 3 Flue Gas

Desulfurization Integration and the Big Bend Units 1 and 2 Flue Gas Desulfurization activities and provide the estimated O&M and capital expenditures for 2006.

A. The Big Bend Unit 3 Flue Gas Desulfurization 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 Flue Gas Desulfurization 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 emissions requirements of the Phase I and II Clean Air Act Amendments of 1990.

For 2006, there will be no capital expenditures for these programs; however, Tampa Electric anticipates O&M expenses for the Big Bend Unit 3 Flue Gas Desulfurization Integration program and the Big Bend Units 1 and 2 Flue Gas Desulfurization program to be approximately $2,585,000 and $5,148,000, respectively. The dominant component of the expenses is projected to be reagents utilized in the scrubbing process with the balance of expenses being incurred for normal maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M and capital expenditures for 2006.

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 2006, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses will be approximately $50,000.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for 2006.

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 2006, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be $65,000.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the O&M and capital expenditures for 2006?

A. The Big Bend Unit 4 SOFA program was approved by Commission for ECRC recovery in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. In that Order the Commission found that the program met the requirements for recovery through the ECRC, contingent upon Big Bend Unit 4 remaining coal fired. On August 19, 2004, Tampa Electric submitted a letter to the EPA declaring the intent for Big Bend Units 1 through 4 to remain coal fired and, as such, complied with the applicable provisions of the CD associated with that decision. The SOFA project was completed in 2004 and the annual O&M expense for 2006 is anticipated to be approximately $75,000.

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 2006.

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.

For 2006, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $761,000.

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 an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement by June 1, 2007. Big Bend Units 1, 2 and/or 3 must either begin operating with an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement by May 1, 2008, May 1, 2009 and May 1, 2010, respectively, one unit per year.

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 installing the necessary NO_x reduction technologies is the most cost-effective alternative to satisfy the NO_x emissions 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 2006.

A. The Big Bend Units 1 through 3 Pre-SCR and the Big Bend Unit 4 SCR projects were approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI, issued October 11, 2004. 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. 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 the units.

The 2006 projected costs for which Tampa Electric is seeking ECRC recovery are for the Big Bend Units 1 through 3 Pre-SCR capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for the projects. Specifically, the 2006 projected O&M expenses for Big Bend Unit 1 Pre-SCR are $50,000 with no capital expenditures anticipated. The 2006 projected O&M expenses for Big Bend Unit 2 Pre-SCR are $75,000 with no capital expenditures anticipated. The 2006 projected capital and O&M expenditures for Big Bend Unit 3 Pre-SCR are $776,000 and $25,000, respectively.

The 2006 projected capital expenditures for Big Bend Units 1 through 4 SCR projects are $2,397,000, $6,130,000, $28,204,000, and $39,606,000, respectively. However, as stated in Tampa Electric witness Howard T. Bryant's Prepared Direct Testimony in this docket, the company will not seek recovery of capital expenditures until the in-service date for each project has occurred.

Q. Please describe how Tampa Electric reached the decision to sell SO_2 emission allowances in 2005 and discuss the company's allowance needs for 2006 and beyond.

A. After the completion of the repowering project at Bayside Power Station, Tampa Electric performed a thorough evaluation of SO_2 emission allowance needs based on current system conditions and those projected to occur over the next 20 years. Current system conditions included the reduction in coal usage due to repowering and the impacts of the CD and CFJ on SO_2 emission allowances. Future conditions took into account generation expansion and the impact of new federal environmental regulations on SO_2 emission allowances, such as the Clean Air Interstate Rule. At the conclusion of the evaluation, it became evident that the company had a significant surplus of allowances that could be sold in the allowance marketplace. Furthermore, there will be a remaining allowance inventory that will meet the company's needs for the next 20 years.

The decision to sell surplus SO_2 allowances was enhanced by the recent high allowance prices available in the marketplace due to increased industry demand. In balancing the appropriate quantity to sell with the company's expected future needs, Tampa Electric sold approximately 125,000 allowances generated from 2002 through 2005. The company will continue to evaluate potential sales opportunities of any future quantities of surplus allowances.

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 which are legally required by the 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 2006. Additionally, my testimony identified other projects which are required for Tampa Electric to meet environmental requirements and I provided associated 2006 activities and projected expenditures. Finally, I addressed the prudent sales of SO_2 emissions allowances that occurred in 2005 and demonstrated that Tampa Electric's approach toward the allowance quantity contained in the sales has not jeopardized the company's long-term future allowance needs.

Q. Does this conclude your testimony?

A. Yes it does.

CHAIRMAN BAEZ: Exhibits?

MS. STERN: Yes. Staff has prepared a comprehensive exhibit list that has been distributed to all the parties and the Commissioners, and staff recommends that the comprehensive exhibit list be marked as Exhibit 1, and that all the other exhibits attached to the prefiled testimony and additional exhibits be marked as shown on the comprehensive exhibit list.

CHAIRMAN BAEZ: Very well. Are there any objections or comments from the parties?

All right. Seeing none, we will show the exhibit titled Comprehensive Exhibit List marked as Exhibit 1. The remaining exhibits are to be marked as shown on Exhibit 1. And, without objection, we will show them moved into the record.

(Exhibits 1 through 27 marked for identification and admitted into evidence.)

CHAIRMAN BAEZ: We can move on to the stipulations.

MS. STERN: Yes. The prehearing order shows that the majority of issues in this docket have been stipulated. But since the issuance of the prehearing order four additional stipulations have been reached, and they are in Issues 9A, 9C, 9G, and 9E. All the parties and the Commissioners have been given copies of the stipulations, and they have been moved -- the text of the stipulations have been moved into the record as Exhibit 2 on the comprehensive exhibit list, and at this time staff would ask that the Commissioners approve all the stipulations shown in the prehearing order and the new stipulations reached after the prehearing order, 9A, 9C, 9E and 9G.

CHAIRMAN BAEZ: I'm sorry, Ms. Stern. You said A, C, G, and E, right?

MS. STERN: That's correct.

CHAIRMAN BAEZ: Very well. Commissioners, the proposed stipulations begin on --

MS. STERN: On page --

CHAIRMAN BAEZ: I'm sorry?

MS. STERN: The stipulations are listed -- the stipulations approved in the prehearing order are listed on Page 22, starting on Page 22 of the prehearing order.

CHAIRMAN BAEZ: Page 22 of your prehearing order. And, in addition, as you heard Ms. Stern direct us, there is also -- you should also have before you proposed stipulated language on Issues 9A, 9C, 9G, and 9E, and there is a recommendation from staff that they be accepted. Do you have any questions? If there aren't any questions, we can entertain a motion at this point.

COMMISSIONER DEASON: Mr. Chairman, I could move all stipulations, including those that were orally identified here this morning.

COMMISSIONER BRADLEY: Second.

CHAIRMAN BAEZ: A motion and a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Very well. I'm showing here, Ms. Stern, some opening statements, and I'm assuming some of the parties, if not all, want to make opening statements, and we have capped it at ten minutes per party.

MS. STERN: I haven't discussed with the parties who wants to make an opening statement, but the prehearing order allows all the parties to make ten-minute opening statements.

CHAIRMAN BAEZ: Now, I know that the 07 docket has several parties.

MR. McWHIRTER: Mr. Chairman, I would like to make an omnibus opening statement for 01 and 07, if I might.

CHAIRMAN BAEZ: Do you think that is going to give you more time to make comments, Mr. McWhirter, or is this some --

MR. McWHIRTER: No, I'd hoped to do it by limiting the time.

CHAIRMAN BAEZ: I'm joking, but then we have -- I'm sorry?

MR. McWHIRTER: I'd hoped to limit the time.

CHAIRMAN BAEZ: You will take the limitation on an omnibus basis. Very well. We will note that your comments will be comprehensive as to all the dockets, but for the time being if you can just hold up. I'll take a pool of the parties as to who is making opening statements, or we can just start left to right, yet again, and see who steps up to the plate.

MR. BUTLER: Florida Power and Light Company does not intend to make an opening statement. I would note that one of the stipulations that you approved contemplates closing statements on one of the issues that is important to us, but I don't need to make an additional opening statement with respect to that.

One other thing. Just for clarification, I would like to point out on the record is that the prehearing order doesn't have FPL Witness R. R. LaBauve shown with an asterisk, indicating that he is excused. And you have excused him, but it wasn't said in a way that explicitly used his name. So I just wanted to put it on the record that he has been excused.

CHAIRMAN BAEZ: And the chair will accept your clarification on the record and show Witness LaBauve has been excused officially. Thank you, Mr. Butler.

And I will just go down the line here. Mr. Perko.

MR. PERKO: We don't feel the need to give an opening statement.

CHAIRMAN BAEZ: Very well. Thank you.

Mr. Beasley.

MR. BEASLEY: We don't, sir.

CHAIRMAN BAEZ: Mr. McWhirter.

MR. McWHIRTER: Mr. Chairman, as I said, this opening statement relates to 01 as well as 07. And I'm doing that because a case of this magnitude is somewhat hard to put into perspective and to focus upon fully. And I would like to point out to you a memorandum that was sent to the Commissioners by the Commission staff on March the 18th of 2004. And I'm not going to ask that that be put in the record, but you may refer to it over time if you wish.

But what that memorandum did was told the Commission what had happened in all of the electric rate cases through the 50 years of its existence from the time the Commission was founded in 1951 through 2004. And during that period of time, as you are well aware, there were many base rate cases, but the request for the fuel cost alone in this case is $3 billion. And the $3 billion increase -- that's a $3 billion increase. And that increase exceeds the amount awarded to all of the utilities in all of the electric rate cases for the last 50 years. This is a big and very important case.

Last year for the first time cost-recovery items exceeded 50 percent of the utilities' operating revenue for the first time. This year, the guaranteed cost recovery revenues in the fuel case, the conservation case, the GPIF, and the conservation, I guess, enviromental case, those now amount to 74 percent of the operating revenues of the utility companies. And this case, although it is this big and this important, are based upon information that we got essentially for the first time in August. And that information was upgraded in September, and that information was changed again in October. The requirement of the parties, if you want to intervene on behalf of consumers and present evidence, is horrendous and almost impossible to achieve because, first of all, you have to line up witnesses, you have to analyze the testimony, and you have to get discovery, because although there is a mass of information filed, it doesn't answer all the questions that need to be answered. So that is a problem. The time that is consumed.

Fortunately, you have a dedicated, active staff that has worked hard and earnestly on these cases, not only to narrow the issues, but to identify places where there may be problems. And in some of these instances they've recommended postponing until next year so we can study the matter in more detail. But this year, the rest of the issues will come before you at this point in time and we may go a whole day on this $3 billion increase, or we may go less, or we may go into two days. But it is overwhelming to me to think that this amount of money is going to go through your processes in the hearings that are set for today.

On behalf of consumer interests, I would recommend four simple things that you do in this case to give consumers the benefit of the doubt. Now, when I say that, I would suggest to you that consumers understand that fuel prices have gone up. My clients are industrial clients, and they are on the front lines with energy costs, and they are doing everything they can to conserve, and they understand and they know that the utilities need the money that they are asking for to pay for their increased gas prices and their increased oil prices and their increased coal prices.

But what has happened in your cost-recovery proceedings is that these cost recoveries are totally guaranteed now, plus interest, and all the risk is assumed by the consumers. And that is probably the only area in America today that consumers bear all the risk.

There are four things that I would like to make as a simple request of you, first have to do with the fact that in 2005 we have a tremendous true-up that came about as a result of the gas prices going up in July, and then the hurricanes that came shortly after July. Of the $3 billion increase sought in fuel cost, 1.1 billion of that is the true-up for the last five months in 2005. Up to July of this year, fuel costs were right on estimate. They were -- in some instances the actual fuel costs were less than the projected fuel cost. But then in July it turned around, and then the hurricanes came, and what we had was an estimate in August, an increase in that estimate in September, and after the September numbers were in, we had another big increase in October.

And what I'm going to suggest to you is that since most of this one billion dollar increase is based upon a guess as to what is going happen in the last four months of this year, since it's based on a guess of what is going to happen the last four months of this year, I would suggest to you that when the actual numbers come in for 2005, and they will come in on the first of March, that you have each of the utilities look at their actual numbers, compare the actual numbers to the estimates they made. And if I'm correct in my assumption, and I may be totally wrong -- we have seen that the price at the gas pump has gone down 50 cents in the last two weeks, and I think that what we are going to find is that the fuel costs are going to ameliorate the last two months of this year, and they are not going to be as high as the conservative estimates that were used by the utilities.

What I would suggest to you is that on March 1st you ask the utilities, now that they have their actual numbers, to change the true-up factor for 2005, and base it on actual numbers rather than the fall of 2005 speculation as to what the costs would be. Now, the obvious response to that is the Commission already has a procedure in the wings to take care of this. And that is that if the costs are 10 percent different than they were projected, then you can do something about it. But the 10 percent number now is applied to $9 billion in fuel costs. That is for all the utilities, all the electric utilities. It is almost too big a hurdle to overcome on a reduction.

The other problem with it is that when these fuel costs come in in March, we don't hear about it until the middle of March. If you request a hearing in the middle of March to seek a reduction, the utilities have time to respond to that, you have the time for discovery, and before anything that can happen at all it will be the middle of the summer or August. And so I would suggest to you that the procedure that is in place is not a procedure that is friendly to consumers.

And normally that procedure works satisfactorily, but this year is such an extraordinary year that I think extraordinary measures are called for. And so the first request we would make of you is an automatic true-up to use actual rather than estimated numbers when the actual numbers come in and are submitted by the utilities. It's not something that the consumers in an adversarial position will come in and give you, it is what the utilities' own numbers will show.

The second thing we are asking of you is that --

COMMISSIONER DEASON: Mr. Chairman, may I ask a question at this point?

CHAIRMAN BAEZ: Sure.

COMMISSIONER DEASON: Mr. McWhirter, your automatic true-up, is that up or down in the sense that it's actuals or even --

MR. McWHIRTER: Representing consumers, I would suggest that it be down only. But I think in fairness to the utilities, if at the end of the year they are up, I think they ought to have that. Let's deal with the actual numbers. There is a problem because customers are getting such a big hit this year that I think you need to look at anything you can to ameliorate that hit. Fuel prices this year are up almost 50 percent of what they were last year, 50 percent, and that's a lot.

In this discovery that was handed out, you'll see that the FPL bill has gone -- the average 1,000 kWh bill is going to go from 91 to $111. But if you can knock that down a dollar or so, that would help most consumers, I would think, or certainly people of modest means that are also facing costs at the gas pump, and it would certainly help my clients who use a lot of energy in the products they produce.

The second thing that we are requesting focuses on Progress Energy only. FPL has taken a position in the fuel case that it recognizes its $900 million underrecovery from last year is too much for consumers to bear in one year, so they have spread it out over two years. And, of course, they get interest on that number, so the utility isn't hurt, and it is the same kind of interest that if they were borrowing money and consumers benefit from the commercial paper rate. So I would suggest to you that FPL has seen the wisdom in doing that. Florida Progress has not. It wants to get all of its money the very first year. The increase attributable to undercharges for 2005 alone is going to impact the average consumer of 1,000 kilowatt hours by $14 a month. That's a lot. We are suggesting that you reduce that down to something like $7 -- $3.94, about half of the total. Well, $7 is the overcharge component. The total charge, including 2006 increases, is something like $14. So we would suggest that.

Then FIPUG along with the AARP and the Public Counsel always take the position that the Commission always should be ever mindful of the matters that are normally collected in base rates and are shifted from base rates to the cost-recovery mechanism. That is a real problem because the more the utilities can get through cost-recovery, which is now up to 75 percent of their total operating revenues, the greater benefit is on base rates because base rates now, the return on their equity can continue to grow and continue to prosper. And we've agreed that we won't attack base rates for the next four years.

So base rates are sacrosanct, but the earnings can go way up if you can sneak more and more things from base rates into the fuel clause. So we have identified a few things in this case, and we hope you will be very mindful and look very carefully at whether or not it is an item that should be in base rates where the rates are frozen or whether it should now be recovered from consumers through the cost-recovery, guaranteed cost-recovery clause.

And the last item I'm going to talk about is the only one that relates to the environmental case that we are in now. And that has to do with the fact that in Florida there are a million consumers, in order to get a small credit on their bill each month, have agreed to sign up for demand-side management programs. And demand-side management programs they get a small reduction in their price, but only -- and the reduction is based on the cost of the generating plant. These consumers don't have the first rights to firm service on that generating plant. When the utilities figure their reserve margin, these million customers are left out of the mix. So you don't know the impact of them. It may be a 20 percent reserve margin, but a lot of that reserve margin may be made up by the demands of these people who have agreed to be cut off.

In the alternative, if they are not cut off, what happens is power is bought on the spot market at very high prices and passed through to these customers. My clients, as I have said, are industrial clients. They don't like to have their service interrupted or curtailed. The only reason they sign up for that is that the curtailable and interruptible rates in Florida are comparable or more expensive than the firm rates in our neighboring state of Georgia. In order to remain competitive, they have got to sign up for these rates.

Now, in the environmental clause what we have done in this case is that when you do an environmental improvement to the power plant, that's a capital cost to the power plant itself and not the amount of energy that goes through it, that you look at that increase in cost that's attributable to the improvement in the power plant, and you recognize that that power plant -- there are certain customers that have a greater right to it than other customers.

And we would suggest to you that you follow through in this case, the same thing that you do in base rate cases, so that capital environmental costs will be treated in the same way that they are in a base rate case. And we think that is a rational way to do it.

I promised I would be short. Those are the four items. The main item is this is the biggest increase that Florida customers are going to be facing in 50 years. And it is something that deserves very, very serious consideration. And any little thing you can do to help the consumers needs to be considered seriously. Thank you.

CHAIRMAN BAEZ: Thank you, Mr. McWhirter.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. I will be very brief. I want to say that I appreciate Mr. McWhirter's wonderful history of things here, and I want to make one point in support of his request for an automatic true-up. Commissioner Deason knows, and some of you all may know, I was in the rate bureau on the staff in the 1980s and served my last year on the staff as chief of that bureau. The point I want to make is that having an automatic true-up, if there is, in fact, an overrecovery or underrecovery, it works both ways, will provide better relief and a better match between those who are getting the benefit of the true-up to those who paid the costs, than getting it later through a true-up in the '06 docket implemented in '07. Doing the true-up in March is better relief. It provides a better match between those who paid and those who ought to get the money back. Thank you.

CHAIRMAN BAEZ: Ms. Christensen.

MS. CHRISTENSEN: Commissioner, OPC has no opening statement for the 07 docket. We may for 01. I don't know if you want to wait until we actually get to the 01 docket.

CHAIRMAN BAEZ: We can wait.

MS. CHRISTENSEN: Okay.

CHAIRMAN BAEZ: Thank you, Ms. Christensen.

Ms. Stern, we have --

MS. STERN: Yeah, I think that completes the opening statements.

CHAIRMAN BAEZ: That completes the opening statements.

MS. STERN: And I think we are ready to call the first witness, who according to the prehearing order is Javier Portuondo for Progress.

CHAIRMAN BAEZ: Very well. Can all the witnesses on the 07 docket that are here just stand up, and we can swear them in right quick.

(Witnesses sworn.)

(Transcript continues in sequence with Volume 2.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 16th day of November, 2005.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732